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JOHAN SETRÉUS On Reliability Methods Quantifying Risks to Transfer Capability in Electric Power Transmission Systems KTH 2009

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On Reliability Methods Quantifying Risks to Transfer Capability in Electric Power Transmission Systems

JOHAN SETRÉUS

KTH Electrical Engineering

Licentiate Thesis in Electrical Systems
Stockholm, Sweden 2009

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On Reliability Methods Quantifying Risks to Transfer Capability in Electric Power Transmission Systems

JOHAN SETRÉUS

Licentiate Thesis
KTH Royal Institute of Technology
School of Electrical Engineering
Division of Electromagnetic Engineering
Stockholm, Sweden 2009

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Abstract

In the operation, planning and design of the transmission system it is of greatest concern to quantify the reliability security margin to unwanted conditions. The deterministic N-1 criterion has traditionally provided this security margin to reduce the consequences of severe conditions such as widespread blackouts. However, a deterministic criterion does not include the likelihood of different outage events. Moreover, experience from blackouts shows, e.g. in Sweden-Denmark September 2003, that the outages were not captured by the N-1 criterion. The question addressed in this thesis is how this system security margin can be quantified with probabilistic methods. A quantitative measure provides one valuable input to the decision-making process of selecting e.g. system expansions alternatives and maintenance actions in the planning and design phases. It is also beneficial for the operators in the control room to assess the associated security margin of existing and future network conditions.

This thesis presents a method that assesses each component's risk to an insufficient transfer capability in the transmission system. This shows on each component's importance to the system security margin. It provides a systematic analysis and ranking of outage events' risk of overloading critical transfer sections (CTS) in the system. The severity of each critical event is quantified in a risk index based on the likelihood of the event and the consequence of the section's transmission capacity. This enables a comparison of the risk of a frequent outage event with small CTS consequences, with a rare event with large consequences.

The developed approach has been applied for the generally known Roy Billinton Test System (RBTS). The result shows that the ranking of the components is highly dependent on the substation modelling and the studied system load level.

With the restriction of only evaluating the risks to the transfer capability in a few CTSs, the method provides a quantitative ranking of the potential risks to the system security margin at different load levels. Consequently, the developed reliability based approach provides information which could improve the deterministic criterion for transmission system planning.

Acknowledgments

This thesis is part of the Ph.D. project "Reliability modelling and design for complex power systems" at KTH School of Electrical Engineering, Division of Electromagnetic Engineering. The project is funded by the Swedish Center of Excellence in Electric Power Engineering (EKC^2). The financial support is gratefully acknowledged.

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Prof. *Roland Eriksson* my supervisor, for good discussions regarding the relevance and applicability of the studied reliability models and methods for the transmission system.

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To all my colleagues in the RCAM research group; Prof. Lina Bertling, Dr. Patrik Hilber, Dr. Stefan Arnborg, Prof. Michael Patriksson, Tech. Lic. Carl Johan Wallnerström, Julia Nilsson, François Besnard and for-

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Most importantly I want to thank my parents, brothers and all my relatives for their support and solidarity when we meets for dinner and sings "För trillen, för trallen..". Finally, but not least, this thesis is dedicated to Lisa for her love and support.

Johan
Stockholm, April 2009

List of papers

I J. Setréus and L. Bertling. Introduction to HVDC technology for reliable electrical power systems. *In Proc. of the 10th International Conference on Probabilistic Methods Applied to Power System (PMAPS)*, Rincón, Puerto Rico, May 2008.

II R. Leelaruji, J. Setréus, L. Bertling and G. Olguin. Availability assessment of the HVDC converter transformer system. *In Proc. of the 10th International Conference on Probabilistic Methods Applied to Power System (PMAPS)*, Rincón, Puerto Rico, May 2008.

III J. Setréus, S. Arnborg, R. Eriksson and L. Bertling. Components' Impact on Critical Transfer Section for Risk Based Transmission System Planning. Accepted to the *IEEE PowerTech 2009 conference, Bucharest, Romania, 28 June - 2 July 2009.*

Abbreviations

AC	Alternating current
BB	Busbar
CB	Circuit breaker
CTS	Critical transfer section [in transmission systems]
CTS [HVDC]	Converter transformer system [in HVDC systems]
Comp	Component
DC	Direct current
DISC	Disconnector
ENS	Energy not served
EENS	Expected energy not served
FEA	Failure effect analysis
GENCO	Generation company
h	Hours
HVDC	High voltage direct current
LP	Load point
MCS	Monte Carlo simulation
MTTF	Mean time to failure
MTTR	Mean time to repair
NERC	North American electric reliability corporation
Nordel	Nordic transmission system operators [in Denmark, Finland, Iceland, Norway and Sweden]

RBTS	Roy Billinton test system
SvK	Svenska Kraftnät [transmission system operator, and owner, of the Swedish national grid]
TR	Transformer
TSO	Transmission system operator
UCTE	Union for the Co-ordination of Transmission of Electricity [in central Europe]
yr	Year

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Chapter 1

Introduction

1.1 Background

The electrical power system has traditionally been considered to consist of three functional zones; the *generation*, *transmission* and *distribution* [1]. The function of the entire system is to transfer energy from the available resources to the end consumers. In the same moment the energy is converted into electric power in the generation system, the energy is consumed by the end users.

The bulk electric power is typically transferred with the transmission system over long distances, at high voltage levels, from the generator centres to the load centres. The distribution systems continue the transfer at lower voltage levels and delivers supply to individual users.

The power system consists of various types of interconnected components such as e.g. overhead lines, underground cables, transformers, reactors, capacitors, disconnectors, and circuit breakers. The system is constantly subjected to random failures of its interconnected components, caused by e.g. lightning, storm, human interaction, or aging equipment. Component failures in the distribution systems account for the absolute majority of the failures that results in an interruption of supply for the end consumers [1]. However, these are normally relatively localized compared to interruptions in the transmission system. The consequences on the modern society of a large interruption of supply (blackout) in the transmission system are considerable high. The related costs are significant [2, 3]. Important and vulnerable functions in the society, such as heating, cooling, and water supply, can only function a few hours after an interruption of supply. Local standby batteries in e.g. cell phone nodes have a limited capacity, necessary for the communication during the restoration process. Groceries at the supermarket get unusable after a few hours. Furthermore,

local generators can be available for some of the functions in the society, but this requires a good distribution of fuel to the effected areas.

Since an event in the transmission system can propagate and paralyse the society and its environment in a widespread geographical area, the system has been constructed to meet the high needs of reliability. It is generally designed, operated and planned with the N-1 criterion, which is a rule according to which the system must be able to withstand the loss of any single component [4]. Clearly this criterion provides a security margin to unwanted conditions in the system. Hence, a disturbance in the transmission system does not necessary lead to consequences for the end users in the system. E.g. only about 10 % of the component outages in the Swedish transmission system result in an interruption of supply for end users[1]. However, in the other 90 % of the outage occurrences, the margins in the system are reduced and the operating criteria set up by the transmission system operator may not be fulfilled. The question addressed in this thesis is how this system security margin can be quantified with probabilistic methods.

A quantitative index of the system security provides one valuable input to the decision-making process of selecting e.g. system expansions alternatives and maintenance actions. Furthermore, demand for reliable supply of electricity is growing, increasing the need for a higher level of system reliability. The N-1 criterion may not provide a sufficient level in the future system, and a stronger N-2 criterion is presumably not possible to justify financially [5]. Instead the N-1 criterion in combination with of a lowest acceptable quantitative value of system security can be used.

Probabilistic methods for the power system have been a topic for extensive research for several years [6–11]. The absolute majority of the work has treated models and methods to evaluate the system adequacy [1][2], i.e. the existence of sufficient facilities within a power system to satisfy the customer demand [1]. Within the area of system security, i.e. the ability of the power system to respond to disturbances [1], relatively few approaches have been published and a review of these are presented in Section 2.4.

1.1.1 Related research within the RCAM group

Maximum asset performance to a minimum total cost is one of the major goals for a power system manager. The problem formulation is constrained by the reliability of supply requirements by the customers and society. In the task, effective and efficient maintenance is one of the tools to reach this goal. Where and when in the system should maintenance optimally

[1] In Section 2.2.1 this approximative value of 10% is justified.
[2] Section 2.1.2 provides the definitions of system adequacy and system security.

be performed? Reliability centered maintenance (RCM) is one generally known method for cost-efficient maintenance planning. However, generally the method does not relate the benefits of maintenance to the system reliability and costs. At KTH, School of Electrical Engineering, a reliability-centered asset maintenance (RCAM) method was developed in [12, 13]. This approach improves the RCM method and it provides a systematic analysis with quantitative results. This work led to the establishment of the research group RCAM which is presented in [14]. The overall vision for the RCAM research group is to establish a comprehensive program for an optimal handling of assets in the electric power systems, as well as development of the own expertise in the area. The group comprises three main research areas that are essential for the RCAM method; (i) maintenance planning and optimization including RCM methods, (ii) reliability modelling and assessment for complex systems, and (iii) lifetime- and reliability modelling for electrical components. This thesis is part of PhD project included in area (ii) in the research group. Within research area (iii) Dr. Tommie Lindquist presented the PhD thesis in [15]. Dr. Patrik Hilber presented his work within area (i) in the PhD thesis in [16]. Currently four PhD projects are in progress within the RCAM group and the recent publications are e.g. [17–26].

Two master theses treating reliability models for High Voltage Direct Current (HVDC) has been performed within the RCAM group and the author's PhD project. In [27], Osama Swaitti developed and implemented models of HVDC links incorporated into the transmission system in the Neplan software, in collaboration with Prof. Math Bollen at STRI. In [28], Rujiroj Leelaruji presented reliability models for the converter transformer system in HVDC stations in collaboration with Gabriel Olguin at ABB.

The originator of the RCAM group, Prof. Lina Bertling, was appointed as Professor in Sustainable Electrical Systems at Chalmers technical university in January 2009. This enables for a future collaboration between the RCAM group and the Division of Electric Power at Chalmers.

1.2 Project Objective

The goal of this PhD project is the study, development and computer implementation of techniques and methods suitable for the assessment of complex power systems. In order to reach this goal, the main objective with this licentiate thesis is to develop an approach for quantifying the security margin to unwanted conditions in the transmission system with probabilistic methods.

One application in the project, that is feasible to perform if the main objective is fulfilled, is the study of high voltage direct current (HVDC) links. The objective is to study models and methods suitable for quantify-

ing the reliability impact on an increasing number of high voltage HVDC links incorporated into the transmission system.

1.3 Main Contributions

The main contributions of the thesis are the following:

- A systematic method for quantifying and ranking the risks to the transfer capacity in critical transfer sections of the transmission system, summarized in appended Paper III.
- Neplan software implementation of the extended substation model of the Roy Billinton Test System (RBTS), and a verification of this with a Monte Carlo simulation method.
- An implementation connecting MATLAB to Neplan, capable of analyzing a large number of outage events consequence to the transmission system transfer capacity.
- An overview of reliability models, methods and assessments of HVDC links incorporated into the transmission system, presented in appended Paper I.

1.3.1 List of Publications

Appended papers

The author has written and contributed to the major parts of appended Paper I, II and III. Prof. Lina Bertling has contributed as the main supervisor for all papers, which e.g. include input of ideas and reviews of draft versions. Prof. Roland Eriksson has contributed to all papers with discussions and proofreading. In Paper II Rujiroj Leelaruji has contributed with the Markov analysis, which was the result of the master thesis project supervised by the author in [28]. Gabriel Olguin at ABB contributed with transformer statistics and reviews of draft version of Paper II. In Paper III the proposed method were developed together with Dr. Stefan Arnborg at SvK, who also contributed with the proofreading of the paper.

I J. Setréus and L. Bertling. Introduction to HVDC technology for reliable electrical power systems. *In Proc. of the 10th International Conference on Probabilistic Methods Applied to Power System (PMAPS)*, Rincón, Puerto Rico, May 2008. [29]

II R. Leelaruji, J. Setréus, L. Bertling and G. Olguin,. Availability assessment of the HVDC converter transformer system. *In Proc. of the 10th International Conference on Probabilistic Methods Applied to Power System (PMAPS)*, Rincón, Puerto Rico, May 2008. [30]

III J. Setréus, S. Arnborg, R. Eriksson and L. Bertling. Components' Impact on Critical Transfer Section for Risk Based Transmission System Planning. Accepted to the *IEEE Power Tech 2009 conference, Bucharest, Romania, 28 June - 2 July 2009.* [31]

Additional publications

A J. Setréus, L. Bertling, S. Mousavi Gargari. Simulation Method for Reliability Assessment of Electrical Distribution Systems. *In Proc. of the Nordic conference on Nordic Distribution and Asset Management (NORDAC)*, Stockholm, Sweden, August 2006. [32]

B J. Setréus, et al. Study visit at the SwePol HVDC Link. Technical report, Royal Institute of Technology (KTH), School of Electrical Engineering, November 2006. TRITA-EE 2006:063. [33]

C J. Setréus, C.J. Wallnerström, L. Bertling. A comparative study of regulation policies for interruption of supply of electrical distribution systems in Sweden and UK. *In Proc. of the International Conference on Electricity Distribution, CIRED 2007*, Vienna, Austria, May 2007. [34]

D J. Setréus. Verification of Results from the Loadflow module in RADPOW_2007. Technical report, Royal Institute of Technology (KTH), School of Electrical Engineering, March 2008. TRITA-EE 2008:013. [35]

E L. Bertling, P. Hilber, J. Jensen, J. Setréus, C.J Wallnerström. RADPOW development and documentation. Technical report, Royal Institute of Technology (KTH), School of Electrical Engineering, January 2008. TRITA-EE 2007:047. [36]

F J. Setréus. Verification of the transmission system model RBTS using Monte Carlo simulation methods. Technical report, Royal Institute of Technology (KTH), School of Electrical Engineering, March 2009. TRITA-EE 2009:019. [37]

1.4 Thesis Outline

This thesis is mainly based on the proposed method described in appended Paper III. This method can in future case studies be applied to the introduced reliability models of HVDC in Paper I and II.

Chapter 2 provides the necessary terminology and definitions used in the thesis. A discussion of reliability models for HVDC is included at the end of the chapter.

Chapter 3 introduces the reliability test system RBTS. This system is used to exemplify the proposed method in this thesis. The electric and reliability data for the system are presented, followed by verifications of the implemented models of RBTS.

Chapter 4 introduces the proposed method of quantifying the risks to the transmission system transfer capability.

Chapter 5 presents the results from the proposed method applied on the test system RBTS.

Chapter 6 concludes the thesis. It summarizes the results and present ideas and discusses future work.

Chapter 2

Introduction to Transmission System Reliability

This chapter gives the definitions and terminology used for the following chapters in the thesis. The behaviour of the transmission system is exemplified with (i) statistics from the Swedish transmission system, and (ii) with description and classification of large historical outage events. The traditional deterministic reliability security criterion is described, followed by a review of published methods with a probability-based approach to assess the security. At the end of the chapter reliability assessments treating HVDC incorporated into the transmission system are discussed.

2.1 General Concepts

2.1.1 General definitions and terminology

- **Component**: A piece of electrical or mechanical equipment viewed as an entity for the purpose of reliability evaluation. [38] [1]
- **System**: A group of components connected or associated in a fixed configuration to perform a specified function. [38]
- **Reliability**: The ability of a component or system to perform required functions under stated conditions for a stated period of time. [38]

[1] Examples of components are: line sections, transformers, generators, circuit breakers, line protection systems, and bus sections.

- **Failure**: The inability of a component to perform its required function. [39] The failure can be either active or passive [1]:
  - **Passive failure**: A component failure mode that does not cause operation of protection breakers and therefore does not have an impact on the remaining healthy components.
  - **Active failure**: A component failure mode that causes the operation of primary protection zone around the failed component and can therefore cause removal of other healthy components and branches from service.
- **Outage state**: The component or unit is not in the in-service state; that is, it is partially or fully isolated from the system. [39]
- **Outage Occurrence** (or simply **Outage**): The change in the state of one component or one unit from the in-service state to the outage state[2] [39]. An outage occurrence is either forced or scheduled:
  - **Forced Outage**: An automatic outage, or a manual outage that cannot be deferred. Forced outages are further classified in four groups: [39]
    - **Transient Forced Outage**: A forced outage where the unit or component is undamaged and is restored to service automatically.
    - **Temporary Forced Outage**: A forced outage where the unit or component is undamaged and is restored to service by manual switching operations without repair but possibly with on-site inspection.
    - **Permanent Forced Outage**: A forced outage where the component or unit is damaged and cannot be restored to service until repair or replacement is completed.
    - **System Related Outage**: A forced outage which results from system effects or conditions and is not caused by an event directly associated with the component or unit being reported.
  - **Scheduled Outage**: An intentional manual outage that could have been deferred without increasing risk to human life, risk to property, or damage to equipment.
- **Outage Event**: An event involving the outage occurrence of one or more units or components. [39]

[2] An outage may or may not cause an interruption of service to consumers, depending on system configuration [39].

  - **Single Outage Event**: An outage event involving only one component or one unit.
  - **Multiple Outage Event**: An outage event involving two or more components, or two or more units.
    * **Related Multiple Outage Event**: A multiple outage event in which one outage occurrence is the consequence of another outage occurrence, or in which multiple outage occurrences were initiated by a single incident, or both.
    * **Multiple Independent Outages**: Outage occurrences each having distinct and separate initiating incidents where no outage occurrence is the consequence of any other, but the outage states overlap.

- **Interruption**: The loss of electric power supply to one or more loads. [38] *More specific: Interruption of supply.*
- **Contingency**: The unexpected failure or outage of a system component(s) (generator, transmission line, breaker, switch, etc.). [40]
- **Disturbance**: Any perturbation to the electric system[3]. [40]
- **Load shedding**: Disconnecting or interrupting the electrical supply to a customer load by the utility, usually to mitigate the effects of generating capacity deficiencies or transmission limitations. [40] *Synonym: Load curtailment.*

2.1.2 Concepts of adequacy and security

System adequacy and system security are two fundamental concepts within reliability of electric power systems. The following definitions are used in this thesis:

- **Adequacy**: (i) "..the existence of sufficient facilities within a power system to satisfy the customer demand." [1], (ii) "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." [41].
- **Security**: (i) "..the ability of a power system to respond to disturbances arising within that system." [1], (ii) "The ability of the power

[3]It is assumed that a disturbance either leads to an equipment trip or not. E.g. a lightning may not always trigger the protection system, but an overvoltage may be present.

system to withstand sudden disturbances such as electric short circuits or non anticipated loss of system components." [41].

In short terms adequacy describes the system's capability to function during a certain time frame, and security describes how many things can go wrong before the function actually is comprised [42].

One example of a system adequacy index is Energy Not Supplied (ENS) (MWh/yr), which is the total interrupted energy for the customers for one year. Example of a security measure is the deterministic N-1 criterion, defined in Section 2.1.3.

Figure 2.1 shows general subdivision of electric power system reliability. System security evaluations often involve dynamical analysis and simulations, but this is not necessarily the case [43]. It can also include steady-state analysis of a selected disturbance (e.g. a component outage) influence on the power system. A dynamic stability assessment tells if the transition between the former and the new (if one exists) equilibrium point is possible. The steady-state analysis determines whether a new equilibrium point exists or not, given that the oscillations from the disturbance are totally damped out.

However, it should be mention that the terminology of adequacy and security differs depending on source. In much of the literature the adequacy reliability criteria is associated with static failure conditions, and the security with dynamic factors [44].

Appended paper I and II treats system adequacy and paper III system security. One of the conclusions in paper I is, however, that a security analysis is needed to assess the impact on reliability of an incorporated HVDC.

In this thesis only steady-state analysis in the system security assessment are considered.

2.1.3 The N-1 criterion

The N-1 criterion is adapted both in the planning of the transmission system and in the operation of the same and the intention of the rule is to ensure a certain level of reliability in the system with a reasonable investment cost. There are several definitions of this criterion in the literature. The following definitions are from UCTE and Nordel:

- **N-1 Criterion**: (i) "The N-1 criterion is a rule according to which elements remaining in operation after failure of a single network element (such as transmission line / transformer or generating unit, or in certain instances a busbar) must be capable of accommodating the change of flows in the network caused by that single failure." [45], (ii) "N-1 criteria are a way of expressing a level of system security

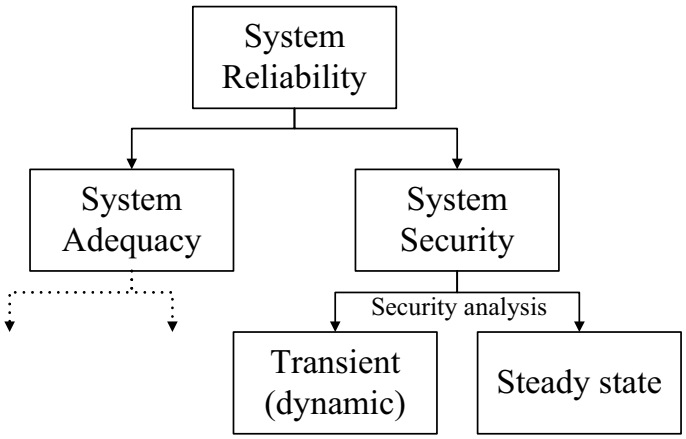

Figure 2.1: Electric power system reliability can be divided into system adequacy and system security. System security analysis can be performed by either dynamic or steady-state assessments.

> entailing that a power system can withstand the loss of an individual principal component (production unit, line, transformer, bus bar, consumption etc.)." [4].

Implementations and details of the N-1 criterion differ depending on the rules specific transmission system operator (TSO) has agreed on. It also depends on if it is used in the planning (design) or operation of the system. These aspect are further discussed in Section 2.3.1 and 2.3.2.

The expression "n-1 fault"

To avoid confusion with the N-1 criterion, the expressions of e.g. "a n-1 fault" or "a n-2 fault" are avoided in this thesis. Instead the terminology of single outage events or multiple outage events are used. If the number of component outages, k, in a multiple outage event needs to be specified, this is achieved by denoting the event *outage order k*.

2.2 Outages in the Transmission System

2.2.1 Outages in the Swedish transmission system

Figure 2.2 depicts that a disturbance in the transmission system does not necessary lead to consequences in terms of interruption of load in the system, because of the N-1 criterion. In fact only about 10 % of them do in

the Swedish transmission system[4]. However, in the other 90 % of the disturbances, the margins in the system are reduced and operating criteria set up by the transmission system operator (TSO) may not be fulfilled. Moreover, overloads may be present at this post-contingency state. Clearly the system is exposed to risk during this state. One of the aims of this thesis is to quantify the associated risk each component contributes with of getting into this state.

Figure 2.3 shows the causes of outages in the Swedish transmission system during the years 2000-2007. The most common cause for outage is lightning that stands for 43%. However, if instead the causes that result in Energy Not Supplied (ENS) are studied, the lightning only stands for 11% and technical equipment for 49% [48].

Table 2.1 shows the failure statistics for the components in the Swedish transmission system during the years 1997-2002. This table have been included as reference for a later comparison of the reliability data in the test system RBTS.

2.2.2 Example on Severe Historical Events

Table 2.2 shows a collection of historical interruptions in the transmission systems. The intention of this survey is provide a list with the events' duration and Energy Not Served (ENS). The list do not serve as a complete list of large interruptions, but, these are the found published events with available data.

The following sections provide a closer description of four of these events.

Europe 4th November 2006

In the evening of 4 November 2006 a disturbance took place in the Europe synchronously interconnected transmission system UCTE. The system, that includes most of the Europe countries except the UK and the Nordic countries, were split into three islands after a fault in north Germany. A total blackout was prevented but the load shedding due the frequency fluctuations led to an interruption of supply for more than 15 million domestic customers [50] [51]. The restoration process, which included the re-synchronization of three separated islands, was completed in less than two hours after the triggering fault.

The cause for the interruption was not due to extraordinary climate conditions or technical failures; instead it was the way the system was op-

[4]This approximate value has been estimated by the author from the annual statistics during the latest eight years in the Swedish transmission system (400 and 220 kV). The source is the SvK annual reports from 2001 [46] to 2008 [47].

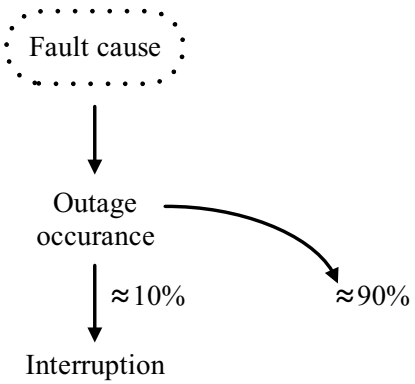

Figure 2.2: Only about 10% of all component outage occurrences results in an interruption of supply for the customers connected to the transmission system. The remaining 90% may however expose the system to a risk.

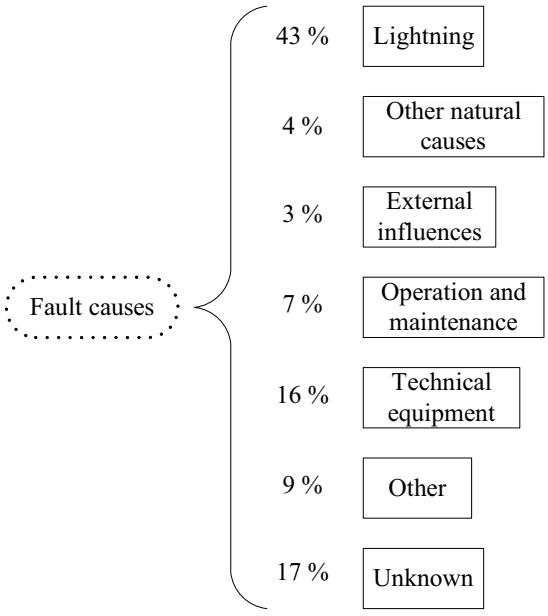

Figure 2.3: Overview of the different causes to outage occurrences in the Swedish transmission system during the years 2000-2007 (at the 400, 220 and 130 kV level) [48].

Table 2.1: Component failure statistics from the 220 kV and 400 kV level in the Swedish transmission system from reference [49]. The data was collected during the years 1997-2002.

Transmission Line	**220 kV**	**400 kV**
Forced outage rate (long[a]) [f/yr,km]	0.0013	0.0007
Average outage duration (long[a]) [h]	14.59	24.68
Forced outage rate (short[a]) [f/yr,km]	0.0109	0.0043
Average outage duration (short[a]) [h]	0.14	0.11
Circuit Breaker	**220/400 kV**	
Forced outage rate [f/yr]	0.0045	
Average outage duration [h]	8.97	
Busbar	**220 kV**	**400 kV**
Forced outage rate [f/yr]	0.0173	0.0269
Average outage duration [h]	1.47	3.42
Disconnector	**220/400 kV**	
Forced outage rate [f/yr]	0.0014	
Average outage duration [h]	20.31	
Station Transformer	**400 kV**	
Forced outage rate [f/yr]	0.0222	
Average outage duration [h]	0.11	

[a] Outages with a duration longer than 2 hours are categorized as "long", otherwise "short" [49].

erated that was crucial. The two main causes were; (i) non fulfilment of the N-1 security criterion and (ii) insufficient coordination of the transmission system operators (TSOs). The conditions in the system before the event was not unusual, with the exception of high power flows from Germany to Netherlands and Poland due to high wind power production. The sequence of events that eventually led to the split up started with a planned disconnect of a double circuit line over the river Elm for the safe passage of the ship Norwegian Pearl. This operation had been performed before, and always preceded by an N-1 security analysis with a load flow calculation by the Germany TSO and its neighbours. However, the time for the passage of the ship was re-scheduled by the German TSO by very short notice and the analysis of the impact of the disconnection of the line was not sufficiently prepared. The TSO also did not have the proper settings of certain line protection devices in their calculations. This led to the fact that when the double line were disconnected the N-1 criterion was not fulfilled by the

Table 2.2: A selection of historical events in the transmission system that resulted in large interruption of supply for the customers

Location, date	**Duration of interruption[a](hours)**	**ENS (MWh/event)**	**Sources**
Europe 2006-11-04	0.5 - 2	-[b]	[50, 51]
Norway 2004-02-13	- 1	1 100	[52, 53]
Italy 2003-09-28	4 - 18.2	177 000	[54]
Sweden-Denmark 2003-09-23	1 - 6.5	18 000	[55–59]
US-Canada 2003-08-14	2 - 30	320 000[c]	[60–62]
Norway 2003-08-09	- 2	1 285	[58, 59]
Sweden 1983-12-27	1 - 6	24 000	[63]
Belgium 1982-08-04	- 6.5	8 000	[64]
Sweden 1979-01-13	- 1.5	4 000	[64]
France 1978-12-19	- 7.5	94 000	[64]
New York 1977-07-13	- 22	102 000	[64]

[a] Interval from when first to last customer has the possibility to re-connect to the system.
[b] Value not published.
[c] This is a value estimated by the author. It is based on an approximate integration of the load curve figure at page 36 in [60].

German TSO and its neighbours. Eventually a relatively small power flow deviation at a line triggered protection devices that started a cascading effect of line tripping that led to the split up of the system [50].

Italy 28th September 2003

One of the most severe disturbance in Europe, in terms of affected customers, is the blackout in Italy at night-time 28th September 2003 [51]. At 03:25 the Italian transmission system were separated from the European network and shortly after it collapsed. The restoration process and re-synchronization to the European grid started immediately. The north and central parts of the country were fully energized after 4 respectively 8 hours and the remaining part of the mainland was fully restored within 13 hours. In Sicily the last customers was fully energized after 18 hours and 12 minutes. The total energy not supplied for the disturbance was estimated to 177 GWh [54].

The sequence of events that led to the separation of the Italian grid, and eventually the blackout, was triggered by the tripping of a Swiss 380 kV line due to a tree flashover. Several attempts to re-close the line failed, since the protection devices' settings prevented this due to the large angle differences caused by the high loading. Another Swiss line was overloaded because of this event and the calculated capability at this load and line was specified to approximately 15 minutes. The operators were unaware of this time limit. Both of these two lines were closely connected to the Italian grid in the north and exported energy from Switzerland to Italy. The Swiss TSO called the Italian counterpart 10 minutes after the first event, with a request to reduce the import and thereby the loading of this line. A small reduce were made, but the urgency of the overload of the line were not taken too serious. At 24 minutes after the first event the second line tripped after a tree flashover, probably caused by the high temperature and sagging of the line. This led to the isolation of the Italian system. Because of instability phenomena in this system, low voltage levels in the north tripped a number of generation units [54].

It can be argued whether or not the Italian system really was N-1 secure before the incident. Is the criteria really fulfilled if the system after the single outage event needs corrective actions, within a short time period, in order to e.g. reduce line overloads? A strong version of the criterion would state that after the contingency (and with an idealized steady state load flow), the system should be able to be operated in that condition for a long time without any line overheating after e.g. 30 minutes.

Sweden and eastern Denmark 23th September 2003

One of the most severe disturbances in the Nordic transmission system in 20 years took place at daytime in September 2003 in the southern part of Sweden and eastern parts of Denmark. Approximately 857 000 domestic and industry customers were affected of this interruption that lasted from about 1 hour to 6.5 hours, when the last customer were reconnected [55].

The cause of the disturbance was the coincident of two independent outages that occurred concurrently within a very short time interval. The first forced outage was a shutdown of a nuclear unit on the south east coast in Oskarshamn due to internal valve problems. Five minutes later a double busbar outage in a substation at the western coast took place due to the malfunction of a 400 kV disconnector that short-circuited two separate sections of the station. To each of these specific busbars a nuclear generator unit was connected and these were automatically disconnected. The massive loss of generation in the southern part of the system led to heavy power oscillations and eventually also to the tripping of a number of line breakers, disconnecting a large part of the system. The combined failure events can be seen either as an second or third order multiple outage event, depending on how the substation outage is considered [55].

As the system is designed and operated with the N-1 criterion these sorts of combined and overlapping faults are not possible to handle. It has been shown in simulations that the system had withstand each of these faults if occurred separately.

Sweden 27 December 1983

In December 1983 the south parts of Sweden suffered a disturbance that led to an interruption of supply of about 60% of the country's load [65]. The length of the blackout was 1-6 hours depending on location in the system. The energy not supplied was estimated to 24 GWh [63]. The north parts of Sweden survived the disturbance, although it suffered over-frequencies up to 54 Hz [65].

The disturbance that eventually led to the blackout was primarily caused by an overheated busbar located in a large switchyard close to Stockholm. The busbar failure caused a cascade tripping of two 400 kV transmission lines to the north parts of Sweden. As a result of this the remaining transmission lines from north to south in Sweden were heavily loaded and this led to the tripping of an additional 400 kV line [66]. All the remaining lines were disconnected due to their loading and the voltage and frequency in the south part drop rapidly since a power deficit of about 7000 MW [67]. The blackout of southern part of Sweden was thereby a fact. The load shedding and under-frequency equipment did not function properly and this resulted in a larger interruption than necessary.

Discussion

An attempt to categorize the main causes to the historical events in the transmission system has been made below:

- Insufficient communication between the TSOs in large synchronous systems.

- Unawareness of non-fulfilment of the N-1 criterion during operation.
- A single forced outage in a substation component result in a related multiple outage event.
- A multiple independent outage with the events closely located in the system.

2.2.3 Classification Outage Events

Given the outage events in Table 2.2, a classification of the severity of these is made. Figure 2.4 shows the classification diagram with these events. The idea for the diagram has been adopted from [68,69]. The division of severity, from minor to catastrophic, is determined by the total disconnected energy for the event[5]. In [69] the classification is described further and the diagram is also more detailed for short events (hours) with large interrupted energy (MW), and for long events (hours) with light energy (MW).

In Figure 2.4 the average disconnected power not supplied (MW) during the event has been calculated to match the ENS (MWh) values in Table 2.2. The duration of the event is defined as the time when the last customer has the possibility to re-connect to the system.

2.3 Deterministic-Based Security Assessments

2.3.1 Deterministic-Based Security Assessment in Operation

To start with, assume that the N-1 criterion has been adopted as a rule for the operation of the transmission system. The Nordic Grid Code in [4], used for the Nordic synchronous system, is here used as an example. Given a specific operation situation (e.g. a specific load level, load flow, network topology etc.) in the system, the N-1 criterion states that the system must be able to withstand the loss of any single principal component in the system without endanger the system function which is to supply electricity to the customers in the system. Here, the expression of principal components includes generating unit sets, compensating installation, transmission circuits (such as lines) and transformers. One example of a component that is generally not included in the group of principal components is the circuit breaker. But of course it is always a matter of choice for the TSOs which

[5] The lines in the diagram represent the following disconnected energy levels; Minor: <1000 Mwh, Moderate: <4000 MWh, Major: <16000 MWh, Critical: <64000 MWh and Catastrophical: >64000 MWh.

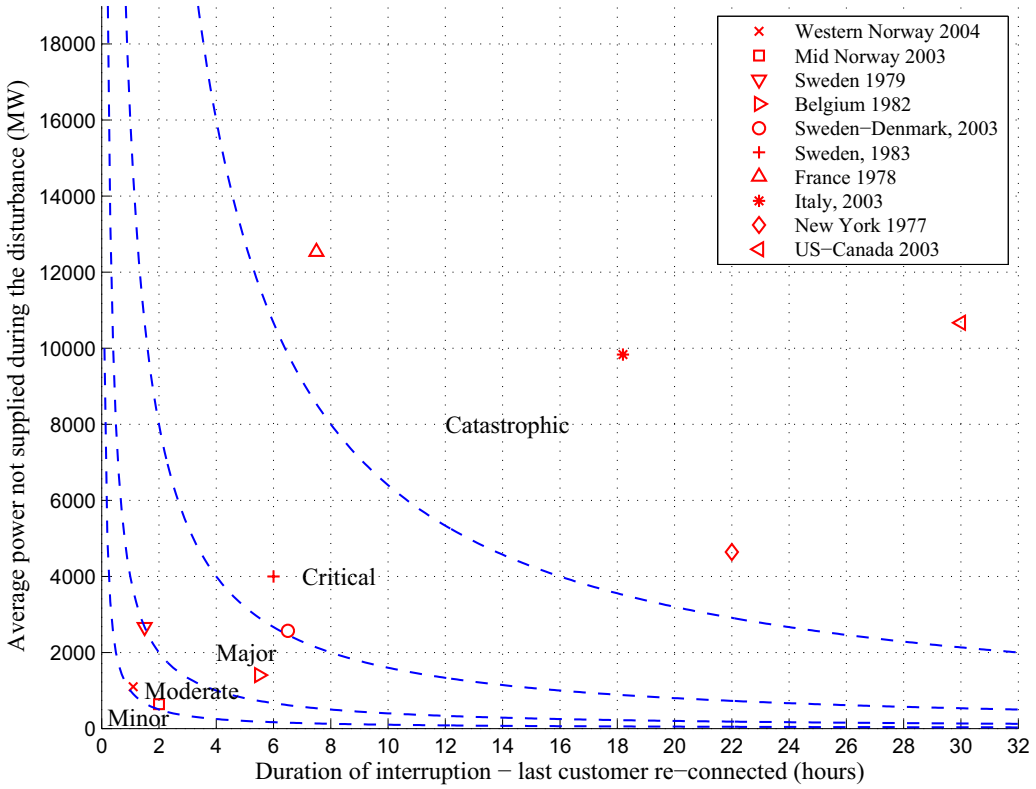

Figure 2.4: Consequence classification of eleven selected historical outage events with large impact on the transmission system. This classification diagram has been adopted from [68, 69].

components that shall be included in the group of principal components for the rules of N-1.

Each fault that leads to a loss of a single component (temporary or permanent) has different impact on the system. The impact does also highly depend on the current operation situation in the system. The faults with the largest impact are in the Nordic Grid Code referred to as dimensioning faults. This enables a reduction of the number of fault scenarios that needs to be monitored for fulfilling the N-1 criterion in the system at this specific operation situation. The dimensioning fault gives in a way a list with the worst case scenario (at the given conditions) when considering the loss of a single component. In the transmission system this list generally consists of central positioned busbars and the largest production unit in the system at the moment. Two separate operation situations (high or low transfer)

may result in different dimensioning faults.

2.3.2 Deterministic Security Assessment in Planning

Assume that the N-1 criterion has been adopted as a rule in the planning of the transmission system. The system then needs to be planned, designed and dimensioned in a way so it can handle each future operation situation that is forecasted, and for each of these situations be able to fulfil the N-1 criterion. The analyses are carried out for different time horizons, everything from minutes to weeks, months and years. The consumption and generation are forecasted and high-load (or peak load) scenarios are used to determine the dimensioning faults and limiting system properties for the given time horizon.

If the system is planned with the N-1 criterion for a certain time horizon, it is also normally planned for handling the worst case scenario with peak load consumption. However, different scenarios for e.g. topology, switching configuration etcetera, could be considered. Now consider an operation scenario within this time horizon, at a time during the year when a very low load situation is present, and where large transfer margins are available in the system. Since the system has been planned with the N-1 criterion, the system also certainly fulfils the N-1 criterion during the operation of the system and the scenario. In fact, the real operational situation may be much more secure than the set up N-1 criterion. At the present time, the system may in fact be able to fulfil the much stronger N-2 criterion. This means that the system is capable of accommodating the situation of any multiple outage event of order two that may occur. This point out the real difference between the N-1 criterion for planning respectively operation. The N-1 criterion in planning is static since it has taken (or at least should have taken) all possible known operational situations in the time horizon into consideration. Based on the information we got and the actions we then take, the system fulfils the N-1 criterion. For the N-1 criterion in operation on the other hand, the system always at least should fulfil the N-1 criterion. The real situation may be much stronger (where in fact an N-2 criterion is fulfilled), and with large margins from a system breakdown in case of a severe situation.

2.3.3 Discussion

The difference between N-1 criterion in planning and operation is in practice even larger. In Nordel's Nordic Grid Code in [4], the N-1 criterion in planning does not has to be fulfilled for all possible faults in the planning time horizon. Some faults are accepted if the risk (probability and consequence is taken into consideration) are low for the faults. In operation the traditional (and stronger) definition of N-1 criterion is still considered.

However, the following statement is made in the Nordic Grid Code [4]: "the aim is that the operation and planning work should be based on the same reliability philosophy, and that the rules should also be able to serve as a guide at the operating stage.".

Two weaknesses of the N-1 criterion are firstly, the lack of evaluation of multiple component outages and secondly, the absent of any estimate of the likelihood of the outage. These weaknesses can lead to a misjudgement of the true critical outages. A single component outage with large consequences, but with a very low likelihood of occurrence may be considered more important than a multiple component outage with the same consequences but with higher probability. Furthermore, single outages with a high expected frequency of occurrence, but with moderate consequences, may provide a higher risk than outages that a low likelihood but large consequences. One other weakness with the N-1 criterion in system planning is that the contingency analysis normally is performed in a worst case scenario at a system peak load level. The expected probability for this load situation may be very small and this may therefore lead to a misjudgement of the, most time of the year, actual risk outage events.

2.4 Probability-Based Reliability Assessments

Reliability modelling of the transmission system is a challenging task. The high level of reliability in the real system results in very few outage events that actually leads to an interruption of supply for the customer. A small number of events consequence to the customers needs to be model and evaluated to provide a quantitative index of the system reliability. Furthermore, major interruptions and blackouts have historically been associated with dependent outage events [5], which is difficult to predict and complex to model accurately. Dynamic phenomena are more or less involved in all outage events and cannot always be neglected in the modelling. Load shedding mechanisms, which act in case of a power deficit or other system violations, are normally triggered by the system frequency in the real system, and this is difficult to include correctly in the reliability modelling. Also, momentary after an outage event, the control room plays an important role in the restoration work, and this human interaction is certainly hard to model. To summarize; the system is extremely complex and approximations, more or less justified, always has to be included in the modelling.

Probabilistic methods for the power system have been a topic for extensive research for several years [6–11]. The research has been focused on adequacy assessments for the generation and transmission systems [1]. However, during the last one or two decades, focus have shifted more towards the distribution system [1, 12]. Still, relatively few methods and models have been published that quantifies the power system security by

considering the likelihood of component outages and the consequences to the system. In the following sections a review on probabilistic security assessments for the power system is presented. Adequacy assessments of the power system are not treated in this thesis.

2.4.1 Well-being analysis

The momentary condition of the transmission system can be divided into a number of system states. Figure 2.5 show one in literature general adopted diagram for the operating states used for security considerations in the transmission system [70]. The unwanted states are all states except the normal. The following state definitions come from [43] and [70]:

- **The normal state**: *"In the normal state, all equipment and operation constraints are within limits, including that the generation is adequate to supply the existing total load demand. In this state there is sufficient margin such that the loss of any components, specified by some criterion, will not result in a limit being violated. The particular criterion, such as the loss of any single component will depend on the planning and operating philosophy of the particular utility".*

- **The alert state:** *"If a system enters a condition where the loss of some component covered by the operating criteria will result in load curtailment, then the system is in the alert state. The alert state is similar to the normal state in that the constraints are satisfied, but there is no longer sufficient margin to withstand an outage. The system can enter the alert state by the outage of component, by change in generation schedule, or a growth in the system load."*

- **The emergency state:** *"If a contingency occurs or the generation and load changes before a corrective action can be (or is) taken, the system will enter the emergency state. No load is curtailed in the emergency state, but components or operating constraints have been violated. If control measures are not taken in time to restore the system to the alert state, the system will transfer from the emergency state to the extreme emergency state."*

- **The extreme emergency state:** *"In the extreme emergency state, the components and operating constraints are violated and load is not supplied."*

- **The restorative state:** *"To transfer out of the extreme emergency state, the system must enter the restorative state to reconnect load and resynchronize the network. The loop can then be close by either entering the alert state or the normal state."*

In the *well-being analysis* approach, a simplification of the operating state diagram in Figure 2.5 is adopted. The aim of the well-being framework is to quantify the different operating states. The deterministic N-1 security criterion is combined with probabilistic concepts in order to quantify the *degree of success* of the composite generation and transmission system [71–75]. This framework enables to determine the probability that deterministic criteria are satisfied. This is achieved by considering the operating states of *healthy*, *marginal* and *at risk*. Figure 2.6 shows the system state diagram used in the method. In the healthy state all components and operating constraints are within the specified limits and the N-1 criterion is fulfilled. At the marginal state the system still is within its operating limits, but there are no margins in the system to fulfil the deterministic criterion. At the risk state components or system constraints are violated and load may be curtailed.

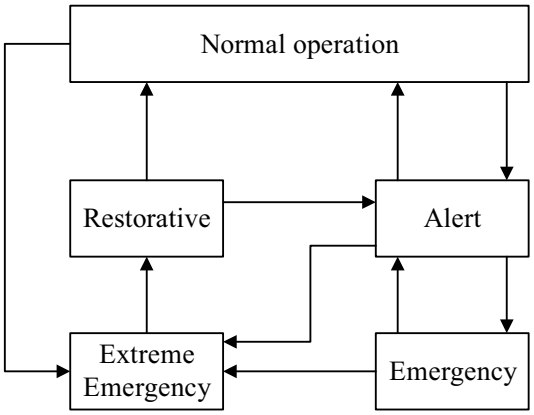

Figure 2.5: Common adopted division of operating states for the transmission system [1].

The probabilities and frequencies of visiting the three states are evaluated with Monte Carlo simulations or enumeration techniques. The result is a quantitative measure of the expected security level for a system designed, planned and operated according to the N-1 criterion. This can be used as one input to the planner or operator of the security margin to unwanted conditions in the system. The results of well-being analysis are hence quite intuitive; e.g. how often and likely is the N-1 criterion violated during the studied year. The indices from the method are the frequency, duration and probability of visiting each of the three states. It may also provide the probability distributions for these well-being indices.

Hence, the studied consequences in the well-being concept are (i) the non-fulfilment of N-1 criterion, and (ii) system or component violations and

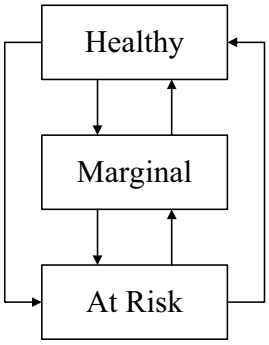

Figure 2.6: System states in the well-being framework [43].

the load shedding necessary to keep the system stable (at risk). However, the well-being method does not tell the degree of severity of visiting these states. One approach to solve this is presented in [43], where the well-being concept is combined with a conventional adequacy assessment. Here the Expected customer interruption cost (ECOST) (dollars/year) is used as one additional system index of the system performance.

The well-being method is dependent on adequate models for load shedding and system restoration after outage events; two properties that are complex to model correctly. The next presented approach is more focused on the direct consequences after the outage events, and hence the modelling of load shedding and restoration becomes less important.

2.4.2 Overload and low voltage security assessment

In the Risk Based Security Assessment (RBSA) framework, introduced in [76], and further described in [44], a probabilistic index is used to quantify the risk to line overload or low bus voltage for each studied contingency. The intention is to assess the security level for a power system in order to support the decision making in the operation of the same. As an example reference [44] mentions that the operating engineer may ask her self: Will there be a significantly impact on the system security if we transfer another 200 MW through this part of the system?

Equation (2.1) shows the risk index for the system security proposed in [44]. The equation is a product of probability and severity for the studied contingencies. It is calculated given a set of E_i possible contingencies, at different load conditions. The failure condition performance measure is denoted X, and this can be the line flow or bus voltage. The forecasted performance (e.g. the line flow) after the i^{th} contingency and with a forecasted loading condition f is denoted as $X^{f,i}$. The term $X^{j,i}$ represent

the performance of the j^{th} possible loading after the contingency i. Hence, $\Pr(X^{j,i}|X^{f,i})$ gives the probability of $X^{j,i}$ and represent the load forecast uncertainty.

$$\text{Risk} \quad = \quad \sum_i \sum_j \Pr(E_i)\ \Pr(X^{j,i}|X^{f,i})\ \text{Sev}(X^{j,i}) \tag{2.1}$$

The term $\text{Sev}(X^{j,i})$ quantifies the severity (or consequence) of the line flow $X^{j,i}$. In [44] this severity increase linearly from 0 at 90% line flow, to 1.0 at 100%. It continues to increase linearly after 100% line flow. Hence, a contingency that result in high line flows is associated with a high risk, and the fundamental idea in this work is that this risk is connected to the system security. This is further discussed in the discussion section below.

Reference [77] treats how the RBSA framework is connected with a multiobjective optimization method to optimally control the system security level associated with low voltages and overloads. The approach is exemplified on the IEEE RTS-96 test system.

In [78] and [79] the work of implementing the RBSA approach in an online computer software is described. The software integration with the existing SCADA system is depicted and it is also described how the methods have been speeded-up for running in an online environment. The work suggests suitable and clear visualizations of e.g. the present risk level, in order to support the decision-making in the control room. The software is tested on a system with 1600 buses and the contingency list contains 17 single or multiple outage events.

In [80] the RBSA concept is used in the transmission system planning by introducing a forecasted load curve for each hour during the year. The total component overload risk for a branch (e.g. a line or a transformer) is evaluated for each hour, given the included contingencies probabilities, a load forecast, and the estimate of the overloads monetary risk for the branch. The momentary risk of an overhead line is in the paper estimated by the impact of the conductors heating to the sag and annealing of the line. The total risk for a particular hour in the system is determined by summarizing all branches associated risks. Furthermore, each branch total annual risk, for the entire year, is determined by summarizing its risk for each hour during the year. The method approach is shown on the IEEE RTS-96 tests system.

In [81] the aim is to determine the risk of voltage insecurity with a probabilistic method. The risk is calculated given future uncertainties on the system and the consequences associated with voltage collapse and violation of limits.

An approach for a quantification of the risk for transient instability is discussed in [82]. The associated risk for eleven initial operating states

are evaluated for a test system. Three contingencies are evaluated in the example.

Discussion

The fundamental idea in the RBSA framework is that the risk index is related to the system security. I.e. a highly stressed system (e.g. overload lines) means a small security margin. However, it can be argued that this not always is the case; historical large interruptions of supply have also occurred during light load conditions, and when the lines are clearly under its capacity limits. Hence, what the correlation is between the system stress and large interruptions in the system is one of the key questions that needs to be further investigated.

2.5 HVDC in the Transmission System

Appended Paper I provides a broad introduction to the HVDC technology and a literature review of reliability assessments published within this area. It gives a background to and motivation for the technology. Published reliability assessments of the HVDC technology have been reviewed and categorized.

Appended Paper II presents a reliability assessment of the HVDC converter transformer system (CTS) at different configurations. The CTS model is based on the Markov modelling approach, which is shown to be well suited for these relatively small systems. The failure rate data in the models is based on statistical surveys by CIGRÉ.

One conclusion from Paper I is that a large number of models and methods for the reliability evaluation of the HVDC system itself have been published, but very few on its impact on the overall system reliability. The domain where the HVDC has its main favourable properties (dynamic) is very complex to model with quantitative reliability methods. One future challenge to be solved is how the "firewall" properties of the HVDC can be quantified in a reliability assessment. Better models to quantify the security level in the transmission system are needed before the reliability impact of HVDC can be evaluated properly.

Chapter 3

Reliability Test System RBTS

This chapter presents the data for the test system RBTS, which in this thesis is used to demonstrate the proposed method. Two different versions of the system are here defined from the general specified data and referred to as RBTS(1) and RBTS(2). The system implementations are validated and tested with already published material at the end of the chapter.

3.1 Introduction

The Roy Billinton test system (RBTS) is a model for reliability studies at the transmission level. Table 3.1 gives a brief summary of the system properties. The system data is defined in [83] and results with system and load point reliability indices are presented in [84]. In five of RBTS six buses (Bus 2-Bus 6) load points are present and for two of these (Bus 2 and Bus 4) the underlying distribution system is defined in detail in [85]. These two subsystems are implemented for reliability studies at the distribution level. In this thesis only the transmission system of RBTS is studied, with the distribution systems represented as perfect single load points (LP).

The level of detail and complexity, as well as the different assumptions and approximations when RBTS is modelled depends on the purpose of the reliability study. Various implementations of RBTS in published material shows that it does not exist one version of the system, but many. One reason is that the specification of RBTS in [83] consists of a large amount of data in order to perform different types of reliability analysis for electrical power systems. Given a selection of this data, RBTS has in this paper been modelled in one basic and one extended version, referred to as RBTS(1) and RBTS(2), shown in Figure 3.1 and 3.2, respectively. The difference be-

Table 3.1: RBTS summary of system data [83]

Number of buses	6
Number of generators	11
Number of load points	5
Number of transmission lines	9
Number of generation buses	2
Installed generation [MW]	240
System peak load [MW]	185
AC nominal voltage [kV]	230

Table 3.2: The additional number of components in RBTS(2) [83]

Number of busbars (BB)	32
Number of circuit breakers (CB)	32
Number of disconnectors (DISC)	51
Number of transformers (TR)	14

tween the two versions is that the extended version includes the substation configuration with disconnectors, circuit breakers and station busbars.

Three critical transfer sections (CTSs) have in this thesis been specified for three line pairs in RBTS, as seen in the figures for RBTS(1) and RBTS(2). These where defined with respect to the power flow pattern in RBTS, where the power flow generally goes from the production in the north to the main load centra in the south. The load flow results for an intact RBTS are presented in Section 3.4.1.

3.2 System Data

3.2.1 Assumptions of the RBTS data

The specification of the RBTS is quite extensive and complete, but a few of the parameters and assumptions of the system are possibly left out intentionally because they are so obvious within the subject. The following assumptions apply for the further modelling of RBTS:

- The system frequency has not been specified in [83], and is here assumed to be 60 Hz[1].

[1] Even if this parameter has a small impact on the result, a difference can be observed in the power flow results when e.g. 50 Hz is chosen.

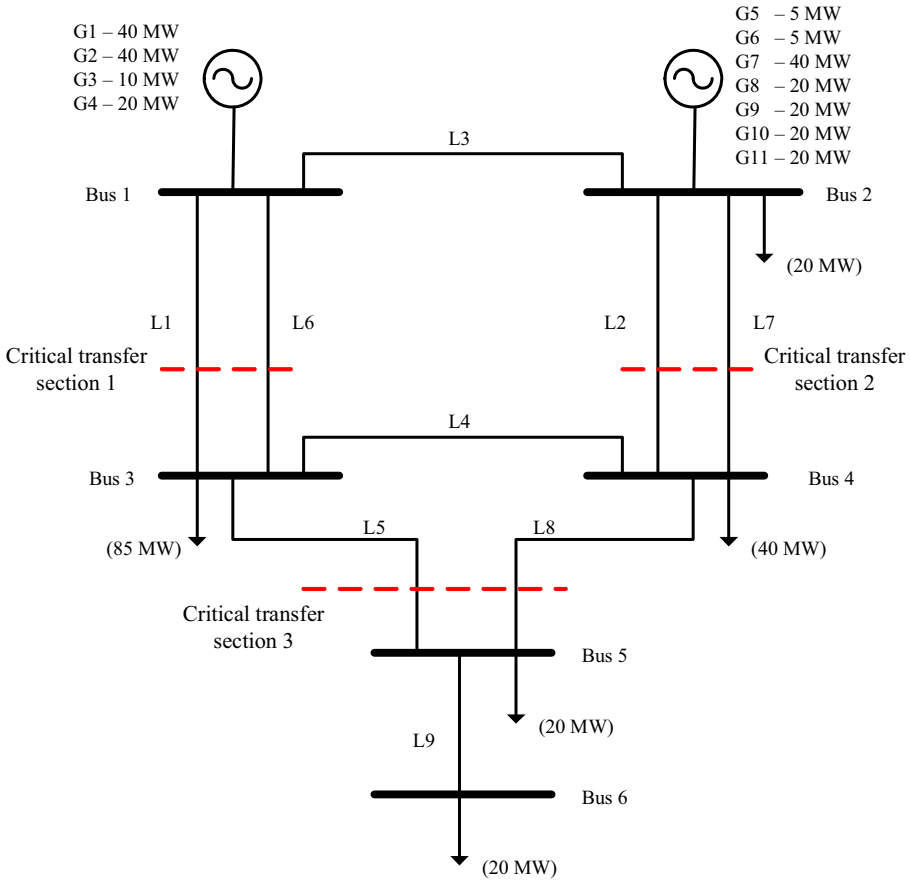

Figure 3.1: Single line diagram of RBTS, referred to as RBTS(1) in this thesis. All loads in the figure represent the system peak load.

- The π-model is assumed for the transmission lines in the model.[2]
- The component lifetime is assumed to be exponentially distributed[3].
- All component outages are assumed to be independent.
- It is assumed that a component (e.g. line, generator, etc) is not taken out for maintenance if it causes system violations.

[2]I.e. the line can be represented with a series impedance with two shunt admittances at each side.

[3]The assumption that the component lifetime follows an exponential distribution is widely adopted [12]. This implies that the resulting outage rate becomes constant.

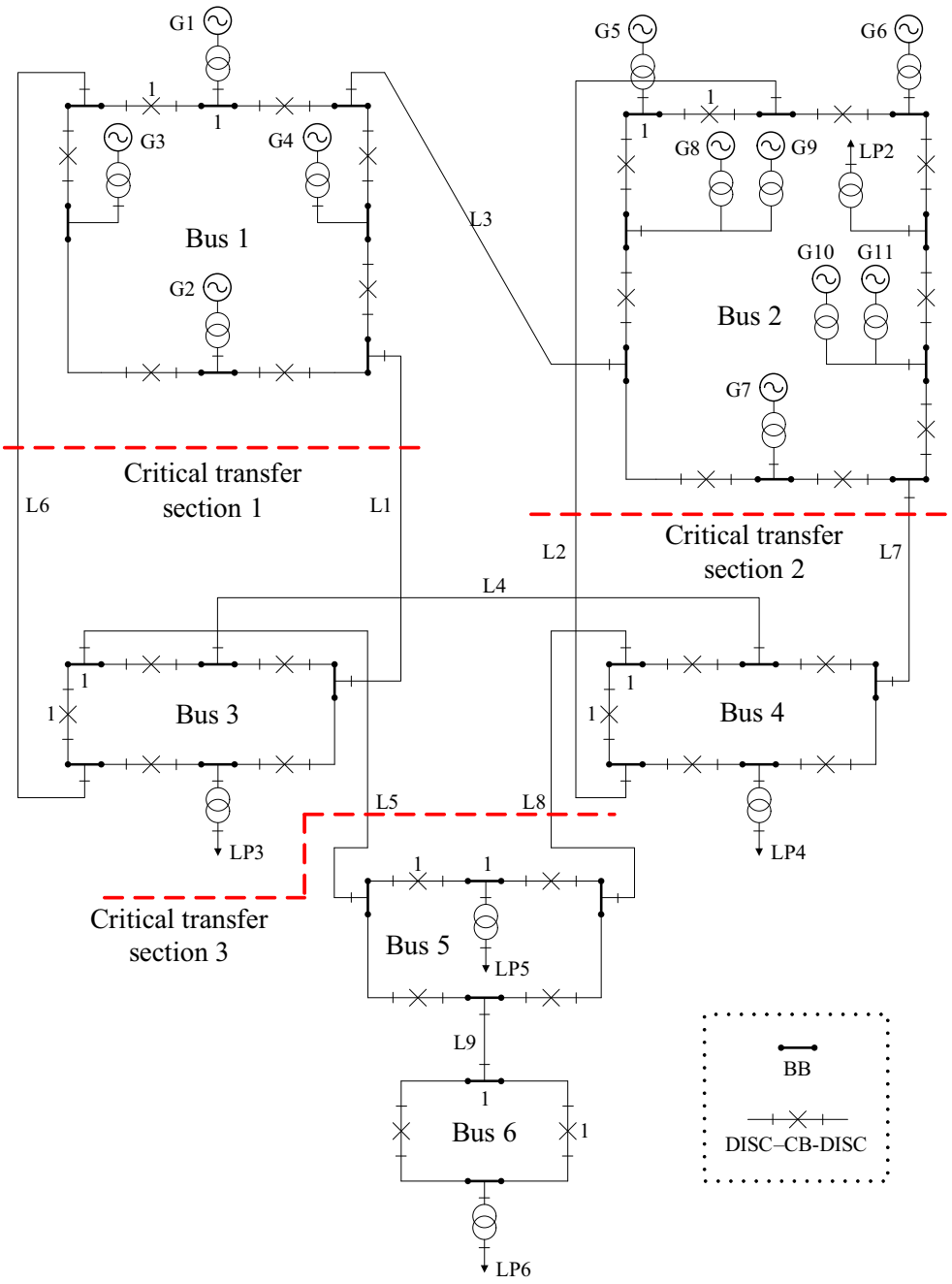

Figure 3.2: Extended single line diagram of RBTS, referred to as RBTS(2), with the buses' substation configuration included.

Table 3.3: RBTS transmission line data [83]

Line	From Bus	To Bus	Length (km)	Impedance (p.u.) R	Impedance (p.u.) X	Susceptance B/2 (p.u.)
L1	1	3	75	0.0342	0.18	0.0106
L2	2	4	250	0.114	0.6	0.0352
L3	2	1	200	0.0912	0.48	0.0282
L4	4	3	50	0.0228	0.12	0.0071
L5	3	5	50	0.0228	0.12	0.0071
L6	1	3	75	0.0342	0.18	0.0106
L7	2	4	250	0.114	0.6	0.0352
L8	4	5	50	0.0228	0.12	0.0071
L9	5	6	50	0.0228	0.12	0.0071
$S_{base} = 100MVA$, $U_{base} = 230kV$						
Max current capacity for lines: L1 and L6 $\rightarrow I_{max} = 0.85$ p.u., other line $\rightarrow I_{max} = 0.71$ p.u.						

- Scheduled maintenance of generator units is assumed to be planned to parts of the year when the forecasted system load is low.
- The frequency of the scheduled maintenance for the generator units is assumed to be once a year.
- Generator G1 is used as slack generator.

The electrical and reliability data for the components is further on in the thesis assumed to be ideal if nothing else is specified.

3.2.2 Electrical data

The system has two generator (PV) buses and four load (PQ) buses. The voltages at the PV buses (Bus 1 and Bus 2) are controlled to 1.05 p.u. The voltage limits in the system are between 0.97 p.u. and 1.05 p.u. [83]. Table 3.3 show the electrical data and lengths of the nine lines in the system. The line pair L1 and L6 is built on the same tower for the entire length. This also applies for the line pair L2 and L7.

Table 3.4 shows the load data for the LP:s at a system peak load. The load variation in RBTS (i.e. in p.u. of the peak load) is specified as the same as in IEEE-RTS [86]. The load in each LP is for RBTS assumed to consist of two categories, one firm load and one curtailable load. The later part is set to 20% of each LP's load in RBTS. No load shedding policy, in case of severe outage events, has been specified in [83]. However, in this thesis the priority order policy, defined for RBTS in [43], is assumed

Table 3.4: Load data for the five load points in RBTS [83]

Load point	Active load [MW]	Reactive load [Mvar]	Priority order[a][43]
LP2	20.0	0	1
LP3	85.0	0	5
LP4	40.0	0	3
LP5	20.0	0	2
LP6	20.0	0	4
Total	185.0	0	-

[a] LP3 is curtailed first (priority 5), with up to 20% of its load. After this, if necessary, the LP:s is curtailed with up to 20%, following the priority list order.

Table 3.5: Ratings for the eleven generators in RBTS [83]

Generator	Location	Rating [MW]	Capability [Mvar]		Type
			Min	Max	
G1	Bus 1	40	-15	17	Thermal
G2	Bus 1	40	-15	17	Thermal
G3	Bus 1	10	0	7	Thermal
G4	Bus 1	20	-7	12	Thermal
G5	Bus 2	5	0	5	Hydro
G6	Bus 2	5	0	5	Hydro
G7	Bus 2	40	-15	17	Hydro
G8	Bus 2	20	-7	12	Hydro
G9	Bus 2	20	-7	12	Hydro
G10	Bus 2	20	-7	12	Hydro
G11	Bus 2	20	-7	12	Hydro

and implemented. This priority order, shown in Table 3.4, is based on the economical impact of an interruption of supply at the load point. Section 3.2.7 comment on this assumption.

The ratings for the eleven generators in RBTS are given in Table 3.5. Bus 1 is defined as the slack bus in load flow analysis of the model. Bus 2 act as slack bus if Bus 1 is isolated. G1 (in Bus 1) is set as the slack generator in this thesis. The scheduled generation in Bus 2 during peak load, given an intact system situation, is 120 MW.

Table 3.6: RBTS component reliability data [83]

Transmission Line	
Permanent outage rate [f/yr,km]	0.02
Average outage duration [h]	10
Circuit Breaker	
Active failure rate [f/yr]	0.0066
Passive failure rate[1] [f/yr]	0.0005
Average outage duration [h]	72
Maintenance outage rate [f/yr]	0.2
Maintenance time [h]	108
Busbar	
Failure rate [f/yr]	0.22
Average outage duration [h]	10
Station Transformer	
Failure rate [f/yr]	0.02
Average outage duration [h]	768
Maintenance outage rate [f/yr]	0.2
Maintenance time [h]	72
Common mode data for towers, L1 and L6	
Failure rate [f/yr]	0.15
Average outage duration [h]	16
Common mode data for towers, L2 and L7	
Failure rate [f/yr]	0.5
Average outage duration [h]	16

[1]Unintended opening of circuit breaker

3.2.3 Reliability data

Table 3.6 shows the component reliability data for the lines, circuit breakers (CB), busbars (BB), transformers (TR) and common line towers in RBTS. Table 3.7 shows the reliability data for the eleven generators in the system. The reliability data for the disconectors (DISC) are not specified in RBTS.

3.2.4 Specification of RBTS(1)

Figure 3.1 shows the single line diagram of RBTS(1). This version of RBTS has a single busbar as substation configuration. All outgoing feeders from the busbars include a perfect CB, with a DISC at each side. RBTS(1) only includes reliability data for the nine transmission lines.

Table 3.7: RBTS generator reliability data [83]

Unit	MTTF (hr)	Failure rate [f/yr]	MTTR (hr)	Scheduled maintenance[a] [hr/yr]
G1	1460	6	45	336
G2	1460	6	45	336
G3	2190	4	45	336
G4	1752	5	45	336
G5	4380	2	45	336
G6	4380	2	45	336
G7	2920	3	60	336
G8	3650	2.4	55	336
G9	3650	2.4	55	336
G10	3650	2.4	55	336
G11	3650	2.4	55	336

[a] In this thesis assumed to take place ones a year

3.2.5 Specification of RBTS(2)

Figure 3.2 shows the single line diagram of RBTS(2). In this extended version of RBTS, the substation configurations for the buses are modelled in detail in accordance to [83]. Table 3.2 shows the additional number of components that are included in the model compared to RBTS(1).

In RBTS(2) reliability data is specified in accordance to Table 3.6. The total number of assessed components is 87 (9+32+32+14). The generators and disconnectors are included in the system model, but are here assumed 100% reliable. The reliability data for the line towers and the circuit breaker's passive failure rate are not included in this version of RBTS(2).

The circuit breakers and transformers include both an active failure mode and a maintenance outage mode.

3.2.6 Notation of components in RBTS

In Figure 3.2, only the individual names of the line and generator components are shown. However, in order to later understand the results for RBTS it is good to know where the other components (CB, BB, DISC, TR) are situated. The component abbreviation in the notation reveals the component type and where it is placed in the system:

- The 14 transformers (TR) : TR_G1-TR_G9, TR_LP2-TR_LP6, where the postfix _G or _LP denotes the attached generator or load point

(LP) to the transformer.

- The 32 circuit breakers (CB) : e.g CB1:2 donates the first CB in Bus 2. The numbering of CBs starts from the upper left in the bus (indicated in Figure 3.2 with 1) and is then incremented clockwise in the bus[4].

- The 32 busbars (BB) : The BB notation follows the same numbering logic as the CBs[5].

3.2.7 Comments on the RBTS model

Model for corrective actions

It is a difficult task to model corrective actions in the transmission system. Load curtailments may be necessary in case of system violations after a contingency. In the power system these corrective actions either can be manually performed by an human or automatically. In the first case this involves a model of the operator's actions, which obviously is complex to model. The actions by an operator are normally assumed to be 100% perfect. Automatically corrective actions for load curtailments in the load points involves the modelling of system equipment that act if there are violations in the system frequency. This is quite complex to model in the today developed power system models for reliability studies.

In this thesis the priority order policy, defined for RBTS in [43], is implemented. This model for the load shedding process implies that the system operator have total control to prioritize the load points in the system in case of system violations. This is generally not the case, and hence a quite large approximation.

Reliability data in RBTS

It can be noted that the reliability of the components are relatively poor in RBTS compared to statistics for existing systems. The component reliability data for RBTS in Table 3.6 can be compared with the statistics for the Swedish system in Table 2.1. The line outage rate is about twenty times higher for RBTS than for the real system. But, it has to be emphasized that RBTS is a test system for educational purposes of reliability methods and models. Exaggerated outage rates may be beneficial for this purpose.

[4]One more example: CB6:1 is situated in Bus 1 at the 6th position (between the generators G2 and G3 in the ringbus configuration).

[5]One example: BB3:4 donates the third BB in Bus 4, situated between the ingoing lines L4 and L7.

Location of generators in RBTS

Table 3.5 shows that the four generators in Bus 1 are thermal units. However, Bus 1 is defined as the slack bus under normal circumstances and therefore it would be more natural if this bus had at least one hydro unit attached to it. Alternatively Bus 2 could be defined as the slack bus instead.

3.3 Implementations of RBTS

3.3.1 Neplan implementation

The two models RBTS(1) and RBTS(2) have been implemented in the commercial computer program Neplan by BCP [87]. Each outage event's impact on the system's protection system, generation and load is displayed to the user in a failure effect analysis (FEA). This FEA list also shows a time-stamped list of all corrective actions needed. The effect on the line power flows may also be displayed. The program evaluates the outage events with an a.c. load flow method, and if this not converges it falls back on a d.c. load flow method.

The reliability method in Neplan is not published, but most likely it uses an enumeration method with approximative evaluations based on Markov models. First and second order component outages in RBTS are assessed by the program. The notation of e.g. L1+L2 includes both the second order outage event L1+L2 and L2+L1, which are treated identically.

Section 4.2 describes how the Neplan implementation of RBTS is connected with the MATLAB programming language. In this language further analysis of the outage events' consequences on the studied system is performed.

3.3.2 MATLAB implementation

A model of RBTS(1) has also been implemented in a MATLAB programming code[6]. The implementation is further described in the report [37]. The reliability method is a non-sequential Monte Carlo simulation, and hence outage events above the second order are also evaluated. However, the implemented d.c. load flow method is not as advanced as the load flow in Neplan. Furthermore, no protection system model is included and there is no graphical interface as in Neplan.

The purpose of the MATLAB code in [37] is to verify the reliability adequacy results from RBTS in Neplan. The objective is also to verify that this thesis implemented versions of RBTS correspond to the specified

[6]This MATLAB code should not be mixed with the code that is used to analyse the Neplan results described in Section 4.2

model of RBTS in [83]. The system reliability index Expected Energy Not Served (EENS) (MWh/yr) is used for the comparison that is presented in Section 3.4.2.

A second model, referred to as RBTS(A) has also been implemented. This includes outage data both for the nine lines and the eleven generators in the system. The purpose of this model is to show on Neplan's limitation of modelling generation outages in the transmission system.

The model RBTS(2), with the extended substation configurations, was too complex to implement in MATLAB for a verification. Furthermore, no published material has been found that presents the adequacy result for this system.

3.4 Verification of RBTS model

3.4.1 Load flow results for intact system

Table 3.8 shows the load flow result for an intact RBTS during the peak load. The result is identical for RBTS(1) and RBTS(2). The table shows that the north-to-south lines L1, L2, L6 and L7 are relatively high loaded during this load situation. These four lines are normally the bottlenecks of the system, due to the large power flows from the production areas in north to the consumptions in south.

No published material has been found that can verify the results in Table 3.8. However, it can be verified indirectly by the result in [88]. In this paper the active losses at peak load for RBTS is evaluated to 4.62 MW. In Table 3.8 the generation at peak load is 190.1 MW and this gives a system loss of 5.1 MW for RBTS(1) and RBTS(2). This small difference is probably explained by the different scheduled generation in paper [88] in Bus 2, compared to this thesis.

3.4.2 Verification of system adequacy

The annualized reliability adequacy results from different implementations of RBTS(1) has been compared for verification. With an annualized result means that a peak load level in RBTS is used for the entire year. The system reliability index EENS (MWh/yr) is used as adequacy measure. Load point indices and other system reliability indices are not included in the verification in this thesis. However, EENS is often preferable in comparisons of results, since this index converge relatively slow in simulations.

Table 3.9 shows the EENS result for RBTS(1). Assessments number one to five have been performed by the author and number six is included as reference. The results from the implemented version of RBTS(1) in Neplan (number one to four) corresponds well to the result for number six. The

Table 3.8: Load flow results for an intact RBTS at the peak load 185 MW

Node result						
Node	Voltage (kV)	Voltage angle (°)	Load (MW)	Load (MVAr)	Generation (MW)	Generation (MVAr)
Bus1	241.5	0.00	0	0	70.1	8.6
Bus2	241.5	7.26	20	0	120	-13.9
Bus3	237.2	-4.60	85	0	0	0
Bus4	236.9	-4.19	40	0	0	0
Bus5	236.3	-5.71	20	0	0	0
Bus6	235.4	-7.03	20	0	0	0
Total	-	-	185	0	190.1	-5.3
Line flow result						
Line	P_{sent} (MW)	Q_{sent} (MVAr)	Losses (MW)	Losses (MWAr)	Loading in % of max limit	
L1	48.89	2.30	0.74	1.62	57	
L2	35.82	-3.60	1.33	-0.67	50	
L3	28.35	-6.67	0.68	-2.69	40	
L4	5.91	-3.18	0.01	-1.46	8	
L5	17.19	-0.39	0.06	-1.17	24	
L6	48.89	2.29	0.75	1.62	57	
L7	35.82	-3.60	1.33	-0.67	50	
L8	23.08	-2.69	0.12	-0.89	32	
L9	20.09	-1.03	0.09	-1.03	28	

difference in result between the a.c. and d.c. load flow setting in Neplan is small. The extended substation configuration for RBTS in assessment number three and four gives a slightly higher result than the simple busbar configuration in RBTS(1).

Table 3.10 shows the results for an RBTS model with both line and generator outages. This model should not be taken for the model RBTS(2). Assessments number one and two have been performed by the author and number three to six are included as references. The result from Neplan is relatively low and this is explained by the enumeration method in this software that exclude outage events above second order. Since generators with relatively high outage rates are included in the model, this affects the result. The results for assessment number two to five are comparable. Number six, the original result reference for RBTS, is relatively high compare to the other results. This is probably explained by different load shedding policies, which can have large influence on the result.

Table 3.9: Annualized system reliability adequacy results for RBTS(1) from Neplan, MATLAB and Mecore

Nr	Software	Method and model	Source	EENS [MWh/yr]
1	Neplan	Enumeration A[a]	Section 3.3.1	213
2	Neplan	Enumeration B[b]	Section 3.3.1	216
3	Neplan	Enumeration C[a, c]	Section 3.3.1	222
4	Neplan	Enumeration D[b, c]	Section 3.3.1	222
5	MATLAB	Non-Sequential MCS	Section 3.3.2	206
6	Mecore	Non-Sequential MCS	[89]	219

[a] Settings: Starts with an a.c. load flow method and falls back on a d.c. load flow if the solution did not converged.
[b] Settings: Only a d.c. load flow is used in the method.
[c] Here the extended substation configuration in RBTS(2) is used, but only line outages are included in the model.

Table 3.10: Annualized system reliability adequacy results for RBTS with both line (L1-L9) and generator (G1-G11) outages included.

Nr	Software	Method	Source	EENS [MWh/yr]
1	Neplan	Enumeration method	Section 3.3.1	638
2	MATLAB	Non-Sequential MCS	[37], Section 3.3.2	1037
3	Secorel	Sequential MCS	[43]	999
4	Mecore	Non-Sequential MCS A	[43]	1111
5	Mecore	Non-Sequential MCS B	[89]	1070
6	unknown	Enumeration method	[84]	1414

Chapter 4

Method Quantifying Risks to System Transfer Capability

This chapter presents the proposed method, summarized in appended Paper III. The steps in the method are described in detail, and this is followed by a discussion of implications and limitations of the method.

4.1 Method Description

The method presented in this thesis uses an approach that is similar to the RBSA framework presented in Section 2.4.2. However, the main difference is that the impact on the system's critical transfer sections (CTS)[1] are studied, instead of evaluating separate branches in the system. The index for quantifying the risk to transfer capability is also different compared to RBSA.

The proposed method quantifies and ranks the outage events impact on a CTS at different load levels. The outage events consequence on the system's load points are not considered in the method. Instead the condition of the system's transmission capacity is studied by the assessment of one or several CTSs. The result is a list of outage events with the highest risk of overloading a defined CTS for each assessed load level. These results are then used to determine how each examined component in the system contributes to the risk of overloading the CTS at different load levels. The components are then ranked according to its associated risk and

[1] In Swedish: Överföringssnitt.

this measure can be used in a risk based system planning scheme.

4.1.1 Definitions of risk-outages and total-outages

Outage events that result in an overload of the CTS, in at least one system load level, are referred to as *risk-outages*. Outage events that result in a 0 MW transfer capability of the section are referred to as *total-outages*. The consequence of total-outages is from the CTS perspective infinitely large and therefore these events are treated separately.

4.1.2 Index for risk-outages, I_i^{Risk}

The fundamental idea of the index is to provide a quantitative measure that makes it possible to compare the risks of different types of outage events. E.g., the associated risk of a frequent outage event with small CTS consequences, should be possible to compare with a rare event with large consequences. The worst case event, in terms of consequences, may not represent the highest risk to the system's transfer capability.

The risk index I_i^{Risk} in (4.1) is defined to quantify the likelihood and consequence of outage events having severe impact on the CTS's capability to transfer active power. The index is only defined for risk-outages i.e. outages which result in an overload on the studied CTS.

$$I_i^{Risk} = \frac{\lambda_i r_i}{8760} \times (\frac{P_{after_i}}{P_{limit_after_i}})^2 \tag{4.1}$$

where:
λ_i = expected outage rate for event i [1/yr],
r_i = expected restoration time for outage event i [h],
8760 = hours per year,
P_{after_i}= active power transfer in CTS after outage event i,
$P_{limit_after_i}$ = active power transfer limit in CTS after outage event i.

The first part in (4.1) describes how likely the outage is to occur and for how long it is expected to last. The second part quantifies the severity of the risk-outage's overload of the section. This is the relative loading of the section after the outage event and this part increase in quadrate with the overload. The quadratic characteristic is justified by the fact that the heating of a conductor is proportional to the current squared.

4.1.3 Method algorithm

Figure 4.1 shows a flow chart for the involved steps in the method. Each step is further described in the following sections.

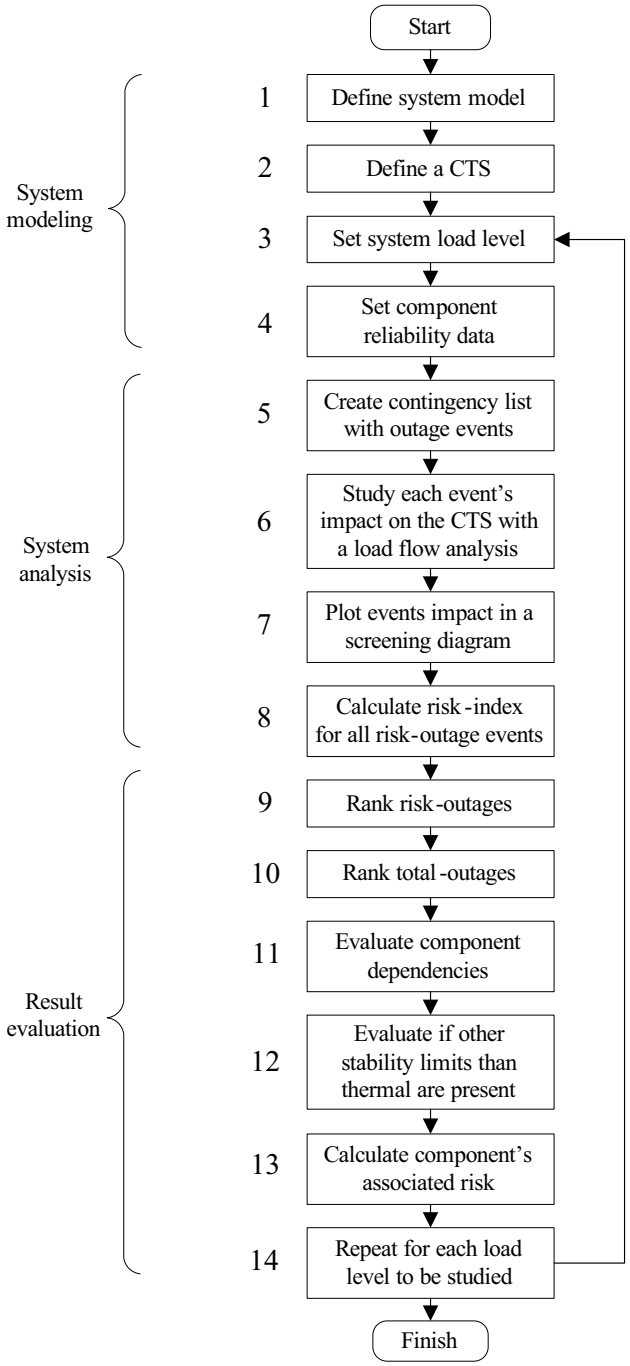

Figure 4.1: Flow chart for the proposed method that quantifies each components' contribution to the risk of overloading a critical transfer section (CTS) at different load levels in the system.

Preparation of system model

1. The transmission system model is defined at component level. Each line, circuit breaker, disconnector, etc. is represented in the model. Impedances for the transmission lines, together with generator and load bus parameters are set in order to perform ordinary load flow analysis.

2. A CTS is defined with a maximum power transfer limit. This consists of e.g. two important lines in the system with the two lines' thermal limits in MW. However, other limits than thermal can be used and the CTS can be arbitrarily defined.

3. A load level in p.u. of the system peak load is set.

4. The expected failure rate (λ_{Comp}) and expected restoration time (r_{Comp}) are set in those components which impact on the CTS is to be studied. Maintenance outage rate and maintenance duration time is also set as a second outage mode for the components.

System analysis

5. A list with single and multiple outage events is constructed, given the included components to be studied. The expected outage rate (λ_i) and expected restoration time (r_i) for each event is determined by the involved components' reliability data. In section 4.1.5 the equations to calculate the events' resulting outage rate and restoration time are given. The component outages in each event are assumed to be independent.

6. Each outage event's impact on the studied CTS active power transfer is evaluated with a load flow analysis. The resulting power transfer through the CTS directly after each outage event is stored.

7. A total screening of the outage events' impact on the CTS is visualized in a diagram in order to evaluate and compare potential risk-outages. The diagram gives an overview of each outage event's expected outage rate versus its resulting relative loading on the CTS after the event. If single component outages are present as risk-outages this implies that the N-1 criterion is not fulfilled for the CTS before the event, and thereby also the system for the studied load level.

8. The severity of each risk-outage on the CTS is quantified with the risk index, I_i^{Risk}, in (4.1). The resulting CTS loading, expected outage rate and restoration time are inputs to the index.

Result evaluation

9. The risk index I_i^{Risk} provides a measure on the severity of each risk-outage, based on the overload of the CTS and the likelihood for this event to occur. The risk-outages are ranked in a list given the risk index for each event.

10. The risk index I_i^{Risk} is not defined for total-outages. These have to be treated separately and are ranked with respect to their expected frequency of outage.

11. As one final assessment the list of risk-outages should be examined manually in order to identify if any components dependency is present in the events. If this is the case, an extra risk factor must be added to the risk given by the risk index defined in (4.1).

12. Outage events that are known to have other constraints on the CTS transfer limit than thermal, such as voltage or angle instability, could be assessed more in detail. Since, e.g. the thermal limit for long overhead lines normally only provide the upper limit of the section's maximum transfer capability.

13. By adding the I_i^{Risk} for each risk-outages' involved components, a cumulative risk is given per component in the system. This gives a measure of the components contribution to the risk of overloading the CTS. The components' associated risk, referred to I_{Comp}^{Risk}, is then sorted in order to determine which components that has the highest impact on the CTS capability to transfer power for the studied load level.

14. Step 3 to 13 is repeated for each load level to be studied in the system.

4.1.4 Outage model for components

Figure 4.2 shows a two state model for a repairable component [5]. This model for component outages is used in this thesis. Parameter MTTF represent the *mean time to failure* (hours), MTTR the *mean time to repair* (hours), λ the *failure rate* (failures/year), and μ the *repair rate* (repairs/year).

In order to get the same units (in years) in the following equations, let $d = MTTF/8760$ and $r = MTTR/8760$, where 8760 is the number of hours per year. The following equations describes the relationship between the model parameters [5]:

$$\lambda \quad = \quad \frac{1}{d} = \frac{8760}{MTTF} \text{ [f/yr]} \tag{4.2}$$

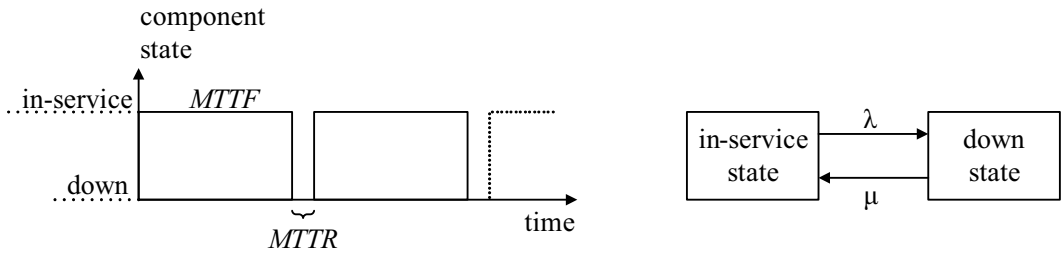

Figure 4.2: Two state outage model for a repairable component.

$$\mu = \frac{1}{r} = \frac{8760}{MTTR} \text{ [1/yr]} \tag{4.3}$$

$$f = \frac{1}{d+r} = \frac{8760}{MTTF + MTTR} \text{ [f/yr]} \tag{4.4}$$

$$U = \frac{MTTR}{MTTF + MTTR} \tag{4.5}$$

$$= fr \tag{4.6}$$

$$\simeq \lambda r \tag{4.7}$$

In the above equations f represent the *average failure frequency* (failures/year). Normally $r << d$ and the numerical values of f and λ are then close. The approximative equation for the component *unavailability* U in (4.7) is therefore justified in most outage types in the power system[2]. In this thesis this approximation is adopted and f and λ are treated as the same quantity if nothing else is mentioned.

4.1.5 Model for multiple independent outages

Approximative equations can be used to calculate the expected outage rate and duration for multiple outage events. Markov techniques are applied to derive these equations from second order events and up to any order above. In this thesis equations for second order events has been obtained from [1]. The reader is referred to this reference for equations of higher order outage events.

[2] For scheduled outages that occur relatively frequently and with relatively long outage duration this approximation may result in a large error.

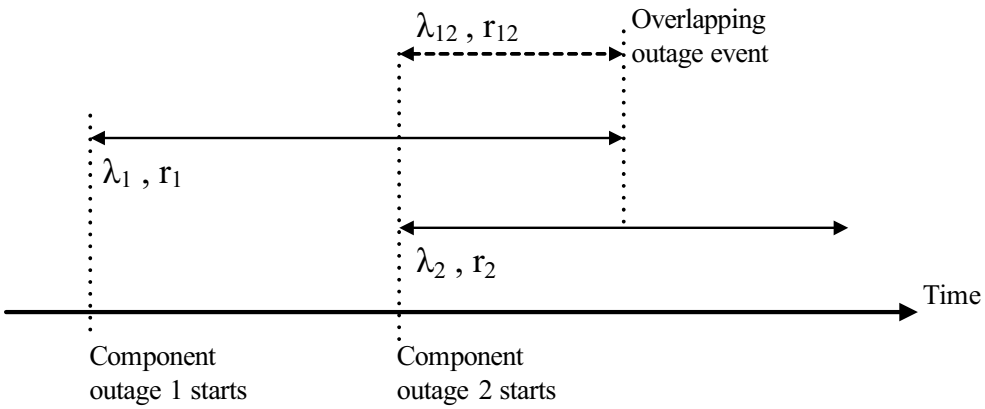

Figure 4.3: Illustrative picture of an overlapping outage event caused by two independent component outages.

Figure 4.3 shows an event of two overlapping single component outages. The notations of the multiple outage events' outage rate and duration are shown in the figure. The involved component outages can be of the same type or of different types[3].

Two overlapping component outages of same outage type

Equations (4.8)-(4.12) gives the resulting reliability properties for the multiple outage event of two component outages of the same type, e.g. two permanent forced outages p.

$$\lambda_{12}^{pp} = \frac{\lambda_1\lambda_2\,(r_1+r_2)}{1+\lambda_1 r_1+\lambda_2 r_2}\ [\text{f/yr}] \tag{4.8}$$

$$\simeq \lambda_1\lambda_2\,(r_1+r_2)\ \text{ when } \lambda_i r_i << 1 \tag{4.9}$$

$$r_{12}^{pp} = \frac{r_1 r_2}{r_1+r_2}\ [\text{yr}] \tag{4.10}$$

$$U_{12}^{pp} = f_{12} r_{12} \tag{4.11}$$

$$\simeq \lambda_{12} r_{12} = \lambda_1\lambda_2 r_1 r_2 \tag{4.12}$$

[3]Same outage type: e.g. two overlapping permanent outages. Different type: e.g. a scheduled component outage followed by a forced outage in the system.

, where (4.13)

λ_i : failure rate for component i [f/yr],
r_i : duration for the outage in component i [yr],
f_{12} : failure frequency for outage event [f/yr],
λ_{12}^{pp} : failure rate for overlapping outage event [f/yr],
r_{12}^{pp} : restoration time for overlapping outage event [yr],
U_{12}^{pp} : unavailability for the overlapping outage event.

Two overlapping component outages of different outage type

If a scheduled outage m is followed by a permanent forced outage p Equations (4.14)-(4.16) can be used to describe this multiple event.

$$\lambda_{12}^{pm} = \lambda_1^p(\lambda_2^m r_2^m) + \lambda_2^p(\lambda_1^m r_1^m) \tag{4.14}$$

$$U_{12}^{pm} = \lambda_1^p(\lambda_2^m r_2^m)\frac{r_1 r_2^m}{r_1 + r_2^m} + \lambda_2^p(\lambda_1^m r_1^m)\frac{r_1^m r_2}{r_1^m + r_2} \tag{4.15}$$

$$r_{12}^{pm} = \frac{U_{pm}}{\lambda_{pm}} \tag{4.16}$$

, where

λ_i^p : forced outage rate for component i [f/yr],
r_i^p : restoration time for forced outage in component i [yr],
λ_i^m : scheduled outage rate for component i [f/yr],
r_i^m : restoration time for scheduled outage in component i [yr],
λ_{12}^{pm} : failure rate for overlapping outage event
of a scheduled outage (m) followed by a forced outage(p),
U_{12}^{pm} : unavailability for the overlapping outage event
of a scheduled outage (m) followed by a forced outage(p),
r_{12}^{pm} : expected restoration time for the overlapping outage event
of a scheduled outage (m) followed by a forced outage(p) [yr].

4.2 Method Implementation

The method has been implemented by the author by connecting the commercial programs Neplan [87] and MATLAB. The modelling of RBTS in Neplan is described in Section 3.3.1. In the method implementation, Neplan evaluates each outage event's consequences on transmission lines' transfer in the system. This is repeated for each studied load level of the system. The results are then imported to MATLAB with the help of the FEA function in Neplan. This import is accomplished by a conversion of the FEA information into several raw text files, readable for MATLAB. Given the equations in Section 4.1.4 and 4.1.5, the MATLAB code calculates each event's outage rate and duration. The events' risk index and the components' cumulative risk are then evaluated for each studied CTS.

4.3 Discussion

4.3.1 Correlation between system stress and security

The fundamental idea with the proposed method is that there exists a correlation between a highly stressed system (i.e. overload lines) and the system security. If this correlation is weak, the method may provide an incorrect ranking of the most critical components to system security. The question, that is complex to answer, is how the system stress and the security margin to unwanted conditions is related. Most likely this correlation depends on the specific transmission system.

4.3.2 Other overloads than thermal in risk index

The index I_i^{Risk} in (4.1) increase in quadrate with the overload at the CTS. This definition is physically justified if the transfer limit for the CTS is set by thermal properties. The limit can however be arbitrary set in the method and then the quadrate property may be reassessed. One example is when the maximum allowed transfer limit is set in respect to given voltage or angle instability constraints.

4.3.3 Selection of CTSs in the system

The assessed CTSs in the method have to be selected carefully in order to reflect the entire transmission system transfer capability. Depending on the system configuration or load level during the year, these CTS always, or a part of the year, represent the transfer bottlenecks of the system. Therefore there is certainly a risk in the method that the studied CTSs do not represent all of the system transfer bottlenecks. A transfer section in the system may be missed and not considered as a CTS, even if this is

the case at e.g. low load level periods with many lines disconnected due to maintenance.

The selection of the CTSs may be difficult in practical and large systems. A technique to determine the appropriate CTSs for a transmission system is not the scope of this work. However, it is the author's belief that the transmission system operators and planners normally are well aware of these sections in the system. This might then not be a problem.

4.3.4 Importance of different CTSs

The method gives a ranking of the assessed outage events' risk to each individual CTS. A ranking of each CTS most critical components is also determined. This means that two different CTSs most likely will get different ranking lists. The question is then how the result from different CTSs is handled. The result for the CTSs can either be considered equally important, or be weighted depending on e.g. the location, the power capability, and past experience of severe historical events.

4.3.5 Order of multiple component outages

In step 5) of the method, a contingency list with single and multiple component outage events is constructed. The number of simultaneous component outages to be considered and included in the list is arbitrary in the method. However, for larger systems, the number of multiple outage events to be analysed may become impractical if higher order outage events is to be included. The computational time may be too extensive. On the other hand important outage events may be missed if some events are excluded from the analysis. In the example study of the method on RBTS, in Chapter 5, all first and second order outages are considered. Third order events and higher are neglected, since the likelihood of these event normally are small. However, in composite reliability analysis, where both the generation and transmission part is included, generator outages up to the third order normally are considered. One reason for this is the long maintenance periods (sometimes weeks per year) these types of components experience.

A reduction of the number of contingencies is one way of gain computational time in the method. A technique for a selection of which multiple component outages to be included in the contingency list is not within the scope of this thesis.

4.3.6 Outage events that result in power transfers close to the CTS limit

The method does not quantify the risk for outage events resulting in a small marginal of the transfer capacity in the studied CTS. Only risk-outages and

total-outages are considered.

Marginal outages are difficult to quantify in a risk index. Suppose e.g. an outage event that results in a 99% loading of the CTS's available transfer capacity. What is the consequence and risk of this event compared to an event resulting in a e.g. 90% loading? This is complex to determine. Furthermore, from an electricity trading perspective, 100% loading of the CTS may be the optimal solution, since the system is fully utilized.

4.3.7 Outage restoration time in risk index

The outage restoration time r_i for the risk index I_i^{Risk} in (4.1) capture how long the system is going to be in a strained condition during the restoration of the components in the outage event. One alternative is to let r_i represent the time it takes to perform corrective actions by the operator, although this parameter can be difficult to estimate.

4.3.8 The transfer limit in risk index

The term $P_{limit_after_i}$ in (4.1) is the sum of the maximum capacity for the included components in the studied CTS after the outage event. This term is constant for all outage events which do not include any components in the CTS, given the assumption of constant component capacities that are independent of the outage event. This is the case if e.g. only thermal constraints are considered in the model[4]. However, this is not necessary the case. If e.g. instability constraints are included in the system model, an outage event may have impact on all component capacities in the CTS, and hence the value of $P_{limit_after_i}$ changes.

4.3.9 Consequence on CTS at various times after outage event

In the proposed method the consequence on the CTS is studied directly after the outage event. The protection system has isolated the fault and the system has settled in a new steady-state condition. At this moment, before any restorative actions are made by the operator, the active power flow through the CTS is studied in the method. System violations may exist at this moment, such as e.g. overloads in lines or undervoltages in buses. But no restorative actions, such as e.g. emergency start of backup generators, re-connections in substations or load shedding actions, has yet been made.

[4]This assumes that the thermal capacity is independent on e.g. the voltage level after the outage event.

The loading on the CTS at e.g. 10 minutes after the outage event is most likely different compared to directly after the event. Restoration actions by the operator may have been performed. Hence the outage events' risk index are different for these two cases.

A study of the impact on the CTS at different times after the outage event is not within the scope of this thesis.

Chapter 5

Method Example on Test System RBTS

In this chapter the proposed method in Chapter 4 is exemplified on the test system RBTS. The result is the most important components for the critical transfer sections CTS 1, CTS 2 and CTS 3 in RBTS(1) and RBTS(2) at four different load levels.

5.1 Example Analysis Setup

5.1.1 System Modelling - Step 1-4 in method

The proposed method is applied on the two described system models RBTS(1) and RBTS(2), as defined in Section 3.2.4 and 3.2.5 respectively.

CTS definition

The location of the CTSs has already been defined for RBTS(1) and RBTS(2). The maximum power transfers for the three CTSs are set to their thermal limits. These are calculated given the line data in Table 3.3. If a nominal voltage with a unity power factor is assumed, the transfer limits are: 170.6 MW for CTS 1 (line L1 and L6), 142.6 MW for CTS 2 (L2 and L7), and 142.6 MW for CTS 3 (L5 and L8). The thermal capacities are assumed to be constant and independent on changes in bus voltages after outage events.

Studied load levels

Four discrete load levels at 0.7, 0.8, 0.9 and 1.0 p.u. of the peak load (185 MW) are considered in the assessment. The load is assumed to be

scaled proportionally in all load points. The scheduled generation in Bus 2 is adjusted in each load level in order to keep the same generation proportion of Bus 1 and Bus 2 as during the system peak load. Table 3.8 shows the generation proportion (70.1 MW/120 MW) at peak load for Bus 1 and Bus 2. In the analysis the active power production in generator G7 (in Bus 2) is adjusted manually as the load goes down. Hence, for an intact system the generation in G7 is 0, 10, 20 and 30 MW for the respective system load levels 0.7-1.0 p.u. Since generator G1 is the slack generator in the system, this is adjusted automatically for the four load levels.

5.1.2 Contingency list - Step 5 in method

Single and multiple independent outage events up to order two are included in the contingency list for RBTS(1) and RBTS(2)[1].

Assumptions of multiple outage events

The order of the involved forced component outages in the multiple outage events is neglected in the assessment of RBTS. E.g., the event L1+L2, which consists of a forced outage of line L1 followed by a forced outage of line L2, is treated identically as the event L2+L1.

Scheduled outage events are assumed to only take place if (i) this do not causes system violations (e.g. interruption of supply in a load point), and (ii) an outage occurrence is already present in the system. This implies that the event CB8:2M+L7, which consist of a scheduled outage (maintenance) in circuit breaker CB8:2 followed by a forced outage in line L7, is included in the assessment but not L7+CB8:2M.

Scheduled outages are assumed to be uncoordinated in the system. I.e. each outage of this type is not coordinated with e.g. the system load level or other scheduled outages that are convenient to perform at the same time.

A component is assumed to be fully reliable when it is not energized. Hence, during a scheduled outage of a component, forced outages do not occur in that component. Furthermore, a scheduled outage of a component cannot be cancelled ones it has started. A scheduled outage always starts with a perfect disconnection of the involved component and do not trip any surrounding circuit breakers.

It is assumed that the component failure rate is independent of the component power loading.

All component outages in this study of RBTS are assumed to be caused by active failures[2]. All circuit breakers are assumed to be totally reliable

[1] For definitions of component outages see Section 2.1.1.
[2] For a definition see Section 2.1.1.

in its operation to isolate faults[3].

Number of outage events in RBTS(1)

In accordance to the specification of RBTS(1) in Section 3.2.4 only permanent forced outages are included in the case study. The nine lines' permanent forced outages results in nine single outage events and 36 [4] multiple independent outage events. In total this gives 45 events to be evaluated.

Number of outage events in RBTS(2)

In RBTS(2) both permanent forced outages and scheduled outages are included, as specified in Section 3.2.5. The total number of outage events that are evaluated is 7395. These events include the following types of outages:

- 128 single outage events, consisting of 87 (9 lines, 32 BBs, 32 CBs, 14 TRs) permanent forced outages and 41 (32 BBs and 9 TRs) scheduled outages. Five of the transformers (TR_LP2-TR_LP6) are not considered in the scheduled outage events, as this would cause system violations in form of an interruption of supply for the connected load points (LP2-LP6).
- 7267 multiple independent outages, consisting of 3741 [5] combinations of permanent forced outages, and 3526 [6] combinations of a scheduled outage followed by a permanent forced outage.

5.1.3 Computational time

The total computational time for all CTSs and load levels in RBTS(2) was approximately 40 min on an ordinary PC. For RBTS(1) the same computational time were less than one minute.

[3] I.e. the stuck probability for the CBs are neglected in the study.

[4] Since the order of the forced outages is irrelevant in the events, this gives $\frac{9*8}{2} = 36$ combinations.

[5] The order of these events is irrelevant and hence the number of combinations is calculated as $\frac{87*86}{2} = 3741$.

[6] The number of combinations are calculated as 41*86=3526, where 41 is the number of scheduled outages, and 86 is the number of remaining components that may suffer a forced outage.

5.2 Results from the RBTS

5.2.1 Result Critical Transfer Section 1

RBTS(1) - CTS 1

Figure 5.1 shows the general screening of the assessed outage events impact on CTS 1 in RBTS(1) at the system peak load[7]. The left vertical line shows the relative loading of CTS 1 for the intact system, which is 57% of the maximum. All outage events left of this line actually means a relief for the transfer on CTS 1. The outage events of losing line L1 or line L6 at the peak load, on the other hand, result in a change of loading from 57% to 102% according to the upper right of the figure. Both these events have each an expected frequency of 1.5 times per year.

All events on the right hand of the dashed vertical line are overloads of the section and these are the risk-outages for CTS 1. The right column shows the total-outages, i.e. outage events that result in a 0 MW transfer capability for the CTS, and for which the risk index I_i^{Risk} is not defined. These outages are not dependent of the system load level.

Figure 5.2 shows the same diagram for CTS 1, but for all four assessed load levels 0.7, 0.8, 0.9 and 1.0 p.u. In the diagram all studied events' impact to the CTS decreases as the load level gets lower. The result shows that the outage events' impact on the CTS is highly dependent on the system load level. E.g. if the events L1 or L6 occur at a system load level of 0.9 p.u., the impact on CTS 1 is 90% of the maximum allowed transfer capacity. Hence, these two events does only result in an overload for the 1.0 p.u. load level. The two events are still referred to as risk-outages, since they result in an overload in at least one load level.

Several events have identical positions in the diagram for all four system load levels, e.g. L1+L2 and L1+L7, L1 and L6. The reason is that the system is symmetrical, i.e. L1 and L6, and, L2 and L7 have the same electrical properties, and many components have identical expected outage frequency.

Table 5.1 presents a ranking of the assessed outage events with the total-outage on top followed by the risk-outages which severity is quantified with (4.1) for each system load level. As shown both in Table 5.1 and in Figure 5.2, no risk-outages results in an overload (>100%) of the CTS for the 0.7 and 0.8 p.u. load levels. Four risk-outages results in an overload at the 0.9 p.u. level, and eight at the 1.0 p.u. load level.

Table 5.2 shows the components cumulative risk, I_{Comp}^{Risk}, of overloading

[7] In order to better show the function of the screening diagram, only the result for the peak load is illustrated at first. All results later in this section includes all four assessed load levels.

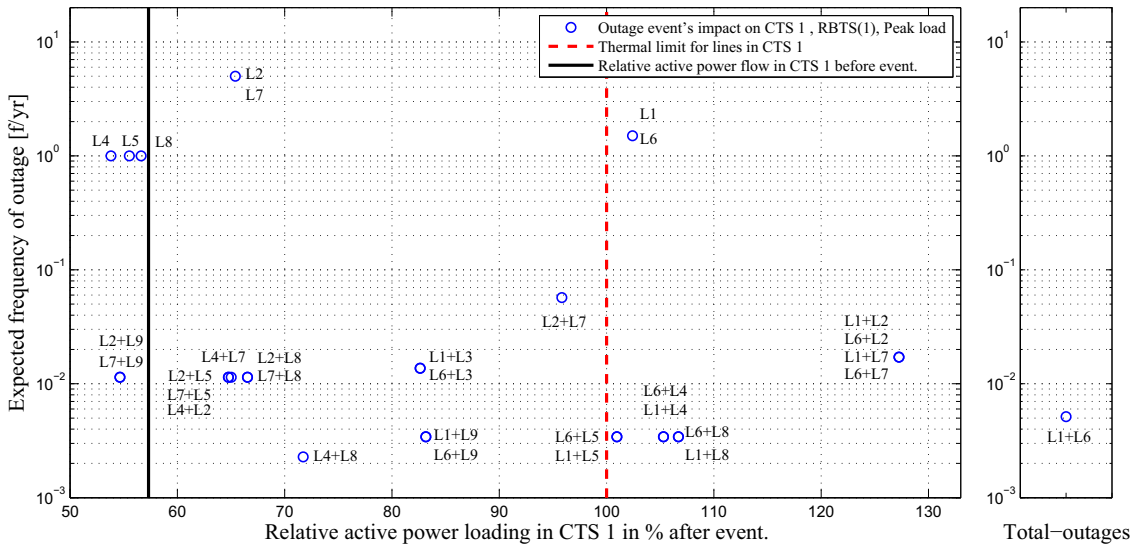

Figure 5.1: Screening of outage events impact on CTS 1 capability to transfer power in RBTS(1) at system peak load. Of the 45 assessed outage events, 32 are shown in the diagram, and the remaining 13 events are below the 50% loading.

CTS 1 at four different system load levels. According to this table the loss of line L1 or L6 has the largest impact on CTS 1 transfer capability for the peak load scenario. This is expected since these two lines actual defines CTS 1. Moreover, a relatively frequent single component outage event (L1 or L6) results in an overload for the CTS and this increase the ranking for these two components. L2 or L7 are the next components in the list, and this is explained by the re-direction of large active power flows from north-to-south through CTS 1 if these components suffer an outage[8]. For the 0.9 p.u. load level, the components L1, L2, L6 and L7 are equally important for CTS 1 capability to transfer active power.

Since a single component outage (L1 or L6) result in an overload of CTS 1, it can be argued that the intact RBTS(1) does not fulfil the N-1 criterion for the peak load level. The system operator's implementation of the criterion may however permit such overload violations if the time for corrective actions is reasonable, e.g. below 15 minutes. Moreover, in RBTS the system load is in the interval 0.9-1.0 p.u. approximately 1.4% of the year [83], and this could also be taken into the consideration in the system

[8]Refer to Figure 3.1.

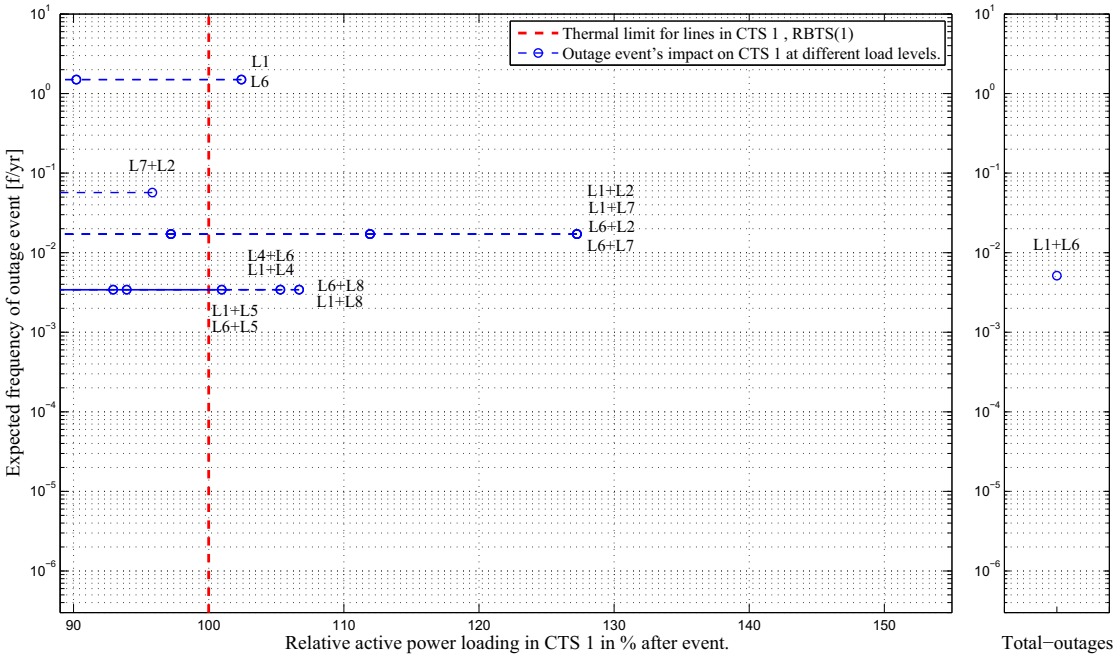

Figure 5.2: Screening of 45 outage events impact on CTS 1 capability to transfer power in RBTS(1) at the four load levels 0.7-1.0 p.u.

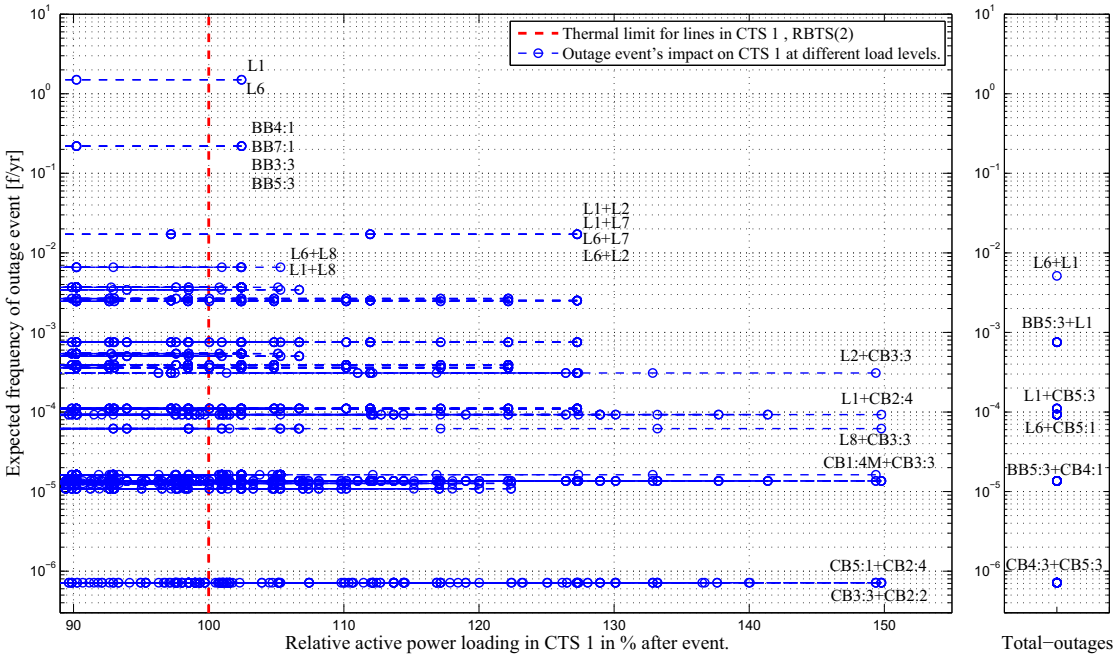

Figure 5.3: Screening of 7395 outage events impact on CTS 1 capability to transfer power in RBTS(2) at the four load levels 0.7-1.0 p.u.

Table 5.1: Outage events with impact on CTS 1 capability to transfer active power in RBTS(1)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 1 (%) after event i, system load (p.u) 0.7 - 0.8 - 0.9 - 1.0				Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u) 0.7 - 0.8 - 0.9 - 1.0			
Total-outages[a]										
L1+L6	0.51	5	-				-			
Risk-outages[b]										
L1+L2	1.71	5	72	97	112	127	0	0	12.2	15.8
L1+L7	1.71	5	72	97	112	127	0	0	12.2	15.8
L6+L7	1.71	5	72	97	112	127	0	0	12.2	15.8
L2+L6	1.71	5	72	97	112	127	0	0	12.2	15.8
L1	150	10	52	78	90	102	0	0	0	1796
L6	150	10	52	78	90	102	0	0	0	1796
L1+L8	0.34	5	56	82	94	107	0	0	0	2.23
L6+L8	0.34	5	56	82	94	107	0	0	0	2.23
L1+L4	0.34	5	57	81	93	105	0	0	0	2.22
L4+L6	0.34	5	57	81	93	105	0	0	0	2.22
L1+L5	0.34	5	52	77	89	101	0	0	0	1.99
L5+L6	0.34	5	52	77	89	101	0	0	0	1.99

[a] Total-outages always result in a 0 MW transfer capability for the CTS

[b] Risk-outages are events that result in a CTS overload (>100%) in at least one system load level.

planning. Furthermore, as shown in Table 5.2, the component ranking for component L1 and L6 and is extremely high during the peak load when the N-1 criterion is not fulfilled.

RBTS(2) - CTS 1

Figure 5.3 shows the general screening of the assessed outage events impact on CTS 1 in RBTS(2). Only a few names for the total 7395 assessed events at four different load levels are shown. 870 of the events are risk-outages located at the right hand of the dashed vertical line, and 50 are total-outages. The screening diagram provides a good overview of the outage events risks to the CTS at different system load levels, especially when the number of assessed events grows larger. The risk for events with large consequences but low expected frequencies can be evaluated and compared

Table 5.2: All assessed components' risk of overloading CTS 1 in RBTS(1) at four different system load levels

Component	Associated risk, I_{Comp}^{Risk} ($\times 10^{-6}$), at system load level (p.u.):			
	0.7	0.8	0.9	1.0
L1	0	0	24	1834
L6	0	0	24	1834
L2	0	0	24	32
L7	0	0	24	32
L8	0	0	0	4.5
L4	0	0	0	4.3
L5	0	0	0	4.0
L3	0	0	0	0
L9	0	0	0	0

with events with the opposite situation. However, the severity of total-outages in the right side diagram is difficult to compare with risk-outages, since the consequence of the first category is infinitely large for the CTS. The expected frequency of these events gives at least an indication of their associated risk.

Table 5.3 shows a selection of the resulting ranking of the total- and risk-outages. Total-outages are sorted by descending λ_i, and these are independent of the system load level. The risk-outages are sorted with a descending I_i^{Risk} for each studied load level. A number of events (e.g. L2+CB3:3) results in an overload in CTS 1 for all four load levels.

Table 5.4 shows the resulting ranking of the components' cumulative risk of insufficient transmission capacity in CTS 1 in RBTS(2) for each studied load level. This result provides information of the assessed components' importance for CTS 1 capability to transfer active power in RBTS(2). The component ranking at each load level shows that the component importance is highly dependent of the system load level. At 1.0 p.u, the eight most important components are the two lines in CTS 1, the four connecting BBs at each side of the two lines, and associated circuit breakers to these BBs. The results for each line and their associated components in the substations are symmetrical. This is not the case at the system load level 0.7 p.u., where e.g. the line L1 is present, but not L6. The system topology and substation design seems to be more important to the result at lower load levels. One example is the circuit breaker CB3:3, located in Bus 3 between the ingoing lines L1 and L4 (see Fig. 3.2), which is top ranked for the 0.7 and 0.8 p.u. load level. It is included in a number of high ranked risk-outages, e.g. L8+CB3:3 which results in the tripping of L1, L4 and

Table 5.3: Outage events with impact on CTS 1 capability to transfer active power in RBTS(2)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 1 (%) after event i, system load (p.u) 0.7 - 0.8 - 0.9 - 1.0				Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u) 0.7 - 0.8 - 0.9 - 1.0			
Top 10 Total-outages										
L1+L6	0.514	5	-				-			
BB5:3+L1	0.076	5	-				-			
BB3:3+L6	0.076	5	-				-			
BB4:1+L6	0.076	5	-				-			
BB7:1+L1	0.076	5	-				-			
BB5:3+BB4:1	0.011	5	-				-			
BB4:1+BB7:1	0.011	5	-				-			
BB3:3+BB7:1	0.011	5	-				-			
BB5:3+BB3:3	0.011	5	-				-			
L6+CB3:3	0.009	9	-				-			
...	*(40 additional total-outages not displayed)*									
10 selected Risk-outages										
L2+CB3:3	0.031	9	101	117	133	149	0.32	0.42	0.55	0.69
L1+CB2:4	0.009	9	102	117	133	150	0.10	0.13	0.16	0.21
L8+CB3:3	0.006	9	102	117	133	150	0.06	0.08	0.11	0.14
L1+L2	1.71	5	72	97	112	127	0	0	12.2	15.8
L1+L7	1.71	5	72	97	112	127	0	0	12.2	15.8
L2+L6	1.71	5	72	97	112	127	0	0	12.2	15.8
L2+L7	1.71	5	72	97	112	127	0	0	12.2	15.8
L1	150	10	67	78	90	102	0	0	0	1797
L6	150	10	67	78	90	102	0	0	0	1797
BB4:1	22	10	67	78	90	102	0	0	0	264
...	*(860 additional risk-outages not displayed)*									

L8, and all power to Bus 5 and Bus 6 is redirected via the remaining line L6 in CTS 1.

Table 5.4: The top 10 components' ranking of overloading CTS 1 in RBTS(2) at four different system load levels

The components associated risk, I_{Comp}^{Risk} ($\times 10^{-6}$), at system load level (p.u.):							
0.7		0.8		0.9		1.0	
CB3:3	0.51	CB3:3	0.69	L1	41	L6	1887
L2	0.32	L1	0.53	L6	40	L1	1884
CB2:4	0.13	L2	0.42	L2	34	BB7:1	277
L1	0.10	CB5:2	0.32	L7	34	BB5:3	277
L8	0.06	L6	0.31	TR_G9	11	BB4:1	277
CB1:4	0.06	CB6:2	0.26	TR_G8	11	BB3:3	277
BB4:1	0.01	CB9:2	0.25	TR_G7	9	CB3:3	66
BB3:3	0.01	CB2:4	0.18	BB4:1	6	CB4:1	62
BB1:4	0.01	CB8:2	0.13	BB3:3	6	CB7:1	62
BB2:5	0.01	L8	0.08	BB7:1	6	CB1:1	61

5.2.2 Result Critical Transfer Section 2

RBTS(1) - CTS 2

Figure 5.4 shows the screening diagram for CTS 2 in RBTS(1). Of the 45 assessed outage events, only three are risk-outages and one is a total-outage. The result can be compared with CTS 1, which has 12 risk-outages for the same set of outage events. For all outage events a higher load level results in a larger loading on the studied CTS.

No single outage event results in an overload of the CTS at any of the four load levels and hence the N-1 criterion is fulfilled.

The multiple component outages L3+L2 and L3+L7 results in an overload for CTS 2 at all studied load levels. The event L1+L6 result in an overload at the 0.9 and 1.0 p.u. The latter event represents the loss of CTS 1, and large amounts of power have to be redirected through CTS 2 according to the topology in Figure 3.1.

Table 5.5 shows the total-outage and the resulting risk index for the three risk-outages.

Table 5.6 shows the resulting component ranking for CTS 2. Since line L3 is included in two of the risk-outages, this component is top ranked for CTS 2 capability to transfer energy at all assessed load levels. This is reasonable result, since line L3 is together with CTS 2 the only paths for the power from the generation centra Bus 2, in north, to the consumption in south. Line L2 and L7, included in CTS 2, are the second ranked components. Line L1 and L6 are ranked on the third position, and provides a risk to CTS 2 during high load conditions, i.e. 0.9 and 1.0 p.u. of the peak load.

Table 5.5: Outage events with impact on CTS 2 capability to transfer active power in RBTS(1)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 2 (%) after event i, system load (p.u)				Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u)			
			0.7	0.8	0.9	1.0	0.7	0.8	0.9	1.0
Total-outages										
L2+L7	5.71	5	-				-			
Risk-outages										
L3+L7	4.57	5	102	113	124	135	26.9	33.1	40.0	47.8
L3+L2	4.57	5	102	113	124	135	26.9	33.1	40.0	47.8
L1+L6	0.51	5	89	95	104	116	0	0	3.2	3.9

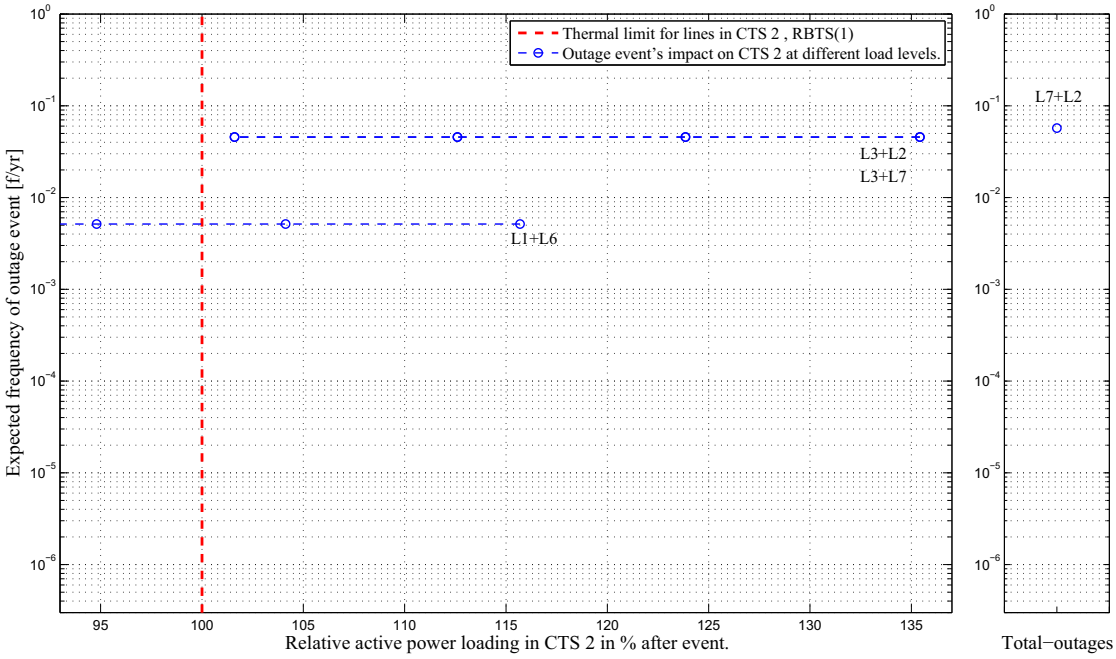

Figure 5.4: Screening of 45 outage events impact on CTS 2 capability to transfer power in RBTS(1) at the four load levels 0.7-1.0 p.u.

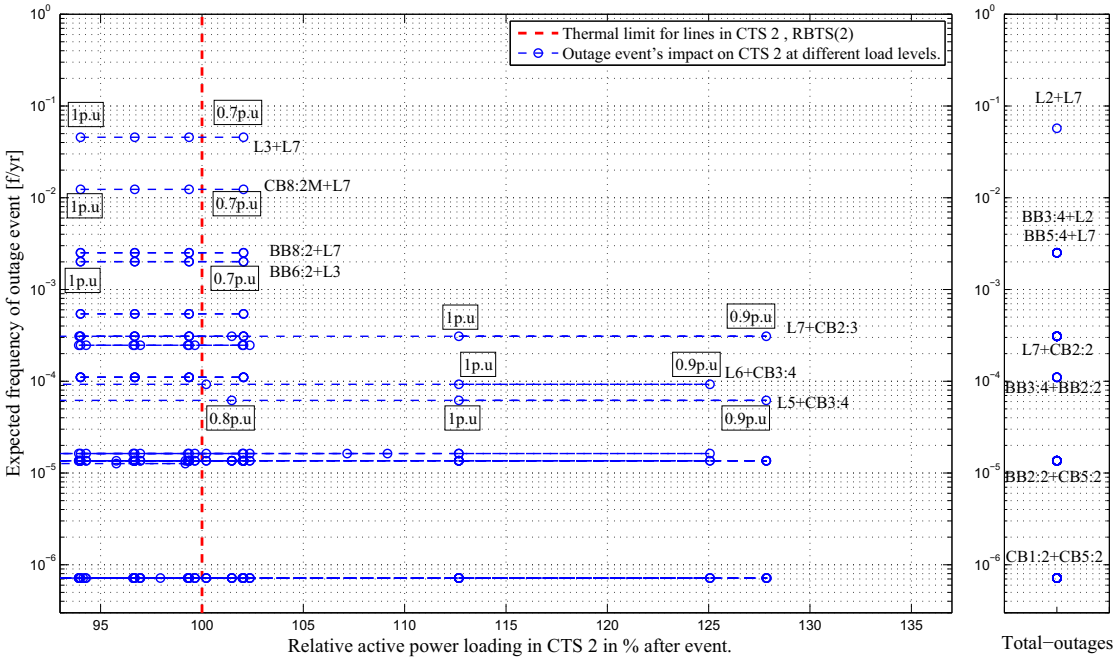

Figure 5.5: Screening of 7395 outage events impact on CTS 2 capability to transfer power in RBTS(2) at the four load levels 0.7-1.0 p.u.

Table 5.6: The components' risk of overloading CTS 2 in RBTS(1) at four different system load levels

Component	Associated risk, I_{Comp}^{Risk} ($\times 10^{-6}$), at system load level (p.u.):			
	0.7	0.8	0.9	1.0
L3	53.8	66.1	80.0	95.6
L2	26.9	33.1	40.0	47.8
L7	26.9	33.1	40.0	47.8
L1	0	0	3.2	3.9
L6	0	0	3.2	3.9
L4	0	0	0	0
L5	0	0	0	0
L8	0	0	0	0
L9	0	0	0	0

RBTS(2) - CTS 2

Figure 5.5 shows the screening of the outage events impact on CTS 2 in RBTS(2). Of the 7395 assessed outage events, 19 are risk-outages and 49 are total-outages. Table 5.7 shows the resulting ranking of the total-outages and risk-outages.

Two major differences can be noticed between Figure 5.5 and Figure 5.4. These are discussed in the two following sections.

Less impact on CTS with substation configuration

Firstly, the events L3+L2 and L1+L6 have disappeared from the diagram. The two event do not result in an overload in RBTS(2). Also, the event L3+L7 have a significantly lower impact on CTS 2 in RBTS(2) than RBTS(1). The changes in result for these three events are explain by the extended substation configuration in RBTS(2) in comparison to RBTS(1). According to the single line diagram for RBTS(2) in Figure 3.2, the event of L3+L2 split up substation Bus 2 and generators G5, G8 and G9 gets isolated. These three generators stand for 45 MW of the generation in Bus 2, and this power is instead generated in Bus 1 after the event. The changes in generation enables CTS 2 to handle the outage event, compared to RBTS(1).

The result of event L3+L7 can be explained in a similar way, where generator G7 instead is isolated. This is further described in the next section.

The event L1+L6 result in a split up of Bus 3, resulting in an interruption of supply for LP3. This LP consumes 85 MW at peak load, and the

loss of this load in the system results in a relatively light loading of CTS 2. The loss of a load point results in a less stressed CTS.

Decreased load level gives increased CTS impact

The second major difference, compared to the results for CTS 2 in RBTS(1), is that a higher load level does not result in a higher loading on the studied CTS for all events. For example, the event L3+L7 does not result in an overload at the 1.0 p.u. load level, but in a 102% loading at the 0.7 p.u. level. This is explained by the split up of Bus 2 substation, which isolates generator G7. This generator has, according to Section 5.1.1, a scheduled generation of 0, 10, 20 and 30 MW for the intact system at the four system loads 0.7-1.0 p.u. respectively. Since the internal load in Bus 2, LP2, decreases with lower system load, the export from Bus 2 increases with lower system load if G7 is isolated. This means that the highest export from Bus 2 is present during the 0.7 p.u. load, and the only path from Bus 2 is through CTS 2. The result on CTS 2 for L3+L7 is equal for RBTS(1) and RBTS(2) at the 0.7 p.u. load level. That is because the 0 MW generation contribution from G7 in both models.

Component ranking

Table 5.8 shows the ten highest ranked components for each studied load level. For the 0.8, 0.9 and 1.0 p.u. the ranking is similar and circuit breaker CB2:3 is top ranked for these levels. It is situated in Bus 3 between line L4 and L5. A single outage of this component split the entire system into two parts that only are interconnected with line L3. Hence, all power to Bus 4, Bus 5 and Bus 6 has to pass through CTS 2 and the section is vulnerable to additional outages. At the 0.7 p.u. load level line L7 and L3 have a high associated risk since these are included in a number of risk-outages with high outage frequencies.

Table 5.7: Outage events with impact on CTS 2 capability to transfer active power in RBTS(2)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 2 (%) after event i, system load (p.u)				Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u)			
			0.7	0.8	0.9	1.0	0.7	0.8	0.9	1.0
Top 10 Total-outages										
L2+L7	5.71	5	-				-			
BB3:4+L2	0.25	5	-				-			
BB5:4+L7	0.25	5	-				-			
BB6:2+L2	0.25	5	-				-			
BB2:2+L7	0.25	5	-				-			
L2+CB3:4	0.03	9	-				-			
L2+CB4:4	0.03	9	-				-			
L2+CB6:2	0.03	9	-				-			
L2+CB5:2	0.03	9	-				-			
L7+CB1:2	0.03	9	-				-			
...	*(39 additional total-outages not displayed)*									
10 selected Risk-outages										
L3+L7	4.57	5	102	99	97	94	27.1	0	0	0
CB8:2M+L7	1.23	9	102	99	97	94	13.4	0	0	0
BB8:2+L7	0.25	5	102	99	97	94	1.5	0	0	0
BB3:4+L3	0.20	5	102	99	97	94	1.2	0	0	0
BB6:2+L3	0.20	5	102	99	97	94	1.2	0	0	0
CB8:2M+BB6:2	0.06	9	102	99	97	94	0.6	0	0	0
CB8:2M+BB3:4	0.05	9	102	99	97	94	0.6	0	0	0
L7+CB2:3	0.03	9	84	101	128	113	0	0.32	0.51	0.39
L6+CB3:4	0.01	9	83	100	125	113	0	0.09	0.14	0.10
L5+CB3:4	0.01	9	84	101	128	113	0	0.06	0.10	0.08
...	*(9 additional risk-outages not displayed)*									

Table 5.8: The top 10 components' ranking of overloading CTS 2 in RBTS(2) at four different system load levels

The components associated risk, I_{Comp}^{Risk} ($\times 10^{-6}$), at system load level (p.u.):							
0.7		0.8		0.9		1.0	
L7	44.5	CB2:3	0.36	CB2:3	0.57	CB2:3	0.54
L3	30.3	L7	0.32	L7	0.51	L7	0.39
CB8:2	14.9	CB3:4	0.31	CB3:4	0.48	CB3:4	0.39
BB6:2	2.0	L6	0.09	L6	0.15	L6	0.12
BB3:4	2.0	CB1:3	0.08	CB1:3	0.13	CB1:3	0.11
BB2:1	1.7	L5	0.06	L5	0.10	CB4:4	0.10
BB8:2	1.7	BB6:2	0.01	CB1:1	0.10	CB1:1	0.10
CB3:4	0.4	BB1:3	0.01	CB5:1	0.09	CB5:1	0.10
CB6:2	0.4	BB3:4	0.01	BB6:2	0.02	L5	0.08
CB4:4	0.4	BB4:5	0.01	BB1:3	0.02	BB7:1	0.02

5.2.3 Result Critical Transfer Section 3

RBTS(1) - CTS 3

Figure 5.6 shows the screening diagram for CTS 3 in RBTS(1). As shown in Table 5.9, one total-outage is present of the 45 assessed outage events. No risk-outages exist since any outage events at the four assessed load levels results in an overload for CTS 3. Hence, there is not possible to determine the ranking for the components' associated risk of overloading the CTS with this assessment.

RBTS(2) - CTS 3

Figure 5.7 shows the screening diagram with the 7395 outage events impact on CTS 3 in RBTS(2). Table 5.10 shows the top ranked total-outages. The number of total-outages is 63. As for RBTS(1) no risk-outages are present for CTS 3.

Comments on the result for CTS 3

The results for both RBTS(1) and RBTS(2) shows that CTS 3 can cope with all single and multiple outage events that do not result in total-outages. The total-outages are not dependent on the system load level, but only on the system topology. No risk-outages are present for CTS 3. This is since the total peak load for LP 5 and LP 6 together is lower than the individual transfer capability in line L5 or L8. Hence, the assessed CTS 3 may not be a critical transfer section in the system and it can be argued, with the given system properties that this section can be excluded in the future analysis.

Table 5.9: Outage events with impact on CTS 3 capability to transfer active power in RBTS(1)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 3 (%) after event i, system load(p.u)				Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u)			
			0.7	0.8	0.9	1.0	0.7	0.8	0.9	1.0
Total-outages										
L5+L8	0.23	5	-				-			
No Risk-outages										

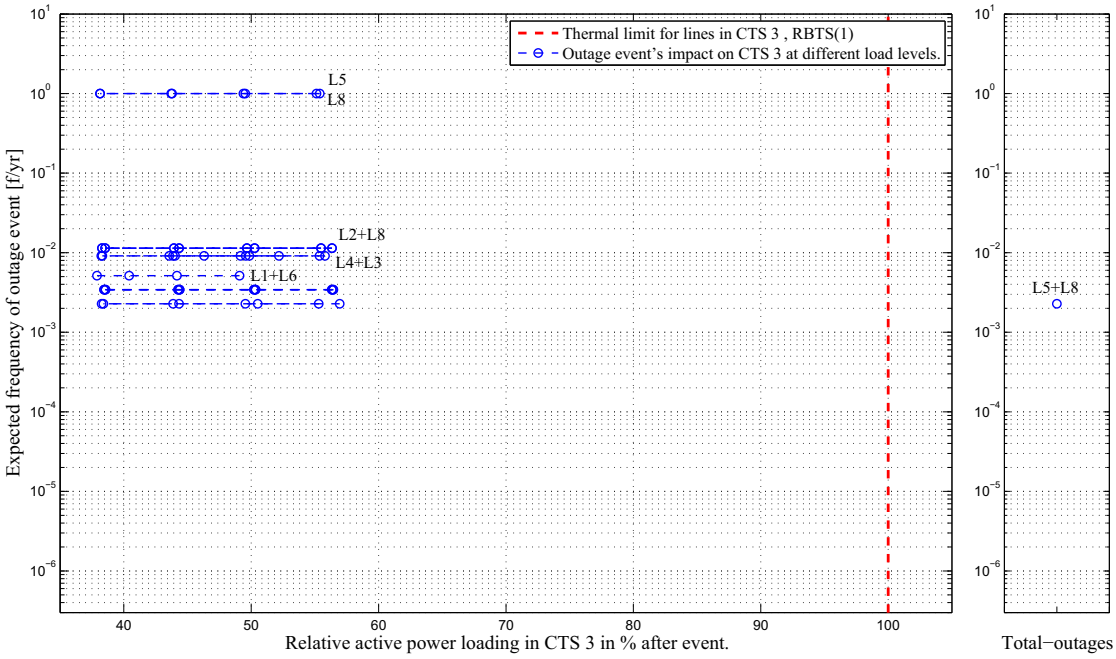

Figure 5.6: Screening of 45 outage events impact on CTS 3 capability to transfer power in RBTS(1) at the four load levels 0.7-1.0 p.u.

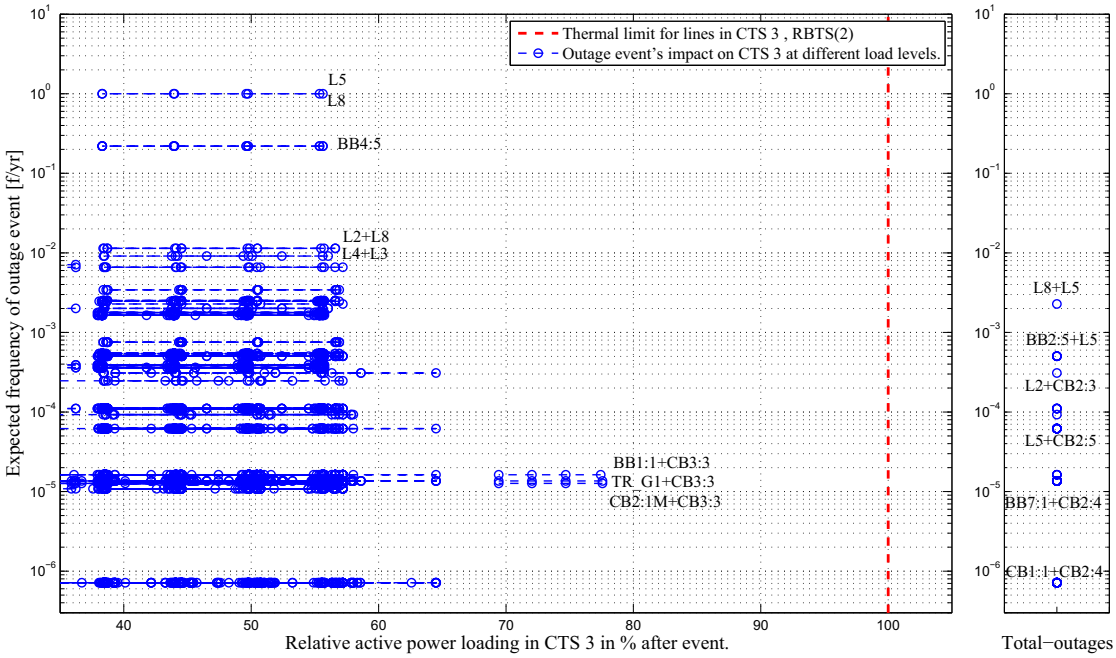

Figure 5.7: Screening of 7395 outage events impact on CTS 3 capability to transfer power in RBTS(2) at the four load levels 0.7-1.0 p.u.

Table 5.10: Outage events with impact on CTS 3 capability to transfer active power in RBTS(2)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 3 (%) after event i, system load (p.u)				Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u)			
			0.7	0.8	0.9	1.0	0.7	0.8	0.9	1.0
Top 10 Total-outages										
L5+L8	0.228	5	-				-			
BB2:5+L5	0.050	5	-				-			
BB1:4+L5	0.050	5	-				-			
BB4:5+L8	0.050	5	-				-			
BB1:3+L8	0.050	5	-				-			
L2+CB2:3	0.031	5	-				-			
BB2:5+BB1:3	0.011	5	-				-			
BB1:4+BB1:3	0.011	5	-				-			
BB4:5+BB1:4	0.011	5	-				-			
BB2:5+BB4:5	0.011	5	-				-			
No Risk-outages										

Chapter 6

Closure

This chapter concludes the thesis. It summarizes the results and present ideas and discuss future work.

6.1 Conclusions

This thesis has presented a method that quantifies each component's associated risk to an insufficient transfer capacity in critical transfer sections (CTS) of the transmission system. Given a correlation between the transfer stress in the CTSs and the system security margin, the method provides a ranking of the most important components to this margin.

The deterministic N-1 criterion has traditionally provided a high security margin for unwanted conditions in the transmission system. However, the approach excludes the different likelihood of component outages and therefore the result may be non-optimal decisions in the improvement of system security in planning, operation and design. A quantitative measure of the security margin could support the deterministic criterion and improve this decision-making process.

Results from the method, applied to the widely used Roy Billinton Test System (RBTS), shows that it can be used to overview a large number of potential risk outage events to the CTSs in a screening diagram. The results also show that the component ranking is highly dependent on the studied load level and the substation design. One unexpected result, which is explained by the substation configuration, is that the associated component risk may increase with a decreased load level.

6.2 Future Work

6.2.1 Model for dependent failures

Major interruptions and blackouts in the transmission system are often associated with dependent component outages. One common scenario is a single incident that initiates a cascading multiple outage event that breaks down the system. Often no one had thought this scenario was likely before it occurred. One of the causes to this propagation and break down of the system is hidden failures in the protection system. If this characteristic could be included in the proposed method in this thesis, the ranking of the components' risk to the system security would be more relevant, and provide one tool for avoiding future blackouts. Hence, for future work is to include models for the protection system in the substations and then focus on these types of outages in the system analysis.

6.2.2 Instability constraints in CTS

In the future work of the project, it would be interesting and challenging to also include voltage or angle instability constraints for the CTSs in the modelling. Such capability in the method is crucial for its applicability in real transmission systems where instability constraints are common.

6.2.3 Selection of outage events

For large power system models the computational speed of the method may be necessary to improve in future work. As been pointed out in Section 4.3.5, a reduction of the number of contingencies is one way to reduce computational time in the method. Second order outage events, or higher, is therefore preferable to select in a more intelligent manner.

The correlation between dependent component outages in the system depends to some extent on the geographical and electrical closeness. The consequences of these component outages are also related. Hence, one solution may be to only select each component's outage combinations in a close region to each component. E.g. it is most likely that a component outage in the south of a large power system, combined with an outage in the north can be excluded in the contingency list since the consequences probably are low.

6.2.4 Customers in the transmission system

Traditionally the focus has been to evaluate the associated reliability for the load points in the transmission system, i.e. the connected distribution systems. However, the connected generator companies (GENCO) are also

customers from the transmission system operator's point of view. An inability to use the system for power transfers might be unacceptable for the GENCOs, since this can lead to penalties for not fulfilling delivery contracts. Larger GENCOs might reschedule the generation and not suffer as much as smaller companies, owning e.g. a single wind farm. Hence, if the number of small GENCOs increases in the future, it is presumable that they will demand for a certain reliability level for their connection to the grid. Therefore, a quantitative reliability index for this purpose is one possible application study in the future work of the project.

6.2.5 HVDC incorporated in the transmission system

One aim of the project has been to investigate quantitative models and methods suitable to determine the reliability impact on an increasing number of HVDC link incorporated into the transmission system. This application study is possible to perform in future work, given the proposed method in appended Paper III and the HVDC reliability models presented in Paper I. This would answer how the CTS's transfer capability changes with the inclusion of HVDC links in the system. This gives an indication of the security reliability impact of HVDC incorporated into the transmission system.

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