Simplified approach for the reliability estimation of large transmission and sub-transmission systems

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I know the meaning of plagiarism and declare that all the work in the document, save for that which is properly acknowledged, is my own.

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Abstract

Various specialised power system reliability modelling software are commercially available to analyse the expected performance of a utility's transmission and sub-transmission network. The software requires a physical network model to be constructed, representing all network components. A high level of accuracy is obtained using such software, but significant effort is required to create these models, especially when large utility-scale networks are modelled. Another limitation of the software is that specific design strategies can only be modelled by physically changing the network model, which again requires significant effort. A simplified approach is therefore required to enable utility engineers to analyse the reliability of different network configurations, reliability improvement strategies and planning criteria.

The aim of this research is to provide a simplified reliability approach that will assist engineers in managing the reliability of their transmission and sub-transmission networks. The approach should be simplified to require minimum user inputs and it should be capable of quantifying the impact of different substation and line configurations on a system level. It is not expected that this approach will have the same level of accuracy as the detailed software models, but it should enable engineers to calculate system indices with much less effort, while still maintaining an acceptable level of accuracy.

The scope of this research is limited to the transmission and sub-transmission networks (lines and substations). Power stations and MV distribution feeders are excluded from the analysis. Only technical, customer-based performance indicators are modelled, no load-based or economic performance indicators are calculated.

An analytical approach is considered for the simplified reliability modelling, starting with a failure mode and effect analysis. The contribution of substation and sub-transmission events is decoupled and a detailed model of the substation is created, including all internal components. A reliability analysis is performed for each substation, to determine the unavailability experienced by customers connected to each busbar. An equivalent system model is then generated by replacing all substations with busbars, of which the outage frequency and outage duration are equal to that of the substation equivalent.

The simplified substation reliability estimation is compared with detailed substation modelling using specialised software. The results obtained with the simplified reliability estimation show a good correlation with the detailed software models.

The simplified reliability methodology was programmed into MS Excel and used to model the expected availability of the Ghana transmission network. Different scenarios were then modelled, analysing the impact of design and operational changes on the expected reliability of the network.

The simplified reliability model developed through this research is capable of calculating system level technical performance indices for utility-scale networks, requiring much less effort than detailed software models, but still providing an acceptable level of accuracy.

The technical system indices (SAIDI and SAIFI), calculated by means of the simplified reliability approach, provide an indication of the technical performance of the network, but they do not provide information on the economic impact of network outages. These technical indices have the potential to result in funding decisions that are not closely linked to economic interest. For this purpose economic indices are required, and it is recommended that the approach be extended to include the calculation of economic indices.

Keywords

Reliability, availability, sub-transmission, transmission, performance evaluation, SAIDI, SAIFI, network planning, substation design.

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Definitions

Availability: The term availability applies either to the performance of individual components or to that of a system. Availability is defined as the long-term average fraction of time that a component or system is in service satisfactorily performing its intended function. An alternative and equivalent definition of availability is the steady state probability that a component or system is in service (Institute of Electrical and Electronics Engineers, Inc. (IEEE), 1990).

Customer average interruption duration index (CAIDI): Customer average interruption duration index is a measure of how long an average interruption lasts for a measurement period, typically a supply period of a year. CAIDI can be calculated as:

$$CAIDI = \frac{\sum Customer\ interruption\ durations}{\sum Customer\ interruptions}$$

expressed as hours per customer interruption.

CAIDI can also be expressed as a function of SAIDI and SAIFI:

$$CAIDI = \frac{SAIDI}{SAIFI}$$

Expected time to failure (ETTF): The ETTF is used to describe the failure behaviour of a component and is defined as (Bollen, 1993):

$$ETTF = \frac{\#components\ \times \#years}{\#failures}$$

It is related to the failure rate:

$$ETTF = \frac{1}{\lambda}$$

Extra high voltage (EHV): Nominal voltage levels > 145 kV.

Firm transformer capacity: A firm substation is a substation with more than one station transformer, and the load supplied from the substation is such that, if one transformer is out-of-service, the remaining transformer(s) can still supply all substation load, without exceeding the rated capacity of the remaining transformer(s).

High voltage (HV): Nominal voltage levels > 36 kV and ≤ 145 kV, also referred to as sub-transmission voltage levels.

Interruption (of supply): This refers to an interruption of power to a customer that was not requested by the customer. In the context of this study, only sustained interruptions are considered.

Low voltage (LV): Nominal voltage levels ≤ 1 kV.

Mean Time To Repair (MTTR): MTTR represents the expected time it will take for a failure to be repaired (measured from the time that the failure occurs) (Brown, 2002).

Medium voltage (MV): Nominal voltage levels > 1 kV and ≤ 36 kV.

Sustained interruption (of supply): A sustained interruption is an interruption lasting longer than a specified duration. For the purpose of this research a sustained interruption is defined as an interruption lasting longer than 5 minutes (National Electricity Regulator of South Africa, 2004).

System average interruption duration index (SAIDI): SAIDI is a measure of how long a customer would experience sustained interruptions on average for a measurement period, typically a supply period of a year. SAIDI can be calculated as:

$$SAIDI = \frac{\sum Customer\ interruption\ durations}{Total\ connected\ customers\ served}$$

expressed as hours per customer year.

System average interruption frequency index (SAIFI): SAIFI is a measure of how often a customer would experience sustained interruptions **on average** for a measurement period, typically a supply period of a year. SAIFI can be calculated as:

$$SAIFI = \frac{\sum Customer\ interruptions}{Total\ connected\ customers\ served}$$

expressed as interruptions per customer year.

Unavailability: The long-term average fraction of time that a component or system is out-of-service due to failures or scheduled outages. An alternative definition is the steady-state probability that a component or system is out-of-service. Mathematically, unavailability = (1 - availability) (Institute of Electrical and Electronics Engineers, Inc. (IEEE), 1990).

Unfirm transformer capacity: A substation with unfirm transformer capacity can have either one transformer or more than one transformer. For the scenario with more than one transformer, the load supplied from the substation is such that, if one transformer is out-of-service, the remaining transformer(s) cannot supply all substation load without exceeding the rated capacity of the remaining transformer(s).

Upstream and downstream busbars: For the purpose of this research, the two busbars on either side of the substation transformer are differentiated based on the direction of power flow. Power flows from the upstream busbar, through the transformer, to the downstream busbar. This convention is applied irrespective of the busbar operating voltages. This is illustrated in Figure 0-1.

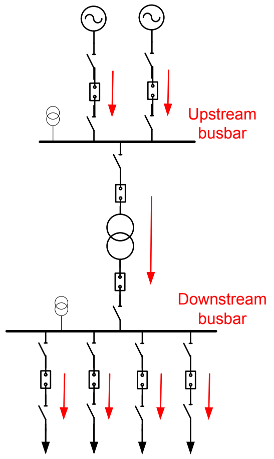


Figure 0-1: Definition of upstream and downstream busbars

The definition of all symbols used in this document is provided in Annex A.

Abbreviations

CAIDI:	Customer average interruption duration index
CT:	Current transformer
ECG:	Electricity Company of Ghana
ECOWAS:	Economic Community of West African States
EHV:	Extra high voltage
EPRI:	Electric Power Research Institute
ETTF:	Expected time to failure
FMEA:	Failure mode and effect analysis
GIS:	Gas insulated switchgear
HV:	High voltage
IEEE:	The institute of electrical and electronic engineers
kVA:	Kilovolt ampere
kWh:	Kilowatt hour
KPI:	Key performance indicator
LV:	Low voltage (≤1kV)
MS Excel:	Microsoft Excel
MV:	Medium voltage
MVA:	Megavolt ampere
MW:	Megawatt
MTTR:	Mean time to repair
NECR/T:	Neutral electromagnetic coupled resistor with auxiliary power transformer
NED:	Northern Electricity Department in Ghana
N/O:	Normally open
PowerFactory:	DIgSILENT PowerFactory Version 14
RBTS:	Roy Billinton test system
SAIDI:	System average interruption duration index
SAIFI:	System average interruption frequency index
VT:	Voltage transformer
WAPP	West African Power Pool

1. Introduction

Although substations are considered to be the strongest points in a power system, substation related outages typically contribute as much as 20% to the total system SAIDI (Brown, 2002). It is therefore necessary to understand the expected downtime associated with different substation layouts and line configurations, in order to manage the impact of substation and line failures on system SAIDI.

The purpose of this research is to develop a simplified approach for modelling the expected performance of a utility's transmission and sub-transmission network. The same approach is used to model the impact of different reliability improvement measures on the expected performance.

Two approaches that are frequently used for reliability evaluation of power system distribution systems are historical assessment and predictive assessment (Chowdhury & Koval, 1998). This research uses predictive assessment and considers a quantitative basis for understanding and managing the performance level of a utility network.

This chapter provides a general background to the research objective and an outline of the rest of the dissertation.

1.1. Problem statement

Traditionally, electricity utilities managed to achieve satisfactory customer services levels without networks that provide significant redundancy. However, with the evolving industry requirements and the increased competitive economic climate, the needs of modern electricity consumers have changed. An unreliable electricity supply can be extremely costly to customers and society is becoming increasingly dependent on a reliable power supply (Chowdhury & Koval, 1998). As a result, reliability has become one of the most important design criteria of any electric power system.

Due to the increasing importance of a reliable power supply, utility engineers are under pressure to find answers to the following questions:

(a) What is the designed performance level (SAIDI, SAIFI) of the utility's transmission and sub-transmission network?

(b) What level of performance (SAIDI, SAIFI) can be expected if specific reliability improvement measures are implemented?

Specialised power system reliability modelling software, such as PowerFactory, can be used to model the expected reliability of a specific network. These software packages require a physical network model to be constructed, representing all network components. Failure rates and outage durations need to be assigned to all components in the network. These software packages provide a high level of computational accuracy, but due to the magnitude of utility networks, the modelling requires significant effort. For example, in 2012 Eskom's transmission network in South Africa consisted of 154 substations and 29 297 km of transmission lines (Eskom Holdings SOC Limited, 2013). Modelling each of these components using physical network models would require significant manpower and time.

Furthermore, when analysing different reliability improvement strategies or developing network planning criteria, several reliability improvement options need be analysed on a system level. For each of these options a reliability model needs to be constructed. Performing these improvement studies with specialised power system reliability modelling software would require significant time and manpower. A simplified approach is therefore required to enable utility engineers to analyse the reliability of different network configurations, reliability improvement strategies and planning criteria.

1.2. Research objective

The aim of this research is to provide a reliability estimation approach that will assist engineers in managing the reliability of their transmission and sub-transmission networks. This approach needs to meet the following criteria in order to provide engineers and management with a reliability decision-making tool:

(a) The outcomes of the modelling should be the expected SAIFI and SAIDI of the system.

(b) The approach should require minimum user inputs.

(c) The modelling should inform, with little effort, the change in system reliability if the configuration of existing substations and/or lines is changed.

The hypothesis that underlies this research is as follows:

A simplified reliability estimation approach exists to determine the expected reliability of a utility scale network. This simplified approach requires significantly less effort than traditional analysis, and can be updated with relatively little effort as the network evolves and input parameters or assumptions such as expected failure rates, protection philosophies, etc. change.

1.3. Scope

An electrical power system can be divided into three hierarchies:

(a) Generation

(b) Transmission

(c) Distribution

These hierarchies are illustrated in Figure 1-1.

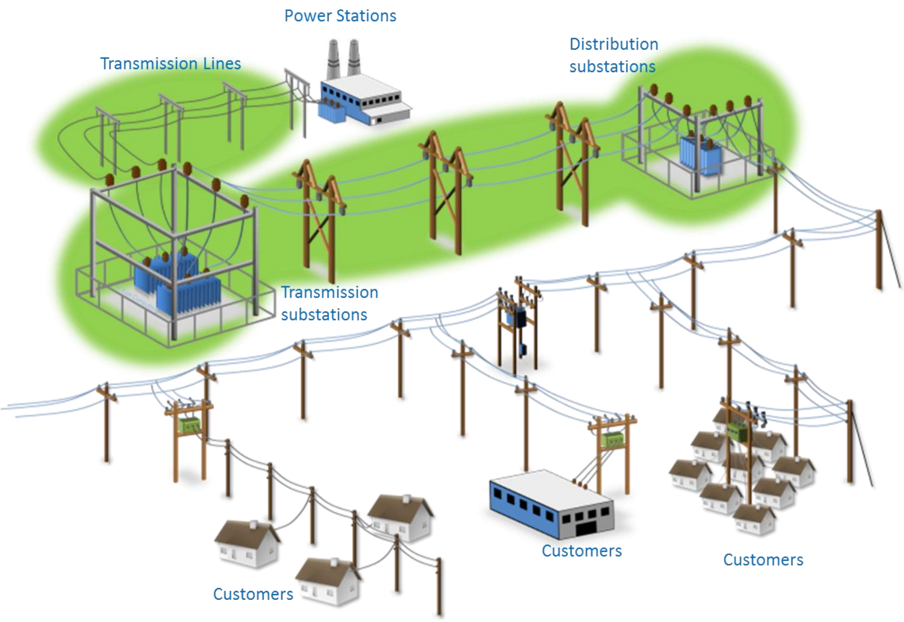


Figure 1-1: Power system elements considered for the simplified reliability approach (Author's presentation of power system hierarchies)

The focus of this dissertation is on the sub-transmission and transmission networks. The MV feeders, connecting the distribution substations with the customers, are excluded from the analysis. Power stations are also excluded from the analysis. The elements included in the study are highlighted in green in Figure 1-1.

The scope of this research is limited to calculating the technical, customer-based reliability indices, and does not include the calculation of any load-based or economic indices.

1.4. Outline of dissertation

This dissertation is structured as follows:

(a) Chapter 2 reviews the literature.

(b) Chapter 3 explains the approach of the simplified reliability modelling.

(c) Chapter 4 contains details of the substation methodology.

(d) Chapter 5 explains the transmission and sub-transmission line methodology.

(e) Chapter 6 considers existing specialised power system reliability modelling software to verify the simplified sub-transmission approach.

(f) Chapter 7 explains how different system indices are calculated, using the simplified reliability approach.

(g) Chapter 8 illustrates the simplified approach on the Ghana transmission and sub-transmission network. The change in system indices for specific strategic design and operational scenarios is also illustrated.

(h) Chapter 9 includes a discussion of the developed approach and some concluding thoughts.

2. Literature review

The literature review focuses on the following aspects of the modelling:

(a) Different evaluation techniques that have been used to calculate the reliability of networks are reviewed in section 2.1.

(b) The causes of network outages and the different ways in which components can fail are reviewed in section 2.2.

(c) Reliability indices, most commonly used for benchmarking and reporting, are reviewed in section 2.3.

(d) The most commonly used test systems, used to illustrate probabilistic applications to electric power systems, are reviewed in section 2.4.

(e) Component failure rates, maintenance frequencies and outage durations used for probabilistic reliability calculations are reviewed in section 2.5.

2.1. Evaluation techniques

Various evaluation techniques have been used successfully to calculate the reliability of a network. The two main approaches are analytical and simulation. The vast majority of techniques have been analytically based, and simulation techniques have played a minor role in specialised applications, due to the large amounts of computing time required (Billinton & Allan, 1996).

Analytical techniques represent the system by means of a mathematical model, and evaluate the reliability indices using direct numerical solutions. Simulation methods estimate the reliability indices by simulating the actual process and random behaviour of the system. The method therefore treats the problem as a series of real experiments (Billinton & Allan, 1996).

A few of the most commonly-used reliability evaluation techniques are discussed in this section.

2.1.1. Failure mode and effect analysis (FMEA)

FMEA is explained as a technique that identifies all possible equipment failure modes and their associated impact on system reliability (Brown, 2002). The following information is required for each component:

(a) List of failure modes;

(b) Possible causes of each failure mode;

(c) Possible system effect of each failure mode;

(d) Probability of each failure mode occurring;

(e) Possible actions to reduce the failure rate or effect of each.

FMEA is often extended to consider criticality information associated with each failure mode.

2.1.2. Markov models

A Markov model is often used for quantitative reliability analysis. A Markov model describes the different states of a system and the transitions between these states. In reliability modelling, the transition between different states represents failures and repairs.

Markov models make two basic assumptions regarding system behaviour (Brown, 2002):

(a) The system is memory-less, therefore the future probability of events is only a function of the existing state of the system and not of any events that occurred prior to the current state.

(b) The system is stationary. This implies that the probability of transitions between one state and the next is constant and does not vary with time.

In the simplest state a two-state model can be used to describe the system, as illustrated in Figure 2-1. One state represents a system that is available, and the second state a system that is unavailable. The systems are therefore either in the available state, illustrated by “U”, or in the failed state, illustrated by “D”.

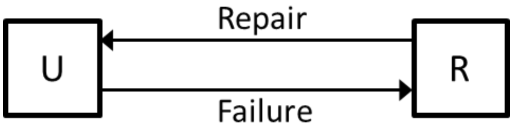


Figure 2-1: A Markov model with two states (adapted from (Billinton & Allan, 1996) and (Retterath et al., 2004))

A Markov model with three states is shown in Figure 2-2. This model includes a network state between the available and failed state. In reliability modelling this state represents the network state before switching has occurred.

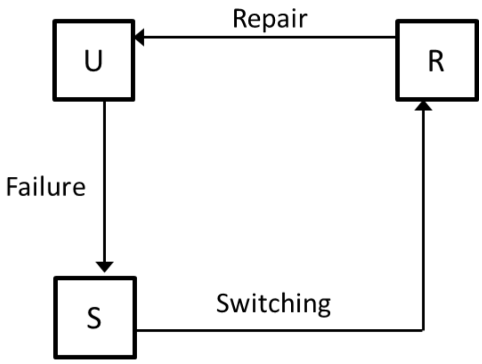


Figure 2-2: A Markov model with three states (adapted from (Billinton & Allan, 1996) and (Retterath et al., 2004))

Another model is shown in Figure 2-3. This model shows that if the system is in the available state, it can be transferred to either the switching state or the repair state. The transitions from the available state to the failed state represent passive failures (refer to section 2.2 for the definition of passive failures).

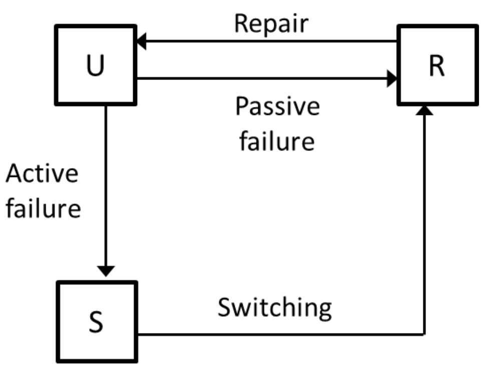
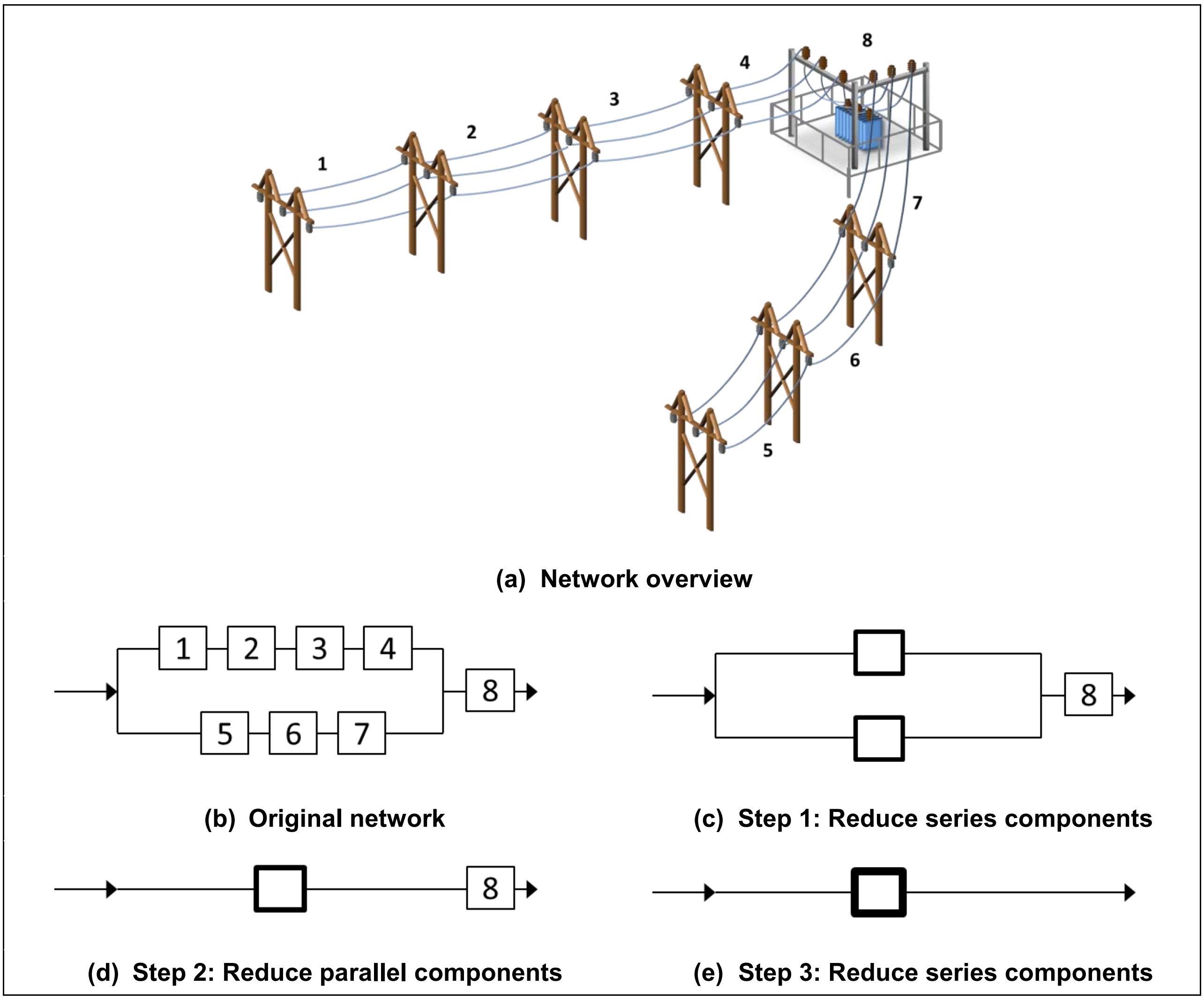


Figure 2-3: A Markov model that considers passive failures (adapted from (Billinton & Allan, 1996) and (Retterath et al., 2004))

Markov models have been successfully applied to many areas related to reliability analysis (Brown, 2002). However, when analyzing complex systems the Markov approach requires significant computer storage and is therefore limited in application (Zhu, 2007).

2.1.3. Network reduction

Network reduction is the process of repeatedly combining sets of parallel and series components into equivalent network components until a single component remains. The availability of the last component is equal to the availability of the original system (Brown, 2002). This is illustrated in Figure 2-4. In this example two lines supply a distribution transformer (component 8). One line consists of 4 line sections (see components 1 – 4) and the other line consists of 3 sections (see components 5 – 7). Three steps of network reduction are required to reduce the network to a single component that represents the total unavailability of the system (see Figure 2-4).



(a) Network overview

(b) Original network

(c) Step 1: Reduce series components

(d) Step 2: Reduce parallel components

(e) Step 3: Reduce series components

Figure 2-4: Network reduction of a simple system (adapted from (Brown, 2002))

For series components, the equivalent failure rate is calculated taking the sum of all component failures (Billinton & Allan, 1996, p.222):

$$\lambda_{series} = \sum_{i=1}^{n} \lambda_i \qquad \textbf{Equation 1}$$

Where:

λ_{series}	=	Equivalent failure rate of series components (occ/a)
λ_i	=	Failure rate of component i (occ/a)
n	=	Number of components in series

The equivalent mean time to repair of series components is computed by taking the weighted average of all component repair times (Billinton & Allan, 1996, p.222):

$$MTTR_{series} = \frac{1}{\lambda_{series}} \sum_{i=1}^{n} \lambda_i \cdot MTTR_i \qquad \textbf{Equation 2}$$

Where:

$MTTR_{series}$	=	Equivalent mean time to repair of series components (h)
λ_{series}	=	Equivalent failure rate of series components (occ/a)
λ_i	=	Failure rate of component i (occ/a)
$MTTR_i$	=	Mean time to repair of component i (h)
n	=	Number of components in series

For parallel components, the equivalent failure rate is calculated using Equation 3. The calculation shown is for three components in parallel (Billinton & Allan, 1996, p.252):

$$\lambda_{parallel} = \lambda_1 \cdot \lambda_2 \cdot \lambda_3 (MTTR_1 \cdot MTTR_2 + MTTR_2 \cdot MTTR_3 + MTTR_3 \cdot MTTR_1) \qquad \textbf{Equation 3}$$

Where:

$\lambda_{parallel}$	=	Equivalent failure rate of parallel components (occ/a)
λ_1, λ_2, λ_3	=	Failure rate of component 1, 2 and 3 respectively (occ/a)
$MTTR_1$, $MTTR_2$, $MTTR_3$	=	Mean time to repair of component 1, 2 and 3 respectively (h)

The equivalent mean time to repair of parallel components is calculated using Equation 4. This calculation is for three components in parallel (Billinton & Allan, 1996, p.252):

$$MTTR_{parallel} = \frac{MTTR_1 \cdot MTTR_2 \cdot MTTR_3}{MTTR_1 \cdot MTTR_2 + MTTR_2 \cdot MTTR_3 + MTTR_3 \cdot MTTR_1} \qquad \textbf{Equation 4}$$

Where:

$MTTR_{parallel}$	=	Equivalent mean time to repair of parallel components (h)
$MTTR_1$, $MTTR_2$, $MTTR_3$	=	Mean time to repair of component 1, 2 and 3 respectively (h)

2.1.4. Minimal cut-set method

Different methods exist to handle the non-radial nature of the substation topology during reliability assessment. One approach to simplify complex systems into more computable portions is the so-called minimal cut-set method.

A minimal cut-set is defined as a set of *n* components that cause the system to be unavailable when all *n* components are unavailable, but will not cause the system to be unavailable if less than *n* components are unavailable (Brown, 2002). This is illustrated by means of the 5 component system in Figure 2-5.

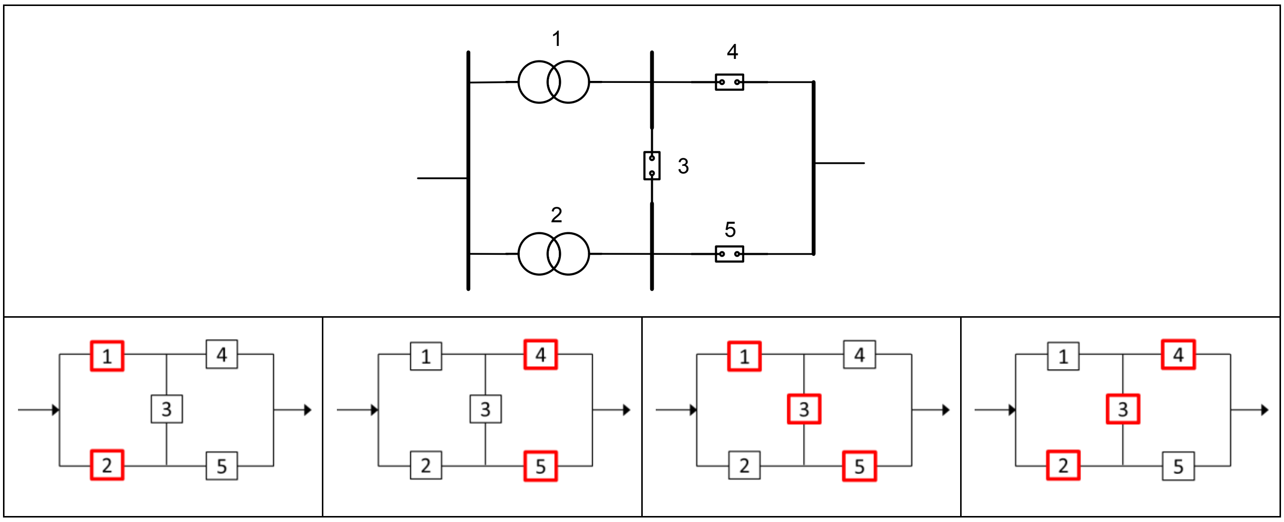


Figure 2-5: Minimal cut sets of a simple system (adapted from (Brown, 2002))

For a distribution system which consists of a wide variety of components and a great number of load points connected in complex configuration and operating in different modes it is quite a tedious procedure to determine minimal cut sets for each load point (Zhu, 2007).

2.1.5. Monte Carlo simulation

A Monte Carlo simulation utilizes random number generators to model stochastic event occurrences. Two Monte Carlo simulations with identical inputs will therefore not necessarily result in the same output. Repeated simulations will eventually produce a distribution of results from which the mean, median, variance and other statistical measures can be computed (Brown, 2002).

Liang and Goel (1997) used a Monte Carlo analysis to analyse the reliability of a test system with 38 load points. Andrade et al. (2009) used a Monte Carlo simulation to calculate the reliability of the Roy Billinton test system (RBTS) and for an actual Brazilian distribution network consisting of one substation and three feeders.

2.1.6. Specialised reliability simulation software

Several specialised software tools are available on the market for the evaluation of power system reliability. References to the following software programs were found in the literature review:

(a) **PowerFactory** was used to investigate the 115 kV transmission system development plan of Electrictite du Laos (EDL), specifically considering indices such as SAIFI and SAIDI. The test network model consisted of 38 buses (Kongmany et al., 2009).

(b) **PSS/E** was used to conduct a power system and substation reliability assessment for two substations (Xu et al., 2010).

(c) **TRELSS** was used to model the reliability of two utility networks. The first utility network (PG&E case study) consisted of 46 busbars. The reliability of one substation was analysed in the second network (DPC case study), (Neudorf et al. 1995).

(d) **NetBas/Levsik** was used to evaluate the reliability of a distribution network in Bhutan. The HV network consists of 2 substations, 7 transformers and 16 outgoing MV feeders. (Dorji, 2009).

(e) **NEPLAN** was used to assess the reliability of the Roy Billinton test (RBTS) system, which consists of 6 buses and 9 circuits (Bangalore, 2011).

(f) **ETAP** was used for the reliability evaluation of the 220 kV Kerala power system. The 220 kV network consist of 24 buses (Jaleel & Shabna, 2013).

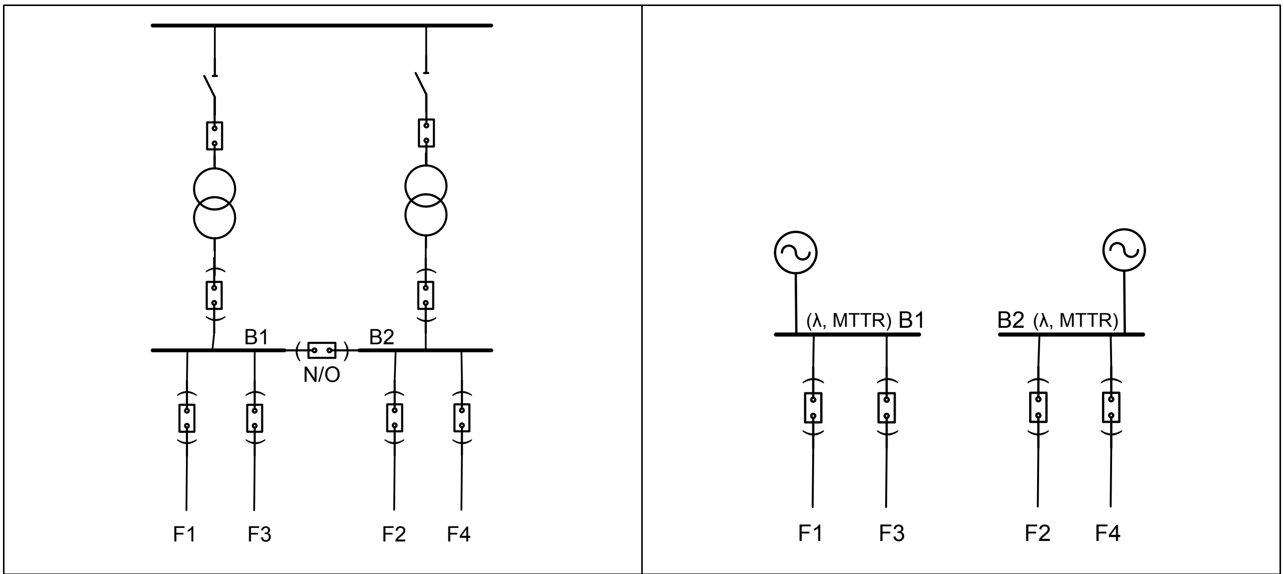
(g) **TPLAN** was used to analyse the reliability of the extra high voltage (EHV) power grid in the East China power system. The 500 kV study network consists of approximately 40 substations (Xu et al., 2002).

(h) **SUBREL** was used to analyse different development options for a 230 kV substation for a wind interconnection project (Bagen, 2011).

In PowerFactory all failure and load models are represented by the Markov method, when simple mean repair durations are modelled (DIgSilent PowerFactory, n.d.). The reliability evaluation methods used by other software could not be found in literature.

2.1.7. Decoupled composite models

Many reliability studies focus on substations and switching stations in isolation from the electrical system, but there are methods that include the impact of the substation on the system. (Brown (2002) and Brown & Taylor (1999) decoupled the contribution of substation events from the distribution system reliability assessment. First a detailed model of the substation is created. A reliability analysis is then performed on this substation and an annual outage frequency and annual outage duration is produced for the downstream busbar of the substation. This is illustrated in Figure 2-6, where the substation is shown in (a) is replaced by the equivalent busbar in (b). The next step is to generate an equivalent system model by replacing all substations with a busbar, of which the outage frequency and outage duration are equal to those of the substation equivalent. This equivalent system model is then used to calculate the reliability of the overall system.



(a) Substation	(b) Equivalent busbars

Figure 2-6: Reducing a substation to a busbar with equivalent unavailability (adapted from (Brown, 2002))

2.1.8. Conclusions from evaluation techniques

Various evaluation techniques have been discussed in this section. For some of the techniques, the test systems to which they were applied have been reviewed briefly. From the test networks it is clear that most of these techniques are feasible for small networks, but are not practical for application to large networks. This demonstrates the need for an alternative approach, which can be used to model the expected reliability of a utility network and the impact of different improvement strategies on the utility network.

The different reliability evaluation techniques showed two decoupled approaches:

(a) Component modelling

(b) Combination of the models into an evaluation.

2.2. Network outages

The main cause of network outages or supply interruptions to customers is component “failures”, and the rate at which it occurs. A failure is defined as any trouble with a power system component that causes any of the following events to occur (Institute of electrical and electronics engineers (IEEE), 1990):

(a) Partial or complete plant shutdown or below-standard plant operation;

(b) Unacceptable performance of a user’s equipment;

(c) Operation of the electrical protective relaying or emergency operation of the plant electrical system;

(d) De-energization of any electric circuit or equipment.

Power system components can fail in various ways, classified as either active or passive failures (Billinton & Allan, 1996):

(a) Active failures can be defined as a component failure mode that causes the operation of the upstream protection zone around the failed component and can cause the removal of other energized components and branches from service. The actively failed component is isolated, and the protection breakers are reclosed. This leads to service being restored to some or all load points.

(b) Passive failures are a component failure mode that does not cause operation of protection breakers and does not have an impact on the rest of the system. Service is restored by repairing or replacing the failed device. Examples are open circuits, inadvertent opening of breakers or stuck breaker conditions.

For the purpose of this research, only active failures are considered.

Brown (2002) classifies outages as either scheduled outages (also referred to as planned outages) or unscheduled outages (also referred to as unplanned outages). Both planned and unplanned outages are considered for this research.

Suwantawat & Premrudeepreechacharn (2004) included overlapping outages as a failure mode in their substation reliability evaluation. The overlap of both forced outages and a forced failure overlapping with a maintenance event is mentioned. The simplified approach developed as part of this research ignores the probability of overlapping outages.

2.3. Reliability indices

Reliability indices can be grouped into customer load point indices and system indices. Load point indices measure the expected number of outages and their duration for individual customers. System indices measure the reliability of the system as a whole, and can be used to compare the effects of different design and maintenance strategies on the system's reliability.

Many distinct reliability indices are discussed by Billinton & Allan (1996) and Brown (2002). From these indices, the indices most commonly used for benchmarking and reporting are summarised below.

Examples of load point indices are:

(a) Interruption frequency;

(b) Interruption duration;

(c) Availability.

System indices can be further divided into customer-based indices and load-based indices. Examples of customer-based system indices are:

(a) System Average Interruption Duration Index (SAIDI);

(b) System Average Interruption Frequency Index (SAIFI);

(c) Customer Average Interruption Frequency Index (CAIFI);

(d) Customer Average Interruption Frequency Index (CAIDI).

Examples of load-based system indices are:

(a) Average System Interruption Duration Index (ASIDI).

(b) Average System Interruption Frequency Index (ASIFI).

2.4. Reliability modelling test networks

The two most commonly used test systems used to illustrate probabilistic applications to electric power systems are the IEEE Reliability Test System (RTS) (Institute of electrical and electronics engineers (IEEE), 1999) and the Roy Billiton test system (RBTS) (Billinton et al., 1989). The first IEEE-RTS was introduced in 1979 to perform comparative and benchmark studies on new and existing reliability evaluation techniques. The Roy Billiton test system (RBTS) was developed at the University of Saskatchewan for educational purposes and research. A description of the two systems is summarised in Table 2-1.

Table 2-1: Description of two reliability modelling test systems

No	Network characteristics	RBTS (Billinton et al., 1989)	IEEE-RTS (Institute of electrical and electronic engineers (IEEE), 1999)
1	No. of buses	6	24
2	No. of generators	11	32
3	No. of loads	5	17
4	No of generation buses	2	11
5	Installed generation	240 MW	3405 MW

No	Network characteristics	RBTS (Billinton et al., 1989)	IEEE-RTS (Institute of electrical and electronic engineers (IEEE), 1999)
6	Total load	185 MW	2 850 MW
7	No of circuits	9	38
8	No of branches	7	34
9	Voltage	230 kV	230 kV and 138 kV

Both these networks are small, do not represent a utility-scale network and are unlikely to be sufficient to test the approach being developed in this research.

2.5. Component failure rates, maintenance frequency and repair times

A probabilistic approach to reliability modelling requires assumptions on forced network outage rates, planned network outage rates and the repair time associated with each. A literature review of these parameters was performed to inform the assumptions.

2.5.1. Component failure rates and duration

Bollen (1993) conducted a literature search for component lifetimes and restoration durations, for use in reliability studies of distribution networks. The research included power transformers, circuit breakers and switches, protective equipment, fuses, voltage and current transformers, generators, cables and busbars. For each component the research was divided into the following sections:

(a) Recommended values;

(b) Data from surveys;

(c) Data used in reliability studies;

(d) Ageing data;

(e) Conclusions.

Bollen (1993) concluded his research with a range of recommended expected time to failure (ETTF) values for each component (see Table 2-2).

Table 2-2: Substation component failure rates

No	Substation component	Expected time to failure[1] (Bollen, 1993, p.3)	Average outage duration (h)
1	MV/MV transformers	75 - 100 years	**48 h** (Bollen, 1993, p.5)
2	HV /MV transformers	40 - 70 years	110 kV/MV: **120 h** (Bollen, 1993, p.5) 220 kV/MV: **180 h** (Bollen, 1993, p.5)
3	MV and LV circuit breakers	1000 - 5000 years	Below 1 kV: **4 h** (Bollen, 1993, p.21) 20 kV closed: **12 h** (Bollen, 1993, p.21)
4	HV circuit breakers	1000 years (Bollen, 1993, p.21)	110 kV closed: **60 h** (Bollen, 1993, p.21)
5	Disconnect switches	250 - 1000 years	10-30 kV: **3 h** (Bollen, 1993, p.21) 100 kV: **12 h** (Bollen, 1993, p.21)
6	MV Voltage and current transformers	500 years	10 kV, 30 kV: **7 h** (Bollen, 1993, p.65)
7	HV Voltage and current transformers	500 years	110 kV: **24 h** (Bollen, 1993, p.65)
8	MV Underground cables (1000 meters)	11 - 26 years	6 kV, 10 kV: **12 h** (Bollen, 1993, p.94) 20 kV, 30 kV: **30 h** (Bollen, 1993, p.94) Average = **21h**
9	HV Underground cables (1000 meters)	11 - 15 years	110 kV: **40 h** (Bollen, 1993, p.94)
10	Busbars (one section)	500 - 2000 years	Insulated switchgear 600V-15kV: **28-261 h** (Bollen, 1993, p.120)

The expected time to failure provided in Table 2-2 shows that HV/MV transformers and underground cables are more likely to fail than any other components in the substation. The busbars and circuit breakers are the most reliable components in the substation.

System reliability models typically use average equipment failure rates. Brown et al. (2004) presented a method to customise failure rates using equipment inspection data. This alternative method allows for available inspection information to be reflected in system models, and allows for calibration based on interruption distributions rather than mean values. The paper begins by presenting a method to map equipment inspection data to a normalized condition score, and suggests a formula to convert this score into failure probability.

The Electric Power Research Institute (EPRI) (2001) performed a detailed literature survey of data and models related to the reliability of electric power distribution system components. This research created a reliability data library, intended to support the further development of models and methodology.

Xu et al. (2002) applied a modern probabilistic reliability assessment method to a 500 kV and 220 kV substation. The typical substation component outage statistics data used in this paper is shown in Table 2-3.

[1] An ETTF of 1000 years does not mean that this kind of component is expected to last a thousand years, but that each year 1% of the population will fail during the next few years (20 or 30 at most).

Table 2-3: Typical substation component outage statistic data used by Xu et al. (2002)

No	Substation component	Outage frequency (occ/a)	Average outage duration (h)
1	500 kV Disconnect	0.002	12
2	220 kV Disconnect	0.002	12
3	500 kV Transformer	0.1	280
4	220 kV Transformer	0.12	100
5	500 kV Line terminal	0.15	15
6	220 kV Line terminal	0.1	10
7	500 kV Line	0.01	10
8	220 kV Line	0.01	7
9	500 kV Breaker	0.06	100
10	220 kV Breaker	0.02	60
11	500 kV Bus-section	0.02	24
12	220 kV Bus-section	0.04	15
13	500 kV Feeders	0.06	100
14	220 kV Feeders	0.02	60

The component outage frequencies listed in Table 2-3 shows that transformers and line terminals are more likely to fail than any other component in the substation. Disconnects are the most reliable components in the substation.

Zhou et al. (2012) analysed the reliability of the IEEE test system using the minimum cut-set method. The failure rates and repair times used for this analysis are shown in Table 2-4.

Table 2-4: Component failure rates and repair time used by Zhou et al. (2012) to analyse the reliability of IEEE test system.

No	Component	Voltage	Failure rate (occ/a)	Time to repair (h)
1	Transformer	138/11	0.001	
		33/11	0.015	
		11/0.415	0.015	200
2	Breaker	138	0.001	8
		33	0.002	4
		11	0.006	2
3	Line		0.04	30
4	Busbar	33	0.001	2
		11	0.001	2

The component outage frequencies listed in Table 2-4 shows that the MV/MV transformers, MV/LV transformers and lines are most likely to fail. The busbars, HV breakers and HV/MV transformers are the most reliable components in the substation.

A planning report on the reliability of transmission networks in Ghana (International Renewable Energy Agency, 2013) suggested the line outage rates given in Table 2-5.

Table 2-5: Ghana measured transmission line outage rate (International Renewable Energy Agency, 2013)

No	Transmission line	Voltage (kV)	Forced outage rate (%)	Average forced outage rate (%)
1	Ghana – Cote d'Ivoire interconnector	225	3.03%	2.765%
2	Ghana – Togo/Benin interconnector	161	2.50%	

2.5.2. Maintenance frequency and duration

Suwantawat & Premrudeepreechacharn (2004) included the impact of planned outages in the reliability analysis of different substation configurations and used the maintenance frequencies and durations shown in Table 2-7.

Table 2-6: Component maintenance rates and maintenance downtime used by Suwantawat & Premrudeepreechacharn (2004)

No	Component	Maintenance frequency (occ/a)	Maintenance downtime (h)
1	Breaker	0.1	4.0
2	Busbar	0	0
3	Transformer	0.2	10.0
4	Line	0.04	4.0

Alan et al. (1979) used the maintenance frequencies and downtimes shown in Table 2-7 to evaluate the reliability of a 33/11 kV test system.

Table 2-7: Component maintenance rates and maintenance downtime used by Allan et al. (1979)

No	Component	Maintenance frequency (occ/a)	Maintenance downtime (h)
1	Breaker	0.25	4.0
2	Transformer	0.25	8
3	Isolator	0.25	8
4	Line	0.25*	8
5	Cable	0.25*	8

* (occ/km/a)

From these figures it is concluded that no routine maintenance was considered for busbars, VTs, CTs and surge arrestors. In both these sources the equivalent annual outage duration associated with transformer maintenance is 20 hours per annum. The breaker outage duration used by Allan et al. (1979) of 1 hour is much higher than the annual outage duration used by Suwantawat & Premrudeepreechacharn (2004) of 0.4 h. The line maintenance frequency used by Suwantawat & Premrudeepreechacharn (2004) is independent from the length of the line, while the maintenance frequency used by Allan et al. (1979) is a function of the line length.

2.6. Conclusions from literature review

The different techniques available for the reliability evaluation of power systems were used to calculate the reliability of relatively small networks. It was concluded in section 2.1.8 that an alternative approach is required which can be used to model the expected reliability of a utility network, since all available methods are only feasible and practical on a small-scale network.

The different reliability evaluation techniques found from the literature (see section 2.1) show two decoupled approaches, i.e. component models and combination of the models into an evaluation. These two decoupled approaches were considered for the simplified approach.

The literature classified failures as either active or passive failures. For the purpose of this research only active failures were considered. The impact of both planned and unplanned outages were included in the reliability calculation.

Various performance indices were found from the literature. The indices most commonly used for benchmarking and reporting were considered as output for the simplified approach. These indices include load point indices and customer-based system indices.

The reliability modelling test networks most commonly used to illustrate probabilistic applications are the IEEE Reliability Test System (RTS) (Institute of electrical and electronics engineers (IEEE), 1999) and the Roy Billiton test system (RBTS) (Billinton et al., 1989). Both these networks are small and do not represent a utility-scale network. An alternative test network was required to illustrate the simplified approach.

Component failure rates, maintenance frequencies and outages durations, used for reliability studies, were found in the literature. These maintenance frequencies were used to inform the assumptions required for the simplified approach.

3. Reliability evaluation approach

In section 2.1 different evaluation techniques were reviewed for the reliability estimation of a power system network. In section 2.1.8 it was concluded that an alternative approach is required to estimate the reliability of a utility-scale network, since detailed modelling using specialised power system reliability modelling software is not feasible or practical on a system level. This research therefore considers a simplified approach to reliability modelling.

This simplified approach considers the same separation of approaches found in the literature, i.e. different component models are analysed and these models are then combined into an evaluation of the entire system. The boundaries of the different component models therefore need to be defined. These boundaries are discussed in section 3.1.

The substation component models needs to be sufficiently complex to ensure that errors in the simplified approach are not one-sided. The approach therefore considers a three-state model for unplanned outages. More information on the different network states are provided in section 3.2. Furthermore, all components in the substation are included in the analyses. This puts a significant burden on the number of calculations. To overcome this problem the network reduction method, explained in section 2.1.3, is used to reduce the number of components. Some of the series components are grouped into modules and only the impact of the module failures are considered, rather than the failure of each component. The different modules are discussed in section 3.3.

The number of different substation configurations is numerous. To simplify the reliability calculations, the approach only makes provision for a few standard layouts. These standard configurations are discussed in detailed in section 3.4.

The last step in the reliability estimation is the evaluation process. The approach considered for the evaluation process is discussed in section 3.5 and the methodology is described in detail in sections 4 and 5.

3.1. System description

In section 2.1.7 the decoupled approach, used to determine the total unavailability of a composite system, was discussed. This simplified reliability analysis makes use of this approach and splits the reliability calculation into two separate parts:

(a) The first part is the substation reliability methodology: a methodology is developed to analyse the reliability of different substation configurations. The outcome of the substation reliability estimation is the total unavailability (in hours per annum) experienced by a customer supplied from each busbar within the substation.

(b) The transmission methodology is then developed, which considers the outage frequency and outage duration due to line failures and maintenance. Each substation in the network is replaced by busbar(s) with the equivalent outage frequency and outage duration, as calculated in the substation methodology. The total unavailability due to all line and substation failures is then calculated.

Splitting the reliability estimation into two separate parts requires a clear demarcation between the substation and the transmission/sub-transmission network. Brown (2002) excluded the feeder breakers when generating an equivalent substation model. The substation calculation considered the availability of the downstream busbar, which is indicated by point “a” in Figure 3-1.

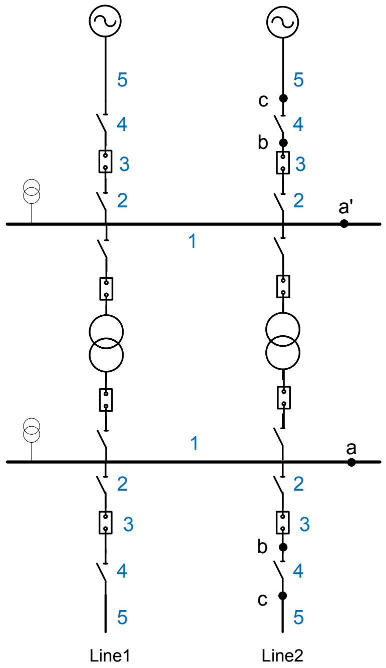


Figure 3-1: Simplified substation diagram indicating different points in the substation where the unavailability can be calculated

For the purpose of this research, the impact of failures is used to identify the point of demarcation. Component failures that cause any of the neighboring feeders to be out-of-service are grouped with the substation. All other components are grouped with the line.

The failure of each component, from the line to the busbar, is analysed to determine the demarcation between the substation and the rest of the network. The failure effects of the different components are shown in Table 3-1, (see Figure 3-1 where the components have been numbered accordingly). It is clear from Table 3-1 that the feeder line isolator and the line will not interrupt supply to any of the neighboring feeders. The busbar, feeder busbar isolator and feeder breaker failures will interrupt supply to the busbar or a section of the busbar, and will therefore cause an interruption of supply to the neighboring feeders. For this reason the line isolator is grouped with the line and the busbar isolator and line breaker is grouped with the substation. The point of demarcation between the substation and the transmission/sub-transmission network is between the feeder breaker and the line isolator (see point "b" in Figure 3-1).

Table 3-1: Effect of failures of lines, terminal equipment and busbars

No	Component failure	Component unsupplied immediately after the failure	Component unsupplied during repair
1	**Busbar**	a) Busbar without bus zone protection: busbar b) Busbar with bus zone protection: section of busbar	Section of busbar
2	**Feeder busbar isolator**	a) Busbar without bus zone protection: busbar & line/cable b) Busbar with bus zone protection: section of busbar & line/cable	Section of busbar & line/cable
3	**Feeder breaker**	a) Busbar without bus zone protection: busbar & line/cable b) Busbar with bus zone protection: section of busbar & line/cable	Line/cable

No	Component failure	Component unsupplied immediately after the failure	Component unsupplied during repair
4	**Feeder isolator (feeder side of breaker)**	Line/Cable	Line/Cable
5	**Feeder (Line/Cable)**	Line/Cable	Line/Cable

3.2. Network states

In section 2.1.1, the use of Markov models for quantitative reliability analysis was explained. For the purpose of this research, a three-state Markov model is considered, where the three states are:

(a) State U: This is the up-state or the normal network configuration.

(b) State P: This is the network state after a fault has occurred and the protection has operated to clear the fault.

(c) State R: This is the state after switching has occurred and supply to all faulty parts of the network has been restored. This is the state before the component repair starts. It also represents the network state when planned maintenance is being performed.

For planned maintenance no protection will operate, and therefore the network changes from state "U" to state "R", without being in state "P". This 3 state Markov model is shown in Figure 3-18.

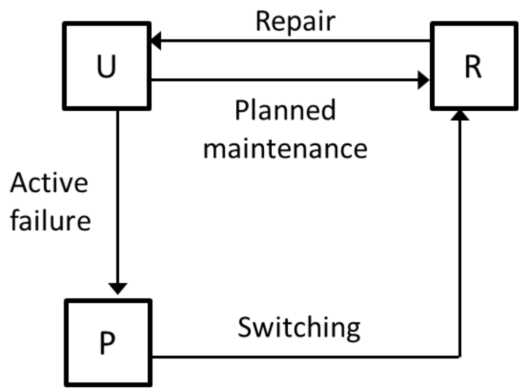
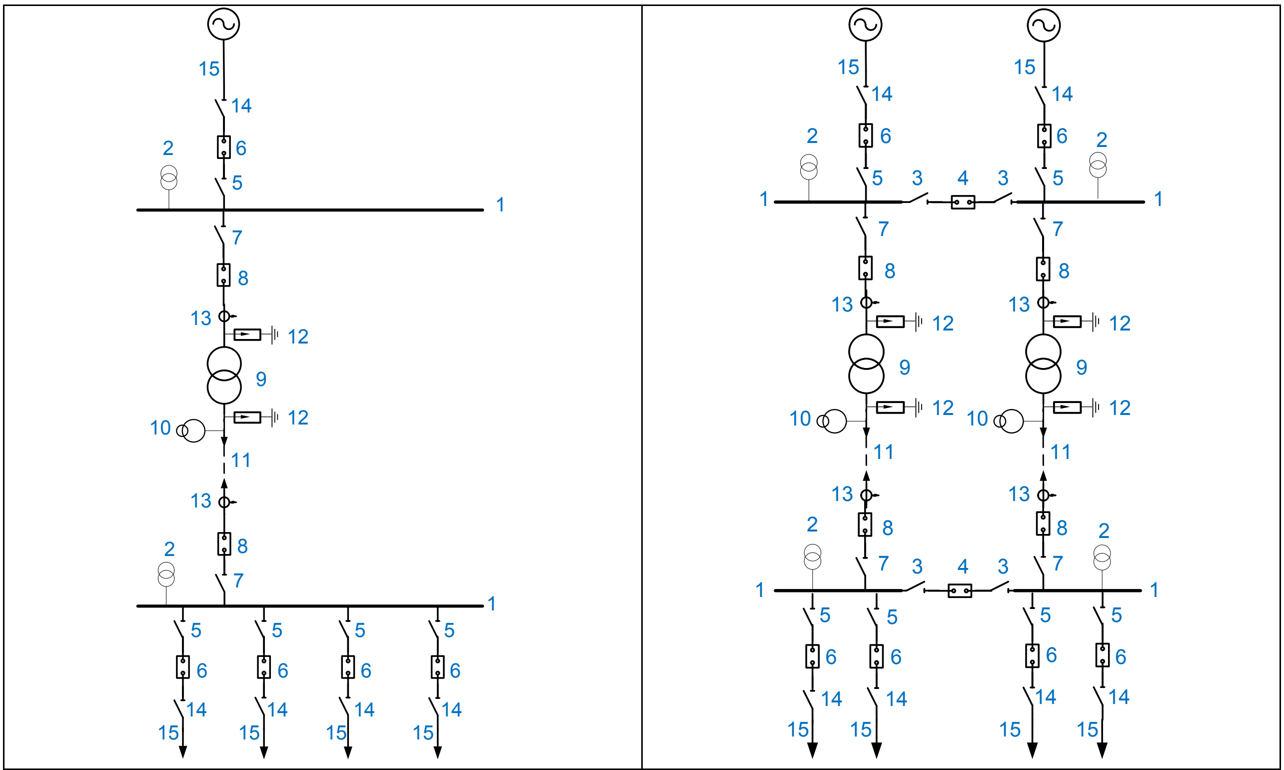


Figure 3-2: Three-state Markov model considered for the simplified reliability approach

3.3. Network simplification

In section 2.1.3, the network reduction method was explained. Some degree of network reduction is used in this approach to reduce the number of components that need to be considered in the unavailability calculation. Reducing the number of components simplifies the calculation and reduces computing time. The network reduction method is applied to all series components of which the post-fault state (state "P" in section 3.2) and repair state (state "R" in section 3.2) are the same.

This approach requires that each component failure is analysed to determine which series components have the same post-fault and repair network states. Such an analysis is illustrated in Table 3-2. The substation diagrams, with the corresponding component numbering, are shown in Figure 3-3.



(a) Single bubar, single transformer, single source feeder

(b) Single bubar with bus-section, double transformer, double source feeders

Figure 3-3: Example illustrating the failure effects of substation components

Table 3-2: Effect of substation component failures used to identify modules

No	Component failure	Component unsupplied immediately after the failure	Component unsupplied while faulty equipment is repaired
1	**Busbar**	a) Busbar without bus zone protection: busbar b) Busbar with bus zone protection: section of busbar	Section of busbar
2	**Busbar VT**	a) Busbar without bus zone protection: busbar b) Busbar with bus zone protection: section of busbar	Section of busbar
3	**Busbar isolator (bus-section or bus-coupler isolators)**	a) Busbar without bus zone protection: busbar b) For busbar with bus zone protection: section of busbar	Section of busbar
4	**Busbar breaker (bus-section or bus-coupler breaker)**	a) Busbar with one bus-section/bus-coupler: busbar b) Busbar with two bus-sections and two bus-couplers: 2 x sections of busbar	None
5	**Feeder busbar isolator**	a) Busbar without bus zone protection: busbar & line/cable b) Busbar with bus zone protection: section of busbar & line/cable	Section of busbar & line/cable

No	Component failure	Component unsupplied immediately after the failure	Component unsupplied while faulty equipment is repaired
6	**Feeder breaker**	a) Busbar without bus zone protection: busbar & line/cable b) Busbar with bus zone protection: section of busbar & line/cable	Feeder & line/cable
7	**Transformer busbar isolator**	a) Busbar without bus zone protection: busbar & transformer b) Busbar with bus zone protection: section of busbar & transformer	Section of busbar & transformer
8	**Transformer breaker**	a) Busbar without bus zone protection: busbar & transformer b) Busbar with bus zone protection: section of busbar & transformer	Transformer
9	**Transformer**	Transformer	Transformer
10	**Transformer NECR/T**	Transformer	Transformer
11	**Transformer Cable (between transformer and downstream side transformer breaker)**	Transformer	Transformer
12	**Transformer surge arrestor**	Transformer	Transformer
13	**Transformer CT**	Transformer	Transformer
14	**Line Isolator**	Line/cable (If it is a source feeder and the substation is supplied by only one source feeder then then entire substation will be without supply)	Line/cable (If it is a source feeder and the substation is supplied by only one source feeder then then entire substation will be without supply)
15	**Line**	Line/cable (If it is a source feeder and the substation is supplied by only one source feeder then then entire substation will be without supply)	Line/cable (If it is a source feeder and the substation is supplied by only one source feeder then then entire substation will be without supply)

It is evident that the failure of some components will result in similar network states, for example the busbar and busbar VT, (see no 1 and 2 above). Another example is the failure of the transformer, NECR/T, surge arrestors, transformer CTs and transformer cable that will result in a similar network state.

The series components that result in similar network states can be grouped together in order to simplify the reliability analysis. The following groupings, referred to as “modules” in the remainder of the document, are considered in this analysis.

(a) Transformer module;

(b) Busbar module;

(c) Line module.

3.3.1. Transformer Module

From Table 3-2, the transformer, NECR/T, surge arrestors, CTs and transformer cable failures result in the same post-fault and repair network states, since the breaker on the upstream side of the transformer will operate for all faults between the upstream and downstream transformer breakers. These components are grouped together and referred to as the transformer module in the rest of this document. All components included in the transformer module are shown in Figure 3-4.

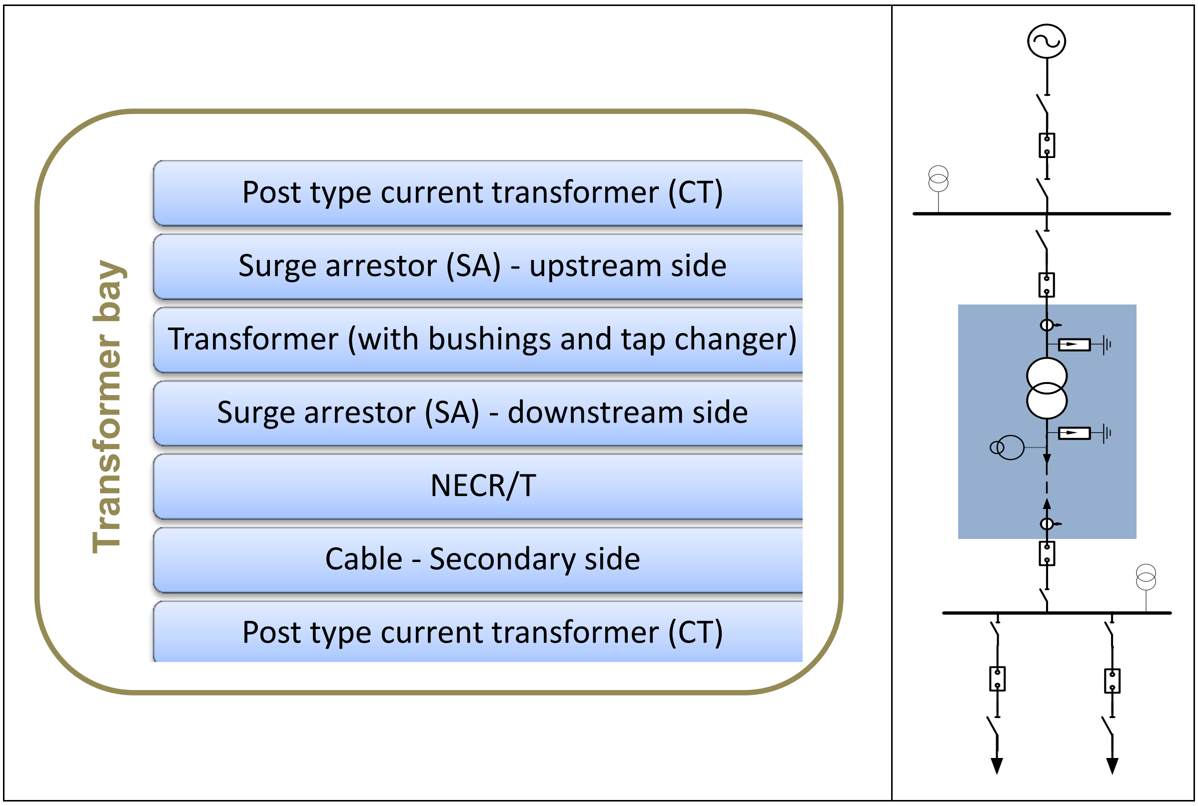


Figure 3-4: Transformer module

The failure rate and outage duration of the transformer module is a composite failure rate, derived from the individual failure rates of all components within the module. Since no overlapping failures are considered, the failure rate of the transformer module is the sum of the failure rates of each of the series components (see Equation 1 and Equation 2 in section 2.1.3). This is shown in Equation 5.

$$\lambda_{TrfrModule} = (2 \times \lambda_{SA}) + (2 \times \lambda_{CT}) + \lambda_{Trfr} + \lambda_{NECRT} + \lambda_{Cable} \qquad \textbf{Equation 5}$$

Where:

$\lambda_{TrfrModule}$	=	Failure rate of the transformer module (occ/a)
λ_{SA}	=	Failure rate of the surge arrestor (occ/a)
λ_{CT}	=	Failure rate of the CT (occ/a)
λ_{Trfr}	=	Failure rate of the transformer (occ/a)
λ_{NECRT}	=	Failure rate of the NECR/T (occ/a)
λ_{Cable}	=	Failure rate of the transformer cable (occ/a)

The annual outage duration of the transformer module is the sum of the annual outage durations of each of the series components. This is shown in Equation 6.

$$U_{TrfrModule} = (2 \times \lambda_{SA} \times MTTR_{SA}) + (2 \times \lambda_{CT} \times MTTR_{CT}) + \left(\lambda_{Trfr} \times MTTR_{Trfr}\right) + (\lambda_{NECRT} \times MTTR_{NECRT}) + (\lambda_{Cable} \times MTTR_{Cable}) \quad \textbf{Equation 6}$$

Where:

$U_{TrfrModule}$	=	Outage duration per annum of the transformer module (h/a)
$MTTR_{SA}$	=	Outage duration per event of the surge arrestor (h/occ)
$MTTR_{CT}$	=	Outage duration per event of the CT (h/occ)
$MTTR_{Trfr}$	=	Outage duration per event of the transformer (h/occ)
$MTTR_{NECRT}$	=	Outage duration per event of the NECR/T (h/occ)
$MTTR_{Cable}$	=	Outage duration per event of the transformer cable (h/occ)
λ_{SA}	=	Failure rate of the surge arrestor (occ/a)
λ_{CT}	=	Failure rate of the CT (occ/a)
λ_{Trfr}	=	Failure rate of the transformer (occ/a)
λ_{NECRT}	=	Failure rate of the NECR/T (occ/a)
λ_{Cable}	=	Failure rate of the transformer cable (occ/a)

The transformer module's outage duration per event is given by Equation 7:

$$MTTR_{TrfrModule} = \frac{U_{TrfrModule}}{\lambda_{TrfrModule}} \quad \textbf{Equation 7}$$

Where:

$\lambda_{TrfrModule}$	=	Failure rate of the transformer module (occ/a)
$U_{TrfrModule}$	=	Outage duration per annum of the transformer module (h/a)
$MTTR_{TrfrModule}$	=	Outage duration per event of the transformer module (h/occ)

3.3.2. Busbar module

From Table 3-2 it can be seen that the busbar and VT failures result in the same post-fault and repair network states. The failure of the busbar and VT can therefore be compared with components being in series, where the failure of any one of the series components will result in the same post-fault (switching and repair) state. The busbar and VT are grouped together and referred to as the busbar module in the rest of this document.

The number of VTs per busbar depends on the number of source feeders, number of load feeders, number of transformers and whether there is a bus-section. Three different busbar modules are considered in order to cater for the different busbar configurations and the number of VTs per busbar for each configuration. This is summarised in Table 3-3 and illustrated in Figure 3-5 (see highlighted blue sections).

Table 3-3 : Number of VTs per busbar

No. of source feeders	No. of load feeders	No. of transformers	Bus-section?	No. of VTs
1	0	≥1	No	0
≥1	≥1	≥1	No	1
≥1	≥0	≥1	Yes	2 (one VT on each bus-section)

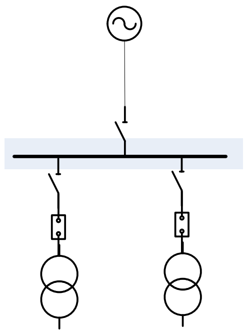
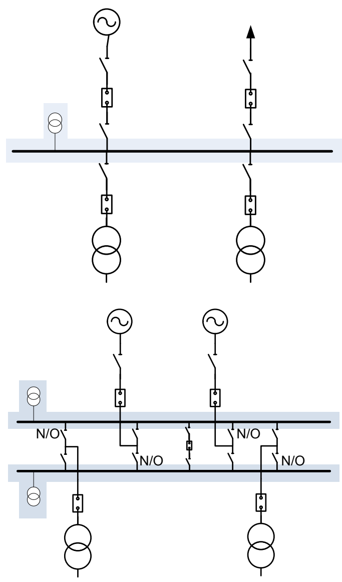
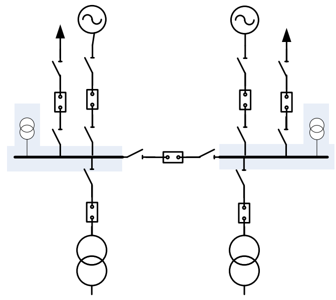
Description	No VTs	One VT	Two VTs
Illustration			
Comment	Applies to busbars with a single source feeder, no load feeders	Applies to single busbars (with load feeders or more than one source feeder) and busbars with bus-couplers	Applies to busbars with bus-section (no bus-couplers)

Figure 3-5: Busbar modules for different busbar configurations

The failure rate and outage duration of the busbar module is a composite failure rate, derived from the individual failure rates of the busbar and VT(s). Since no overlapping failures are considered, the failure rate of the busbar module is the sum of the failure rates of each of the series components. This is shown in Equation 8 for each of the three configurations listed in Table 3-3.

0 x VT: $$\lambda_{BBModule} = \lambda_{BB}$$

1 x VT: $$\lambda_{BBModule} = \lambda_{BB} + \lambda_{VT}$$ **Equation 8**

2 x VT: $$\lambda_{BBModule} = \lambda_{BB} + (2 \times \lambda_{VT})$$

Where:

$\lambda_{BBModule}$ = Failure rate of the busbar module (occ/a)

λ_{BB} = Failure rate of the busbar (occ/a)

λ_{VT} = Failure rate of the VT (occ/a)

The annual outage duration of the busbar module is the sum of the annual outage durations of each of the series components. This is shown in Equation 9 for each of the three configurations listed in Table 3-3.

0 x VT: $$U_{BBModule} = \lambda_{BB} \times MTTR_{BB}$$

1 x VT: $$U_{BBModule} = (\lambda_{BB} \times MTTR_{BB}) + (\lambda_{VT} \times MTTR_{VT})$$ **Equation 9**

2 x VT: $$U_{BBModule} = (\lambda_{BB} \times MTTR_{BB}) + (2 \times \lambda_{VT} \times MTTR_{VT})$$

Where:

$U_{BBModule}$ = Busbar module outage duration per annum (h/a)

MTTR_{BB} = Outage duration per event of the busbar (h/occ)

MTTR_{VT} = Outage duration per event of the VT (h/occ)

λ_{BB} = Failure rate of the busbar (occ/a)

λ_{VT} = Failure rate of the VT (occ/a)

The busbar module's outage duration per event is given by Equation 10:

$$MTTR_{BBModule} = \frac{U_{BBModule}}{\lambda_{BBModule}}$$ **Equation 10**

Where:

$\lambda_{BBModule}$ = Failure rate of the busbar module (occ/a)

$U_{BBModule}$ = Busbar module outage duration per annum (h/a)

$\mathrm{MTTR}_{BBModule}$ = Outage duration per event of the busbar module (h/occ)

The breakers and isolators of the bus-section and bus-coupler are often considered to be part of the busbar module. From the example discussed in Table 3-2 it is clear that a busbar failure and bus-section breaker failure will not result in the same repair states. Furthermore, different busbar configurations are considered in this research (as discussed in 3.4) and not all busbar configurations have a bus-section or bus-coupler breaker or isolator. For this reason the bus-section and bus-coupler breakers and/or isolators are handled separately and do not form part of the busbar module.

The line/transformer isolator results in the same post-fault and repair network states as the busbar. The number of line/transformer isolators is a function of the number of lines and transformers connections. The number of different combinations of lines and transformers connected are numerous. For this reason the isolators are handled separately and do not form part of the busbar module.

3.3.3. Line/cable module

From Table 3-2 it can be seen that the outage of the line and line isolator result in the same post-fault and repair network states. The line and the line isolator on each side of the line are grouped together and referred to as the line module. Similarly, the cable and cable isolators are grouped together[2] and referred to as the cable module in the rest of this document.

The failure rate and outage duration of the line/cable module is a composite failure rate, derived from the individual failure rates of the line/cable and two isolators, i.e. one isolator on each side of the line/cable. Since no overlapping failures are considered, the failure rate of the line/cable module is simply the sum of the failure rates of each of the series components (see section 2.1.3). This is shown in Equation 11.

$$\lambda_{LineModule} = \lambda_{Line} + (2 \times \lambda_{Isolator}) \qquad \textbf{Equation 11}$$

Where:

$\lambda_{LineModule}$	=	Failure rate of the line/cable module (occ/a)
λ_{Line}	=	Failure rate of the line/cable (occ/a)
$\lambda_{Isolator}$	=	Failure rate of the isolator (occ/a)

The annual outage duration of the line/cable module is the sum of the annual outage durations of each of the series components. This is shown in Equation 12.

$$U_{LineModule} = (\lambda_{Line} \times MTTR_{Line}) + (2 \times \lambda_{Isolator} \times MTTR_{Isolator}) \qquad \textbf{Equation 12}$$

Where:

$U_{LineModule}$	=	Line/cable module outage duration per annum (h/a)
$MTTR_{Line}$	=	Outage duration per event of the line/cable (h/occ)
$MTTR_{Isolator}$	=	Outage duration per event of the isolator (h/occ)
λ_{Line}	=	Failure rate of the line/cable (occ/a)
$\lambda_{Isolator}$	=	Failure rate of the isolator (occ/a)

From section 2.1.3, the MTTR of the line/cable module is given by Equation 13:

$$MTTR_{LineModule} = \frac{U_{LineModule}}{\lambda_{LineModule}} \qquad \textbf{Equation 13}$$

Where:

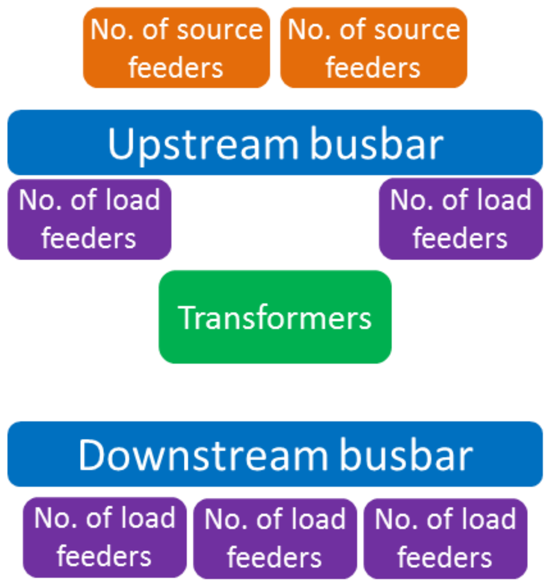
$\lambda_{LineModule}$	=	Failure rate of the line/cable module (occ/a)
$U_{LineModule}$	=	Line/cable module outage duration per annum (h/a)
$MTTR_{LineModule}$	=	Outage duration per event of the line module (h/occ)

[2] To simplify the analysis the failures of cable sealing ends are ignored for this analysis.

3.4. Standard configurations

Following the network reduction performed in 3.3, the substation configuration can be described by the 4 elements illustrated in Table 3-4. More information on each is provided in the rest of this section, as referred to in Table 3-4. Another element of the substation configuration is the two different types of switchgear. This is discussed in section 3.4.1.

Table 3-4: Substation configuration elements used to describe the substation

<table>
<tr><th>Diagram</th><th>Description</th><th>Relevant section</th></tr>
<tr><td rowspan="4">
</td><td>Number of source feeders</td><td>Section 3.4.4.1</td></tr>
<tr><td>Busbar configuration (both on the upstream and downstream side)</td><td>Section 3.4.1</td></tr>
<tr><td>Number of transformers (as well as the installed capacity and peak substation load)</td><td>Section 3.4.3 and 3.4.4.2</td></tr>
<tr><td>Number of load feeders</td><td>Section 3.4.4.1</td></tr>
</table>

3.4.1. Metalclad (indoor) vs non-metalclad switchgear

For the purpose of this research, switchgear are categorised as “metalclad (indoor)” or “non-metalclad”. Metalclad (indoor) switchgear refers to metalclad switchgear, while non-metalclad refers to air-insulated switchgear and gas-insulated switchgear.

The breaker and isolator(s) of a metalclad transformer bay, feeder bay and bus-section are housed in a single unit and only one failure rate and repair duration is assigned to this single unit. In the event of a switchgear failure, the switchgear unit can be racked out and supply can be restored to the busbar(s), transformer bays and line bays.

3.4.2. Busbar configurations

The following busbar configurations are discussed as part of this research:

(a) Single busbar;

(b) Single busbar with bypass busbar;

(c) Single busbar with bus-section, where the bus-section consists of back-to-back isolators;

(d) Single busbar with bus-section, where the bus-section consists of breaker with isolator on each side;

(e) Single busbar with bus-section and bypass busbar;

(f) Double busbar, no bus-coupler (feeders can be linked to any one of two busbars);

(g) Double busbar, no bus-coupler, with bypass isolator;

(h) Double busbar with bus-coupler (feeders can be linked to any one of two busbars and the busbars are connected via a bus-coupler);

(i) Double busbar with bus-sections and bus-couplers (feeders can be linked to any one of two busbars and the sections of the busbars are connected via bus-couplers and bus-sections);

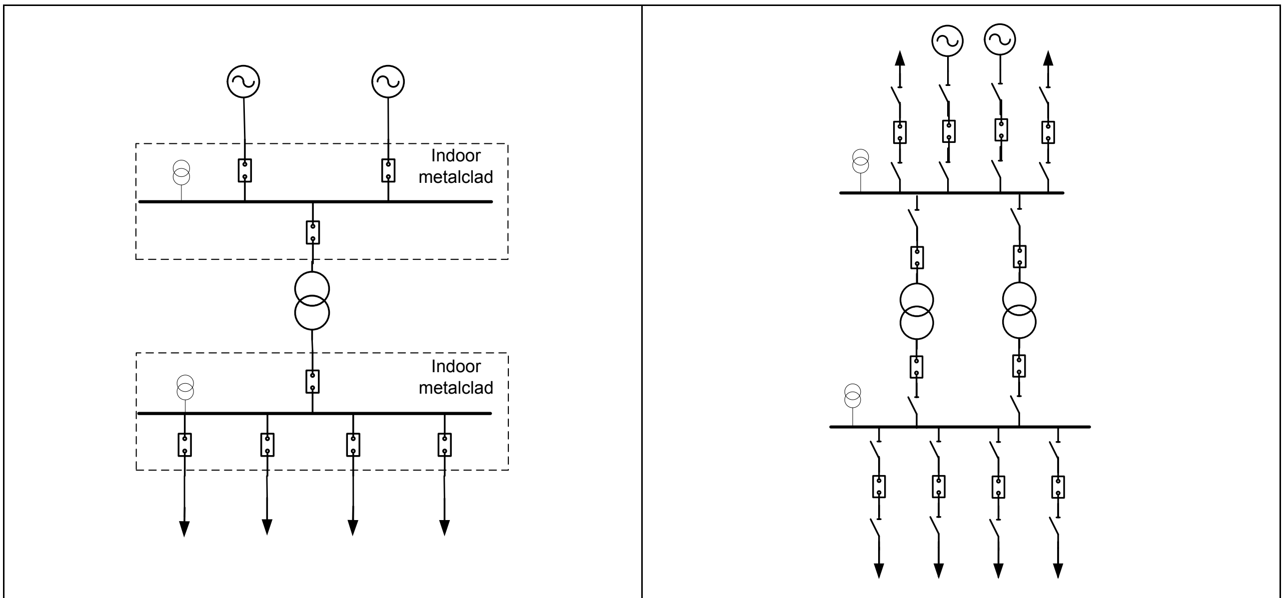
(j) Breaker and a half.

For ease of reference, the different busbar configurations listed above were numerically numbered and each type is explained in more detail below. It is important to note that the substation configuration is defined using a combination of the upstream and downstream busbar configurations. Although most of the examples in this section illustrate similar busbar configurations upstream and downstream of the transformer, a substation can have different upstream and downstream busbar configurations, e.g. a single busbar on the upstream side and a double busbar with bus-coupler on the downstream side.

Simplified single line diagrams of each of the types are given below. It is important to note that these diagrams do not represent the station electric diagrams, but are single line diagrams which indicate the electrical connectivity. Isolators with N/O indicated next to them are operated normally open. All other isolators are operated normally closed. All symbol definitions are provided in Annex A.

3.4.2.1. Busbar type 1

Description: A single busbar, without bus-sections or bus-couplers (see Figure 3-6). The metalclad (indoor) switchgear is shown in (a) and non-metalclad switchgear is shown in (b).



(a) Metalclad (indoor)	**(b) Non-metalclad**

Figure 3-6: Type 1 busbar configuration

3.4.2.2. Busbar type 1 with bypass busbar

A bypass busbar, also referred to as a hospital bar, is often used to improve the reliability of supply. A single busbar with a hospital bar is shown in Figure 3-7. The bypass configuration only applies to non-metalclad switchgear.

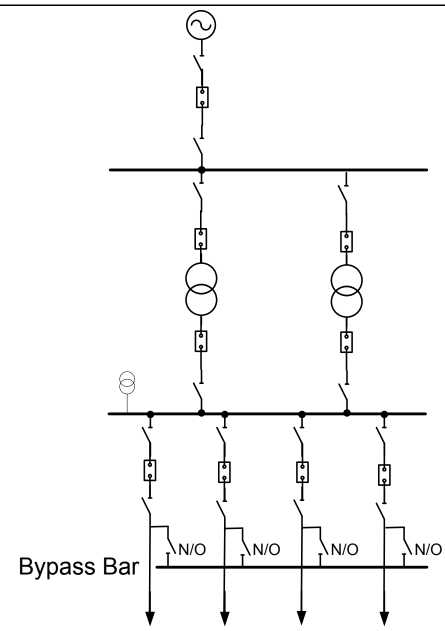


Figure 3-7: Type 1 busbar configuration with bypass (illustrated on the downstream side only)

With this configuration, all objects (feeders and transformers) are connected to one busbar. If the feeder breaker needs to be taken out-of-service, due to a planned or unplanned outage, the following changes are made in order to maintain supply:

a) The feeder of which the breaker needs to be taken out-of-service is connected to the hospital bar.

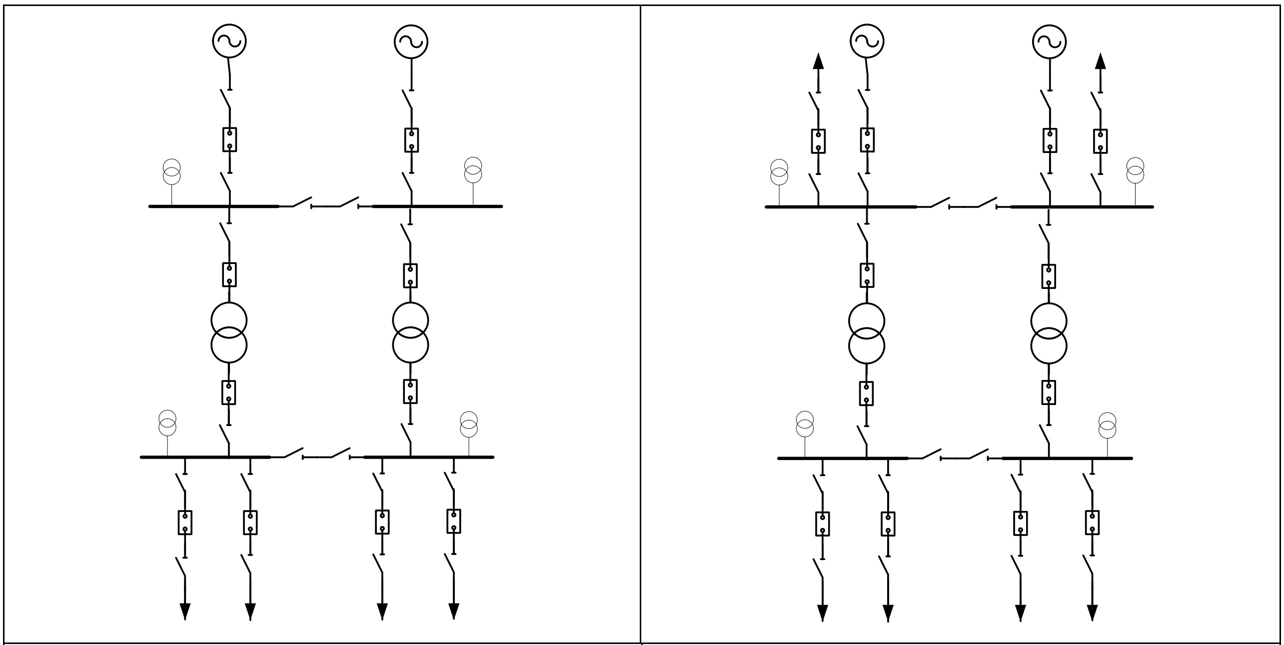
b) The isolators on both sides of the feeder breaker are opened in order to take the breaker out-of-service for repair/maintenance.

c) One of the other feeders is switched to both busbars in order to supply the hospital bar.

A hospital bar therefore minimises the interruption duration due to outage(s) of the feeder breaker(s).

3.4.2.3. Busbar type 2

Description: A single busbar, with a bus-section. The bus-section consists of two isolators and no breaker (see Figure 3-8). Figure 3-8 (a) shows a substation with no load supplied from the upstream busbar and Figure 3-8 (b) shows a substation with two load feeders supplied from the upstream busbar.

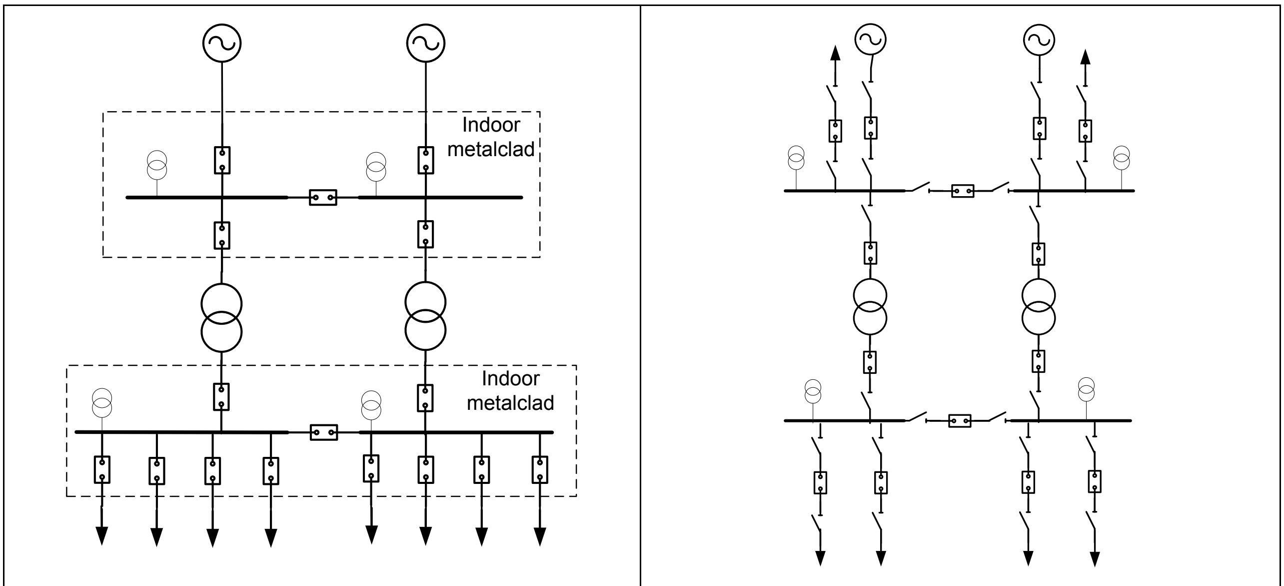


(a) No load supplied from upstream busbar | **(b) Load supplied from upstream and downstream busbar**

Figure 3-8: Type 2 busbar configuration

3.4.2.4. Busbar type 3

Description: A single busbar, with a bus-section. The bus-section consists of two isolators and a breaker (see Figure 3-9). The metalclad (indoor) switchgear is shown in (a) and non-metalclad switchgear is shown in (b). The breaker and isolators of a metalclad (indoor) bus-section is contained in a single unit, referred to as the bus-section breaker.



(a) Metalclad (indoor) | **(b) Non-metalclad**

Figure 3-9: Type 3 busbar configuration

3.4.2.5. Busbar type 3 with bypass busbar

A bypass busbar can be added to a Type 3 busbar configuration. Similar to the type 1 with bypass busbar configuration, this bypass busbar has the benefit that supply can be maintained if a feeder breaker is taken out-of-service. The layout of Type 3 with a bypass busbar configuration is shown in Figure 3-10. The bypass configuration only applies to non-metalclad switchgear.

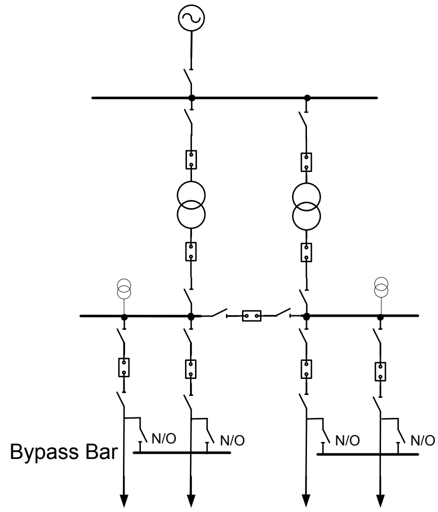
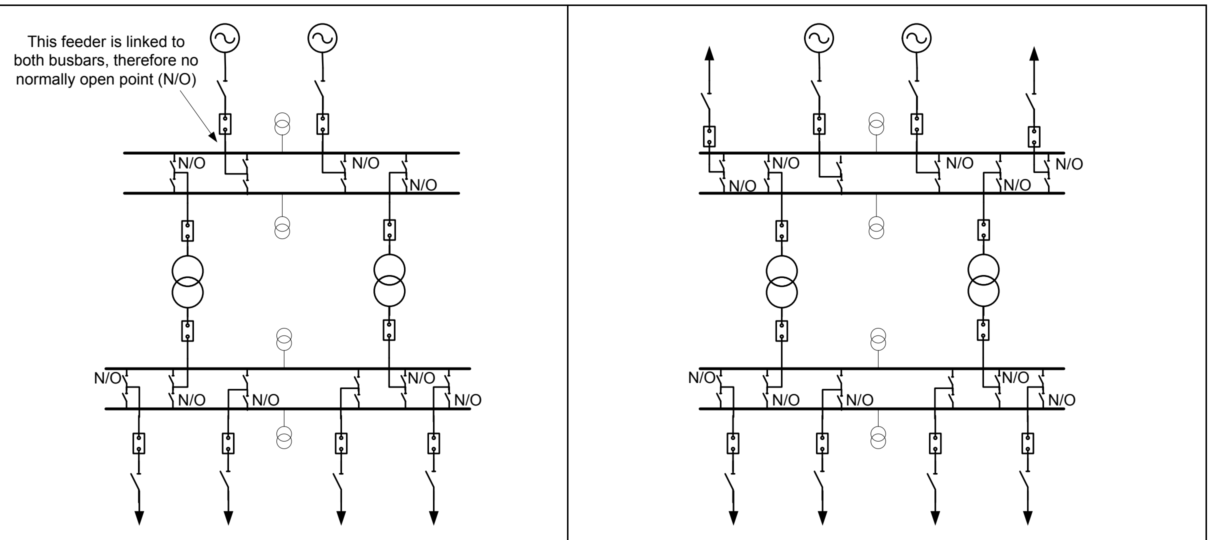


Figure 3-10: Type 3 busbar configuration with bypass busbar (illustrated on downstream side only)

3.4.2.6. Busbar type 4

Description: A double busbar, without a bus-coupler.

All feeders and transformers have two busbar isolators, one connected to each busbar. One of the two busbar isolators of each feeder/transformer is operated normally open (see N/O in Figure 3-11). One of the feeders is linked to both busbars, in order to link the two busbars. There is no bus-coupler. Figure 3-11 (a) shows a substation with no load supplied from the upstream busbar and Figure 3-11 (b) shows a substation with two load feeders supplied from the upstream busbar.



(a) No load supplied from upstream busbar	(b) Load supplied from upstream and downstream busbar

Figure 3-11: Type 4 busbar configuration

3.4.2.7. Busbar type 4 with bypass isolator

A bypass isolator can be added to the feeder bays of a type 4 configuration. This is shown in Figure 3-12.

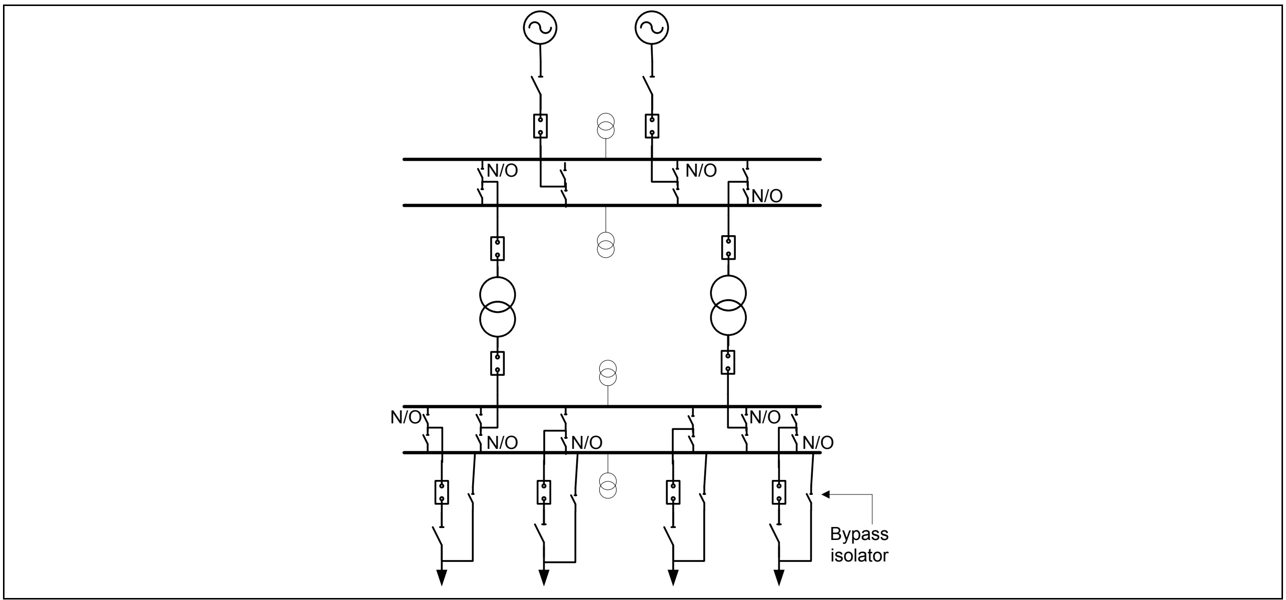


Figure 3-12: Type 4 busbar configuration with bypass isolator (illustrated on downstream side only)

3.4.2.8. Busbar type 5

Description: A double busbar, with a bus-coupler. All feeders and transformers have isolators connected to each busbar. One busbar isolator of each feeder and transformer is operated normally open (see Figure 3-13). The bus-coupler breaker and isolators are operated normally closed.

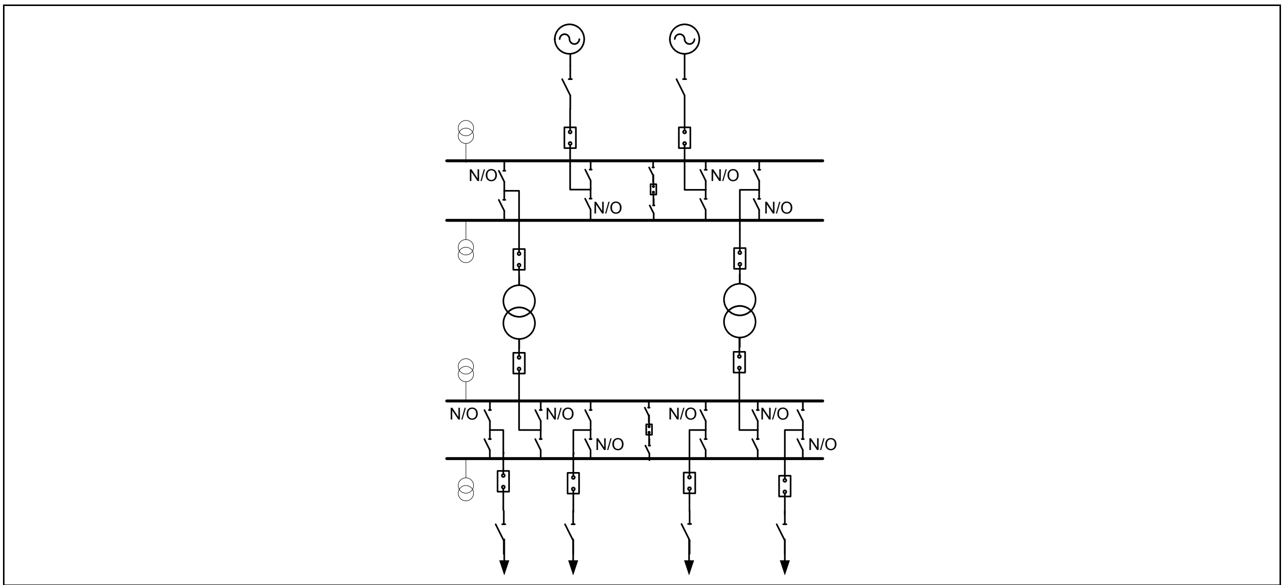


Figure 3-13: Type 5 busbar configuration

3.4.2.9. Busbar type 6

Description: A double busbar, with two bus-couplers and two bus-sections. All feeders and transformers have isolators connected to each busbar. One busbar isolator of each feeder and transformer is operated normally open (see Figure 3-14).

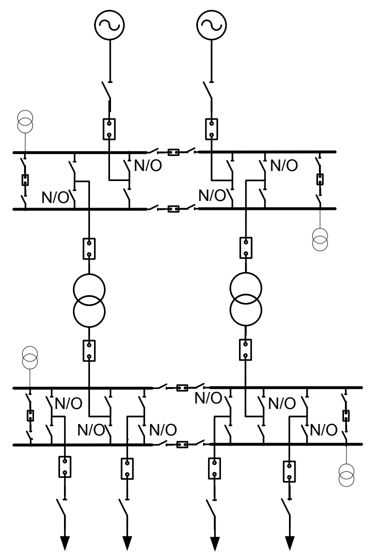


Figure 3-14: Type 6 busbar configuration

3.4.2.10. Busbar type 7

Description: This is the breaker and a half configuration. This layout is shown for an upstream busbar in Figure 3-15.

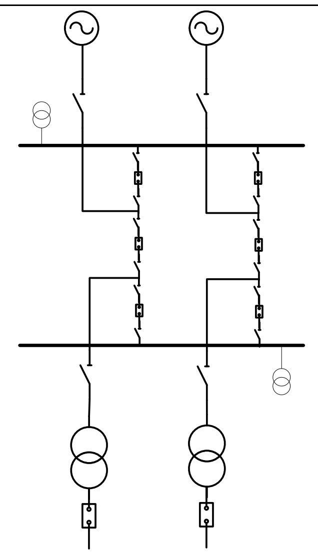


Figure 3-15: Type 7 busbar configuration (breaker and a half)

The substation model is designed so that the user specifies a type classification for both the upstream and the downstream busbar. As a result the user can define all the different combinations of upstream and downstream busbar classifications, such as Type 3 – Type 4, Type 1 – Type 3 etc.

A Type 2 – Type 4 substation is shown in Figure 3-16 (a) and a Type 6 – Type 4 substation is shown in Figure 3-16 (b).

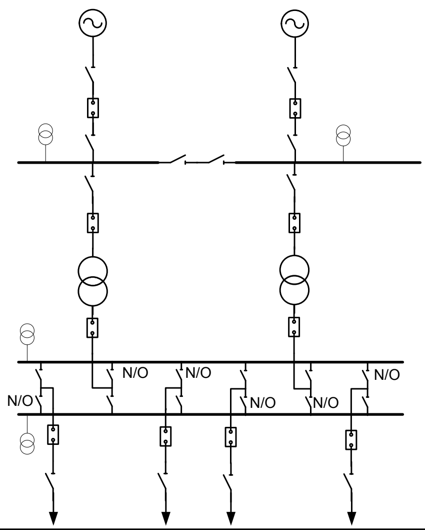
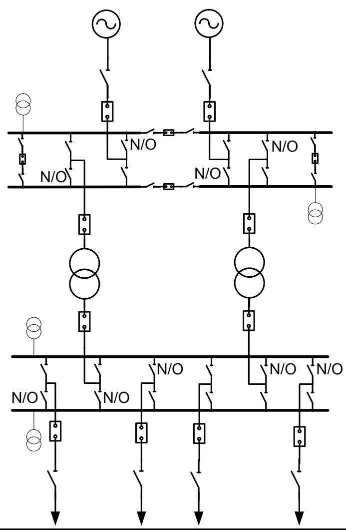
	
(a) Type 2 to Type 4	**(b) Type 6 to Type 4**

Figure 3-16: Combinations of different upstream and downstream busbar configurations

3.4.3. Number of transformers

The availability of a back-up transformer in the event of a transformer failure impacts on the percentage of customers interrupted following a transformer failure. However, if the total load supplied by the transformers exceeds the capacity of the remaining transformer, some customers will be interrupted while replacing/repairing the faulty transformer. The different transformer configurations impacting on the reliability of the substation can be summarised as follows:

(a) Single transformer configuration: supply to all customers is interrupted if one transformer module is out-of-service.

(b) Unfirm transformer capacity: supply to some customers is interrupted if one transformer module is out-of-service.

(c) Firm transformer capacity: no supply is interrupted if one transformer module is out-of-service.

3.4.4. Feeder and transformer bays

Each line bay and transformer bay contains terminal equipment that can fail and needs to be maintained. These failures and maintenance activities could interrupt supply to either the entire busbar or parts thereof. Therefore, the number of bays connected to a busbar impacts on the availability of the busbar to which it is connected.

For the purpose of this analysis all connections are considered to be symmetrical. Therefore, if a substation has two lines connected to a busbar with a bus-section, one line is connected to each bus-section.

3.4.4.1. Feeder bay components

The number of line(s) supplying the substation has(ve) a significant impact on the availability of supply at the specific substation. The user must identify the actual number of sources connected to each busbar, independent of the busbar and/or transformer layout.

The components in a feeder bay depend on the busbar configuration and the number of feeders connected to the busbar. The different components that can be present in the feeder bay are:

(a) Busbar isolator(s);

(b) Breaker;

(c) Line isolator.

The different feeder bay configurations and the scenarios they apply to are illustrated in Figure 3-17.

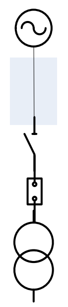
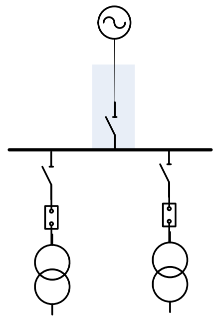
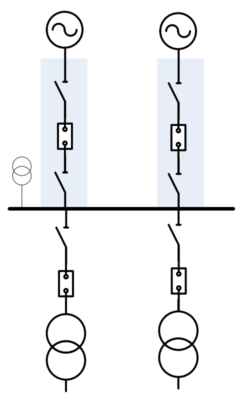
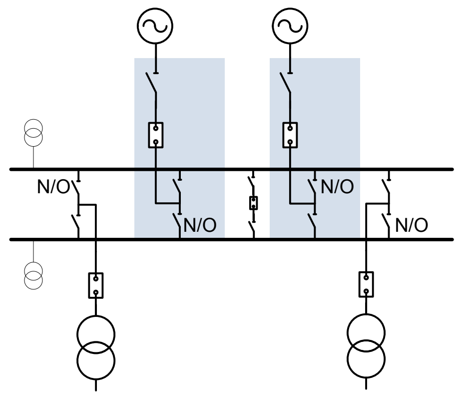
Description	No feeder bay components	1 x Feeder bay isolator
Illustration		
Comment	Applies to busbars with a single feeder and single transformer	Applies to single source feeder, no load feeders with single busbar (without bus-section or bypass busbar)
Description	**Line isolator, breaker and busbar isolator**	**Line isolator, breaker and 2 x busbar isolators**
Illustration		
Comment	Applies to single busbars (with or without bus-section) with more than one feeder connected	Applies to double busbars or single busbar with bypass

Figure 3-17: Feeder bay components for different busbar configurations and number of feeders connnected

Each of these bay components will result in a different post-fault and repair network state:

(a) The failure of the busbar isolator will result in one busbar being out-of-service for the full repair duration.

(b) A breaker failure will result in a busbar outage for a short duration. Once the operator arrives on site he can restore supply to all busbars by opening the busbar isolator of the faulty feeder bay. Now only this feeder will be out-of-service while the breaker is being repaired.

(c) As explained in section 3.1, the failures of the line isolator are considered in the line model and not the substation model, since they will have the same effect as a line failure and not result in any of the busbars and/or neighbouring feeders being out-of-service.

The different component failures within the bay are therefore handled differently in the model, and no composite failure rate and outage duration are calculated for a feeder bay.

3.4.4.2. Transformer bay components

A transformer bay consists of the following components:

(a) Busbar isolator (or two busbar isolators for double busbar configurations);

(b) Breaker.

The different transformer bay configurations and the busbar configurations they apply to are illustrated in Figure 3-18.

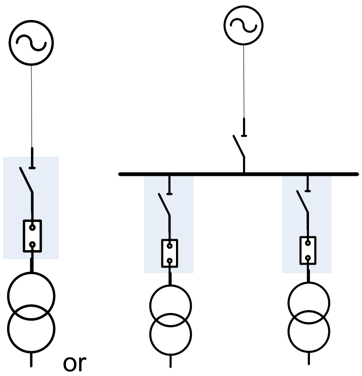
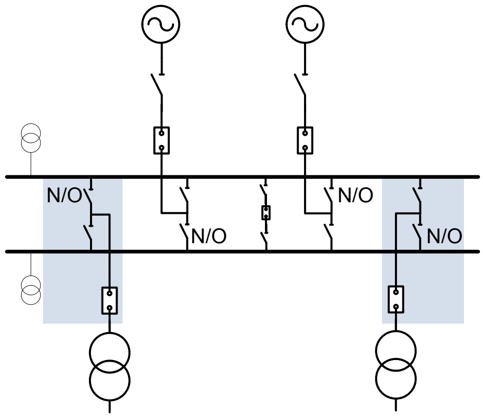
Description	Breaker and busbar isolator	Breaker and 2 x busbar isolators
Illustration		
Comment	Applies to substations with no busbar or single busbar (with or without bus-section) and single busbar with bypass	Applies to double busbars

Figure 3-18: Transformer bay components for different busbar configurations

The failure of the busbar isolator will result in one busbar or a section of the busbar being out-of-service for the full repair duration. A breaker failure will also result in one busbar or a section of the busbar being out-of-service, but only until the operator gets to the site, opens the busbar isolator of the transformer bay, closes all breakers that operated and restores supply to the busbar. The different component failures within the transformer bay are therefore handled differently in the model and no composite failure rate and outage duration are calculated for a transformer breaker and isolator.

The different number of feeder bays and/or transformer bays that can be connected to a busbar is numerous. In order to simplify the number of substation configurations for the purpose of this research, but still consider the impact of all bays connected, the number of feeder bays is not treated as part of the substation classification. The user must identify the actual number of feeder bays connected, independent of the busbar and/or transformer layout.

3.5. Applied evaluation technique

The failure modes and effects analysis technique, described in section 2.1.1, is used as the basis for the simplified reliability calculation. The different failure modes of each component are ignored, but the probability of each component failure and the impact of each failure on the customers supplied is evaluated. This impact, combined with the probability of the failure, is used to calculate the expected interruption frequency of each customer/load, due to the failure of a specific component.

An enumerative method is used that examines the failure of each component, calculates the expected frequency of interruptions due to this failure and adds all these frequencies to determine the total interruption frequency caused by the failures of all the components in the system. This is explained by the formula in Equation 14:

$$Interruption\ frequency_j = \sum_{i=1}^{n} \#_i \times \lambda_i \times \%Unsupplied_i \qquad \textbf{Equation 14}$$

Where:

$Interruption\ frequency_j$	=	Number of interruptions experienced by a customer supplied by busbar j
$\#_i$	=	Number of components of type i
λ_i	=	Failure rate of component/module i (occ/a)
$\%Unsupplied_i$	=	Percentage of customers unsupplied if component i fails
n	=	Number of distinct components/modules

The duration of each interruption can now be added to Equation 14 to calculate the unavailability of each load point. Since a three-state Markov model is considered, as described in section 3.2., the outage duration and the load/customers unsupplied during both periods need to be considered. The formula for the unavailability is shown in Equation 15.

$$Unavailability_j = \sum_{i=1}^{n} \#_i \times \lambda_i \times \left(S_i \times \%Unsupplied_{i\_s} + R_i \times \%Unsupplied_{i\_r}\right) \qquad \textbf{Equation 15}$$

Where:

$Unavailability_j$	=	Duration of interruptions experienced by a customer supplied by busbar j
$\#_i$	=	Number of components of type i
λ_i	=	Failure rate of component/module i (occ/a)
S_i	=	Time that elapse from the fault occurs until the operator can start with the fault repair, e.g. the time required to drive to site (h/occ).
R_i	=	Repair time of component/module i (h/occ)
$\%Unsupplied_{i\_s}$	=	Percentage customers unsupplied, immediately after the protection has operated, if component i fails.
$\%Unsupplied_{i\_s}$	=	Percentage customers that remain unsupplied after switching, while the faulty component i is being repaired
n	=	Number of distinct components/modules

The parameters in Equation 14 and Equation 15 are discussed in more detail in chapters 4 and 5. The relevant section where each parameter is discussed is listed in Table 3-5.

Table 3-5: Relevant section where each of the parameters of the unavailability calculation are discussed.

No	Parameter	Parameter description	Relevant section
1	$\#_i$	Number of components of type i.	Sections 4.3 and 5.2
2	λ_i	Failure rate of component/module i (occ/a).	Sections 4.4 and 5.3
3	S_i	Time required to do switching following a failure of component/module i (h/occ).	Sections 4.4 and 5.3
4	R_i	Repair time of component/module i (h/occ).	Sections 4.4 and 5.3
5	$\%Unsupplied_{i\_s}$	Percentage customers unsupplied, immediately after the protection has operated, if component i fails.	Section 4.5
6	$\%Unsupplied_{i\_r}$	Percentage customers that remain unsupplied after switching, while the faulty component i is being repaired.	Section 4.5
7	n	Number of distinct components/modules.	Section 4.2 and 5.2

3.6. Summary of identified approach

In this section the approach to the simplified reliability estimation was explained and the boundaries of each of the two parts of the approach have been clearly defined. The different building blocks for the approach were defined in a consistent way, ensuring that the model is sufficiently complex to ensure that errors are not one-sided, but still minimising the number of calculations of the reliability evaluation. These building blocks are now used in the reliability estimation methodology, explained in detail in the following two chapters.

4. Substation modelling methodology

In section 3.1 it was explained that the substation reliability estimation will be decoupled from the transmission and sub-transmission reliability estimation. This chapter focusses on the substation reliability calculation and describes the methodology used to calculate the unavailability of each busbar in the network. It is important to note that this is slightly different from the approach explained in section 2.1.7., since the approach explained in section 2.1.7 calculates the outage frequency and unavailability of only the downstream busbar, while this approach calculates the outage frequency and unavailability of both the upstream and downstream busbar. This is illustrated in Figure 4-1.

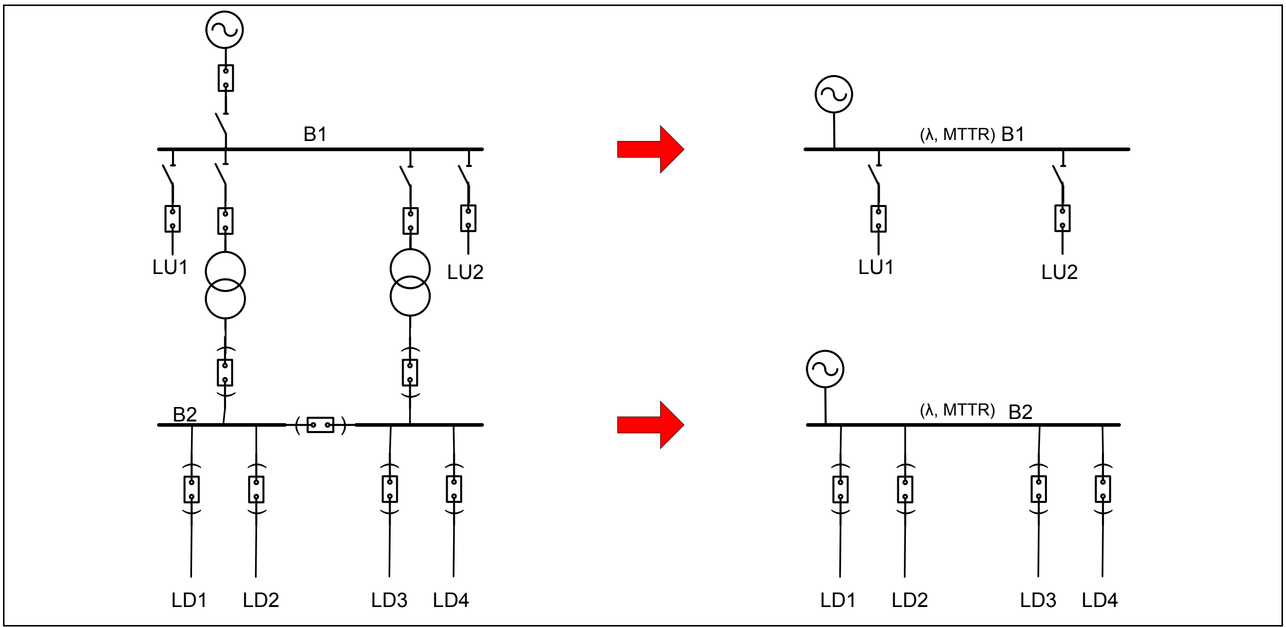


Figure 4-1: Reducing a substation to busbars with equivalent unavailability

This chapter starts with a list of assumptions used for the substation reliability modelling. The rest of the section provides details on the reliability estimation methodology. A list of substation data required to perform the substation reliability estimation is summarised in Annex C.

4.1. Assumptions

The following assumptions were made in order to simplify the substation methodology:

(a) The probability of two or more substation components failing at the same time, such as a busbar failure and transformer failure, is assumed to be zero. Furthermore, the probability that a substation component failure would occur while another substation component is out-of-service for planned maintenance is assumed to be zero.

(b) Only equipment failures that result in an interruption of supply to some parts of the network are considered, i.e., active failures. Passive failures such as locked tap-changers, which do not result in a protection operation and subsequently a transformer outage, are not considered. (Note, this does not imply that only equipment failures that result in customer outages are considered, e.g. a single transformer failure in a substation with firm transformer capacity is considered, although this failure will not result in any customer outages).

(c) Equipment in the normally open position cannot cause interruptions to a network. For example, if a feeder has a bypass isolator, which is operated normally open, the failure of this isolator will not cause any interruptions to customers, and is therefore ignored for the purposes of this study. Furthermore, breakers actively failing cannot clear their own faults, but an upstream breaker needs to open to clear the fault.

(d) The full capacity of a transformer(s) can be utilised under n-1 conditions. This implies that if one transformer fails in a substation with unfirm transformer capacity and more than one transformer, load shedding can be done such that the remaining transformer(s) is/are loaded to its/their full capacity (also see section 0).

Consider the substation illustrated in Figure 4-2. If one transformer fails, the remaining transformer will be loaded to 32 MVA and manual load shedding is required to limit the load to 20 MVA (the capacity of 1 x transformer). It is assumed that exactly 12 MVA can be shed, such that the remaining transformer is loaded to 100% its capacity.

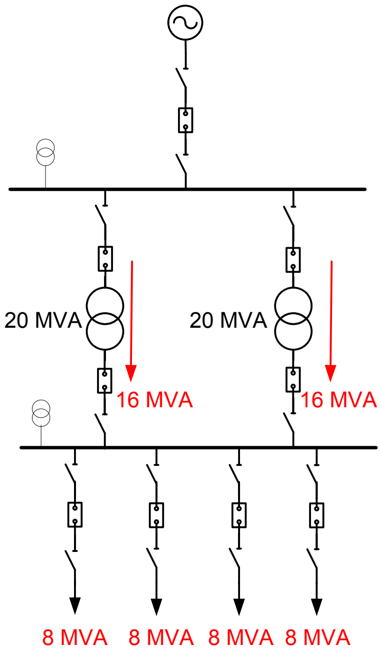


Figure 4-2: Substation with unfirm transformer capacity

(e) If a fault occurs it appears at peak load, and the load/customers lost is/are analysed considering the peak load of the substation.

(f) All substation configurations are balanced configurations. This implies that:

- The feeders and transformers are distributed equally amongst the different busbars, e.g. if a busbar has 2 sections and it is supplied by 2 transformers, one transformer is connected to each bus-section.
- The customers and load supplied are distributed equally amongst the different load feeders, e.g. if a busbar has 4 load feeders and supplies 24 MVA peak load and 4000 customers, each feeder supplies 6 MVA peak load and 1000 customers.

(g) A substation component is taken out-of-service for planned maintenance, irrespective of whether it causes the outage of a customer load.

(h) All bus-sections are operated normally closed.

(i) All HV equipment are non-metalclad.

(j) If a busbar is supplied by more than one source feeder, the substation has a firm line capacity, i.e. if one line is out-of-service, the second line has sufficient capacity to supply the total load.

(k) No switching is done remotely (i.e. from the control centre) for substation faults.

(l) All transformers have NECR/Ts. The failure rate and mean outage duration of all transformer modules with the same primary and secondary voltages are therefore the same.

4.2. Component groupings

Considering each of the parameters in Equation 14 and Equation 15, it is necessary to understand which components/modules are distinct, i.e. the index *n* referred to in Equation 14 and Equation 15.

Some components can be grouped together, for example the busbar isolators of all source feeder bay isolators can be grouped, since they have the same failure rate and will result in the same post-fault and repair network states. But can the busbar isolators of the source feeders and the isolators of the bus-section be grouped together?

The different groupings of components were identified considering the failure rate and different impacts of each component failure. Two isolators that result in the same post-fault and repair network states are grouped together, but if they result in different post-fault and repair network states, they need to be considered separately. Similarly, an isolator and breaker may result in the same post-fault and repair network state, but since they could have different failure rates they need to be considered separately. The post-fault and repair network states of components and modules were analysed to determine which components can be grouped together. This analysis is shown in Table 4-1 and a substation diagram with corresponding numbering is shown in Figure 4-3.

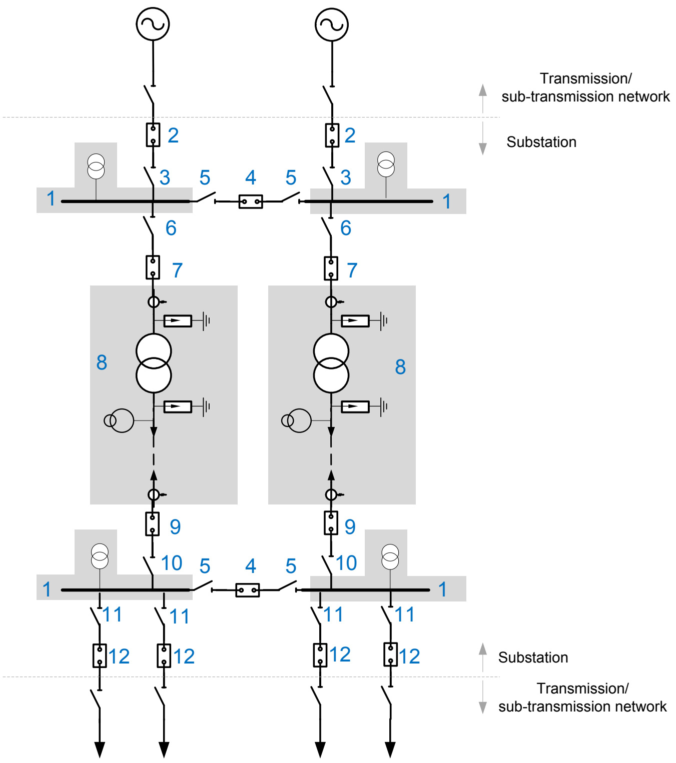


Figure 4-3: Identifying component groupings in the substation

Table 4-1: Effect of substation component failures used to identify component groupings

No	Component failure	Component(s) unsupplied immediately after the failure	Component unsupplied while faulty equipment is being repaired
1	**Busbar**	(a) Busbar without bus zone protection: busbar (b) Busbar with bus zone protection: section of busbar	Section of busbar
2	**Source feeder bay breaker**	(a) If only 1 source feeder: entire substation If > 1 source feeder: (b) Busbar without bus zone protection: busbar & line/cable (c) Busbar with bus zone protection: section of busbar & line/cable	(a) If only 1 source feeder: entire substation (b) If > 1 source feeder: line/cable
3	**Source feeder busbar isolator**	(a) If only 1 source feeder: entire substation If > 1 source feeder: (b) Busbar without bus zone protection: busbar & line/cable (c) Busbar with bus zone protection: section of busbar & line/cable	(a) If only 1 source feeder: entire substation (b) If > 1 source feeder: bus-section & line/cable
4	**Busbar breaker (bus-section or bus-coupler breaker)**	(a) Busbar with one bus-section/ coupler: busbar (b) Busbar with two bus-sections and two bus-couplers: 2 x sections of busbar	None
5	**Busbar isolator (bus-section or bus-coupler isolators)**	(a) Busbar without bus zone protection: busbar (b) Busbar with bus zone protection: section of busbar	Section of busbar
6	**Transformer upstream busbar isolator**	(a) Busbar without bus zone protection: busbar & transformer (b) Busbar with bus zone protection: section of busbar & transformer	Section of busbar & transformer
7	**Transformer upstream breaker**	(a) Busbar without bus zone protection: busbar & load transformer (b) Busbar with bus zone protection: section of busbar & load transformer	Load Transformer
8	**Transformer**	Transformer	Transformer
9	**Transformer downstream breaker**	(a) Busbar without bus zone protection: busbar & source transformer (b) Busbar with bus zone protection: section of busbar & source transformer	Source Transformer
10	**Transformer downstream busbar isolator**	(a) Busbar without bus zone protection: busbar & transformer (b) Busbar with bus zone protection: section of busbar & transformer	Section of busbar & transformer
11	**Load feeder busbar isolator**	(a) Busbar without bus zone protection: busbar & line/cable (b) Busbar with bus zone protection: section of busbar & line/cable	Section of busbar &line/cable

No	Component failure	Component(s) unsupplied immediately after the failure	Component unsupplied while faulty equipment is being repaired
12	**Load feeder bay breaker**	(a) Busbar without bus zone protection: busbar & line/cable (b) Busbar with bus zone protection: section of busbar & line/cable	Line/cable

The post-fault and repair network states in Table 4-1 were used to derive the component groupings. The only components that can be grouped together are the source transformer isolator and the load transformer isolator. These two components are grouped and referred to as “Transformer busbar isolators”. The component groupings are listed in Table 4-2 and an abbreviation is specified for each component grouping, which will be used as a reference for the component grouping in the rest of this document.

Table 4-2: Component groupings

No	Group description	Group abbreviation
1	Source feeder bay breaker	SrcFdrBayBrkr
2	Load feeder bay breaker	LdFdrBayBrkr
3	Source feeder busbar isolator	SrcFdrBBIsol*
4	Load feeder busbar isolator	LdFdrBBIsol*
5	Busbar	BB
6	Busbar breaker	BBBrkr
7	Busbar isolator	BBIsol*
8	Source transformer bay breaker	SrcTrfrBayBrkr
9	Load transformer bay breaker	LdTrfrBayBrkr
10	Transformer busbar isolator	TrfrBBIsol*
11	Transformer	Trfr

** The postfix “MC” is used with the listed abbreviations to refer to metalclad (indoor) equipment.*

4.3. Number of components per substation

From Equation 14 and Equation 15, the number of components of each type is required. In section 4.1 it was agreed that only normally closed components can fail, and failures of normally open components are to be ignored. However, all equipment (including the normally open components) needs to be maintained. The number of components of each equipment grouping and the number of normally open components of each equipment grouping should therefore be determined from the user inputs.

The model requires the following inputs to determine the number of components:

(a) Busbar type;

(b) Number of source feeders;

(c) Number of load feeders;

(d) Number of source transformers;

(e) Upstream busbar ID.

From these inputs, the number of isolators, breakers and busbars is calculated, considering the component count assumptions shown in Table 4-3 and Table 4-4.

The component count is specified per feeder, per transformer, etc., as per the unit indicated. For example, the number of feeder busbar isolators that need to be maintained for a Type 6 busbar with 4 load feeders is calculated using:

$$
\begin{aligned}
No.of\ feeder\ busbar\ isolators &= No.of\ components\ per\ Unit\ \times Unit \\
&= 2\ isolators\ per\ load\ feeder \times No.of\ load\ feeders \\
&= 2\ isolators\ per\ load\ feeder \times 4\ load\ feeders \\
&= 8\ isolators
\end{aligned}
$$

Table 4-3: Number of normally closed components per busbar type (applied to unplanned outage calculation)

No	Component	Busbar Types										Unit
		Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type1Bp	Type3Bp	Type4Bp	
1	NC_SrcFdrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Source feeder
2	NC_LdFdrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Load feeder
3	NC_SrcFdrBBIsol	1	1	1	1	1	1	3	1	1	1	/Source feeder
4	NC_LdFdrBBIsol	1	1	1	1	1	1	3	1	1	1	/Load feeder
5	NC_BB	1	1	1	2	2	2	2	1	1	2	/Busbar
6	NC_BBBrkr	0	0	1	0	1	4	0	0	1	0	/Busbar
7	NC_BBIsol	0	2	2	0	2	8	0	0	2	0	/Busbar
8	NC_SrcTrfrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Source transformer
9	NC_LdTrfrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Load transformer
10	NC_TrfrBBIsol	1	1	1	1	1	1	3	1	1	1	/Transformer
11	NC_SrcFdrBBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Feeder
12	NC_LdFdrBBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Feeder
13	NC_BBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Busbar
14	NC_TrfrBBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Transformer

** For metalclad (indoor) equipment the busbar isolators are part of the breaker module, therefore the count is 0.*

Table 4-4: Number of components per busbar type (applied to planned outage calculation)

No	Component	Busbar Types										Unit
		Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type1Bp	Type3Bp	Type4Bp	
1	SrcFdrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Source feeder
2	LdFdrBayBBIsol	1	1	1	2	2	2	3	2	2	3	/Load feeder
3	SrcFdrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Source feeder
4	LdFdrBayBBIsol	1	1	1	2	2	2	3	2	2	3	/Load feeder
5	BB	1	1	1	2	2	2	2	1	1	2	/Busbar
6	BBBrkr	0	0	1	0	1	4	0	0	1	0	/Busbar
7	BBIsol	0	2	2	0	2	8	0	0	2	0	/Busbar
8	SrcTrfrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Source transformer
9	LdTrfrBayBrkr	1	1	1	1	1	1	1.5	1	1	1	/Load transformer
10	TrfrBBIsol	1	1	1	2	2	2	3	1	1	2	/Transformer
11	FdrBBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Feeder
12	BBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Busbar
13	TrfrBBIsol_MC*	0	0	0	0	0	0	0	0	0	0	/Transformer

** For metalclad (indoor) equipment the busbar isolators are part of the breaker module, therefore the count is 0.*

4.4. Outage frequency and duration

4.4.1. Outage frequency

The outage frequency (occ/a) of each substation component and module needs to be defined by the user. A constant scalar value is considered for the component failure rates, where this failure rate is representative of the different failure modes of the specific component. The outage frequencies are external inputs into the model and can therefore be changed with little effort at one central point in the model.

The different modules used to simplify the analysis were explained in section 3.3. For these modules composite failure rates are used, where the failure rate of the module is calculated from the failure rate of the different modules, as explained in section 3.3.

4.4.2. Outage duration

The total outage duration per fault depends on various factors such as travelling time to site, the specific component that failed, etc. The outage duration associated with substation outages was broken down into different components to accommodate these different factors.

The outage components associated with substation failures are shown in Figure 4-4. A short description of each element is provided below:

(a) **T_{Dispatch}**: The dispatch time is the time required by the control centre to acknowledge that there was a substation fault and dispatch an operator.

(b) **T_{Travel}**: This is the time required for the operator to travel to the substation/line. This duration therefore depends on the distance between the operator's office and the substation, and could be different for different areas of the network.

(c) **T_{Switch}**: The sectionalising time is the time required by the operator to perform the necessary switching to restore supply to all healthy parts of the network.

(d) **T_{Repair}**: This is the time required to repair/replace the faulty equipment. It includes the time required to apply and remove earths.

For unplanned outages, the time that elapses from the moment the fault occurs to the moment when the necessary switching has been done and the fault repair starts, indicated by S_i in Equation 15, is therefore calculated using:

$$S_i = T_{Dispatch} + T_{Travel} + T_{Switch} \qquad \textbf{Equation 16}$$

The repair time of the component R_i in Equation 15 is the repair time for the component, as specified by the user.

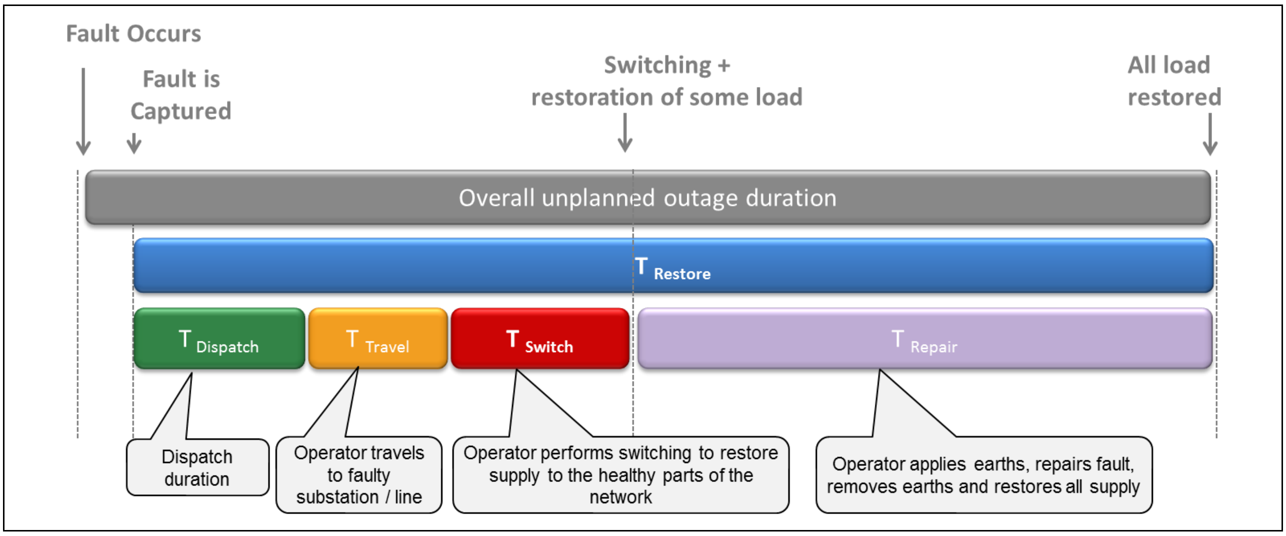


Figure 4-4: Substation unplanned outage duration components

The outage components for planned outages are slightly different. Firstly, there is no dispatch time, since dispatch is only associated with unplanned events. Another difference is that supply is only interrupted once the operator has arrived on site and performed the necessary switching to isolate the component that needs to be maintained. The time associated with travel and switching is therefore not part of the outage duration. Only the component repair time is considered for the planned outage duration. This is illustrated in Figure 4-5.

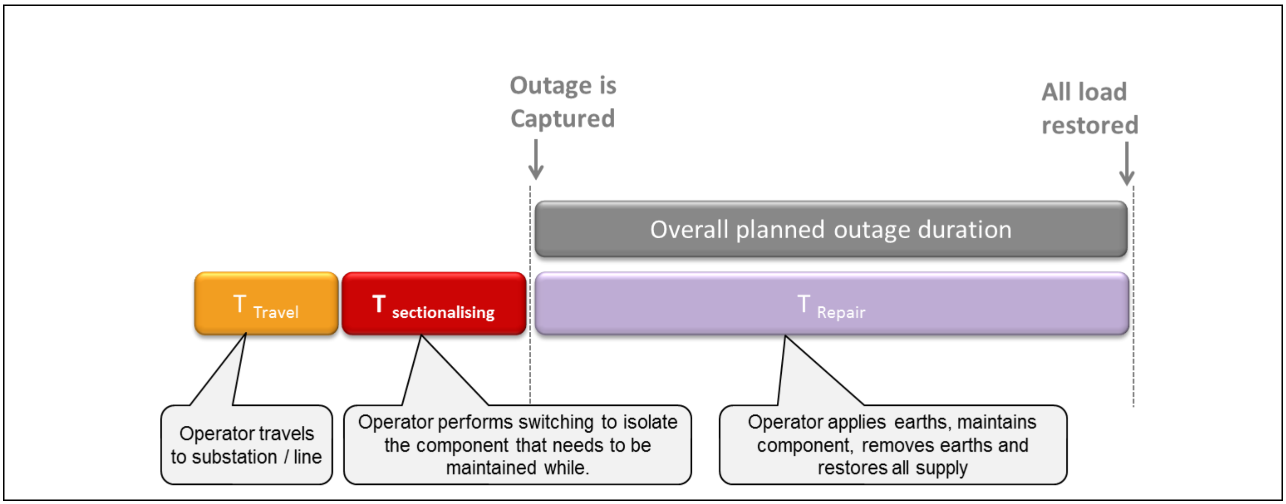


Figure 4-5: Substation planned outage duration components

For planned outages, the time required to perform switching, indicated by S_i in Equation 15, is therefore zero. The repair time of the component R_i in Equation 15 is the maintenance duration of the component, as specified by the user.

4.5. Impact of outages

4.5.1. Unplanned outages

Equation 14 and Equation 15 require the percentage of customers unsupplied when each component/module fails. Since a three-state model is considered (see section 3.2), two different customer impacts need to be defined, i.e.:

(a) The impact on customers supplied from the busbar, immediately after the fault occurs.

(b) The impact on customers supplied from the busbar after an operator has arrived on site and performed switching to restore supply to healthy sections of the busbar.

Furthermore, the upstream busbar also has an impact on the downstream busbar. If the upstream busbar configuration consists of more than one busbar or bus-section, then the impact on the downstream busbar is not necessarily the same as for the upstream busbar. This is illustrated in Figure 4-6. A fault occurs on the one bus-section of the upstream busbar. The bus zone protection of the upstream busbar will operate and open all breakers connected to the faulty busbar (also refer to section 4.5.1.2 for more information on bus zone protection). This will interrupt supply to "Load U1", while "Load U2" will still be supplied. The transformer capacity is firm and therefore all load on the downstream busbar will still be supplied.

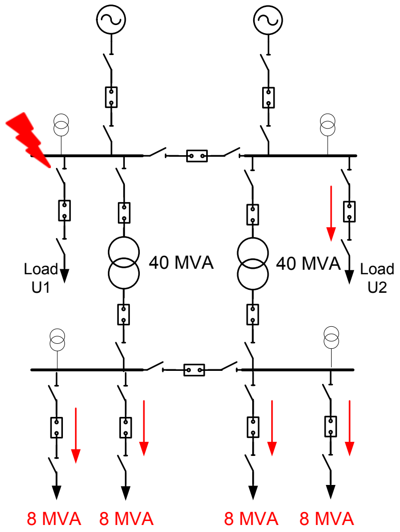


Figure 4-6: Difference in impact of upstream busbar failures on upstream vs downstream busbars.

The upstream and downstream busbars can therefore not be considered as components in series where the unavailability of the upstream busbar (due to upstream busbar faults) is simply added to the unavailability of the downstream busbar (due to transformer and downstream busbar faults) to get the total unavailability of the downstream busbar. It is necessary to analyse the impact of each upstream component failure on the downstream busbar's unavailability. Therefore, the following two additional customer impacts should also be analysed:

(a) The impact on customers supplied from the downstream busbar, following an equipment failure on the upstream busbar, immediately after the fault occurs. (E.g. the impact on the 22 kV busbar for a fault on the 132 kV equipment in a 132/22 kV substation, immediately after the fault occurs.)

(b) The impact on customers supplied from the downstream busbar, following an equipment failure on the upstream busbar, after an operator has arrived on site and restored supply to healthy sections of the substation.

The four different customer impacts are summarised in Table 4-7 to Table 4-10, for each component failure and busbar configuration. A summary of the network state, the relevant busbar and the table reference is given in Table 4-5.

Table 4-5: Table reference to the customer impact descriptions, given the network state and relevant busbar.

No	Planned /Unplanned	Network state	Impact on busbar / Impact on downstream busbar	Table reference
1	Unplanned	After fault, before switching	Impact on busbar	**Table 4-7**
2	Unplanned	After Switching	Impact on busbar	**Table 4-8**
3	Unplanned	After fault, before switching	Impact on downstream busbar	**Table 4-9**
4	Unplanned	After Switching	Impact on downstream busbar	**Table 4-10**

The abbreviations used in Table 4-7 to Table 4-10 to define the customer impact are described in Table 4-6. From this abbreviation the percentage customers interrupted is calculated in the model using the formula in the column "% customers unsupplied":

Table 4-6: Abbreviations used to define the percentage of customers/load interrupted

No	Abbreviation	Description	% customers unsupplied
1	**100%**	All customers supplied from the busbar are interrupted.	100%
2	**50%BB**	50% of customers supplied from the busbar are interrupted.	50%
3	**1xSrcFdr**	1 Source feeder is out-of-service. If the substation is supplied by only one source, all customers are interrupted. If the busbar is supplied from more than one source, no customers are interrupted.	If 1 x source feeder: 100% If >1 source feeder: 0
4	**2/3xSrcFdr**	This is similar to 1 x source feeder being out-of-service, but it is only applicable to 2 of every 3 failures of the specific component. This is illustrated by the schematic diagram in Figure 4-7. • If Bay 1, isolator 1 is out-of-service, line 1 will still be supplied. • If Bay 1, isolator 2 is out-of-service, line 1 will NOT be supplied. • If Bay 1, isolator 3 is out-of-service, line 1 will NOT be supplied. For 2 of the 3 isolator outages, Line 1 will be out-of-service. The impact is therefore 2/3 x 1 source feeder (see no.3).	If 1 x source feeder: 66.7% If >1 source feeder: 0
5	**1xLdFdr**	1 Load feeder is out-of-service. If the busbar supplies 4 x load feeders, then 25% (1/4 feeders) of the customers supplied are interrupted.	$\frac{1}{\#LdFdrs}$
6	**2/3xLdFdr**	This is similar to 1 x load feeder being out-of-service, but it is only applicable to 2 of every 3 failures of the specific component. (Also see comment for 2/3xSrcFdr in no.4).	$\frac{1}{\#LdFdrs} \times \frac{2}{3}$
7	**1TrfrCap**	1 transformer is out-of-service. If the downstream busbar is supplied by only one transformer, all supply is interrupted. If the downstream busbar is supplied by more than one transformer, the loading on the remaining transformer determines the percentage of customers affected.	If 1 x transformer: 1 If >1 transformer: see Equation 19 in section 0
8	**50%TrfrCap**	50% of the transformer capacity is lost. If the downstream busbar is supplied by only one	If 1 x transformer: 1

No	Abbreviation	Description	% customers unsupplied
		transformer, all supply is interrupted. If the downstream busbar is supplied by more than one transformer, the loading on the remaining 50% of transformer capacity determines the percentage of customers affected.	If >1 transformer: see Equation 20 in section 0
9	**50%BBCap**	50% of the busbar capacity is lost.	50%TrfrCap of downstream busbar (see no. 8 above).
10	**Max:50%BB/ 1xSrcFdr**	This is the maximum of no.2 and no.3. For example, if a substation is supplied by a single source feeder, the load lost will be 100% (as determined by no.3). If a substation is supplied by more than one source feeder, the load lost is determined by no.2 above ("50% BB").	Maximum [50%BB (no. 2), 1xSrcFdr (see no.3)]
11	**Ave:50%BB/ 1xSrcFdr**	This is the average of no.2 and no.3.	Average [50%BB (see no. 2), 1xSrcFdr (see no.3)]

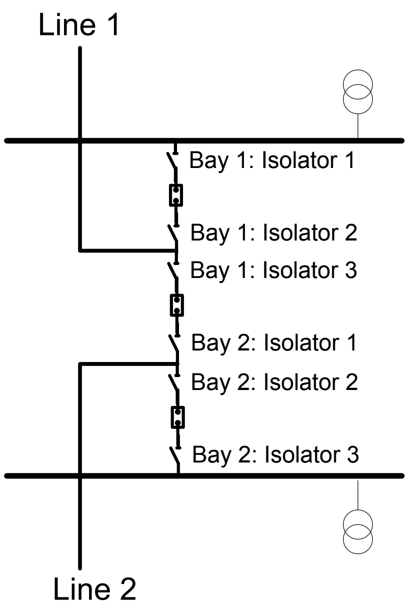


Figure 4-7: Illustrating the impact of 2/3xSrcFdr

Table 4-7: Impact of unplanned outages immediately after the fault (post-fault network state); impact on busbar itself

No	Component	Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type4 with Bypass	Type1 with Bypass	Type3 with Bypass
1	**SrcFdrBrkr**	100%	100%	Max_50%BB/ 1xSrcFdr	100%	Max_50%BB/ 1xSrcFdr	Max_25%BB/ 1xSrcFdr	1xSrcFdr	100%	100%	Max_50%BB/ 1xSrcFdr
2	**LdFdrBrkr**	100%	100%	Ave_50%BB/ 1xSrcFdr	100%	Ave_50%BB/ 1xSrcFdr	Ave_25%BB/ 1xSrcFdr	1xLdFdr	100%	100%	50%BB
3	**SrcFdrBBIsol**	100%	100%	50%BB	100%	50%BB	25%BB	2/3xSrcFdr	100%	100%	50%BB
4	**LdFdrBBIsol**	100%	100%	Ave_50%BB/ 1xSrcFdr	100%	Ave_50%BB/ 1xSrcFdr	Ave_25%BB/ 1xSrcFdr	2/3xLdFdr	100%	100%	50%BB
5	**BB**	100%	100%	Ave_50%BB/ 1xSrcFdr	100%	Ave_50%BB/ 1xSrcFdr	Ave_25%BB/ 1xSrcFdr	0	100%	100%	50%BB
6	**BBBrkr**	0	0	1	0	100%	Ave_50%BB/ 1xSrcFdr	0	0	0	100%
7	**BBIsol**	0	100%	Ave_50%BB/ 1xSrcFdr	0	Ave_50%BB/ 1xSrcFdr	Ave_25%BB/ 1xSrcFdr	0	0	0	50%BB
8	**SrcTrfrBrkr**	100%	100%	50%BB	100%	50%BB	25%BB	0	100%	100%	50%BB
9	**LdTrfrBrkr**	100%	100%	50%BB	100%	50%BB	25%BB	0	100%	100%	50%BB
10	**TrfrIsol**	100%	100%	50%BB	100%	50%BB	25%BB	1SrcTrfrCap	100%	100%	50%BB

Table 4-8: Impact of unplanned outages after switching (repair network state); impact on busbar itself

No	Component	Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type4 with Bypass	Type1 with Bypass	Type3 with Bypass
1	**SrcFdrBrkr**	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	0	0	0
2	**LdFdrBrkr**	1xLdFdr	1xLdFdr	1xLdFdr	1xLdFdr	1xLdFdr	1xLdFdr	0	0	0	0
3	**SrcFdrBBIsol**	100%	50%BB	50%BB	1xSrcFdr	1xSrcFdr	1xSrcFdr	2/3xSrcFdr	1xSrcFdr	100%	50%BB
4	**LdFdrBBIsol**	100%	50%BB	50%BB	1xLdFdr	1xLdFdr	1xLdFdr	2/3xLdFdr	1xLdFdr	100%	50%BB
5	**BB**	100%	50%BB	50%BB	0	0	0	0	0	100%	50%BB
6	**BBBrkr**	0	0	0	0	0	0	0	0	0	0
7	**BBIsol**	0	50%BB	50%BB	0	0	0	0	0	0	50%BB
8	**SrcTrfrBrkr**	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	0	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap
9	**LdTrfrBrkr**	0	0	0	0	0	0	0	0	0	0
10	**TrfrIsol**	100%	Max_50%BB/ 1SrcTrfrCap	Max_50%BB/ 1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	100%	Max_50%BB/ 1SrcTrfrCap

Table 4-9: Impact of unplanned outages immediately after the fault (post-fault network state); impact on downstream busbar (not applicable to components connected to downstream busbars)

No	Component	Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type4 with Bypass	Type1 with Bypass	Type3 with Bypass
1	**SrcFdrBrkr**	100%	100%	Max_50%BBCap/ 1xSrcFdr	100%	Max_50%BBCap/ 1xSrcFdr	Max_25%BBCap/ 1xSrcFdr	1xSrcFdr	100%	100%	Max_50%BBCap/ 1xSrcFdr
2	**LdFdrBrkr**	100%	100%	Ave_50%BBCap/ 1xSrcFdr	100%	Ave_50%BBCap/ 1xSrcFdr	Ave_50%BBCap/ 1xSrcFdr	0	100%	100%	50%BBCap
3	**SrcFdrBBIsol**	100%	100%	50%BBCap	100%	50%BBCap	25%BBCap	0	100%	100%	50%BBCap
4	**LdFdrBBIsol**	100%	100%	50%BBCap	100%	50%BBCap	25%BBCap	0	100%	100%	50%BBCap
5	**BB**	100%	100%	50%BBCap	100%	50%BBCap	25%BBCap	0	100%	100%	50%BBCap
6	**BBBrkr**	0	0	1	0	100%	Max_50%BBCap/ 1LdTrfrCap	0	0	0	100%
7	**BBIsol**	0	100%	50%BBCap	0	50%BBCap	25%BBCap	0	0	0	50%BBCap
8	**SrcTrfrBrkr**	100%	100%	50%BBCap	100%	50%BBCap	25%BBCap	0	100%	100%	50%BBCap
9	**LdTrfrBrkr**	100%	100%	Max_50%BBCap/ 1LdTrfrCap	100%	Max_50%BBCap/ 1LdTrfrCap	Max_25%BBCap/ 1LdTrfrCap	0	100%	100%	Max_50%BBCap/ 1LdTrfrCap
10	**TrfrIsol**	100%	100%	Max_50%BBCap/ 1LdTrfrCap	100%	Max_50%BBCap/ 1LdTrfrCap	Max_25%BBCap/ 1LdTrfrCap	1LdTrfrCap	100%	100%	Max_50%BBCap/ 1LdTrfrCap

Table 4-10: Impact of unplanned outages after switching (repair network state); impact on downstream busbar (not applicable to components connected to downstream busbars)

No	Component	Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type4 with Bypass	Type1 with Bypass	Type3 with Bypass
1	SrcFdrBrkr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	0	0	0
2	LdFdrBrkr	0	0	0	0	0	0	0	0	0	0
3	SrcFdrBBIsol	100%	50%BBCap	50%BBCap	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	0	100%	50%BBCap
4	LdFdrBBIsol	100%	50%BBCap	50%BBCap	0	0	0	0	0	100%	50%BBCap
5	BB	100%	50%BBCap	50%BBCap	0	0	0	0	0	100%	50%BBCap
6	BBBrkr	0	0	0	0	0	0	0	0	0	0
7	BBIsol	0	50%BBCap	50%BBCap	0	0	0	0	0	0	50%BBCap
8	SrcTrfrBrkr	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	0	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap
9	LdTrfrBrkr	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	0	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap
10	TrfrIsol	100%	Max_50%BBCap/ 1LdTrfrCap	Max_50%BBCap/ 1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	100%	Max_50%BBCap/ 1LdTrfrCap

4.5.1.1. Customer impact due to transformer outages

In section 4.1 the assumption was made that the full capacity of a transformer(s) can be utilised under n-1 conditions. Considering this assumption, the number of customers interrupted due to one transformer out-of-service can be calculated using Equation 17:

$$\%Unsupplied_{1\times trfr-out} = \frac{P_{max} - \left[\left(\sum_{i=1}^{n} TrfrCap_i - \frac{\sum_{i=1}^{n} TrfrCap_i}{\#_{Trfr}}\right)\right]}{P_{max}} \quad \textbf{Equation 17}$$

Where:

%Unsupplied$_{1xtrfr-out}$	=	Percentage customers unsupplied if one transformer is out-of-service (%)
P_{Max}	=	Maximum transformer load (MVA)
$TrfrCap_i$	=	Rated capacity of transformer i (MVA)
# Trfr	=	Number of transformers
n	=	Number of transformers connected

If 50% of the transformer capacity is interrupted, the percentage of customers interrupted is calculated using Equation 18:

$$\%Unsupplied_{50\%\times trfr-out} = \frac{P_{max} - \left[\left(\sum_{i=1}^{n} TrfrCap_i - \frac{\sum_{i=1}^{n} TrfrCap_i}{0.5 \times \#Trfr}\right)\right]}{P_{max}} \quad \textbf{Equation 18}$$

Where:

%Unsupplied$_{50\%xtrfr-out}$	=	Percentage customers unsupplied if 50% of the transformers are out-of-service (%)
P_{Max}	=	Maximum transformer load (MVA)
$TrfrCap_i$	=	Rated capacity of transformer i (MVA)
# Trfr	=	Number of transformers
n	=	Number of transformers connected

Transformers can however be loaded above their rated capacity, for short durations, in the event of an emergency. To accommodate this emergency rating, the simplified approach makes provision for the user to define the maximum loading on the transformer under n-1 conditions. Including this emergency rating, Equation 17 becomes:

$$\%Unavailable_{1\times trfr-out} = \frac{P_{max} - \left[\left(\sum_{i=1}^{n} TrfrCap_i - \frac{\sum_{i=1}^{n} TrfrCap_i}{\#_{Trfr}}\right) \times TrfrRating\right]}{P_{max}} \quad \textbf{Equation 19}$$

Where:

%Unsupplied$_{1xtrfr-out}$	=	Percentage customers unsupplied if one transformer is out-of-service (%)
P_{Max}	=	Maximum transformer load (MVA)
$TrfrCap_i$	=	Rated capacity of transformer i (MVA)

Trfr = Number of transformers

n = Number of transformers connected

TrfrRating = Maximum transformer loading under n-1 conditions (%)

Similarly, Equation 18 changes to:

$$\%Unsupplied_{50\%\times trfr-out} = \frac{P_{max} - \left[\left(\sum_{i=1}^{n} TrfrCap_i - \frac{\sum_{i=1}^{n} TrfrCap_i}{0.5 \times \#_{Trfr}}\right) \times TrfrRating\right]}{P_{max}} \quad \textbf{Equation 20}$$

Where:

$\%Unsupplied_{50\%xtrfr-out}$ = Percentage customers unsupplied if 50% of the transformers are out-of-service (%)

P_{Max} = Maximum transformer load (MVA)

$TrfrCap_i$ = Rated capacity of transformer i (MVA)

Trfr = Number of transformers

n = Number of transformers connected

TrfrRating = Maximum transformer loading under n-1 conditions (%)

It is important to note that the failure of any component within the transformer module (as per the composite classification in section 3.3.1), only impacts the downstream busbar and not the upstream busbar. The impact of all transformer failures can be analysed using the equations above, irrespective of the busbar configuration. The impact of transformer failures is therefore not shown for each busbar configuration in the tables below, since the impact is independent of the busbar configuration.

4.5.1.2. Bus zone protection

The customer impacts defined in the tables above assume that all busbars have bus zone protection installed. For example, if one bus-section of a Type 3 busbar fails, it is assumed that only 50% of the customers are interrupted immediately after the fault, since the bus zone protection will open the bus-section breaker and isolate the fault, as illustrated in Figure 4-8.

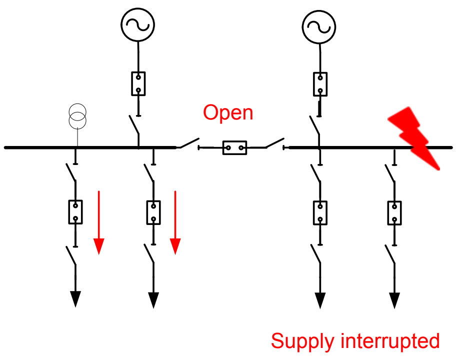


Figure 4-8: Diagram illustrating the post-fault state of a busbar fault for a busbar with bus-section and bus zone protection

The modelling also makes provision for busbars without bus zone protection. If a fault occurs on a busbar without bus zone protection, the upstream transformer breakers (for a downstream busbar) or the upstream line breakers (for an upstream busbar) will open and interrupt supply to all customers on that busbar. This scenario is included in the modelling by altering the formula for the unplanned customer impact immediately after the fault (post-fault network state). The formula used for calculating the customer impact immediately after the fault first evaluates whether bus zone protection is installed. If no bus zone protection exists, the customer impact is 1 (all customers are interrupted). If bus zone protection does exist, the customer impact as indicated in Table 4-7 and Table 4-9 respectively is applied. This applies to all equipment failures except transformer module failures, since transformer module failures are cleared by the transformer upstream breaker and not the bus zone protection. The availability of bus zone protection does not change any of the calculations for the customer impact repair network state.

4.5.2. Planned outages

The impact of maintenance on continuity of supply is similar to the impact of a fault after switching has taken place. The impact on customers is therefore similar to Table 4-8 and Table 4-10. This is shown in Table 4-11 and Table 4-12 below.

Using the approach explained for planned outages resulted in some customers experiencing very long planned outage durations per annum. For example, consider a substation with a single source, single busbars and single transformer. If a maintenance frequency of once every 5 years is applied and all switchgear and transformers are maintained for 4 hours, the total outage duration experienced will be 5.6 h/a. This equates to 28 h over a 5 year maintenance cycle, which is unrealistically high.

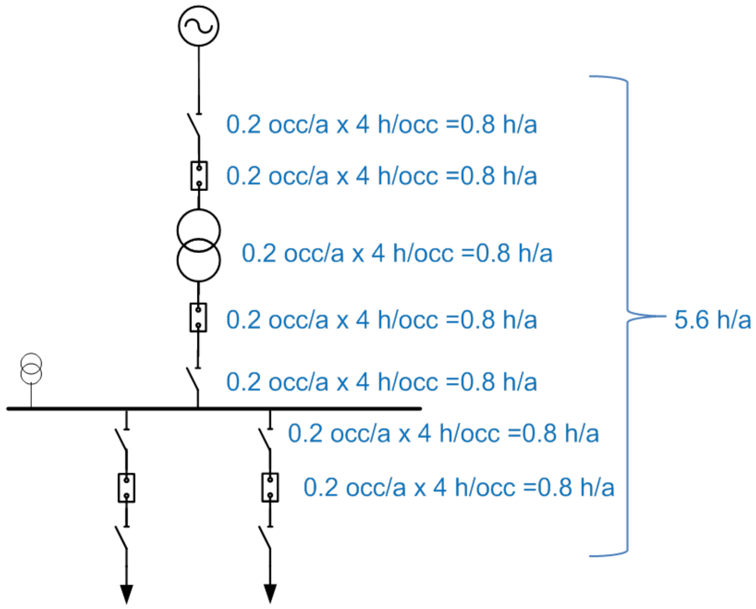


Figure 4-9: Illustrative impact of planned maintenance in substations with no redundancy

4.5.2.1. Planned outage optimisation

To prevent such high outage durations, utilities will minimize the outage duration by using more than one team to perform the maintenance. An example of such a scenario is that each breaker and isolator pair is maintained by a separate team, and the transformer is maintained by a fourth team. The total outage duration will now be 1.6 h/a. This optimisation was included in the simplified reliability modelling by introducing a cap to the calculated planned outage duration. The user needs to specify the frequency and duration cap for planned substation maintenance.

Table 4-11: Impact of planned outages on busbar itself

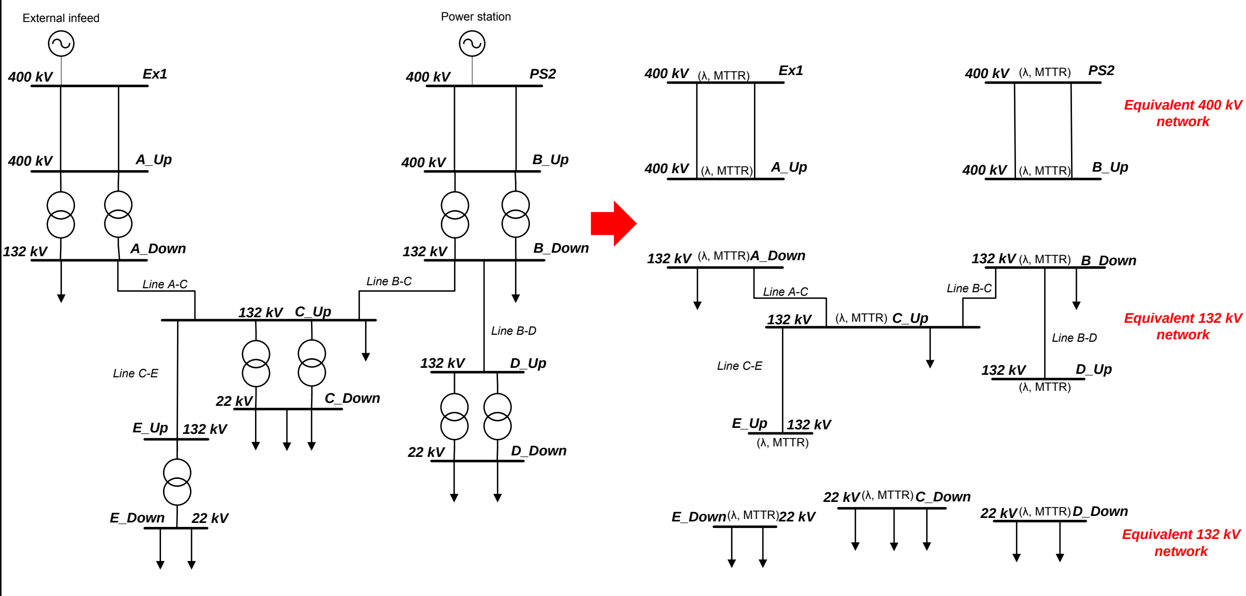
No	Component	Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type4 with Bypass	Type1 with Bypass	Type3 with Bypass
1	**SrcFdrBrkr**	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	0	0	0
2	**LdFdrBrkr**	1xLdFdr	1xLdFdr	1xLdFdr	1xLdFdr	1xLdFdr	1xLdFdr	0	0	0	0
3	**SrcFdrBBIsol**	100%	50%BB	50%BB	1xSrcFdr	1xSrcFdr	1xSrcFdr	2/3xSrcFdr	1xSrcFdr	100%	50%BB
4	**LdFdrBBIsol**	100%	50%BB	50%BB	1xLdFdr	1xLdFdr	1xLdFdr	2/3xLdFdr	1xLdFdr	100%	50%BB
5	**BB**	100%	50%BB	50%BB	0	0	0	0	0	100%	50%BB
6	**BBBrkr**	0	0	0	0	0	0	0	0	0	0
7	**BBIsol**	0	50%BB	50%BB	0	0	0	0	0	0	50%BB
8	**SrcTrfrBrkr**	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	0	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap
9	**LdTrfrBrkr**	0	0	0	0	0	0	0	0	0	0
10	**TrfrIsol**	100%	Max_50%BB/ 1SrcTrfrCap	Max_50%BB/ 1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	100%	Max_50%BB/ 1SrcTrfrCap

Table 4-12: Impact of planned outages on downstream busbar (not applicable to components connected to downstream busbars)

No	Component	Type1	Type2	Type3	Type4	Type5	Type6	Type7	Type4 with Bypass	Type1 with Bypass	Type3 with Bypass
1	**SrcFdrBrkr**	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	0	0	0
2	**LdFdrBrkr**	0	0	0	0	0	0	0	0	0	0
3	**SrcFdrBBIsol**	100%	50%BBCap	50%BBCap	1xSrcFdr	1xSrcFdr	1xSrcFdr	1xSrcFdr	0	100%	50%BBCap
4	**LdFdrBBIsol**	100%	50%BBCap	50%BBCap	0	0	0	0	0	100%	50%BBCap
5	**BB**	100%	50%BBCap	50%BBCap	0	0	0	0	0	100%	50%BBCap
6	**BBBrkr**	0	0	0	0	0	0	0	0	0	0
7	**BBIsol**	0	50%BBCap	50%BBCap	0	0	0	0	0	0	50%BBCap
8	**SrcTrfrBrkr**	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap	0	1SrcTrfrCap	1SrcTrfrCap	1SrcTrfrCap
9	**LdTrfrBrkr**	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	0	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap
10	**TrfrIsol**	100%	Max_50%BBCap/ 1LdTrfrCap	Max_50%BBCap/ 1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	1LdTrfrCap	100%	Max_50%BBCap/ 1LdTrfrCap

5. Transmission and sub-transmission network evaluation methodology

In chapter 4 the methodology was described to calculate the unavailability of each busbar. For a given transmission and/or sub-transmission network an equivalent system model can now be generated by replacing all substations in the network with busbars that have the equivalent outage frequency and outage duration. This is illustrated by the simplified network diagrams in Figure 5-1. Figure 5-1 (a) shows the complete transmission and sub-transmission network. Figure 5-1 (b) shows the equivalent system model, where each substation has been replaced by the outage rate and unavailability of each busbar within the substation. It is important to note that the equivalent system model is split into separate networks, where each network has only one voltage level.



(a) Network diagram

(b) Equivalent system model with no substations

Figure 5-1: Generating an equivalent system model by replacing all substations with busbars of equal outage frequency and duration

The next step is to calculate the total unavailability of each busbar, which includes the unavailability of the lines and upstream busbars. The methodology for calculating the contribution of the lines and upstream busbar is discussed in this chapter. The section starts with a list of assumptions used for the transmission and sub-transmission modelling. The rest of the section provides details on the reliability estimation methodology. A list of data required to perform the transmission and sub-transmission reliability estimation is summarised in Annex D.

5.1. Assumptions

The following assumptions are made in order to simplify the transmission and sub-transmission network evaluation methodology:

(a) Overlapping failures are not considered in the failure scenarios. For example, the probability of a line failure occurring at the same time as a substation component failure, such as a busbar failure, is assumed to be zero. Similarly, the probability of any two lines failing at the same time is assumed to be zero. Another example is the probability that a line (or line isolator) failure occurs while another line (or line isolator) is out-of-service for planned maintenance is assumed to be zero.

(b) Transmission and sub-transmission ring networks provide firm line capacity to all substations supplied from the ring. Therefore, if one of the lines in the ring fails, all load at each of the substations supplied from the ring can still be supplied.

(c) Not all ring networks are operated normally closed. Ring networks ≥ 88 kV are assumed to be operated normally closed, while ring networks < 88 kV are operated normally open.

(d) A line (or line isolator) is taken out-of-service for planned maintenance, irrespective of whether it causes the outage of a customer load.

5.2. Number of components per line/cable

The line/cable module was discussed in detail in section 3.3.3. Each line/cable module consists of a line/cable of specified length and two isolators, i.e. one isolator on each side of the line/cable. The line/cable breaker was included in the substation modelling and is therefore not considered as part of the transmission and sub-transmission approach.

Since overlapping failures are ignored, failures of the line/cable module are ignored for substations supplied by more than one source feeder. Failures of the line/cable module are only considered for substations supplied by a single source feeder, or substations supplied by more than one feeder of which one feeder is operated normally open and all the other feeders are operated normally closed.

5.3. Outage frequency and duration

The outage frequency per km (occ/km/a) of the line/cable and the failure rate (occ/a) of the isolators need to be defined by the user. From these failure rates the equivalent failure rate of the line module is calculated, as explained in section 3.3.3.

The outage durations for line/cable faults were broken down into outage components, similar to the outage duration of substation faults. The outage components are different for radial networks vs ring networks operated normally open. For ring networks operated normally closed, the line failure will not interrupt any supply, due to the assumption that the line capacity of all ring networks is firm.

The outage components for radial networks are shown in Figure 5-2. These components are similar to those for substation faults, discussed in section 4.4.2. The only difference is that no load can be restored after switching, before the fault is repaired.

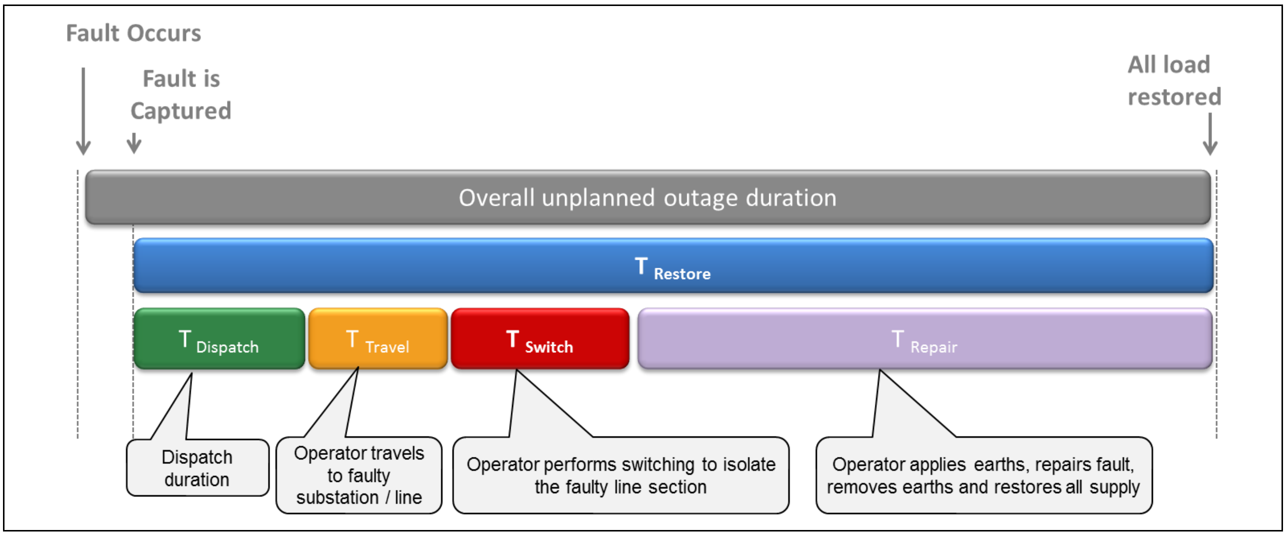


Figure 5-2: Unplanned outage duration components for line failures of radial networks

The outage components for ring networks operated normally open are shown in Figure 5-3. This figure illustrates that supply to all customers will be restored before the fault is repaired. It is important to note that this implies that ring networks supply firm capacity to all substations supplied from the ring. The outage duration, due to line failures, experienced by customers on ring networks depends on whether there is remote visibility at the normally open point. If there is remote visibility, the normally open point can be switched from remote and all supply is restored. If there is no remote visibility, the dispatch centre needs to dispatch an operator, the operator needs to drive to the site and then switch the normally open point. The total supply interruption is therefore much longer for the scenario without network visibility than the scenario with network visibility.

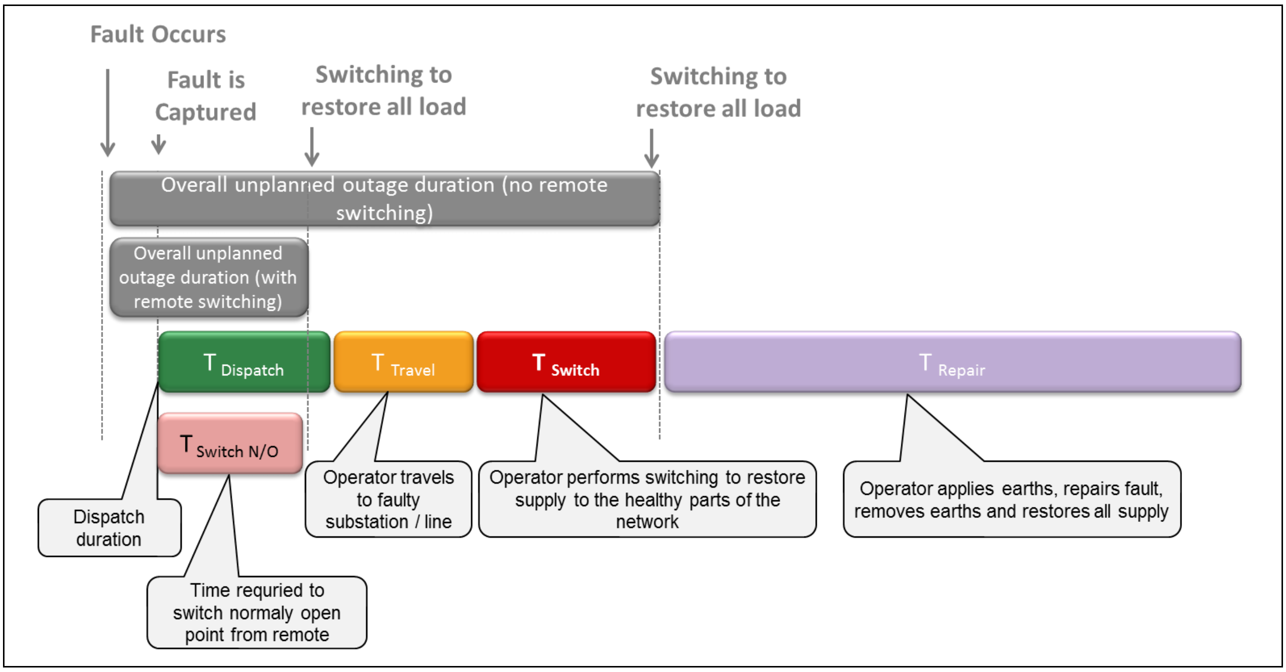


Figure 5-3: Unplanned outage duration components for line failures of ring networks operated normally open.

The annual downtime experienced by a customer supplied from a radial network is calculated using:

$$U_{line} = \left[(\lambda_{line} \times LL) \times \left(T_{Dispatch} + T_{Travel} + T_{Switch} + R_{line}\right)\right] + \left[(\lambda_{isolator} \times 2) \times \left(T_{Dispatch} + T_{Travel} + T_{Switch} + R_{isolator}\right)\right]$$ **Equation 21**

Where:

U_{line}	=	Outage duration (per annum) of the line/cable module (h/a)
λ_{line}	=	Failure rate of the line/cable (occ/km/a)
LL	=	Line length (km)
$\lambda_{isolator}$	=	Failure rate of the line isolator (occ/a)
$T_{Dispatch}$	=	Dispatch time (h)
T_{Travel}	=	Travel time (h)
T_{Switch}	=	Switching time (h)
R_{line}	=	Repair time of the line (h)
$R_{isolator}$	=	Repair time of the isolator (h)

The annual downtime experienced by a customer supplied from a ring network operated normally open is calculated using:

$$U_{line} = \left[(\lambda_{line} \times LL) \times \left(T_{Switch\ N/O}\right)\right] + \left[(\lambda_{isolator} \times 2) \times \left(T_{Switch\ N/O}\right)\right]$$ **Equation 22**

Where:

U_{line}	=	Outage duration (per annum) of the line/cable module (h/a)
λ_{line}	=	Failure rate of line/cable (occ/km/a)
LL	=	Line length (km)
$\lambda_{isolator}$	=	Failure rate of line isolator (occ/a)
$T_{SwitchN/O}$	=	Time required to switch the normally open point (h)

5.4. Total system unavailability

The simplified substation reliability evaluation model calculates the frequency and unavailability for both the upstream and downstream busbars. The total unavailability of each busbar can now be calculated by adding the unavailability of all upstream lines and substations in series with the specific busbar (see Figure 5-5). This requires information on which line(s) supplies each busbar, as well as the upstream busbar that supplies each line. The user needs to provide this information as input to the simplified reliability model.

The system level calculation considers two distinct busbar frequency and unavailability indices, i.e. the busbar only frequency ($\lambda_{BusbarOnly}$) and unavailability ($U_{BusbarOnly}$) as calculated in the substation modelling, and the total frequency ($\lambda_{BusbarTotal}$) and unavailability of the busbar ($U_{BusbarTotal}$) which includes the unavailability of the upstream transmission and sub-transmission network. The contribution of the upstream network is that of the line(s) supplying the busbar and the total frequency and unavailability of the busbar(s) on the upstream side of this/these line(s). The frequency and unavailability calculation is shown in Equation 23:

$$\lambda_{BBTotal} = \lambda_{BBOnly} + \lambda_{Line} + \lambda_{UpstreamBBTotal}$$

$$U_{BBTotal} = U_{BBOnly} + U_{Line} + U_{UpstreamBBTotal}$$

Equation 23

Where:

$\lambda_{BBTotal}$	=	Interruption frequency (per annum) of the busbar, including the contribution of the upstream network (occ/a).
λ_{BBOnly}	=	Interruption frequency (per annum) of the busbar as calculated in the substation modelling. It excludes the contribution of the upstream line and the busbar on the upstream side of the line (occ/a).
$\lambda_{UpstreamBBTotal}$	=	Interruption frequency (per annum) of the busbar on the upstream side of the line, including the contribution of this busbar's upstream network (occ/a).
λ_{line}	=	Interruption frequency (per annum) of the line that supplies the busbar (occ/a). If the busbar is supplied by more than one line, this frequency is 0 occ/a.
$U_{BBTotal}$	=	Outage duration (per annum) of the busbar, including the contribution of the upstream network (h/a).
U_{BBOnly}	=	Outage duration (per annum) of the busbar as calculated in the substation modelling. It excludes the contribution of the upstream line and the busbar on the upstream side of the line (h/a).
$U_{UpstreamBBTotal}$	=	Outage duration (per annum) of the busbar on the upstream side of the line, including the contribution of this busbar's upstream network (h/a).
U_{line}	=	Outage duration (per annum) of the line that supplies the busbar (h/a). If the busbar is supplied by more than one line, this outage duration is 0 h/a.

If Equation 23 is applied on the network illustrated in Figure 5-4, the total unavailability of Busbar C can be calculated as follows:

$$U_{Total\_C} = U_{BB\_C} + U_{L\_B-C} + U_{Total\_B}$$

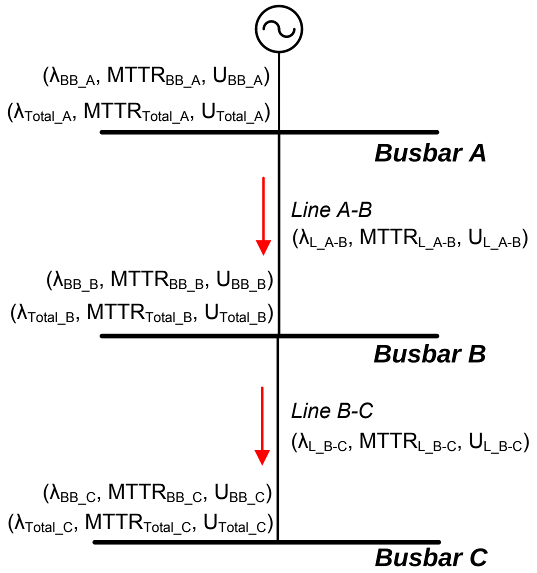


Figure 5-4: Illustrating the total busbar unavailability calculation

The contribution of the upstream busbar is ignored if the busbar is supplied in a ring from two different upstream busbars. For example, consider busbar "C_Upstream" in Figure 5-5. The two busbars upstream from this busbar are "A_Downstream" and "B_Downstream". If "A_Downstream" is unavailable, busbar "C_Upstream" is still supplied from busbar "B_Downstream". Since busbar "C_Upstream" is not affected by the unavailability of a single busbar, no upstream busbar should be specified by the user. The user should only specify an upstream busbar if the unavailability of this busbar will impact the availability of the busbar for which the unavailability is calculated.

The system-level calculation for a small section of a network is illustrated by means of the single line diagram in Figure 5-5 and the formulae in Table 5-1.

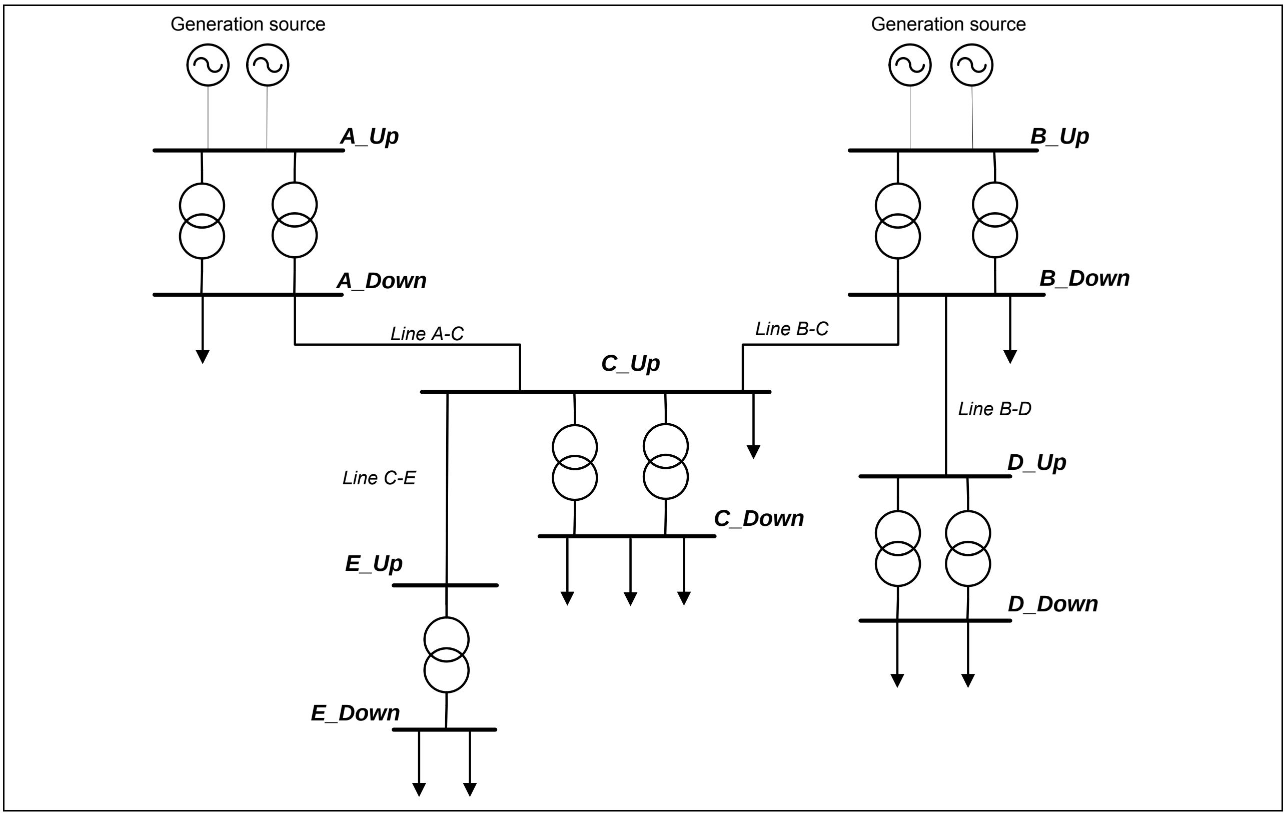


Figure 5-5: Transmission and sub-transmission reliability calculation approach

Table 5-1: Calculating the unavailability of each busbar in the system

No	Busbar description	U_{BBOnly}	+	U_{Line}+$U_{UpstreamBBTotal}$	=	$U_{BBTotal}$
1	**Downstream busbar of substation C**	C_Down_{BBOnly}	+	*0 (2 lines operated normally closed)*	=	$C\_Down_{BBTotal}$
2	**Downstream busbar of substation D**	D_Down_{BBOnly}	+	*Line B-D* + B_Down_{BBotal}	=	D_Down_{BBOnly} + *LineB-D* + $B\_Down_{BBTotal}$
3	**Downstream busbar of substation E**	E_Down_{BBOnly}	+	*Line C-E* + $C\_Up_{BBTotal}$	=	E_Down_{BBOnly} + *LineC-E* + $C\_Up_{BBTotal}$
4	**Upstream busbar of substation C**	C_Up_{BBOnly}	+	*0 (2 lines operated normally closed)*	=	$C\_Up_{BBTotal}$

The simplified approach allows the user to define the availability of an external supply source or power station. For example, consider the network illustrated in Figure 5-6. The simplified reliability evaluation model is used to calculate the availability of all “Utility B” (highlighted in green) networks. “Utility B” is supplied by “Utility A” (networks highlighted in blue). The availability of “Line A-C”, “Line B-C” substation A’s downstream busbar and substation B’s downstream busbar will therefore impact the performance of “Utility B”. In the simplified model, substation B’s downstream busbar needs to be included as the source of “Line B-D”. As part of the substation input parameters (see no. 13 & 14 in Table C-1, in Annex C) the user needs to indicate that this busbar is an external supply source and specify the expected unavailability of this external busbar.

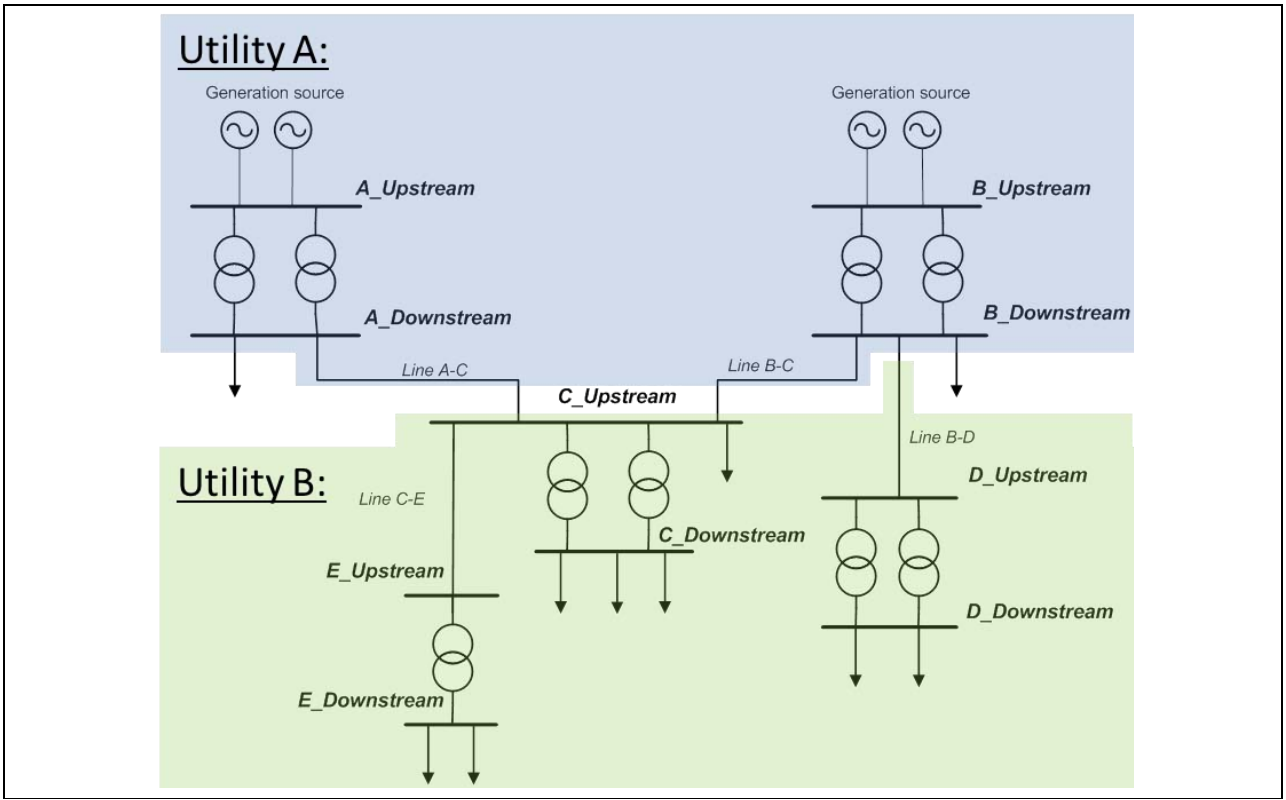


Figure 5-6: Illustration of external supply sources to a given network.

5.5. System indices

In section 5.4, the customer load point indices (discussed in section 2.3 of the literature study) were calculated. From these customer load point indices, the system indices can be calculated. The scope of this research is limited to the technical performance indices and the two system indices that are most commonly used for reporting and benchmarking, i.e. SAIFI and SAIDI.

5.5.1. SAIFI

One of the outcomes of the reliability calculation is the interruption frequency (occ/a) of each busbar in the system. This indicator, combined with the number of customers supplied from each busbar, is used to calculate the total SAIFI of the network.

The modelled SAIFI for the system is calculated as follows:

$$SAIFI = \frac{\sum_{i=1}^{n} Interruption\ frequency_i \times Customers_i}{\sum_{i=1}^{n} Customers_i}$$ **Equation 24**

Where:

SAIFI	=	System SAIFI (occ/a)
Interruption frequency$_i$:	=	Interruption frequency of busbar *i* (occ/a)
Customers$_i$	=	Number of customers supplied from busbar *i*
n	=	Number of busbars

5.5.2. SAIDI

Another outcome of the reliability calculation is the unavailability (hours per annum) of each busbar in the system. This indicator, combined with the number of customers supplied from each busbar, is used to calculate the total SAIDI of the network.

The modelled SAIDI for the system is calculated as follows:

$$SAIDI = \frac{\sum_{i=1}^{n} Unavailability_i \times Customers_i}{\sum_{i=1}^{n} Customers_i}$$ **Equation 25**

Where:

SAIDI	=	System SAIDI (h/a)
Unavailability$_i$	=	Total navailability of busbar *i* (h/a)
Customers$_i$	=	Number of customers supplied from busbar *i*
n	=	Number of busbars

6. Verification of simplified approach

Existing reliability modelling software was used to verify the unavailability results obtained from the simplified approach. Some of the reliability modelling software packages available on the market are listed in section 2.1.6 of the literature study. All these software packages were considered for the verification of the simplified approach.

6.1. Verify the substation approach

PowerFactory is used by various South African distribution utilities. For this reason and due to the availability of a license for the reliability analysis functions of PowerFactory, this software was selected for the verification of the simplified substation approach. The following conventions were applied to the software model:

(a) The line isolators have a failure rate of 0, since the failures of these isolators are included in the line calculations and not the substation calculations.

(b) A response time of 1 hour was assumed for all components. This represents the sum of the dispatch time (30 minutes) and travel time (30 minutes) used in the simplified reliability model.

(c) The failure rates and repair durations are shown in Table 6-1. These failure rates and repair durations were selected based on empirical studies.

(d) Only the unplanned impact of failures was considered. The planned component was ignored, to simplify the verification.

(e) It was assumed that there is bus zone protection on all HV busbars, but no bus zone protection on MV busbars.

Table 6-1: Failure rates and repair durations applied in the simplified reliability model

No.	Composite description	Frequency (Occ/a)	Mean repair duration (h)	Total outage duration (h)*
1	HV busbar with single VT	0.023	14.957	15.957
2	HV busbar with dual VT	0.026	14.154	15.154
3	HV bus-section with single VT on each section	0.013	14.154	15.154
4	HV breaker	0.023	12	13
5	HV isolator	0.010	10	11
6	Transformer	0.054	60.444	61.444
7	MV busbar with single VT	0.007	9.7	10.7
8	MV busbar with dual VT	0.008	9.5	10.5
9	MV bus-section with single VT on each section	0.004	9.5	10.5
10	MV breaker	0.006	10	11
11	MV isolator	0.006	6	7

** Includes 1 hour response time*

6.1.1. PowerFactory results

PowerFactory Version 14.1 was used to verify the substation reliability modelling. The failure rates and repair times as listed in Table 6-1 were assigned to the relevant components. It is important to note that in PowerFactory a failure rate and repair duration cannot be assigned to an isolator or breaker. A workaround for this shortcoming is to assign the failure rate and repair duration to the terminal to which the isolator/breaker is connected. The breaker operating times were set to 30 seconds. The time required to switch the disconnectors was set to 60 min, which is the assumed response time of 1 hour.

The first substation configuration was a single transformer HV/MV substation, with a single MV busbar. The configuration is illustrated in Figure 6-1.

The results obtained with the simplified reliability approach are shown in Table 6-2. In Figure 6-1 (a), the PowerFactory results show a frequency of 0.136 occ/a and a duration of 4.036 h/a for the downstream busbar. This is different from the simplified reliability modelling which calculated a frequency of 0.154 occ/a and a duration of 4.162 h/a for the downstream busbar (see Table 6-2). The reason for this discrepancy is the following: In Power Factory each MV line's busbar isolator failure rate is assigned to the terminal to which the isolator is connected (see Figure 6-1 (a)). If this terminal fails (representing the failure of the isolator), the isolator connected to the failed terminal is switched and supply is restored to the MV busbar and the other three loads on the busbar. However, in reality, the busbar will have to remain out-of-service while the busbar isolator is repaired. To model this scenario accurately, an additional terminal was added between each busbar isolator and the busbar (see Figure 6-1 (b)). Each of these terminals was connected to the busbar via a very short section of line (with no failure rate). The failure rate of the isolator was assigned to this new terminal. If this new terminal fails (representing the failure of the isolator), the busbar will remain out-of-service while the terminal is being repaired, since there is no isolating mechanism between the failed terminal and the busbar.

Table 6-2: Unavailability results obtained using simplified approach

No	Description	Impact on												
		Load supplied from upstream busbar				Load supplied from downstream busbar								
		Upstream busbar equipment failures								Downstream busbar equipment failures				
		Before switching		After switching		Before switching		After switching		Before switching		After switching		
		Fr*	D**	Fr*	D**	Fr*	D**	Fr*	D**	Fr*	D**	Fr*	D**	
1	Transformer Bay isolator	0.010	0.010	0.010	0.100	0.010	0.010	0.010	0.100	0.006	0.006	0.006	0.036	
2	Busbar									0.007	0.007	0.007	0.068	
3	Busbar breaker													
4	Busbar isolator													
5	Source feeder bay isolator													
6	Load feeder bay isolator									0.024	0.024	0.024	0.144	
7	Source transformer bay breaker									0.006	0.006	0.006	0.060	
8	Load transformer bay breaker	0.023	0.023			0.023	0.023	0.023	0.276					
9	Source feeder bay breaker													
10	Load feeder bay breaker									0.024	0.024	0.006	0.060	
11	Transformer					3	5		6	0.054	0.054	0.054	3.264	
12	**Unplanned Total**	0.033	0.033	0.010	0.100	0.033	0.033	0.033	0.376	0.121 4	0.121 7		3.632	8
13	**Unplanned Total**	0.033	1		0.133	2				0.154	3+4		4.162	5+6+7+8
14	**Total Frequency**	(Upstream busbar) 0.033				1				(Downstream busbar) 0.154				3+4
15	**Total Duration**	(Upstream busbar) **0.133**				2				(Downstream busbar) **4.162**				5+6+7+8

*Fr = Frequency; **D = Duration*

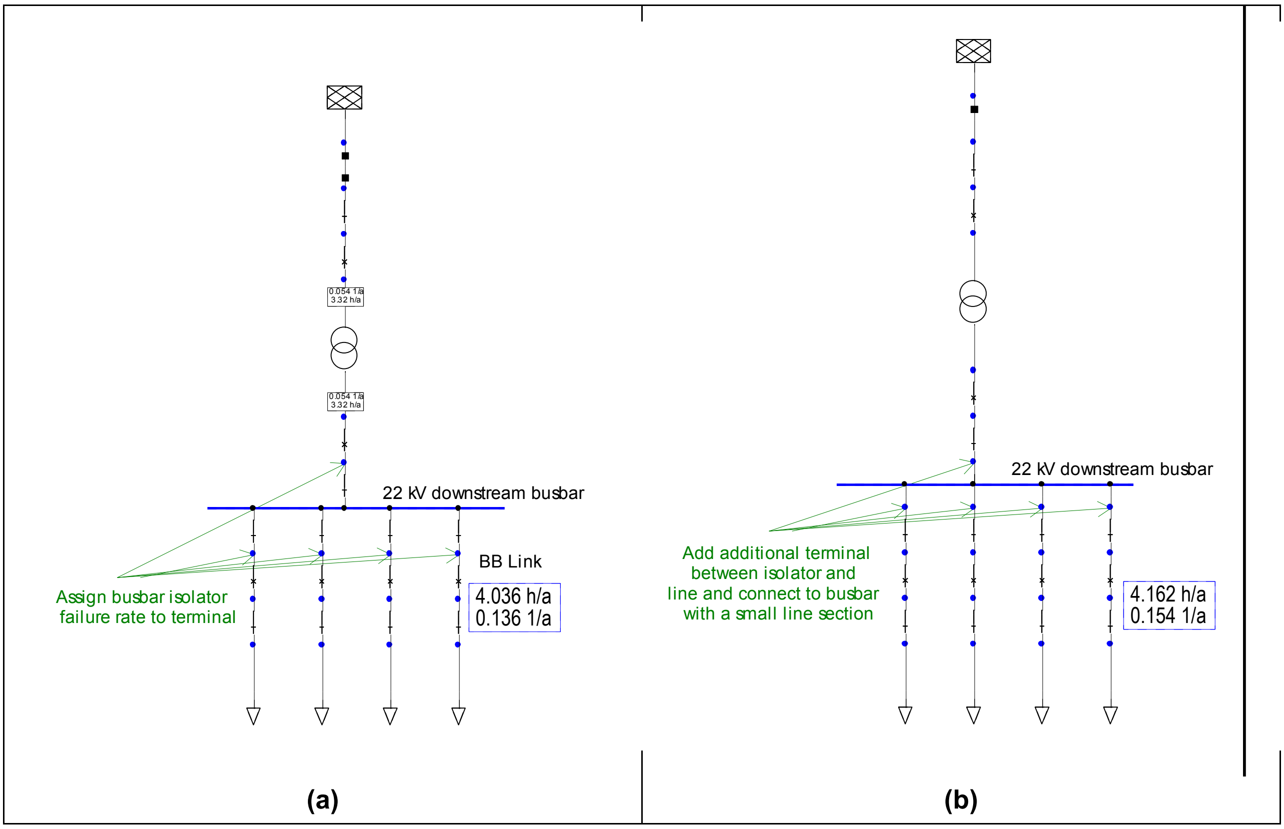


Figure 6-1: PowerFactory model of a single busbar single transformer HV/MV substation

The next substation configuration that was compared with the simplified reliability model included a busbar with a bus-section, where the bus-section consisted of 2 x isolators and 1 x breaker. This is illustrated in Figure 6-2. The failure rate of the bus-section isolators were again assigned to a terminal that is connected to the relevant bus-section via a short section of line (with no failure rate). If, for example the terminal of Isolator 1 fails, all breakers connected to bus-section 1, including the bus-section breaker, will operate. Supply will be interrupted to bus-section 1, but bus-section 2 will still have supply. This corresponds with the protection operation that will occur in the real world.

The problem is however to represent the bus-section breaker failure. If a bus- section breaker fails, all breakers connected to both bus-sections will operate. If the failure rate of the breaker is assigned to terminal “T1” in PowerFactory, PowerFactory will open the bus-section breaker when a fault occurs on “T1”, and supply to bus-section 2 will not be interrupted. Similarly, if the failure rate of the breaker is assigned to terminal “T2” in PowerFactory, PowerFactory will open the bus-section breaker when a fault occurs on “T2”, and supply to bus-section 1 will not be interrupted. Another workaround is required for this scenario, where the failure rate and outage duration of the breaker are assigned to the terminal on each side of the breaker.

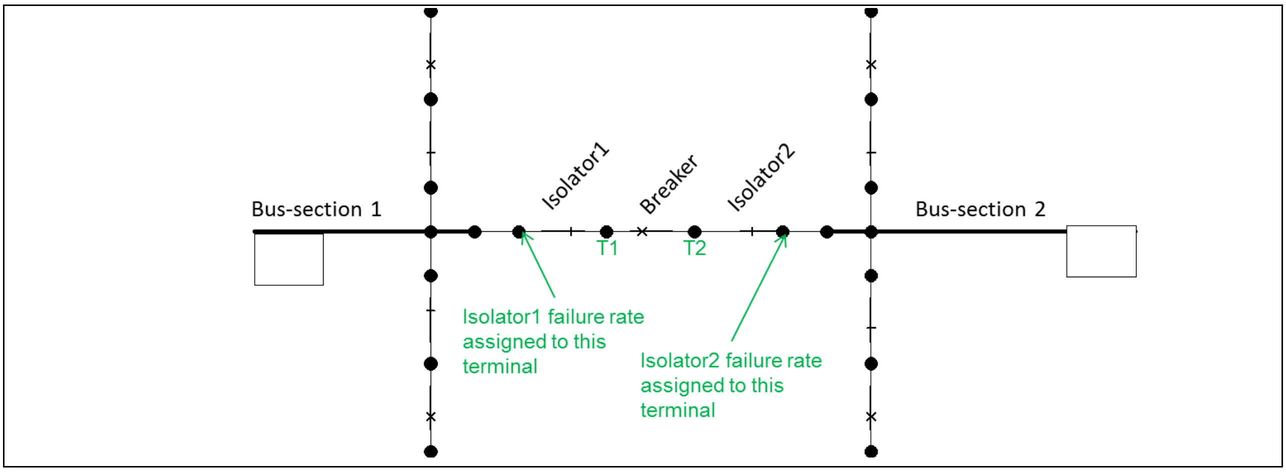


Figure 6-2: PowerFactory model of a single busbar with bus-section

The outcome of this investigation was that PowerFactory cannot accurately model all identified substation configurations without customised workarounds. The main shortcoming is that a failure rate cannot be assigned to a breaker or isolator in PowerFactory, therefore substations with bus-sections and bus-couplers cannot be accurately modelled.

6.1.2. ETAP

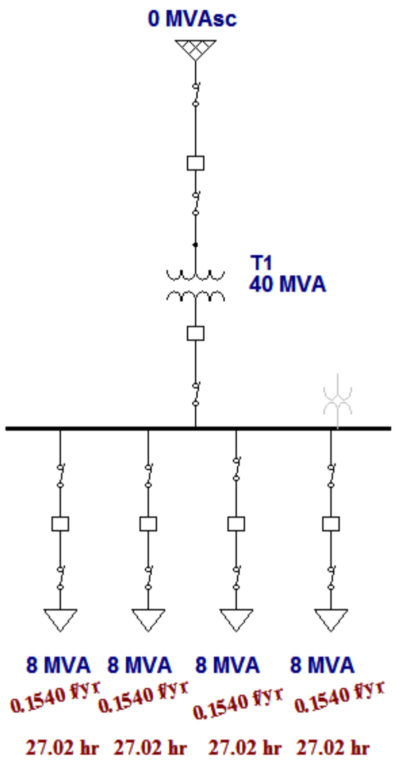
Due to the shortcomings experienced with the substation modelling in PowerFactory, another specialised software package was used to verify the results calculated with simplified reliability approach. ETAP was found to have an alternative approach to reliability modelling compared to PowerFactory, since failure rates can be assigned to breakers and isolators. A demo licence for ETAP could easily be obtained and therefore ETAP was selected for the verification of the simplified substation approach.

Three of the substation configurations modelled in ETAP and compared with the simplified reliability modelling are discussed in more detail below.

6.1.2.1. Substation configuration 1

The first substation configuration was a single transformer HV/MV substation, with a single MV busbar and four load feeders connected to the MV busbar. This configuration corresponds with the first busbar configuration modelled in PowerFactory.

The reliability values obtained using ETAP are shown in the ETAP diagram in Figure 6-3 and they are compared with the simplified reliability modeling outcomes in the table in Figure 6-3. It is clear from these results that the outcomes of the simplified reliability modelling correspond with the outcomes of the detailed modelling in ETAP.



	Customer Interruptions (h/a)	Interruption durations (h)	Outage duration per event (h)
Simplified model	0.154	4.162	27.026
ETAP	0.154	0.154 x 27.02= 4.16	27.02
% Difference	0%	0%	0%

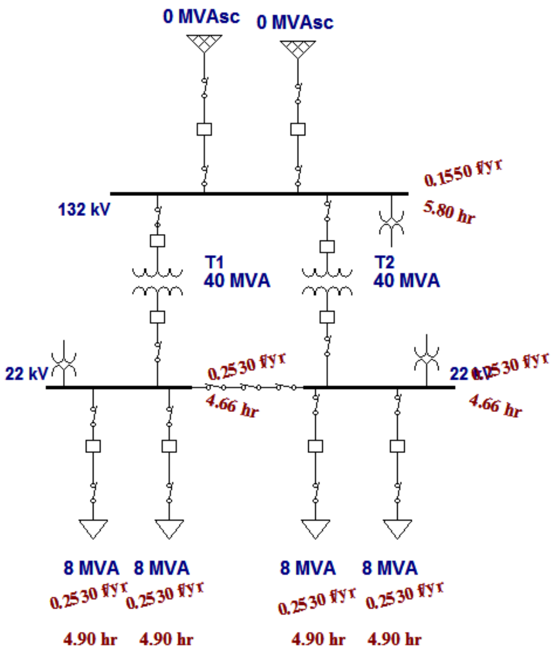
Figure 6-3: HV/MV substation Type 1 – Type 1 busbar configuration, single transformer

6.1.2.2. Substation configuration 2

The next substation configuration was a dual source HV/MV substation, with a single HV busbar and a single busbar with bus-section on the MV side. The transformer capacity was firm.

For all examples it was assumed that there is no bus zone protection on MV. All breakers in ETAP open automatically for faults, which simulates a busbar with bus zone protection. In order to simulate an MV bus-section breaker with no bus zone protection, the bus-section breaker was replaced with an isolator. The breaker failure rate and repair duration was however assigned to this isolator. This is illustrated in Figure 6-4.

The reliability values obtained using ETAP are shown in the ETAP diagram in Figure 6-4 and they are compared with the simplified reliability modeling in the table in this figure. It is clear from these results that the outcomes of the simplified reliability modelling correspond with the outcomes of the detailed modelling in ETAP.



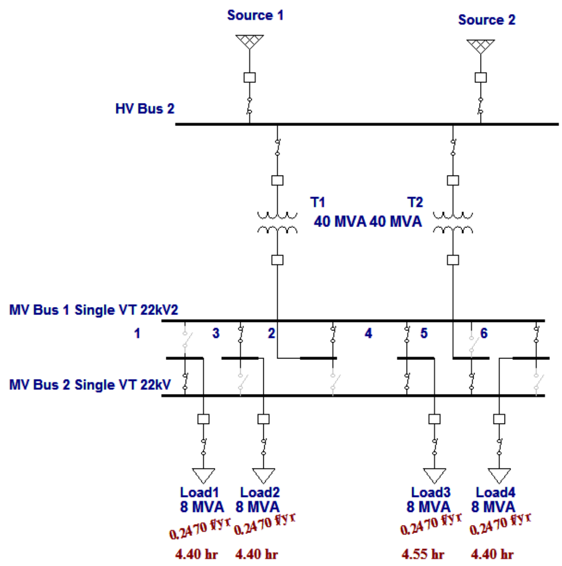
	Customer Interruptions (h/a)	Interruption durations (h)	Outage duration per event (h)
Simplified model	0.253	1.239	4.897
ETAP	0.253	0.253 x 4.9 = 1.24	4.9
% Difference	0%	0%	0%

Figure 6-4: HV/MV substation Type 1 – Type 3 busbar configuration, firm transformer capacity, dual source

6.1.2.3. Substation configuration 3

The third substation configuration was a dual source HV/MV substation with a single HV busbar. The downstream side had double busbars, without a bus-coupler. This is illustrated in Figure 6-5.

The reliability values obtained using ETAP are shown in the ETAP diagram in Figure 6-5. Three of the four load feeders have an unavailability of 4.4 h/a, and the fourth feeder, which is linked to both busbars, has an unavailability of 4.55 h/a. This difference is due to the one additional normally closed isolator which introduces additional failures and therefore results in a longer unavailability. The average unavailability of an MV load feeder is therefore 4.4375 h/a. This is compared with the simplified reliability modeling in the table in Figure 6-5. The average unavailability of an MV load feeder, calculated in ETAP, corresponds with the average unavailability calculated with the simplified approach. However, the error between the simplified model and the 3 load feeders linked to the one busbar is 0.8%, while the error between the simplified model and the one load feeder linked to both busbars is 2.5%.



	Customer Interrup-tions (h/a)	Interruption durations (h)	Outage duration per event (h)
Simplified model	0.247	1.096	4.437
ETAP	0.247	0.247 x 4.437= 1.1	3 feeders = 4.4 1 feeder = 4.55 Average = 4.437
% Difference	0%	0%	3 feeders = 0.8% 1 feeder = 2.5% Average = 0%

Figure 6-5: HV/MV substation Type 1 – Type 4 busbar configuration, firm transformer capacity, dual source

More substation configurations were modelled in ETAP and compared with the results from the simplified reliability model. This is summarised in Table B-1 in Annex B. Switching substation configurations were also modelled in ETAP and compared with the results from the simplified reliability model. This is summarised in Table in Annex B.

One limitation experienced with the ETAP demo licence was that the maximum load allowed on the transformer could not be set. Due to this limitation, the unfirm transformer configurations could not be verified.

6.2. Verification of the transmission and sub-transmission approach

PowerFactory was selected for verification of the transmission and sub-transmission simplified approach. The following conventions were applied to the software model:

(a) A response time of 1 hour is assumed for all components. This represents the total of the dispatch and travel time in the simplified reliability model.

(b) The failure rate and repair durations of the line module (including the line and the isolator on each side) are shown in Table 6-3. These failure rates and repair durations were selected based on empirical studies.

(c) Only the unplanned impact of failures was considered, the planned component was ignored to simplify the verification.

(d) All sub-transmission lines are 20 km long.

(e) All busbars were assumed to have a failure rate of 0.2 occ/a and an outage duration of 2h per annum.

(f) The time required to switch normally open points was assumed to be 30 minutes.

Table 6-3: Failure rates and repair durations applied in the simplified reliability model

No.	Composite description	Frequency (Occ/a)	Mean repair duration (h)	Total outage duration (h)*
1	HV line module, 20 km long, with 2 x line isolators (one isolator at each end)	0.1	10	11

** Includes 1 hour response time*

A diagram of a radial test network is shown in Figure 6-6. The results obtained with the simplified reliability approach are shown in Table 6-4. The results obtained with the simplified approach correspond very closely, and in some cases exactly, with the results from the detailed PowerFactory model.

Table 6-4: Simplified reliability results for a radial network

No	Busbar description	Busbar only unavailability (from substation model) ($U_{BusbarOnly}$)		+	Unavailability of lines (U_{Line})		+	Unavailability of upstream busbars ($U\_Upstream_{BusbarTotal}$)		=	Total unavailability of busbar ($U_{BusbarTotal}$)	
		Failure rate (occ/a	Outage duration (h/a)		Failure rate (occ/a	Outage duration (h/a)		Failure rate (occ/a	Outage duration (h/a)		Failure rate (occ/a	Outage duration (h/a)
1	**Bus A**	0.2	2	+	0	0	+	0	0	=	0.2	2
2	**Bus C**	0.2	2	+	0.1	1.1	+	0.2	2	=	0.5	5.1
3	**Bus E**	0.2	2	+	0.1	1.1	+	0.5	5.1	=	0.8	8.2

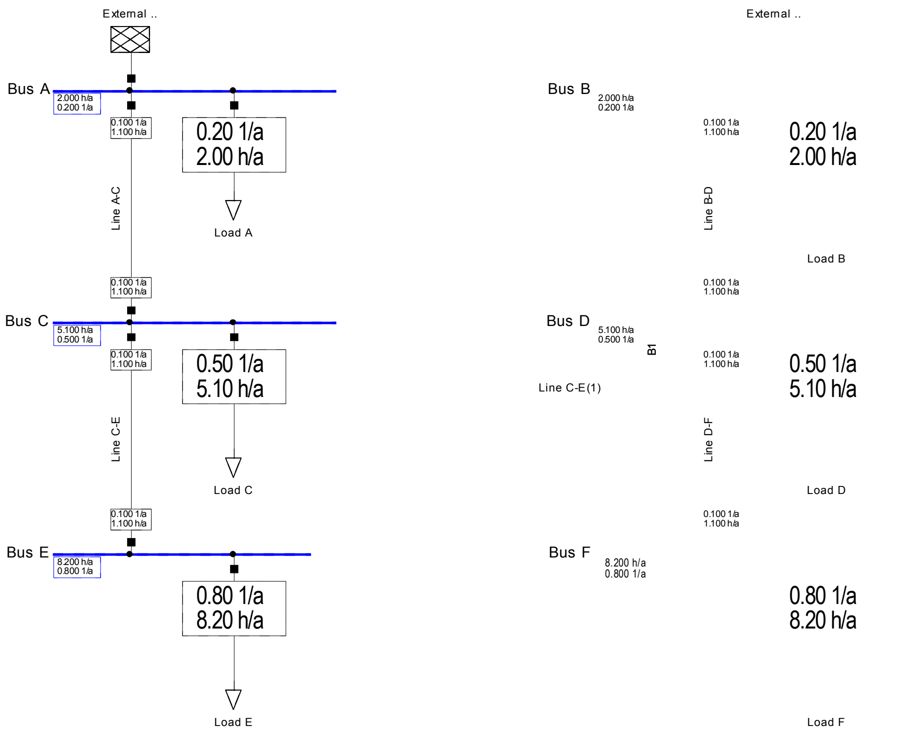


Figure 6-6: PowerFactory model of a radial network

A diagram of a ring test network is shown in Figure 6-7. The results obtained with the simplified reliability approach are shown in Table 6-5. The results obtained with the simplified approach correspond very closely, and in some cases exactly, with the results from the detailed PowerFactory model.

Table 6-5: Simplified reliability results for a ring network

No	Busbar description	Busbar only unavailability (from substation model) ($U_{BusbarOnly}$)		+	Unavailability of lines (U_{Line})		+	Unavailability of upstream busbars ($U\_Upstream_{BusbarTotal}$)		=	Total unavailability of busbar ($U_{BusbarTotal}$)	
		Failure rate (occ/a	Outage duration (h/a)		Failure rate (occ/a	Outage duration (h/a)		Failure rate (occ/a	Outage duration (h/a)		Failure rate (occ/a	Outage duration (h/a)
1	**Bus A**	0.2	2	+	0	0	+	0	0	=	0.2	2
2	**Bus B**	0.2	2	+	0	0	+	0	0	=	0.2	2
3	**Bus C**	0.2	2	+	0.1	0.05*	+	0.2	0.1**	=	0.5	2.15
4	**Bus D**	0.2	2	+	0.1	0.05*	+	0.2	0.1**	=	0.5	2.15
5	**Bus E**	0.2	2	+	0.1	1.1	+	0.5	2.15	=	0.8	5.25
6	**Bus F**	0.2	2	+	0.1	1.1	+	0.5	2.15	=	0.8	5.25

** 0.1 (failures per annum) x 0.5 (outage duration per event = switching time) = 0.05 (outage duration per annum)*

***0.2 (failures per annum) x 0.5 (outage duration per event = switching time) = 0.1 (outage duration per annum)*

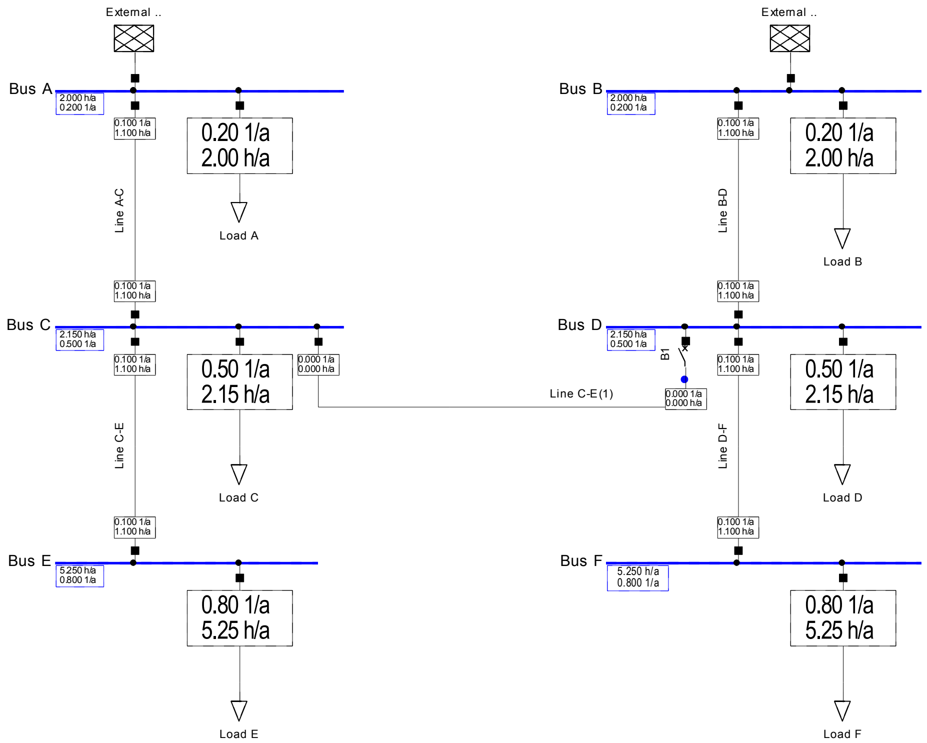


Figure 6-7: PowerFactory model of a ring network

7. Illustrating the approach on a utility-scale network

In this chapter the simplified reliability estimation approach, explained in the preceding chapters, is illustrated on a test system. The methodology was programmed into an MS Excel model and this model was used to calculate the expected unavailability of each busbar, as well as the SAIFI and SAIDI of the entire system.

In section 7.1 the test system is described in detail. In section 7.2 the modelling assumptions used for the analysis are discussed. The results obtained with the simplified approach are discussed in section 7.3 and the impact of some strategic scenarios is illustrated in section 7.4.

7.1. Description of the test network

In section 2.4 the two most commonly used reliability test systems were discussed, but these systems do not represent a utility-scale network. To illustrate that this simplified approach can be applied to a utility-scale network, an alternative, typical, utility-scale transmission and/or sub-transmission network was required.

The West African power network was studied for this purpose. The West African Power Pool (WAPP) is a specialised institution of the Economic Community of West African States (ECOWAS). It covers 14 of the 15 countries of the regional economic community, i.e. Benin, Côte d'Ivoire, Burkina Faso, Ghana, Gambia, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo (West African Power Pool (WAPP), n.d.). A map of all the WAPP countries is shown in Figure 7-1.

Figure 7-1: WAPP countries (adapted from (African development bank group, n.d.))

The WAPP high voltage network includes 330 kV, 225 kV, 161 kV, 150 kV, 132 kV, 110 kV, 90 kV, 66 kV and 63 kV lines. A geographic view of the WAPP HV lines (and some 33 kV and 30 kV lines) is shown in Figure 7-2.

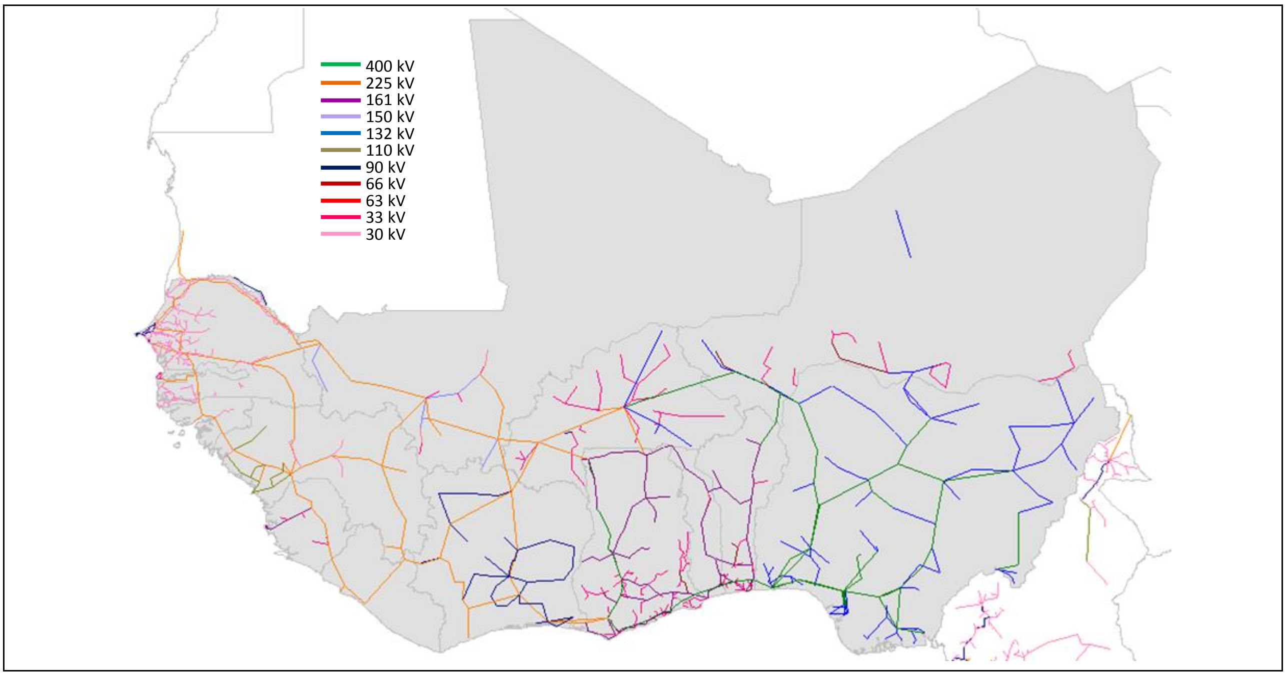


Figure 7-2: Geographic view of the WAPP lines (30 kV – 330 kV)

Detailed network information, such as line lengths, installed transformer capacity and number of customers connected, was not readily available for all WAPP lines and substations, and significant effort was required to collect all the required network information. The study was therefore limited to only one of the WAPP countries in order to demonstrate the approach. The analysis can however easily be extended to the rest of the WAPP countries, if the necessary information is added to the model.

The Ghana network was selected as the test network, since the Ghana network information could easily be obtained from published documents. A geographic view of the Ghana transmission network is shown in Figure 7-3.

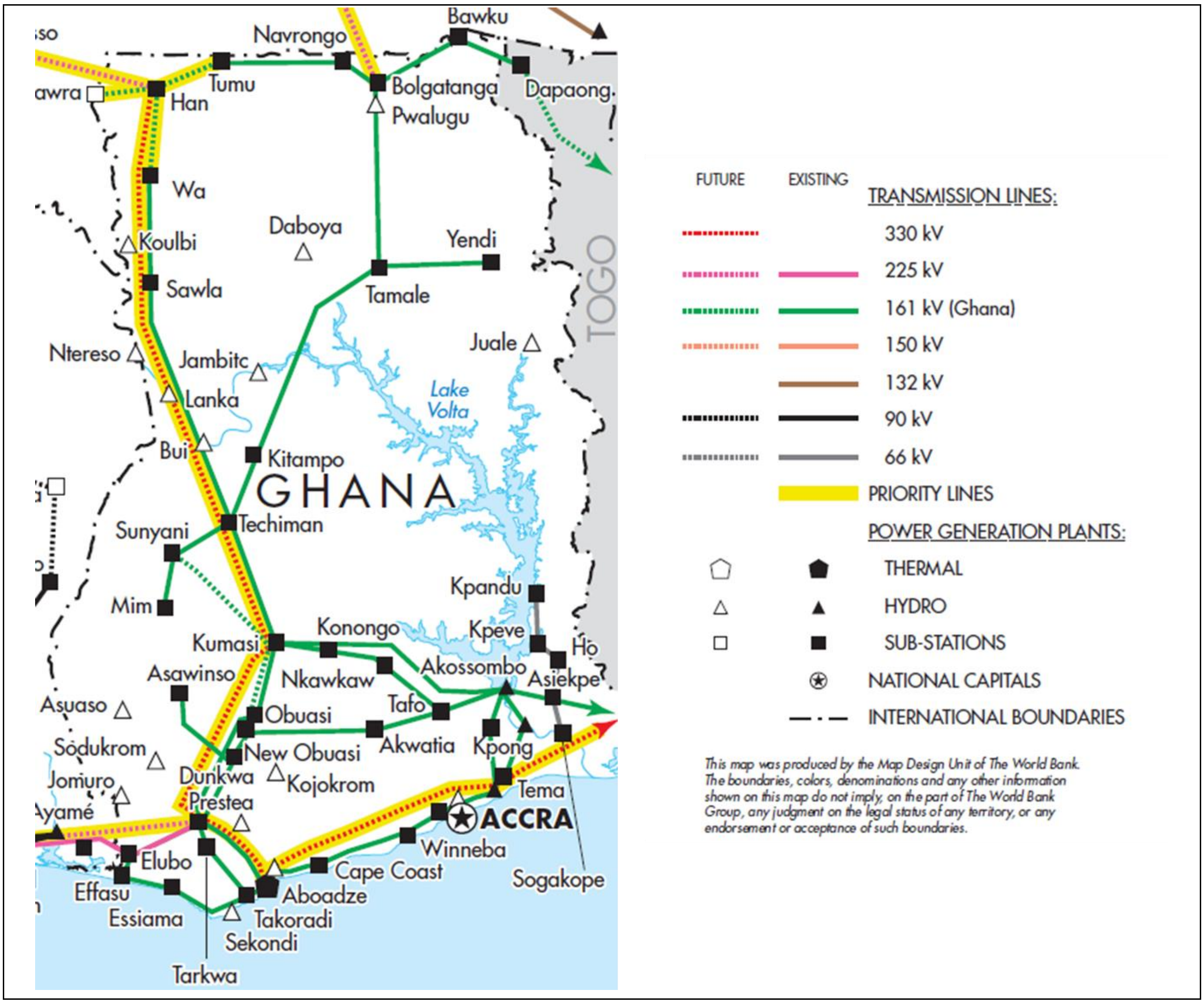


Figure 7-3: Geographic view of the Ghana transmission lines (Worldbank, 2008, West Africa Power Pool APL Program: Inter-zonal transmission hub, APL 3 (Map no. IBRD 34436R))

7.1.1. Substations and lines

The geographic view in Figure 7-3 was used to derive a list of all the Ghana transmission substations. This view, together with a more detailed view of the southern parts of Ghana (see Figure E-2 in Annex E), was used to estimate the transmission line lengths. All future lines were ignored.

The number of transformers, installed capacity and peak load was obtained from Ghana's 2010 Electricity supply plan (Ghana Grid Company Limited (GridCo), 2010). The number of substations, transformers and installed transformer capacity is summarised in Table 7-1. A summary of the number of busbars of each voltage level is shown in Table 7-2. A summary of the line lengths per voltage level is shown in Table 7-3[3].

More information on the network and detail on how it was derived are provided in Annex E.

[3] The number of transformers and installed transformer capacity obtained from Ghana's 2010 Electricity supply plan (Ghana Grid Company Limited (GridCo), 2010) and the total 161 kV line lengths derived from the maps are different from the asset volumes quoted by Power Systems Energy Consulting (PSEC) (2010). No detail on the quoted asset volumes is provided by Power Systems Energy Consulting (PSEC) (2010) in order to understand the reasons for the discrepancies.

Table 7-1: Summary of number of substations, transformers and installed capacity

No	Description	Value
1	No. of substations/switching stations	42
2	No. of transformers	72
3	Installed transformer capacity	2591.2 MVA

Table 7-2: Summary of number of busbars per voltage level

No	Voltage (kV)	No. of busbars
1	**11.5**	2
2	**33**	2
3	**34.5**	31
4	**69**	5
5	**161**	37
6	**225**	2
7	**Grand Total**	**79**

Table 7-3: Summary of line lengths per voltage level

No	Voltage (kV)	Total line length (km)
1	**69**	133
2	**161**	3223
3	**225**	73.4
4	**Grand Total**	**3429.4**

A list of all power stations is provided in Annex E. The network has one transmission supply from Cote d'Ivorie, which is the Elubo 225 kV busbar. Prestea 225 kV busbar is supplied from Elubo 225 kV busbar.

The following additional assumptions were made about the Ghana network:

(a) All HV busbars have bus zone protection and all MV busbars don't have bus zone protection.

(b) All switchgear are non-metalclad.

(c) All 34.5 kV and 11.5 kV busbars are Type 1. The 225 kV busbars are Type 5 and all other busbars are Type 3.

7.1.2. Number of customers supplied

The Electricity Company of Ghana (ECG) delivers power to customers in the southern half of the country, while the Northern Electricity Department (NED) delivers power to customers in the northern half. This is illustrated in Figure 7-4. The number of customers supplied by each of these companies, as recorded in 2004 (Resource center for energy economics and regulation (2005)), is also shown. It is clear from Figure 7-4 that the majority of the customers are based in the southern part of the country.

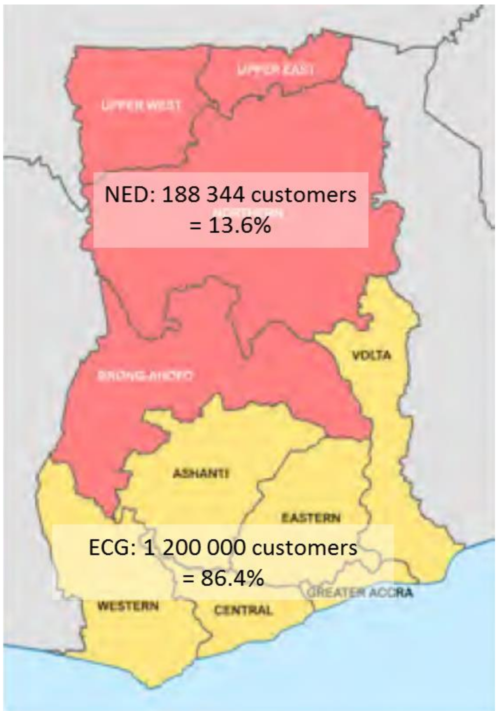


Figure 7-4: Electricity distribution zones for ECG (yellow) and NED (red) (Power System Energy Consulting (PSEC), 2010 & Resource Center for Energy Economics and Regulation (2005))

This information was overlaid with the substation information. This is shown in Figure 7-5. From this view, the distribution company responsible for each substation was determined. The total number of customers supplied by each distribution company was then divided equally between all the 34.5 kV and 11.5 kV busbars owned by the specific distribution company.

Figure 7-5: Ghana transmission network overlaid with the electricity distribution zones for ECG (yellow) and NED (red) (Power System Energy Consulting (PSEC), 2010 & World Bank (2008) West Africa Power Pool APL Program: Inter-zonal Transmission Hub, APL 3.)

The assumed number of customers supplied from each busbar, derived using this approach, is shown in Annex E (see Table E-5).

7.2. Assumptions

7.2.1. Component failure rates and repair duration

A literature study of the component failure rates and repair durations was performed and documented in section 2.5.1. The assumption used to illustrate the simplified approach is derived from this literature study. It is important to note that the component failure rates and repair durations are inputs into the model, and can easily be changed by the user at one central point in the model. The assumptions used in this section are therefore purely illustrative.

The range of recommended expected time to failure (ETTF) values for different components, recommended by Bollen (1993), is summarised in Table 2-2 (see section 2.5.1.). From these ETTF values, the failure rates can be calculated. The highest ETTF value of each component was used to calculate the lowest failure rate, and the lowest ETTF value of each component was used to calculate the highest failure rate. This is illustrated by the formulae below and the corresponding numbering in Table 7-4.

1 $$\lambda_{Low} = \frac{1}{ETTF_{High}}$$

2 $$\lambda_{High} = \frac{1}{ETTF_{Low}}$$

The lowest and highest failure rate per component was then used to calculate the average failure rate per component:

3 $$\lambda_{Average} = \frac{\lambda_{High}+\lambda_{Low}}{2}$$

Table 7-4: Substation component failure rates derived from the range of ETTF values proposed by Bollen (1993)

No	Substation component	Expected time to failure (Bollen, 1993, p.3)	1 Calculated outage frequency-Low (occ/a)	2 Calculated outage frequency - High (occ/a)	3 Calculated outage frequency - Average (occ/a)
1	**MV/MV transformers**	75 - 100 years	0.010	0.013	0.0117
2	**HV/MV transformers**	40 - 70 years	0.0143	0.025	0.0196
3	**MV and LV circuit breakers**	1000 - 5000 years	0.0002	0.001	0.0006
4	**HV circuit breakers**	1000 years	0.001	0.001	0.001
5	**Disconnect switches**	250 - 1000 years	0.001	0.004	0.003
6	**MV Voltage and current transformers**	500 years	0.002	0.002	0.002
7	**HV Voltage and current transformers**	500 years	0.004	0.004	0.004
8	**MV Underground cables (1000 meters)**	11 - 26 years	0.013	0.025	0.0192
9	**HV Underground cables (1000 meters)**	11 - 15 years	0.067	0.091	0.079
10	**Busbars (one section)**	500 - 2000 years	0.0005	0.002	0.0013

The failure rates used by Xu et al. (2002) (see Table 2-3) was assumed for all HV equipment. The HV VT and CT failure rates, not provided by Xu et al. (2002), was taken from the failure rates proposed by Bollen (1993) (see Table 2-2 and Table 7-4). The MV failure rates used by Zhou et al. (2012) (see Table 2-4) was used for all MV equipment. The MV CT, VT and disconnect failure rates, not provided by Zhou et al. (2012) was taken from the failure rates proposed by Bollen (1993) (see Table 2-2 and Table 7-4). The Ghana measured transmission line failure rate (International Renewable Energy Agency, 2013) was used for all lines (see Table 2-5) with the 220 kV line outage duration used by Xu et al. (2002) (see Table 2-3). The assumed forced outage rate and repair duration per component is listed in Table 7-5. The source of each parameter is also indicated.

Table 7-5: Substation component failure rates and repair durations

No	Composite Description	Failure rate (Occ/a)	Repair duration (h)	Source: Failure rate	Source: Repair duration
1	**HV busbar**	0.04	15	Table 2-3: 220 kV bus-section	Table 2-3: 220 kV bus-section
2	**HV VT**	0.004	24	Table 2-2 and Table 7-4: HV VT & CT	Table 2-2 and Table 7-4: HV VT & CT
3	**HV breaker**	0.02	60	Table 2-3: 220 kV beaker	Table 2-3: 220 kV breaker

No	Composite Description	Failure rate (Occ/a)	Repair duration (h)	Source: Failure rate	Source: Repair duration
4	**HV isolator**	0.002	12	Table 2-3: 220 kV isolator	Table 2-3: 220 kV isolator
5	**HV CT**	0.004	24	Table 2-2 and Table 7-4: HV VT & CT	Table 2-2 and Table 7-4: HV VT & CT
6	**HV Surge arrestor**	0.004	24	Not available in scanned literature, use HV CT or VT failure rate	Not available in scanned literature, use HV CT or VT failure rate
7	**Transformer**	0.12	100	Table 2-3: 220 kV transformer	Table 2-3: 220 kV transformer
8	**NECR/T**	Not available*	Not available*		
9	**MV CT**	0.002	7	Table 2-2 and Table 7-4: MV VT & CT	Table 2-2 and Table 7-4: MV VT & CT
10	**MV Surge arrestor**	0.002	7	Not available in scanned literature, use MV CT or VT failure rate	Not available in scanned literature, use MV CT or VT failure rate
11	**MV VT**	0.002	7	Table 2-2 and Table 7-4: MV VT & CT	Table 2-2 and Table 7-4: MV VT & CT
12	**MV busbar**	0.001	2	Table 2-4: average of 33 & 11 kV busbar	Table 2-4: average of 33 & 11 kV busbar
13	**MV breaker metalclad (indoor)**	0.004	3	Table 2-4: average of 33 & 11 kV busbar	Table 2-4: average of 33 & 11 kV busbar
14	**MV breaker non-metalclad**	0.004	3	Table 2-4: average of 33 & 11 kV busbar	Table 2-4: average of 33 & 11 kV busbar
15	**MV isolator**	0.003	3	Table 2-2 and Table 7-4: Disconnect switches	Table 2-2 and Table 7-4: Disconnect switches
16	**HV line**	0.02765	7	Table 2-5: average of 3.03% and 2.5% = 2.765%	Table 2-3: 220 kV line outage duration

** NECR/T failure rates could not be found in any of the scanned literature. For the purpose of illustrating the simplified modelling approach, a failure rate of 0 occ/a was assumed.*

In section 3.3 it is explained that the different components within the substation are grouped into modules, such that all components in the module will result in the same outage and switching sequence. These composite failure rates are given in Table 7-6, considering the component failure rates given in Table 7-5.

Table 7-6: Substation composite element failure rates and repair durations

No	Composite Description	Frequency (occ/a)	Repair duration (h)
1	**HV busbar (no VTs)**	0.0400	15.000
2	**HV busbar (with 1 x VT)**	0.0440	15.818
3	**HV busbar (with 2 x VTs)**	0.0480	16.500
4	**HV breaker**	0.0200	60.0
5	**HV isolator**	0.0200	12.0
6	**Transformer HV/HV**	0.1360	91.059

No	Composite Description	Frequency (occ/a)	Repair duration (h)
7	**Transformer HV/MV**	0.1320	92.576
8	**Transformer MV/MV**	0.1280	94.188
9	**MV busbar (no VTs)**	0.0010	2.0
10	**MV busbar (with 1 x VT)**	0.0030	5.3
11	**MV busbar (with 2 x VTs)**	0.0050	6.0
12	**MV breaker metalclad (indoor)**	0.0040	3.0
13	**MV breaker non-metalclad**	0.0040	3.0
14	**MV isolator**	0.0030	3.0
15	**HV line**	0.02765	7

7.2.2. Maintenance frequency and duration

From the literature review (see section 2.5.2) the following high level assumptions were made regarding the maintenance frequencies and duration:

(a) Routine maintenance of the following equipment only requires a visual inspection, but no equipment outages: busbars, CTs, VTs and surge arrestors.

(b) The maintenance frequencies and durations used by Allan et al. (1979) for transformers, breakers and isolators were used for the analysis. The same maintenance frequency and duration was used for HV and MV components. Furthermore, the same maintenance frequency and duration was assumed for metalclad switchgear and non-metalclad switchgear.

(c) To simplify the analysis it was assumed that all HV line maintenance is performed using live line techniques and hence no customers are interrupted. The frequency and duration of HV line maintenance was therefore set to zero.

(d) A maintenance cap of 1 outage per year and 12 hours over a 4 year maintenance cycle was assumed.

The assumed maintenance frequency and repair duration per component is summarised in Table 7-7.

Table 7-7: Planned maintenance frequency and duration for substation components

No	Composite Description	Failure rate (Occ/a)	Repair duration (h)
1	**HV busbar**	No maintenance	No maintenance
2	**HV VT**	No maintenance	No maintenance
3	**HV breaker**	0.25	4
4	**HV isolator**	0.25	8
5	**HV CT**	No maintenance	No maintenance
6	**HV Surge arrestor**	No maintenance	No maintenance
7	**Transformer module**	0.25	8
8	**NECRT**	Included in transformer module maintenance	Included in transformer module maintenance
9	**MV CT**	No maintenance	No maintenance

No	Composite Description	Failure rate (Occ/a)	Repair duration (h)
10	**MV surge arrestor**	No maintenance	No maintenance
11	**MV VT**	No maintenance	No maintenance
12	**MV busbar**	No maintenance	No maintenance
13	**MV breaker metalclad (indoor)**	0.25	4
14	**MV breaker non-metalclad**	0.25	4
15	**MV isolator**	0.25	8
16	**Substation maintenance cap**	1	12/4*=3
17	**HV line**	0	0

** This is equivalent to a total outage duration of 12 hours over a four year maintenance cycle (Refer to section 4.5.2 for more information on the substation maintenance cap)*

7.2.3. Outage duration

The outage duration assumptions for each element of the total outage duration, discussed in section 4.4.2, are shown in Table 7-8.

Table 7-8: Outage duration assumptions

No	Outage duration component	Outage duration assumptions
1	**Dispatch time**	30 minutes
2	**Travel time**	60 minutes
3	**Switch time**	0 minutes*
4	**Repair time**	Component specific – see Table 7-5, Table 7-6 and Table 7-7
5	**Time to switch the normally open point**	20 minutes

**The switch time is considered to be small compared to the travel time and repair time, and is therefore ignored.*

7.3. Estimated availability of the test network

The calculated designed performance level of the Ghana transmission and sub-transmission network are shown in Table 7-9. The results indicate that a customer will experience on average 3.8 interruptions per annum and a total outage duration of 36.9 hours per annum due to faults on the transmission and sub-transmission network.

Table 7-9: Calculated system indices – Base Case

No	Scenario	SAIFI (occ/a)	SAIDI (h/a)
1	**Base Case**	3.80	36.59

Detailed results per busbar, for all the 34.5 kV, 33 kV and 11.5 kV busbars, are shown in Figure 7-6. These detailed results show that Yendi busbar has the longest unavailability and contributes the most to system SAIDI (i.e. the highest customer hours interrupted).

It is important to note that the SAIDI of 36.59 hours is the contribution from the transmission and sub-transmission network only and excludes the contribution of the distribution network to the total SAIDI.

The distribution network dominates SAIDI and account for up to 90% of all customer reliability problems (Brown, 2002). If it is assumed, for example, that the transmission and sub-transmission network contributions 20% of the total system SAIDI, then this implies that the total system SAIDI of the transmission and distribution network is 183 hours.

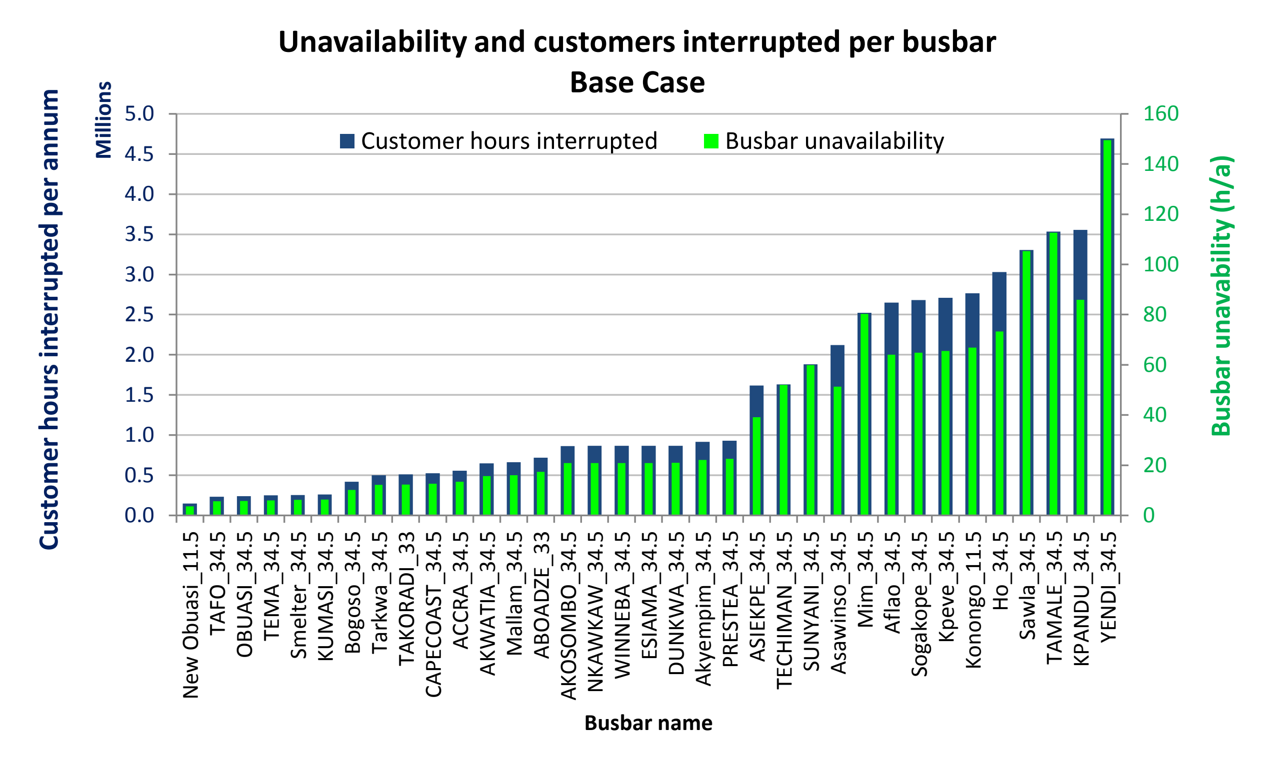


Figure 7-6: Simplified reliability estimation results per busbar – Base case

7.4. Illustrating the impact of various performance improvement strategies

The simplified model can also be used to model the impact of different scenarios on the overall reliability of the system. Three such scenarios are discussed below for illustrative purposes:

(a) Change the line failure rate;

(b) Change the busbar configuration;

(c) Upgrade the transformers in all substations with unfirm transformer capacity.

7.4.1. Change the line failure rate

This scenario represents a strategy of, for example, doing more line maintenance, since more line maintenance is expected to reduce the failure rate of the line.

The average transmission line failure rate of 0.02765 occ/a reported by Ghana (see Table 2-5) is much higher than the failure rate documented in other literature, e.g. the 220 kV line failure rate used by Xu et al. (2002) was 0.01 occ/a. For this scenario the line failure rate is changed from 0.02765 occ/a to 0.01 occ/a. The new calculated SAIDI and SAIFI are shown in Table 7-10. A decrease of 64% in the failure rate (from 0.02765 occ/a to 0.01 occ/a) resulted in a 26% improvement in the system SAIDI.

Table 7-10: Calculated system indices for the base case and the reduced line failure rate scenario

No	Scenario	SAIFI (occ/a)	SAIDI (h/a)
1	**Base Case**	3.80	36.59
2	**Reduce line failure rate**	2.68	27.12

Detailed results per busbar, for all the 34.5 kV, 33 kV and 11.5 kV busbars, are shown in Figure 7-7. The unavailability of the Yendi busbar, which was 149.5 hours for the base case, has now dropped to 83.6 hours. This is a 44% improvement.

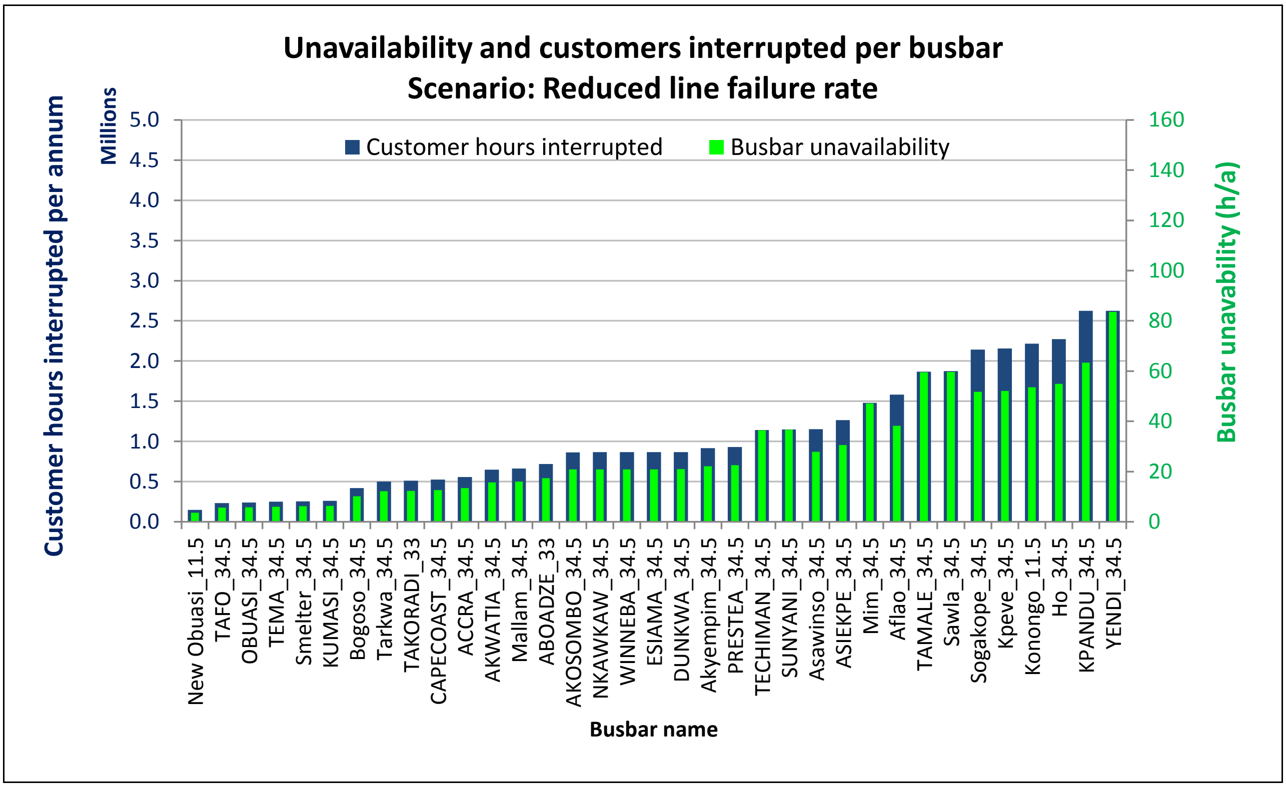


Figure 7-7: Simplified reliability estimation results per busbar – Reduced line failure rate scenario

7.4.2. Change the busbar configuration

For the base case, the following assumptions were made regarding the busbar configuration: All 34.5 kV and 11.5 kV busbars are Type 1. The 225 kV busbars are Type 5 and all other busbars are Type 3 (see section 7.1.1).

For this scenario, all busbars are changed to Type 5 configurations. The new calculated system SAIDI and SAIFI are shown in Table 7-11. Changing the busbar configurations result in a 3.8% improvement in system SAIDI, but the SAIFI is 1.8% worse. The reason why SAIFI is worse is because of all the additional failures that was introduced by the additional equipment (double busbar configurations) in the network.

Table 7-11: Calculated system indices for the base case and the changed busbar configuration scenario

No	Scenario	SAIFI (occ/a)	SAIDI (h/a)
1	**Base Case**	3.80	36.59
2	**Changed busbar configuration**	3.87	35.20

Detailed results per busbar, for all the 34.5 kV, 33 kV and 11.5 kV busbars, are shown in Figure 7-8. The biggest improvement is experienced by the Kumasi 34.5 kV busbar, which had an unavailability of 6.3 hours for the base case and an unavailability of 5.2 hours when the busbar configuration is changed. This is an 18% improvement in unavailability.

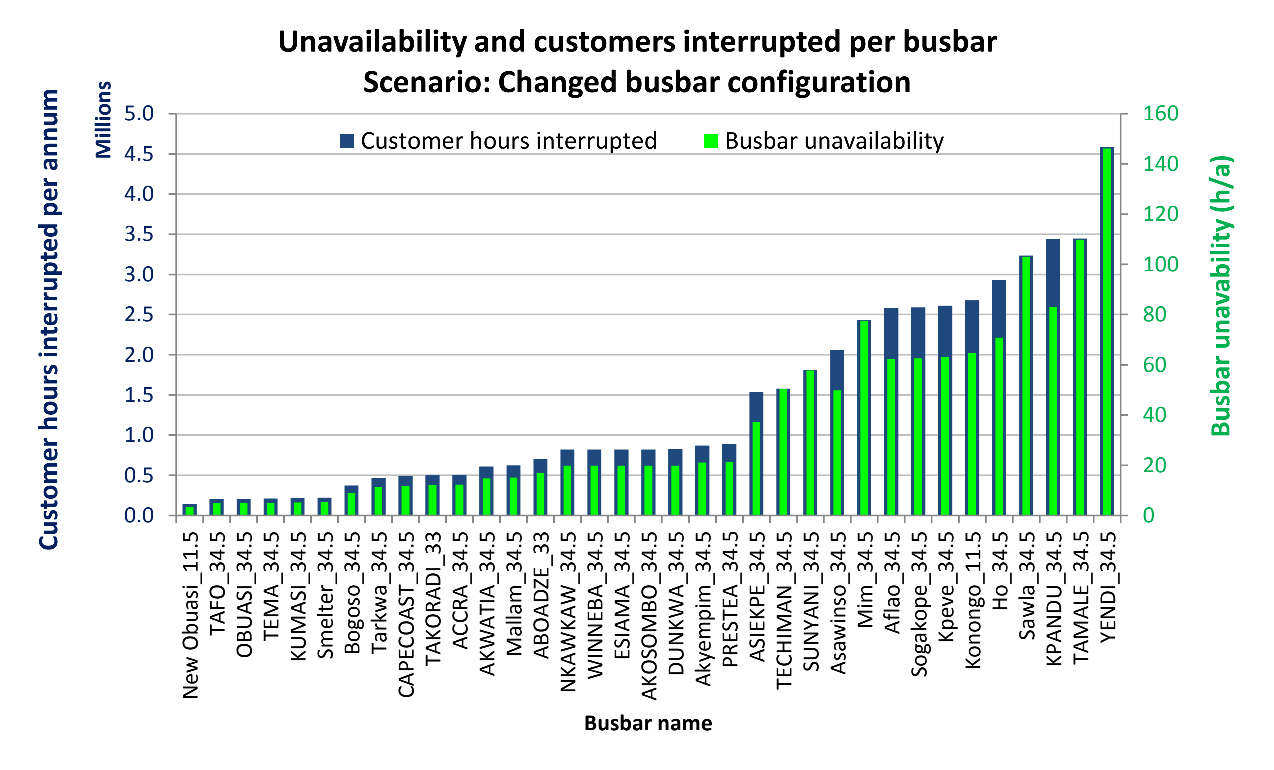


Figure 7-8: Simplified reliability estimation results per busbar – Changed busbar configuration scenario

7.4.3. Change the transformer capacity

Not all substations in the Ghana network have a firm transformer capacity. For this scenario all substations that don't have firm transformer capacity are identified. The transformers in these substations are then upgraded such that the transformer capacity is firm. The new calculated SAIDI and SAIFI are shown in Table 7-12. Upgrading all transformers will improve the system SAIDI by 6.4%.

Table 7-12: Calculated system indices for the base case and the changed busbar configuration scenario

No	Scenario	SAIFI (occ/a)	SAIDI (h/a)
1	**Base Case**	3.80	36.59
2	**Changed transformer capacity**	3.78	34.26

Detailed results per busbar are shown in Figure 7-9. Although an improvement of 6.4% on a system level seems low, this intervention can have a significant impact on the availability of specific busbars. The unavailability of Takoradi 33 kV busbar changed from 12.3 hours to 3.4 hours, which is an improvement of 73%.

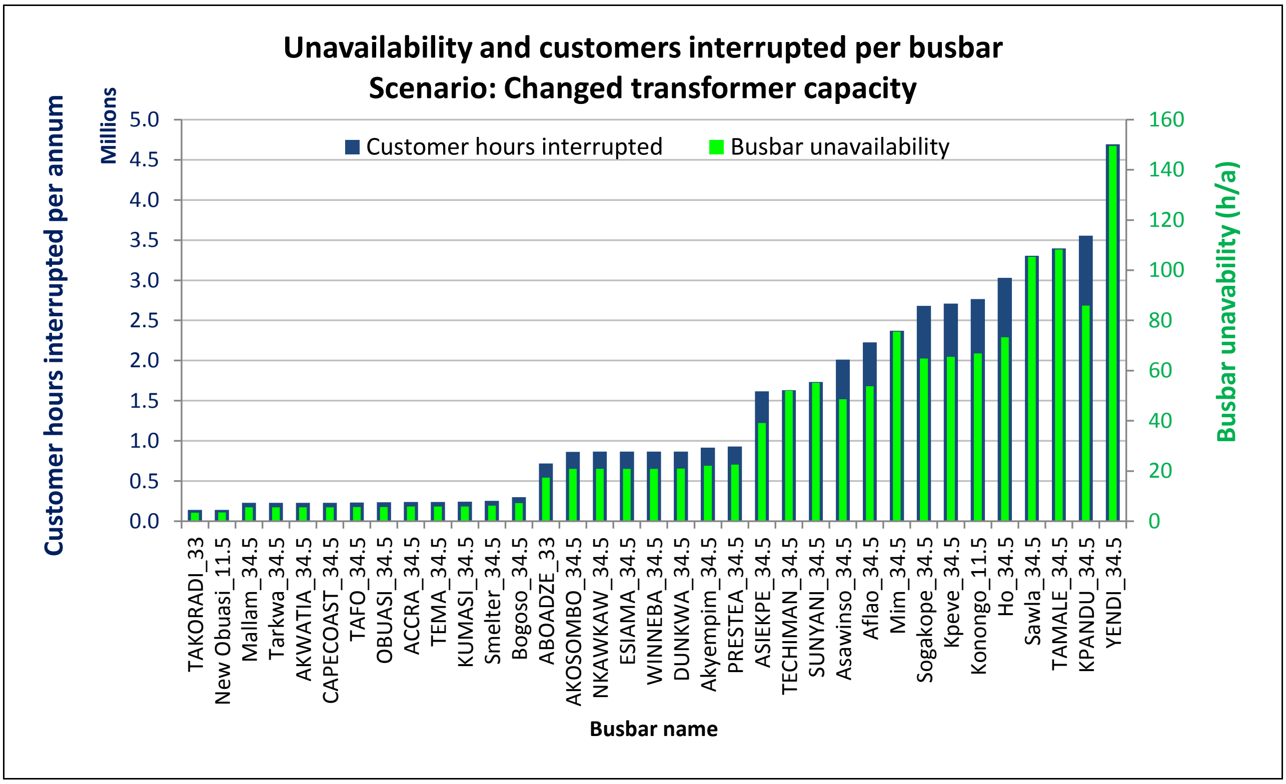


Figure 7-9: Simplified reliability estimation results per busbar – Changed busbar configuration scenario

The above scenarios illustrated typical operational and design strategies that can be modelled on utility-scale networks, using the simplified approach. These scenarios were modelled within a few minutes and no changes were required to any physical models, such as the physical models in specialised reliability modelling software packages (e.g. PowerFactory). The outcomes from these 3 scenarios can be used by engineers to develop a reliability improvement strategy for the Ghana transmission and sub-transmission network.

8. Discussion and conclusions

This research developed an analytical simplified network reliability modelling approach, capable of informing the expected performance levels of a utility-scale transmission and sub-transmission network. The approach was programmed in MS Excel and used to calculate the expected performance levels of a utility-scale network. The outcome of the approach provides performance indices (e.g. SAIFI and SAIDI) for each busbar in the network. From these busbar indices the resultant system indices can be calculated. The model was further used to illustrate the impact of different operational and design scenarios on a system level.

The approach used simplifies the detail of each substation and the different line configurations. The result will therefore be less accurate than for a detailed model, but due to the composite models considered for the approach, the errors will not be one-sided. The approach is applied to large systems, which includes many samples of slightly different substations. If the system includes a sufficiently large sample of substations and lines, the Central Limit Theorem will tend to bring the outcome on a system level close to the real mean. The aim of the approach is to provide answers on a system level, i.e. the average SAIFI and SAIDI of a utility network, where this average SAIFI and SAIDI is the mean result of all the different substations and lines in the system. The approach is therefore statistically likely to give good results, compared with more detailed analysis that considers the detail of each substation and line configuration.

The approach provides answers on a system level with significantly less effort than traditional analysis, utilising detailed network models in customised reliability analysis software. The RBTS was used to compare the effort required with the simplified approach and detailed software models, and it was found that the simplified approach requires only 50% of the effort associated with modelling the network using specialised reliability modelling software. Once programmed into any analytical software, such as MS Excel, the analysis is repeatable and can be updated with relatively little effort as the network evolves and input parameters or assumptions such as expected failure rates, protection philosophies, etc. change. Although it might seem that there is a high level of complexity involved in the simplified approach, this complexity is programmed into analytical software once, and the utility engineer subsequently needs to enter only basic network information and failure models, similar to the network information and failure models required for specialised reliability modelling software.

The advantages of the simplified approach can therefore be summarised as follows in terms of effort and complexity:

(a) The simplified reliability modelling requires only 50% of the effort associated with modelling in specialised reliability modelling software.

(b) There is no increase in complexity associated with the simplified reliability modelling approach compared to specialised reliability modelling software, as experienced by the utility engineer who needs to provide the basic network information and failure models.

In order to identify which networks are feasible for this approach, the following two factors are considered:

(a) The effort saved by the approach is a function of the size of the network analysed. The different test networks found from the literature (see section 2.1.6) showed that networks with approximately 40 substations are still feasible for detailed reliability modelling.

(b) Statistically the sample needs to be sufficiently large to ensure that the result is close to the mean. Hammersley and Handscomb (1995) states that the so-called central limit theorem asserts that the sum of n independent random variables has an approximately normal distribution when n is large; in practical cases, more often than not, n = 10 is a reasonably large number, while n = 25 is effectively infinite. The Central limit theorem therefore indicates that you need about 25 substations to reduce the risk of large errors.

Considering the minimum size of the sample and the number of substations that is still feasible for detailed modelling, this simplified approach is not recommended for networks with less than 40 substations. Networks with less than 40 substations might statistically not be sufficiently large to yield accurate results and the effort saved by the approach, compared to detailed models, is not substantial.

Some simplifications were made in the approach that is not valid for all networks. Examples of such simplifications are:

(a) The line capacity of all ring networks are firm: This is often not the case and could result in underestimating the actual unavailability of a substation.

(b) Overlapping failures are ignored: Transmission and sub-transmission double circuit lines, or lines that share the same servitude, are exposed to various common mode failures. Again this assumption could result in underestimating the actual unavailability of a substation.

In addition to the various simplifications that are not valid for all networks, the following shortcomings were identified in the approach:

(a) Adding additional components and complexity to power networks could result in additional failures. For example, a busbar configuration with a bus-section breaker or bus-coupler breaker could result in additional failures due to malfunctioning of the bus zone protection, compared to a single busbar. These more complex failures, introduced by adding more equipment, should be considered in the simplified approach.

(b) If a busbar supplying customer feeders is not available, this feeder can be supplied by another substation if a backfeed from another substation does exist. The simplified approach assumes that all customer feeders are without supply if supply to the busbar/feeder is interrupted, and does not consider the benefit of backfeeds on MV customer feeders. It is recommended that the approach be revised to include the benefit of backfeeding.

8.1. Conclusions

The approach developed through this research can be used to calculate the expected system SAIFI and SAIDI of a utility-scale network.

The modelling does not require a detailed network model to be created, but minimum user inputs are required in database format. This provides engineers with the ability to create the utility-scale network with much less effort compared to the effort required to construct detailed network models using specialised power system reliability modelling software. The approach therefore meets the research criterion that it should require minimum user inputs.

This approach further allows engineers to change the configuration of existing substations and/or lines by changing the input values in the database, which is significantly less effort than changing the configuration of physical models. The change in system reliability can then be evaluated on a system level. The approach therefore meets the research criterion that the modelling should inform, with little effort, the change in system reliability if the configuration of existing substations and/or lines is changed.

The approach was applied on a utility network and it was illustrated how it can be used to answer the following questions:

(a) What is the designed performance level of the utility's transmission and sub-transmission network?

(b) What level of performance can be expected if specific reliability improvement measures are implemented?

The answers to these questions provide utilities with an understanding of the expected performance of their networks and give engineers the ability to manage the expected reliability of their transmission and sub-transmission networks. It can therefore be concluded that the approach developed meets the aim of this research.

The following benefits could be derived by further development of this simplified approach:

(a) The calculated system indices (SAIDI and SAIFI) provide an indication of the technical performance of the network, but don't provide information on the economic impact of network outages. These technical indices have the potential to result in funding decisions that are not closely linked to economic interest. For this purpose economic indices are required. This simplified approach can be developed further to include the calculation of economic indices.

(b) The economic indices mentioned in (a) above can be used to calculate the cost of supply interruptions to the economy. Furthermore, the cost associated with the additional equipment required for specific reliability improvement interventions can be calculated as part of the simplified approach by including an equipment cost library. The calculated economic cost of supply interruptions and capital required for reliability improvement options can then be used to identify minimum cost solutions, i.e. solutions where the costs to the utility are balanced by the value of the benefits received by its customers.

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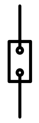
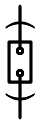
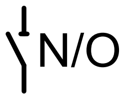
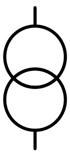
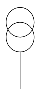
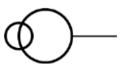
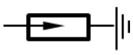
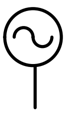
Annex A Electric symbol definition

The following symbols are used in this document:

No	Symbol	Description
1		Non-metalclad breaker
2		Metalclad (indoor) breaker
3		Isolator
4		Normally open isolator
5		Substation transformer
6		Voltage transformer
7		NECRT
8		Surge arrestor
9		Source
10		Load

Annex B Verification of substation results

The process of verifying the simplified reliability modelling results with the results obtained using ETAP was discussed in section 6.1.2. This annexure shows the outcomes of additional substation configurations modelled in ETAP.

The following design rules were applied to each of the modelled substation configurations:

(a) Each substation has 4 load feeders supplied form the downstream busbar;

(b) Each feeder has a load of 8 MVA.

(c) All transformers have a capacity of 40 MVA.

All substation configurations modelled are balanced configurations, i.e. each busbar has the same number of feeders connected. The only instances where the ETAP models were unbalanced, was the busbar linking for some of the double busbar configurations (as discussed in section 6.1.2.3). For these unbalanced configurations, two sets of results are shown. The average of these two set of results are then compared with the simplified reliability model.

The substation configurations modelled in ETAP are listed in Table B-1 below and the ETAP results are compared with the simplified reliability model. The switching station configurations are compared in Table . From these summary tables it is clear that there is a good correlation between simplified reliability modelling and the detailed modelling in ETAP.

Table B-1: Summary of ETAP verifications for selected substation configurations

No	Substation configuration					Difference between interruption durations calculated in ETAP and simplified reliability model (%)[4]	
	Sub-station voltages	Busbar configuration	Transformer capacity	Source feeders	No of load feeders (upstream busbar)	Upstream busbar	Downstream busbar
1	HV/MV	Type 1–Type 1	Single	Single	0	N/A	0%
2	HV/MV	Type 1–Type 1	Firm	Single	0	N/A	0%
3	HV/MV	Type 1–Type 1	Firm	Dual	0	N/A	0%
4	HV/MV	Type 1–Type 1	Firm	Dual	0	N/A	0%
5	HV/MV	Type 1–Type 2	Firm	Dual	0	N/A	0%
6	HV/MV	Type 1–Type 3	Firm	Dual	0	N/A	0%
7	HV/MV	Type 1–Type 4	Firm	Dual	0	N/A	0%
8	HV/MV	Type 2–Type 2	Firm	Dual	0	N/A	0%
9	HV/MV	Type 3–Type 3	Firm	Dual	0	N/A	0%
10	HV/MV	Type 1–Type 3 with bypass	Firm	Dual	0	N/A	-15%
11	HV/MV	Type 1–Type 4 with bypass	Firm	Dual	0	N/A	-3%
12	HV/MV	Type 1–Type 5	Firm	Dual	0	N/A	0%

[4] A negative difference indicates that the ETAP result is lower than that of the simplified reliability model.

No	Substation configuration					Difference between interruption durations calculated in ETAP and simplified reliability model (%)[4]	
	Sub-station voltages	Busbar configuration	Transformer capacity	Source feeders	No of load feeders (upstream busbar)	Upstream busbar	Downstream busbar
13	HV/MV	Type 1–Type 6	Firm	Dual	0	N/A	0%
14	HV/MV	Type 7–Type 1	Firm	Dual	0	N/A	0%
15	HV/MV	Type 1–Type 1	Firm	Dual	2	0%	0%
16	HV/MV	Type 2–Type 2	Firm	Dual	2	1%	0%
17	HV/MV	Type 3–Type 3	Firm	Dual	2	0%	0%
18	HV/MV	Type 3–Type 1	Firm	Dual	2	0%	0%
19	HV/MV	Type 3–Type 3 with bypass	Firm	Dual	2	0%	-60%
20	HV/MV	Type 3 with bypass–Type 3	Firm	Dual	2	-81%	-1%
21	HV/MV	Type 1–Type 4	Firm	Dual	2	0%	0%
22	HV/MV	Type 1–Type 4 with bypass	Firm	Dual	2	-1%	-5%
23	HV/MV	Type 4–Type 1	Firm	Dual	2	-7%	0%
24	HV/MV	Type 4 with bypass–Type 1	Firm	Dual	2	-26%	0%
25	HV/MV	Type 1–Type 5	Firm	Dual	2	0%	0%
26	HV/MV	Type 5–Type 1	Firm	Dual	2	0%	0%
27	HV/MV	Type 1–Type 6	Firm	Dual	2	0%	0%
28	HV/MV	Type 6–Type 1	Firm	Dual	2	0%	-1%
29	HV/MV	Type 7–Type 1	Firm	Dual	2	6%	-1%
30	HV/MV	Type 4–Type 1	3 transformers - firm	Dual	2	-7%	0%
31	HV/MV	Type 5–Type 1	3 transformers - firm	Dual	2	-1%	-9%
32	HV/MV	Type 6–Type 1	3 transformers - firm	Dual	2	0%	-5%
33	HV/MV	Type 7–Type 1	3 transformers - firm	Dual	2	4%	0%
34	HV/HV	Type 1–Type 1	Firm	Dual	0	N/A	0%
35	HV/HV	Type 2–Type 2	Firm	Dual	0	N/A	1%
36	HV/HV	Type 3–Type 1	Firm	Dual	0	N/A	0%
37	HV/HV	Type 3–Type 3	Firm	Dual	0	N/A	0%
38	HV/HV	Type 3–Type 3 with bypass	Firm	Dual	0	N/A	0%
39	HV/HV	Type 1–Type 4	Firm	Dual	0	N/A	0%
40	HV/HV	Type 1–Type 4 with bypass	Firm	Dual	0	N/A	-6%

No	Substation configuration					Difference between interruption durations calculated in ETAP and simplified reliability model (%)[4]	
	Sub-station voltages	Busbar configuration	Transformer capacity	Source feeders	No of load feeders (upstream busbar)	Upstream busbar	Downstream busbar
41	HV/HV	Type 4–Type 1	Firm	Dual	0	N/A	0%
42	HV/HV	Type 4 with bypass–Type 1	Firm	Dual	0	N/A	0%
43	HV/HV	Type 1–Type 5	Firm	Dual	0	N/A	0%
44	HV/HV	Type 5–Type 1	Firm	Dual	0	N/A	0%
45	HV/HV	Type 1–Type 6	Firm	Dual	0	N/A	0%
46	HV/HV	Type 6–Type 1	Firm	Dual	0	N/A	0%
47	HV/HV	Type 1–Type 7	Firm	Dual	0	N/A	1%
48	HV/HV	Type 7–Type 7	Firm	Dual	0	N/A	0%
49	HV/HV	Type 1–Type 1	Firm	Dual	2	0%	0%
50	HV/MV	Type 3–Type 1	Firm	Dual	2	1%	0%

Table B-2: Summary of ETAP verifications for selected switching station configurations

No	Switching station configuration				Difference between ETAP and Excel interruption durations p.a. (%)
	Switching station voltage	Busbar configuration	Source feeders	Load feeders	
1	HV	Type 1	Single	4	0%
2	HV	Type 4	Single	4	0%
3	HV	Type 5	Single	4	0%
4	HV	Type 6	Single	4	0%
5	HV	Type 1	Dual	4	0%
6	HV	Type 1 with bypass	Dual	4	0%
7	HV	Type 2	Dual	4	0%
8	HV	Type 3	Dual	4	0%
9	HV	Type 3 with bypass	Dual	4	0%
10	HV	Type 4	Dual	4	0%
11	HV	Type 4 with bypass	Dual	4	0%
12	HV	Type 5	Dual	4	0%
13	HV	Type 6	Dual	4	0%
14	HV	Type 7	Dual	4	4%

Annex C Substation model data inputs

The user is required to provide the inputs listed in Table C-1 in order to perform the simplified substation reliability modelling.

Table C-1: Inputs required for the simplified substation reliability modelling

No	Description	Unit	Validation	Comment
Plant information				
1	Busbar Plant slot ID			The unique identifier of the busbar
2	Busbar voltage	kV		The voltage is used to determine which failure rates to used.
3	Upstream busbar ID			The unavailability of each downstream busbar includes the unavailability caused by equipment failures on the upstream side of the transformer module. The upstream busbar ID should therefore be provided for each downstream busbar. For each upstream busbar this field will be blank.
Equipment data				
4	Type classification		Type 1, Type 2, Type 3, etc. (see list of standard configurations in section 3.4)	The type classification describes the busbar configuration and is used to determine the number of substation components, as well as the customer impact of component failures.
5	Number of load feeders			This is used to determine the number of substation components, and the customer impact of component failures
6	Number of source feeders			This is used to determine the number of substation components, and the customer impact of component failures
7	Number of transformers (source transformers only)			This is used to determine the number of substation components. The number of transformers, peak load and the installed capacity are used to determine the percentage customers interrupted in substations with unfirm transformer capacity.
8	Switchgear type		metalclad (indoor)/non-metalclad	Different failure rates can be defined for metalclad (indoor) and non-metalclad switchgear. The equipment considered for metalclad (indoor) switchgear is also different than for non-metalclad (see section 3.4.1.)
9	MV Bus zone protection		yes/no	
Load information				
10	Installed capacity (source transformers only)	MVA		This is the sum of total installed capacity for a specific step-down, e.g. 132/66

No	Description	Unit	Validation	Comment
11	Peak substation load	MVA		The peak load, number of transformers and the installed capacity is used to determine the percentage of customers interrupted in substations with unfirm transformer capacity.
Customers information				
12	Number of customers connected			The customer count is used for the calculation of the system indices.
Other				
13	Power station or external infeed		yes/no	This indicates whether the busbar is an external infeed or power station.
14	Unavailability of power station or external infeed			This field is only completed if the busbar is an external infeed (see section 5.4)

Annex D Transmission and sub-transmission data inputs

The user is required to provide the inputs listed in Table D-1 in order to perform the simplified transmission and sub-transmission reliability modelling.

Table D-1: Inputs required for the simplified transmission and sub-transmission modelling

No	Description	Unit	Validation	Comment
Plant information				
1	Busbar Plant slot ID			The unique identifier of the busbar
2	Upstream line ID			The unique identifier of the line that supplies the busbar. If more than one line supplies the substation, then: • if two or more lines are operated normally closed, this field is blank. • if only one line is operated normally closed, the ID if the normally closed line is entered here.
3	Upstream busbar ID			The unavailability of each busbar includes the unavailability of the busbar on the upstream side of the line that supplies the given busbar. The ID of the busbar on the upstream side of each line should therefore be provided.
Equipment data				
4	Upstream line/cable length			The total length of the line/cable
5	Line type		overhead/cable	The line can either be overhead or cable.
Other				
6	Remote visibility		yes/no	This input is required for the line failure outage duration, as specified in section 5.2

Annex E Test system network data

This annexure describes how the Ghana network information, required as input to the simplified reliability model, was derived.

The substation names and transmission line lengths were derived using the geographic views in Figure E-1 and Figure E-2.

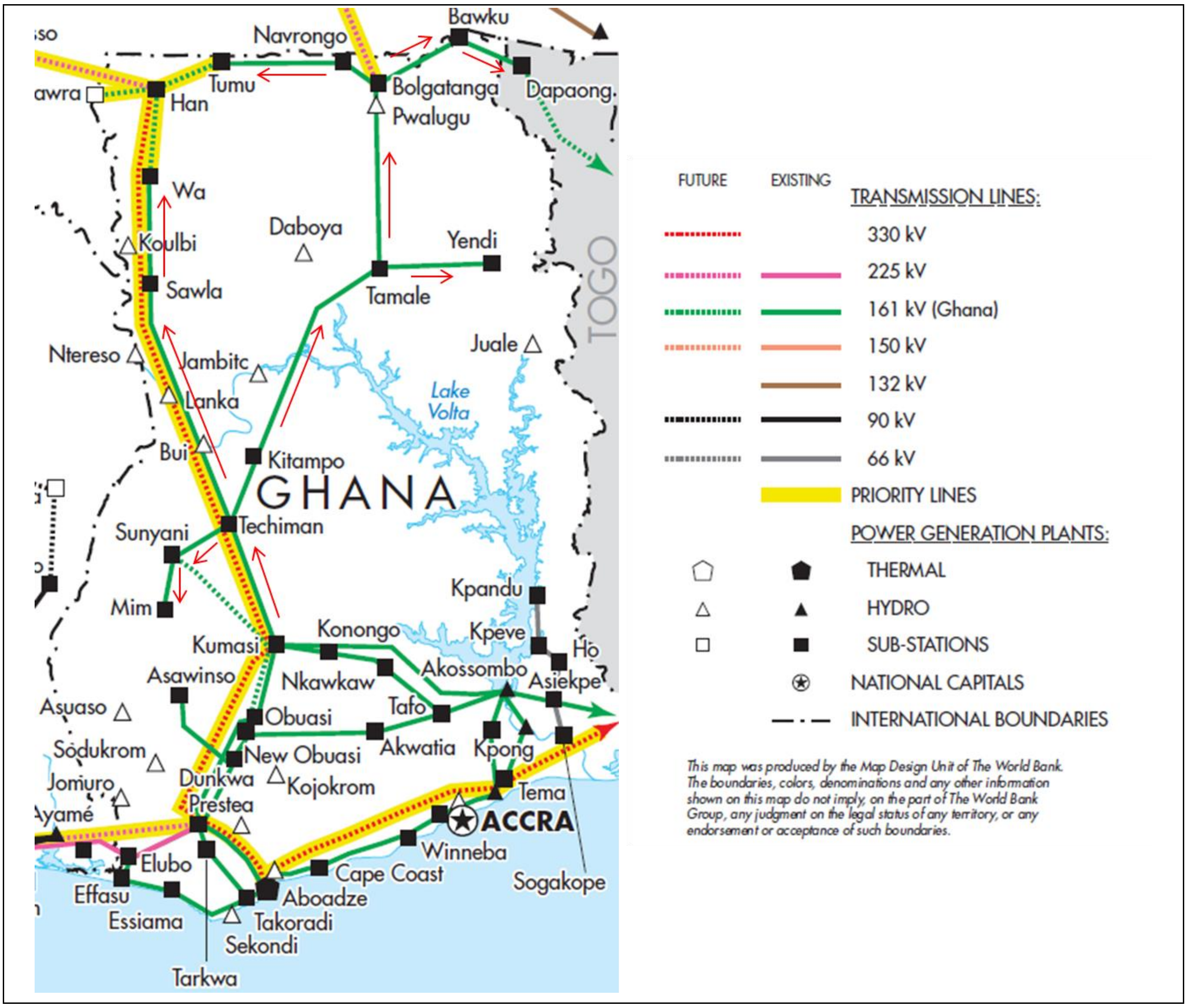
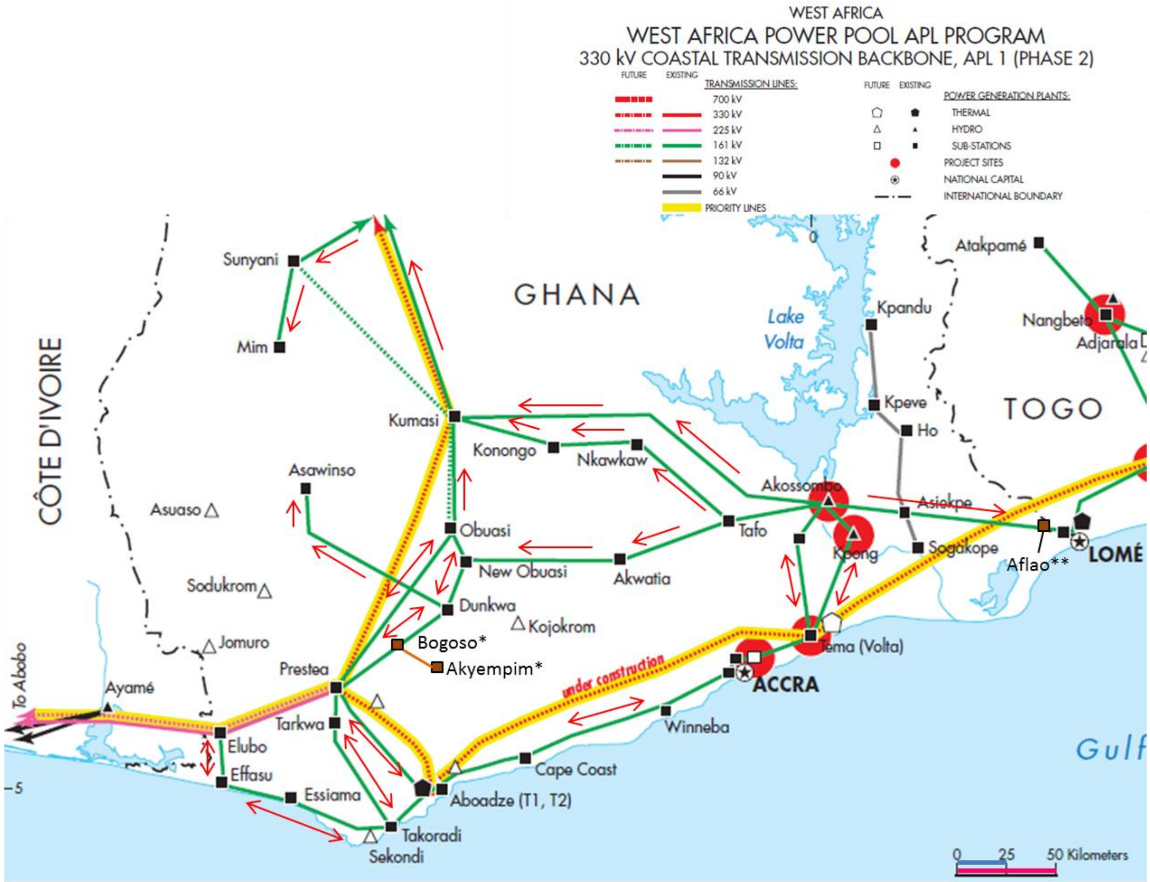


Figure E-1: Geographic view of the Ghana transmission network, with assumed direction of power flow. (adapted from (Worldbank, 2008, West Africa Power Pool APL Program: Inter-zonal transmission hub, APL 3 (Map no. IBRD 34436R)))



*161/34.5 kV substations; Source: http://energycenter.knust.edu.gh/downloads/10/10395.pdf
** 161/34.5 kV substation; Source: http://infrastructureafrica.org/library/doc/1045/aicd-all-countries-electricity-transmission-network

Figure E-2: Geographic view of the southern Ghana transmission network, with assumed direction of power flow. (adapted from (Worldbank, 2008, West Africa Power Pool APL Program: 330 kV coastal transmission backbone, APL 1 (Phase 2), (Map no. IBRD 33827R1)))

A list of all substations included in the simplified modelling, as obtained from Figure E-1 and Figure E-2, is shown in Table E-1. The number of transformers, installed capacity and peak load was obtained from Ghana's 2010 Electricity supply plan (Ghana Grid Company Limited (GridCo), 2010) and is shown in Table E-2. All other substation data inputs are also listed in Table E-2.

All line data are listed in Table E-3. The line lengths were derived from measurements from the scaled maps in Figure E-1 and Figure E-2. The upstream busbar was determined by assuming a certain direction of power flow. This direction is indicted in Figure E-1 and Figure E-2. For the ring networks, were a substation can be supplied from either side, the arrows point in both directions. These substations were assumed to have dual sources, since the substation can be supplied from either side.

Table E-1: List of substations included in the simplified reliability modelling

No	Substation name	No	Substation name	No	Substation name	No	Substation name
1	Aboadze	12	Esiama	23	Tafo	34	Kpeve
2	Accra	13	Kintampo	24	Takoradi	35	Ho
3	Aflao	14	Kumasi	25	Tamale	36	Sogakope
4	Akosombo	15	Mim	26	Techiman	37	Konongo
5	Akwatia	16	Navrongo	27	Tema	38	Tarkwa

No	Substation name	No	Substation name	No	Substation name	No	Substation name
6	Asawinso	17	New Obuasi	28	Tumu	39	Bogoso
7	Bawku	18	Nkawkaw	29	Wa	40	Akyempim
8	Bolgatanga	19	Obuasi	30	Winneba	41	Smelter
9	Capecoast	20	Prestea	31	Yendi	42	Mallam
10	Dunkwa	21	Sawla	32	Asiekpe		
11	Elubo	22	Sunyani	33	Kpandu		

Table E-2: Simplified reliability model inputs: Ghana substation data

No	BB_ID	Voltage (kV)	BB Config	SrcBB_ID	Count Trfrs	Installed Capacity	Peak Load	Count SrcFdrs	Count LdFdrs	Power station / Tx infeed*
1	Aboadze_161	161	Type3					0	2	1
2	Aboadze_33	33	Type1	Aboadze_161	1			0	2	0
3	Accra_161	161	Type3					2	0	0
4	Akosombo_161	161	Type3					0	3	1
5	Akwatia_161	161	Type3					2	0	0
6	Asiekpe_161	161	Type3					1	1	0
7	Asiekpe_69	69	Type3	Asiekpe_161	1				2	0
8	Asawinso_161	161	Type3					1	0	0
9	Bawku_161	161	Type3					1	1	0
10	Sawla_161	161	Type3					1	1	0
11	Bolgatanga_161	161	Type3					1	2	0
12	Capecoast_161	161	Type3					2	0	0
13	Mim_34.5	34.5	Type1					1	0	0
14	Dunkwa_161	161	Type3					2	1	0
15	Elubo_161	161	Type3	Elubo_225	1			0	1	0
16	Esiama_161	161	Type3					2	0	0
17	Kintampo_161	161	Type3					1	1	0
18	Konongo_161	161	Type3					2	0	0
19	Kpandu_69	69	Type3					1	0	0
20	Kumasi_161	161	Type3					3	1	0
21	Navrongo_161	161	Type3					1	1	0
22	New Obuasi_161	161	Type3					2	0	0
23	Nkawkaw_161	161	Type3					2	0	0
24	Obuasi_161	161	Type3					3	0	0
25	Prestea_161	161	Type3	Prestea_225	2	100	50	0	2	0
26	Prestea_225	225	Type5					1	0	1
27	Sunyani_161	161	Type3					1	1	0
28	Tafo_161	161	Type3					2	1	0
29	Takoradi_161	161	Type3					0	2	1
30	Takoradi_33	33	Type1	Takoradi_161	2	66	53.17	0	4	0

No	BB_ID	Voltage (kV)	BB Config	SrcBB_ID	Count Trfrs	Installed Capacity	Peak Load	Count SrcFdrs	Count LdFdrs	Power station / Tx infeed*
31	Tamale_161	161	Type3					1	2	0
32	Techiman_161	161	Type3					1	3	0
33	Tema_161	161	Type3					0	2	1
34	Tumu_161	161	Type3					1	0	0
35	Wa_161	161	Type3					1	0	0
36	Winneba_161	161	Type3					2	0	0
37	Yendi_161	161	Type3					1	0	0
38	Kpeve_69	69	Type3					1	1	0
39	Ho_69	69	Type3					1	1	0
40	Sogakope_69	69	Type3					1	0	0
41	Tarkwa_161	161	Type3					2	0	0
42	Capecoast_34.5	34.5	Type1	Capecoast_161	2	46.3	33.07	0	4	0
43	Esiama_34.5	34.5	Type1	Esiama_161	1	33	7.94	0	4	0
44	Winneba_34.5	34.5	Type1	Winneba_161	1	20	13.8	0	4	0
45	Tarkwa_34.5	34.5	Type1	Tarkwa_161	2	66	46.12	0	4	0
46	Kumasi_34.5	34.5	Type1	Kumasi_161	5	201.4	173.5	0	4	0
47	Obuasi_34.5	34.5	Type1	Obuasi_161	3	60	28.72	0	4	0
48	New Obuasi_11.5	11.5	Type1	New Obuasi_161	3	99	47.94	0	4	0
49	Dunkwa_34.5	34.5	Type1	Dunkwa_161	1	7	2.53	0	4	0
50	Asawinso_34.5	34.5	Type1	Asawinso_161	2	46.3	27.87	0	4	0
51	Konongo_11.5	11.5	Type1	Konongo_161	1	7	5.49	0	4	0
52	Nkawkaw_34.5	34.5	Type1	Nkawkaw_161	1	13.3	11.58	0	4	0
53	Techiman_34.5	34.5	Type1	Techiman_161	1	20	17.3	0	4	0
54	Sunyani_34.5	34.5	Type1	Sunyani_161	2	53	34.5	0	4	0
55	Tamale_34.5	34.5	Type1	Tamale_161	2	40	25.7	0	4	0
56	Yendi_34.5	34.5	Type1	Yendi_161	1	13.3	7.7	0	4	0
57	Sawla_34.5	34.5	Type1	Sawla_161	1	13.3	7.7	0	4	0
58	Prestea_34.5	34.5	Type1	Prestea_161	1	33	7.16	0	4	0
59	Kpandu_34.5	34.5	Type1	Kpandu_69	1	20	8.91	0	4	0
60	Kpeve_34.5	34.5	Type1	Kpeve_69	1	7	3.35	0	4	0
61	Ho_34.5	34.5	Type1	Ho_69	1	7	5.87	0	4	0
62	Sogakope_34.5	34.5	Type1	Sogakope_69	1	15	9.8	0	4	0
63	Tafo_34.5	34.5	Type1	Tafo_161	2	46	23.79	0	4	0
64	Akwatia_34.5	34.5	Type1	Akwatia_161	2	18	14.74	0	4	0
65	Asiekpe_34.5	34.5	Type1	Asiekpe_69	1	33	28.05	0	4	0
66	Accra_34.5	34.5	Type1	Accra_161	5	330	321.2	0	4	0
67	Tema_34.5	34.5	Type1	Tema_161	5	251	171.11	0	4	0
68	Akosombo_34.5	34.5	Type1	Akosombo_161	1	13.3	9.11	0	3	0
69	Bogoso_161	161	Type3					1	1	0
70	Bogoso_34.5	34.5	Type1	Bogoso_161	2	66	40.19	0	4	0
71	Akyempim_161	161	Type3					1	0	0

No	BB_ID	Voltage (kV)	BB Config	SrcBB_ID	Count Trfrs	Installed Capacity	Peak Load	Count SrcFdrs	Count LdFdrs	Power station / Tx infeed*
72	Akyempim_34.5	34.5	Type1	Akyempim_161	1	33	11.9	0	4	0
73	Smelter_161	161	Type3					4	0	0
74	Smelter_34.5	34.5	Type1	Smelter_161	8	550	200	0	4	0
75	Mallam_161	161	Type3					2	0	0
76	Mallam_34.5	34.5	Type1	Mallam_161	2	132	109.8	0	4	0
77	Aflao_161	161	Type3					1	0	0
78	Aflao_34.5	34.5	Type1	AFLAO_161	2	132	109.8	0	4	0
79	Elubo_225	225	Type5					1	1	0

** 1 = yes; 0 = no*

Table E-3: Simplified reliability model inputs: Ghana line data

No	BB_ID	Line_ID	Line length (km)	Line type	Line upstream busbar
1	Aboadze_161				
2	Aboadze_33				
3	Accra_161				
4	Akosombo_161				
5	Akwatia_161				
6	Asiekpe_161	Akosombo-Asiekpe_161	57	Line	Akosombo_161
7	Asiekpe_69				
8	Asawinso_161	Dunkwa-Asawinso_161	156	Line	Dunkwa_161
9	Bawku_161	Bolgatanga-Bawku_161	73	Line	Bolgatanga_161
10	Sawla_161	Techiman-Sawla_161	200	Line	Techiman_161
11	Bolgatanga_161	Tamale-Bolgatanga_161	146	Line	Tamale_161
12	Capecoast_161				
13	Mim_34.5	Sunyani-Mim_34.5	66	Line	Sunyani_34.5
14	Dunkwa_161				
15	Elubo_161				
16	Esiama_161				
17	Kintampo_161	Techiman-Kintampo_161	60	Line	Techiman_161
18	Konongo_161				Kpeve_69
19	Kpandu_69	Kpeve-Kpandu_69kV	61	Line	Kpeve_69
20	Kumasi_161				Akosombo_161
21	Navrongo_161	Bolgatanga-Navrongo_161	33	Line	Bolgatanga_161
22	New Obuasi_161				
23	Nkawkaw_161				
24	Obuasi_161				
25	Prestea_161				
26	Prestea_225	Elubo-Prestea_225	73.4	Line	Elubo_225
27	Sunyani_161	Techiman-Sunyani_161	51	Line	Techiman_161
28	Tafo_161				Akosombo_161
29	Takoradi_161				

No	BB_ID	Line_ID	Line length (km)	Line type	Line upstream busbar
30	Takoradi_33				
31	Tamale_161	Kitampo-Tamale	190	Line	Kintampo_161
32	Techiman_161	Kumasi-Techiman_161	104	Line	Kumasi_161
33	Tema_161				
34	Tumu_161	Navrongo-Tumu_161	93	Line	Navrongo_161
35	Wa_161	Sawla-Wa_161	89	Line	Sawla_161
36	Winneba_161				
37	Yendi_161	Tamale-Yendi_161	85	Line	Tamale_161
38	Kpeve_69	Ho-Kpeve_69kV	32	Line	Asiekpe_69
39	Ho_69	Asiekpe-Ho_69kV	65	Line	Asiekpe_69
40	Sogakope_69	Asiekpe-Sogakope_69kV	30	Line	Asiekpe_69
41	Tarkwa_161				
42	Capecoast_34.5				
43	Esiama_34.5				
44	Winneba_34.5				
45	Tarkwa_34.5				
46	Kumasi_34.5				
47	Obuasi_34.5				
48	New Obuasi_11.5				
49	Dunkwa_34.5				
50	Asawinso_34.5				
51	Konongo_11.5				
52	Nkawkaw_34.5				
53	Techiman_34.5				
54	Sunyani_34.5				
55	Tamale_34.5				
56	Yendi_34.5				
57	Sawla_34.5				
58	Prestea_34.5				
59	Kpandu_34.5				
60	Kpeve_34.5				
61	Ho_34.5				
62	Sogakope_34.5				
63	Tafo_34.5				
64	Akwatia_34.5				
65	Asiekpe_34.5				
66	Accra_34.5				
67	Tema_34.5				
68	Akosombo_34.5				
69	Bogoso_161				
70	Bogoso_34.5				
71	Akyempim_161				

No	BB_ID	Line_ID	Line length (km)	Line type	Line upstream busbar
72	Akyempim_34.5				
73	Smelter_161				Tema_161
74	Smelter_34.5				
75	Mallam_161				
76	Mallam_34.5				
77	Aflao_161	Asiekpe-Aflao_161	115	Line	Asiekpe_161
78	Aflao_34.5				

A list of all power stations and the maximum capacity of each is shown in Table E-4.

Table E-4: Power plant expected outage durations (Power Systems Energy Consulting (PSEC), 2010)

No	Station name	Available capacity (MW)	Forced outage
1	Akosombo	900	14%
2	Kpong	140	13%
3	Takoradi T1 (TAPCO)	300	24.2%
4	Takoradi T2 (TICO)	200	24.2%
5	Tema T1 (TT1PP)	113	N/A
6	Mines reserve plant (MRP)	50	N/A
7	Tema T2 (TT2PP)	-	N/A

The assumed number of customers, derived using the approach explained in section 7.1.2, is shown in Table E-5.

Table E-5: Assumed number of customers supplied per busbar

No	Substation name	Assumed supply Authority	Voltage (kV)	Customers
1	Aboadze	ECG	33	41 379
2	Accra	ECG	34.5	41 379
3	Afloa	ECG	34.5	41 379
4	Akosombo	ECG	34.5	41 379
5	Akwatia	ECG	34.5	41 379
6	Akyempim	ECG	34.5	41 379
7	Asawinso	ECG	34.5	41 379
8	Asiekpe	ECG	34.5	41 379
9	Bogoso	ECG	34.5	41 379
10	Capecoast	ECG	34.5	41 379
11	Dunkwa	ECG	34.5	41 379
12	Esiama	ECG	34.5	41 379
13	Ho	ECG	34.5	41 379
14	Konongo	ECG	11.5	41 379

No	Substation name	Assumed supply Authority	Voltage (kV)	Customers
15	Kpandu	ECG	34.5	41 379
16	Kpeve	ECG	34.5	41 379
17	Kumasi	ECG	34.5	41 379
18	Mallam	ECG	34.5	41 379
19	Mim	NED	34.5	31 391
20	New Obuasi	ECG	11.5	41 379
21	Nkawkaw	ECG	34.5	41 379
22	Obuasi	ECG	34.5	41 379
23	Prestea	ECG	34.5	41 379
24	Sawla	NED	34.5	31 391
25	Smelter	ECG	34.5	41 379
26	Sogakope	ECG	34.5	41 379
27	Sunyani	NED	34.5	31 391
28	Tafo	ECG	34.5	41 379
29	Takoradi	ECG	33	41 379
30	Tamale	NED	34.5	31 391
31	Tarkwa	ECG	34.5	41 379
32	Techiman	NED	34.5	31 391
33	Tema	ECG	34.5	41 379
34	Winneba	ECG	34.5	41 379
35	Yendi	NED	34.5	31 391
36	**Grand Total**			**1 388 337***

This total is less than the 1 388 344 customers shown in Figure 7-4, due to rounding errors when dividing the total number of customers with the total number of busbars.

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