On Risk Management of Electrical Distribution Systems and the Impact of Regulations

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Abstract

The Swedish electricity market was de-regulated in 1996, followed by new laws and a new regulation applied to the natural monopolies of electrical distribution systems (EDS). These circumstances have motivated distribution systems operators (DSOs) to introduce more comprehensive analysis methods. The laws, the regulation and additional incentives have been investigated within this work and results from this study can be valuable when developing risk methods or other quantitative methods applied to EDS. This tendency is not unique for Sweden, the results from a comparative study of customer outage compensation laws between Sweden and UK is for example included.

As a part of investigating these incentives, studies of the Swedish regulation of customer network tariffs have been performed which provide valuable learning when developing regulation models in different countries. The Swedish regulatory model, referred to as the Network Performance Assessment Model (NPAM), was created for one of the first de-regulated electricity markets in the world and has a unique and novel approach. For the first time, an overall presentation of the NPAM has been performed including description of the underlying theory as a part of this work. However, the model has been met by difficulties and the future usage of the model is uncertain. Furthermore, the robustness of the NPAM has been evaluated in two studies with the main conclusion that the NPAM is sensitive toward small variations in input data. Results from these studies are explained theoretically investigating algorithms of the NPAM.

A pre-study of a project on developing international test systems is presented and this ongoing project aims to be a useful input when developing risk methods. An application study is included with the approach to systematically describe the overall risk management process at a DSO including an evaluation and ideas of future developments. The main objective is to support DSOs in the development of risk management, and to give academic reference material to utilize industry experience. An idea of a risk management classification has been concluded from this application study. The study provides an input to the final objective of a quantitative risk method.

Key words: Electrical Distribution System, Maintenance Management, Project Planning, Regulation, Reliability Analysis, Reliability Centred Maintenance (RCM), Reliability Centered Asset Management (RCAM), Risk Analysis, Risk Management, Risk Methods, the Network Performance Assessment Model (NPAM).
Preface

This licentiate thesis is based on results from a Ph.D. project within the research group of RCAM, at the Department of Electromagnetic Engineering, School of Electrical Engineering, Royal Institute of Technology (KTH).

This project has been possible to perform because of all financiers that I would like to acknowledge. The major part has been funded by a research program within Elforsk AB referred to as “Riskanalysprogrammet 06-10” (the risk analysis program). More than 20 companies, organizations and authorities have contributed. The largest part of the economical contribution comes from the Swedish Emergency Management Agency (Krisberedskapsmyndigheten) distributed via the Swedish National Electrical Safety Board (Elsäkerhetsverket). Especially, I would like to thank the members of the reference group within this research program chaired by Sven Jansson and also all members of my other reference group associated with RCAM. Some of the included results in this thesis are also based on a study funded by SwedEnergy.

I would like to greatly acknowledge Associated Professor Lina Bertling, my main supervisor and chair of the research group of RCAM, who has contributed with invaluable support through the whole work. I will also thank my other supervisor Professor Roland Eriksson for his great support through the work. Further, I acknowledge Patrik Hilber for proofreading and his will of being my future associated supervisor; Johan Setréus and Julia Nilsson for valuable collaborations and being nice travel partners at conferences among other things, Tommie Lindquist, François Besnard, Karin Alvehag and of course all my other, current as well as former, colleagues for valuable discussions and for their contribution to a pleasant environment to work within.

I would also acknowledge all other persons that has contributed to this work and I could unfortunately not mention all of them, but a special thank to: Olle Hansson, Jörgen Hasselström and Per Bengtsson at Fortum Distribution for sharing of their knowledge, providing input data and proofreading of publications; Mats B-O Larsson, originator of the NPAM, for sharing of his knowledge, Herlita Bobadilla Robles at Gävle Energi AB for all support.

Carl Johan Wallnerström
Stockholm, April 2008
List of Publications

Appended Papers


**Author’s contributions in appended papers**

The author of this thesis has written and contributed to the major parts of Paper I - Paper IV. In Paper V, the main contribution was a description of the Swedish circumstances and some involvement in the performed analyses. Dr. Lina Bertling has contributed as the main supervisor, which for example include input of ideas and reviews of draft versions. Paper I and Paper III are in significant parts based on interviews with the other co-authors of these papers.
Additional publications not appended

Papers:

Other publications (in Swedish):

- Wallnerström C. J., “An algorithm for the maximal simultaneity power through power lines with regard to the method in The Network Performance Assessment Model” (“Algoritm för uppskattnings av den maximala effekten i eldistributionsnät - med avseende på Nätnyttomodellens sammanlagringsfunktion”), A-ETS/EEK-0508, KTH School of Electrical Engineering, Sweden, December 2005


Paper II - Paper IV are partly based on some of the main results from these publications. However, these publications often provide the results more in detail and also some results not included in this thesis.
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Chapter 1
Introduction

1.1 Background

There are several risks connected with electrical distribution systems (EDS). This thesis focuses on risks related to customer outages. Reliability analysis methods have been proposed in several international studies as the primary tool to handle this category of risks [1], [2]. Traditionally, the research and the development of reliability analysis methods have focused on the generation and the transmission part of electrical power systems [3]. However, several studies have shown that most of the customer outages depend on failures at the distribution level [4], [5], [6]. Furthermore, there is an international tendency towards re-regulations using more performance based methods [1], [7], [8]. Hence, the focus on customer outages has increased and consequently the interest of introducing reliability assessment applied on EDS. Performance based regulation is currently used in for example UK, Sweden, Norway and Spain [9] among an increasing amount of countries. More severe weather events have been noticed internationally and an increased fear of extremer events in the future followed by the current climate debate gives an additional focus on the risks with EDS which often are weather vulnerable. An example of an event which has affected the opinion in Sweden was the severe storm Gudrun. This storm struck the southern part of Sweden 8-9 January 2005 and caused the interruption of supply for approximately 450 000 customers. About one year after this event, a Swedish law of compensation for interruptions longer than 12 hours was founded [10], which in informal language is named after this storm. Other countries, e.g. UK, have also adopted new laws of customer compensations [11] working parallel with the regulation of customer network tariffs.

No technical systems are 100 % reliable. Accordingly, risk of failures with the consequence of customer outages in electrical distribution systems is unavoidable and there is not economical motivated, or possible, to work towards maximal reliability. Hence, there has to be a balance between the aim of decreasing the risk of customer
outages and the investment costs. Furthermore our society has become more dependent on reliable distribution of electricity and simultaneous the demand of cost efficiency has increased since new incentives have appeared. A re-regulation of the Scandinavian electricity market was performed during the mid 90s. The Swedish electrical power industry has, in a similar way as in many other countries, gone through several significant changes since the re-regulation of the electricity market. More private operators, new regulations and laws, new ways of building (e.g. more underground cables and more distributed generation) are some examples of resulting changes. The distribution of electricity is a natural monopoly, i.e. it is not economically realistic with parallel infrastructures. However, different distribution system operators (DSOs) own the local electrical distribution systems located in Sweden. At the same time some of these DSOs compete with each other at the de-regulated part of the electrical market. This special situation demands a good and fair regulation by the government, but there is however potential risks if a regulation becomes too detailed. For example if companies tactical invest to take care of some specific parameters in the regulation without looking at a more overall level. Hence, a good regulation must both have flexibility enough to facilitate for the company to reach real cost efficiency with sensible relevant methods and at the same time be strict enough to reach fairness between companies and give good incentives for the overall society; i.e. a difficult balance for the regulator. Furthermore, the regulation could never take every single aspect and detail into consideration, especially if the regulated systems have different regional conditions such as the case in electrical distribution systems (e.g. urban or rural, the amount of forest, weather conditions, possibilities of digging for underground cables).

To meet current and future requirement, new methods and tools to perform good risk analyses are needed. Risk management is in itself not new, however the use of quantitative approaches on distribution systems are limited if existing at all. A solution could be to introduce quantitative maintenance management and more comprehensive reliability analysis methods as input to the development of the risk management at DSOs. Always when developing new methods, there has to be a balance between complexity and usefulness, a new method must give higher profit than the resources it demands from the company. For example, the necessary input data must be realistic to acquire. Hence, experience both from the industry and from more theoretical academic methods, could be valuable to coordinate within the development work. A first step is to examine possible risks and different incentives to the risk management (such as regulations). One specific reason in Sweden of developing risk methods within the electrical distribution industry is a new law which makes it compulsory for every DSO to annually report on performed risk and vulnerability analysis [10]. However, there are several strong incentives of developing good risk analysis, as mentioned above; so regardless of this obligation there is still strong motivation to develop quantitative and knowledge based methods. This PhD project focuses on reliability aspects and risk analyses connected to the
investment planning of EDS. The idea is to connect risk analysis with investment- and maintenance plans for distribution system – especially “optimal” plans which are the goal with RCAM (see section 1.3).

1.2 Terminology
Following list defines some fundamental terms used in the thesis:

- **Reliability** is “the ability of a component or system to perform required functions under stated conditions for a stated period of time [12]”.
- **Redundancy** is “more than one independent opportunity for a piece of equipment to carry out a desired function [13]”; active redundancy is obtained if one or more reserve items operate parallel; passive redundancy is obtained if one or more reserve items are in cold standby [14].
- **Failure** is “the termination of the ability of a component or system to perform a required function [12]”.
- **Risk related definitions**, see section 2.1
- **Definitions of Reliability indices and Life Cycle Cost (LCC)**, see section 2.3

1.3 Related work at the RCAM research group
Reliability Centered Maintenance (RCM) is an advanced form of preventive maintenance planning, first developed by the aircraft industry [15]. High costs related to maintenance, combined with extreme demand on safety, motivated the development of a more systematic maintenance planning. This method has then spread to other industries, for example the electrical industry. At the Royal Institute of Technology (KTH), School of Electrical Engineering, there is ongoing research of developing RCM since about ten years [16]. The approach is to develop a more analytical (quantitative) RCM-method, adjusted to the electrical industry, referred to as RCAM (Reliability Centered Asset Management) [6], [17]. The development work of RCAM is in great parts focused on electrical distribution systems (EDS). As a part of this focus area, component reliability modeling [18], reliability analysis methods and component priority methods [19] are studied and further developed. This research is collected in the research-group of RCAM [16]. The connection between this PhD project and the overall RCAM research is to study consequences (i.e. risks) related with a possible introduction of RCAM-plans. The RCAM approach is explained further in section 2.3.1.

1.4 Objectives
This PhD project aims to complement ongoing projects within the RCAM research group (see section 1.3) [6], [20]. The overall goal, according to the original project proposal, is to evaluate risks related to the introduction of “optimal” maintenance- and investment plans. However, this problem also includes a general dimension of
investigating risks followed by new possible circumstances affecting the net planning such as regulation models. The focus is on the long-term influence followed by introduction of quantitative reliability methods in the net planning process. Furthermore the PhD project also includes an objective of going one step further by develop a quantitative general risk method integrated with investment- and maintenance planning in EDS.

This licentiate thesis includes mid-term results from this PhD Project. The overall mid-term objective is to investigate how different incentives effect the risk management of EDS, with a special focus on the impact of means of control by the Swedish government such as the choice of regulation model. This is motivated by the fact that new incentives, especially the paradigm shift of the regulation, have forced the DSOs to adopt more quantitative methods and develop more comprehensive risk methods. The aim is also to relate the general definition of risk with the special characteristic of EDS in terms of reliability. Furthermore, the current risk management performed at a DSO is described systematically within this study including an evaluation. The objective is to provide experience and knowledge to use in the future development work.

It is important to facilitate quantitative comparison, reproduction and validation of developed methods. International test systems could be useful for this purpose, but has also other benefits (see Chapter 5). The objective of participating in an international project on developing test system was included in the original project proposal.

1.5 Scientific contribution

The main scientific contribution of this thesis is divided into three parts:

1. An investigation of different incentives related to the risk management of EDS, with focus on the impact of regulations.

2. Studies of the Swedish Network Performance Assessment Model (NPAM):
   - A comprehensive description of the NPAM and its underlying theory; knowledge valuable to use as reference material in future developments of regulatory models, both by learning from novel approaches of the NPAM and from other received experiences of this model.
   - Development of a statistical method evaluating the robustness of regulation models which has been applied on the NPAM.

3. A description of current risk management at a DSO, with an approach of an evaluation which provides ideas of future development concluded from this study.
1.6 Thesis outline

Chapter 2 provides an introduction to risk management in electrical distribution systems in general. This includes definitions and an overview of existing risk assessment approaches; identified characteristics of EDS which are important to take into consideration within the management and last, a summary of theory used by the RCAM research group to use in the development work. This chapter is based on Paper I, but a significant part is new.

Chapter 3 investigates incentives to risk management in electrical distribution systems, with focus on the impact of regulations. A summary of results from performed studies of the Network Performance Assessment Model (NPAM) are included in this chapter, motivated by the fact that the customer tariffs regulation gives significant consequences for the DSOs. Other incentives are for example models for customer outages compensation and possible effects on the goodwill. This chapter mostly consists of summaries based on results from all appended papers and several international reports.

Chapter 4 gives some first results from an ongoing application study. This includes a description of the current risk management at a DSO (section 4.1), a first evaluation (section 4.2) and finally, some ideas of further development concluded from experience received within this study (section 4.3). Mainly, this chapter summarizes results provided in Paper I.

Chapter 5 introduces the developing work of international test systems, and is based on a pre-study performed by the author. Furthermore, the relevance and explanation of test systems, as a part in this PhD project on developing risk management, is provided here.

Chapter 6 concludes the thesis and proposes ideas of the future work within this PhD project.
Chapter 2
Risk and Reliability Methods

The word *risk* have several meanings, especially in informal contexts. A risk could be assessed differently: quantitative or qualitative; by an overall estimation or by comprehensive calculations. Hence, a risk could be more or less objective and possible to measure; sometimes quite diffuse. Risks could be categorized in different ways, e.g. by which part of the society the risk gives effect on. Often, a risk is defined as a negative event that has a possibility to happen. However, sometimes the word risk is involved in more positive contexts, such as an opportunity to invest money with a possible good profit as a compensation for taking the risk. This work focus on risk related with customer outages in electrical distribution systems (EDS). In this chapter the risk related terms first is introduced and defined with focus on technical system (section 2.1), then the risk theory adjusted and specified more into electrical distribution systems together with the special characteristics of these systems (section 2.2) affecting risk management. Finally, examples of applications and appropriate methods of assessment are introduced to use in future development of risk management (section 2.3).
2.1 Definitions and Basics

According to a current ISO- and IEEE standard [21] the definition of risk is “The combination of the probability of an event and its consequence” where:

- event is “The occurrence of a particular set of circumstances”,
- probability is “The extent to which an event is likely to occur”,
- consequence is “an outcome of an event”.

The definitions in [21] could be used as an overall frame in the development of risk methods in EDS, but are however wide and have to be more specified. For example, [2] discusses the risk concept in EDS and shows on the connection between reliability and risk, i.e. that higher risk of customer outages means lower reliability of the distribution and vice versa. The connection to reliability is practical to use, especially at the medium voltage level (which is explained further in e.g. section 2.2). Also other paper [1] proposes using reliability assessment within the risk management. A risk analysis could be performed using three questions [22]:

1. “What can go wrong?” (event),
2. “How likely is it to happen?” (probability) and
3. “What are the consequences?” (consequence).

A common approach to assess a risk or compare and prioritize risks is the use of “risk matrices”. This approach has been used by the electrical power industry in Sweden. For example, within a developed RCM process for hydro power generators [23] (see Table 1), as a part of the risk management of regional distribution systems at a DSO (see Chapter 4) and in a recently developed risk method adjusted to local EDS in Sweden [24] (see section 2.2). The probability and the consequence are first estimated and divided into settled categories. The categorization could either be done by qualitative or quantitative methods. The probability and consequence categories give two axes with a resulting two dimensional matrix with estimated risk values or proposed action measures. A simple, but commonly used definition of the risk value is exemplified in equation (1), where P is a settled number associated with a probability category, while C is a settled number associated with a consequence category. The risk value could then be used as input to decide if and how the risk should be treated (often combined with a cost analysis).

\[ \text{Risk value} = P \cdot C \]  

(1)

A risk matrix could however be designed differently, for example as illustrated in Table 1. The exemplified risk matrix is used as a part of a RCM method (maintenance management) applied on hydro power generators in Sweden. If the risk value is 3 or more, a preventive maintenance strategy will be recommended [23].
Table 1 – A risk matrix exemplified from the RCM of hydro power generators [23]

<table>
<thead>
<tr>
<th>Probability</th>
<th>Consequence</th>
<th>A Minor</th>
<th>B Average/Serious</th>
<th>C Severe/Catastrophic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Failures occurs more often than once a year</td>
<td>2</td>
<td>3 Safety, Efficiency loss, Environmental</td>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>Failures occurs in intervals of between 1 and 20 years</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Failures occurs in intervals of between 20 and 50 years</td>
<td>1</td>
<td>2 Safety</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Failures occurs in intervals of over 50 years</td>
<td>0</td>
<td>1</td>
<td>2 Interrupted production, flooding</td>
<td></td>
</tr>
</tbody>
</table>

A settled risk category regarding to the characteristic of its consequence could be an additional valuable input to the prioritizing of risks and the further management. There is not always obvious that two risks with the same resulting location in the matrix should be handled equal. This is exemplified in Table 1, where for example safety risks sometimes are prioritized higher and handled different compared with other risks within the same probability and consequence category.

A main benefit of using risk matrices is that they are easy to use, could be (but not always are) defined objectively (i.e. independent result from the matrix despite the user) and the results could be used to easily prioritize risks or to receive guidelines to handle them (e.g. low risk value $\rightarrow$ no action, high $\rightarrow$ investment needed). Measures like cost per reduced risk value could be defined and used (for example as proposed in [24]); however, it is not obvious that the same risk reduction from two different original levels has the same benefit. Hence, these kinds of measures should be used carefully. The drawback of this approach is the simplification when creating matrices based on “template categories” without further analysis. Consequently, risk matrices could often be useful but are not always sufficient and have to be complemented or replaced by more comprehensive assessment.

*Risk communication* is an important part of the risk management to e.g. internally motivate projects and to receive higher acceptance and good-will effects from other stake holders such as customers. Risk communication could be defined as
“exchanging or sharing of information about risk between the decision maker and other stakeholders [22]”; where a stakeholder is “any individual, group or organization that can affect, be affected by, or perceive itself to be affected by, a risk [21]”. According to risk management used by Swedish DSOs, risk communication could be divided into three categories:

1. The regulating authority: Due to the Swedish law, every DSO must perform annual risk and vulnerability analysis including an action plan. Other kinds of information sharing are also partly regulated [10]. However, the laws are recently changed, thus the work with guidelines and details are not finished.

2. Internal: The projects have to be motivated due to the decreased risks and to the cost effectiveness. Goodwill effects must sometimes internally be estimated and included to make single project profitability.

3. Customers: Important, both during the project planning and afterwards to increase the acceptance and goodwill.
2.2 Electrical Distribution Systems

Risks associated with EDS could typically be divided into three categories (1-3):

1. Risks of breaking any environmental or safety law.
2. Risks of customer outages which give repair costs, but also direct and indirect costs related to the outage such as customer compensation and damage of the trade mark.
3. Risks of other events which give a repair cost, but not any customer outages.

This study mainly focuses on the risk management of risk category 2. According to the definitions introduced in section 2.1, applied on risk category 2, consequences could be expressed in terms of customer outages, event as a possible scenario which includes this consequence and probability as a quantitative estimated measure of the frequency of these events (e.g. failure rate). Compared with other technical systems, electrical distribution systems have special characteristics affecting the risk management to take into consideration when developing new methods:

- The entire society is dependent of reliable distribution of electricity.
- An event could affect a greater area of the system than the local affected part since failures have to be disconnected according to safety aspect for humans and equipments (regulated by laws). However, if there are breakers, disconnectors etc., parts of the systems could be in function while other parts are not. The outage time could also differ between parts of the system.
- Some components such as overhead lines are significantly exposed and vulnerable to weather events (e.g. lightning, snow and wind). This gives dependent effects on the EDS when failure occurs which has to be handled.
- EDS are operated as local regulated monopolies. The incentives of new investments or how to reduce the risks could become different compared with non monopolies, i.e. strongly dependent of the regulation.
- EDS are connected to other electrical systems such as the transmission system, supply points and load points (customers). Because there are dependences between these systems which could affect the operation and the risk of customer outages, this has to been taken into consideration within the risk management at DSOs.

Followed by a new law of annual mandatory risk and vulnerability analysis [10], development- and research project on developing risk methods applied on EDS have started in Sweden to handle the risk of customer outages (risk category 2). These projects are organized by industry organizations, universities and public authorities. One example is “the risk analysis program” (see the Preface), where three development projects recently have been completed [24], [25] and [26]. For example, a risk method has been developed, adjusted to be easy to use at the medium voltage level at EDS [24]. The aim of the method is to reduce the risk of long and severe
customer outages (above 12 hours). The method is based on the risk matrix approach
described in section 2.2, but has three dimensions instead of two to also capture the
redundancy in EDS. The risk value (between 0.05 and 400) is the product of a
redundancy value (alternative supply, a value between 0.05 and 1; 1 = no alternative
supply), a consequence value (in terms of load, a value between 1 and 20) and a
probability value (in terms of exposure, a value between 1 and 20). The estimated
reduction of the risk value associated with a project could be compared with its
estimated investment cost which gives a quotient to use when prioritize investment
proposals. Benefits and disadvantages of these kinds of methods are discussed in
section 2.1.
2.3 Reliability and Economical Assessment

This thesis is a publication within the research group on Reliability Centred Asset Management (RCAM), see section 1.3. The overall research within RCAM is development of optimal maintenance management [17] (see section 2.3.1). This includes working with reliability analysis methods for EDS to handle protection system failures, dependences and redundancy by using network modeling, minimal cuts, primary and secondary failures [14], [27] etc (see section 2.3.2). The RCAM group also develops RADPOW [6], [28]; a software for reliability analysis of EDS. The algorithms used by RADPOW are, unlike commercial software, accessible which has a value in research and education. A new version of RADPOW, RADPOW_2007, has recently been presented which includes new routines for simulation and sensitivity analysis [28]. Cost analysis methods are used within the research of the RCAM-group integrated with the reliability assessment, see sections 2.3.3 and 2.3.4.

2.3.1 Reliability-centered asset management (RCAM)

RCAM [6] is based on Reliability Centered Maintenance (RCM). The major difference compared with traditional RCM is the use of quantitative methods. The approach is to find a relationship between reliability and the effect of maintenance measures. The overall goal is to develop maintenance plans which are optimal according to the total LCC cost of the system by creating a good balance between corrective maintenance (i.e. wait until the consequence occurs to act), condition based maintenance (e.g. inspections of equipments investigating the condition or measure methods of the cables condition) and predetermined maintenance (i.e. scheduled maintenance).

The process of RCAM is divided into three stages [6]:

1. System reliability assessment to identify critical components for further studies in the next stage, i.e. components which impact on the system reliability.
2. Component reliability modeling of critical components investigating and modeling the effect of maintenance, i.e. λ(age, maintenance)
3. System reliability assessment and cost analysis using the component reliability models from stage 2 to optimize the maintenance as input to construction of maintenance plans.

Risk management can be a useful tool through the whole process when introducing RCAM: before, during and after the development of RCAM-plans:

- Before: RCM and RCAM are extensive projects, with a long time between the start and useful outcomes. Therefore some kind of risk analysis could be preferable before even starting these kinds of projects.
• During stage 1: Assessment of the risks (probability and consequence) gives a priority which could be used to identify which components that are determined as critical.
• During stage 2: Investigating the reduction of a risk (reduction of the failure rate) as an effect of performed maintenance.
• During stage 3: Optimize the balance between the maintenance costs and the outcomes from this (could be seen as a kind of risk reduction actions).
• After, when introducing the RCAM-plans: See, section 6.2.3.

2.3.2 Reliability terms and theory used in this thesis
Reliability theory and methods are shortly introduced in this section and are explained more in detailed in several other publications, e.g. [14] and [27]. An alternative approach to this analytical theory is to use Monte Carlo simulation, see e.g. [29]. This is performed by simulating stochastic events, for example to simulate dependency between failure rate and weather conditions [30].

A Customer outage is in Sweden traditionally defined as an interruption of the electrical supply ≥3 minutes affecting one or more customers. 3 minutes is defined due to the earlier Swedish regulations [31]. However, the definition will be changed in future to include all measured interruptions. The average outage time is significant smaller compared with the average time an electrical distribution system normally is in function (i.e. when customers receive electrical energy). This characteristic is used to approximate the reliability calculations to deduce useful indices for reliability analysis of electrical distribution systems. Markov theory is used to deduce approximate derivations. If $\lambda_{ij}$ is the failure rate that component j affects Load Point i (LP$_i$) with a customer outage and $r_{ij}$ is the average outage time a failure in component j affecting LP$_i$; the resulting unavailability of LP$_i$, equals $U_i$ [hours/year] $\approx \sum_j \lambda_{ij} r_{ij}$ (valid if $r << \lambda_{ij}$), if the components have the characteristics of being in series (two parallel components, 1 and 2, give $U_p = \lambda_1 \lambda_2 r_1 r_2$). All component failures are assumed to be independent from each other. When a component fail, the outage time could vary between the different load points as a result of different possibilities of restoration by disconnectors, breakers and other protection components. From this theory, system indices could be defined (either weighed according to number of customer affected or electrical power affected). A selection of these reliability measures is provided here, with focus on those which are commonly used in regulations and by DSOs:

- $N_i$ = Number of customers in LP$_i$.
- Customer outage minutes = $\sum_i (U_i / N_i)$ [minutes/year] (an index used by a DSO, see Paper I)

14
• System Average Interruption Duration Index (SAIDI) = \( \frac{\sum_i (U_i N_i)}{\sum_i (N_i)} \) [hours/year] [27]

• System Average Interruption Frequency Index (SAIFI) = \( \frac{\sum_i (A_i N_i)}{\sum_i (N_i)} \) [hours/year] [27]

• Energy Not Supplied Index (ENS) [kWh] = \( \sum_i \left( U_i L_{a(i)} \right) \), \( L_{a(i)} \) = average load connected to LP\(_i\). [27]

Other reliability terms used in this thesis:

• Expected Energy At Risk (EEAR) [MWh] is the expected amount of demanded energy that cannot be served without overloading transmission equipment. [32]

• The N-1 criterion means that the system could withstand worst case scenarios including the removal of any single component, but not necessary additional events or affected components [33]. This is a commonly used criterion applied on transmission systems, but could also be applied as an internal goal or requirement on regional EDS (see for example Paper I). Following definition of “N-1” is provided by Nordel: “a power system can withstand the loss of an individual principal component (production unit, line, transformer, bus bar etc.) [13]”.

2.3.3 Costs and incomes related to the management

Estimation of costs related with risk reduction is important because risk management of EDS often is a balance between investment costs and possibly reduced costs followed by lower risks. Risk management is often used as a tool within project planning or maintenance management. Hence, resulting costs and incomes from a project or a new maintenance strategy could be seen as the positive or negative cost differences compared with doing nothing. Proposed categories of costs to take into consideration within the risk management are as follows:

• Investment and capital costs
• Outage costs: This category of costs includes for example customer outage compensations (see section 3.4.1) and repair costs.
• Cost of operation and maintenance: Costs within this category could both increase and decrease when doing an investment. For example, new components such as redundant lines could give more costs in maintenance
and operation, but replacement of overhead lines with underground cable could instead give less maintenance costs.

- **Costs and incomes after the economical life time (rest value):** Potential incomes are for example values of the raw material such as copper and potation costs are for example decontaminations.
- **Indirect costs and incomes:** Costs within this category are often difficult to estimate, for example incomes indirectly affected by changes of the goodwill.
- **Other costs:** For example, electric power losses and reactive compensations needed in the EDS if the amount of underground cables increases.

### 2.3.4 LCC analysis

LCC is the annualized cost of an investment during its entire economical life time (note that this is not equals to technical life time). This often includes costs of investments, outages, maintenance, interests and possible incomes (i.e. negative costs) etc. A LCC analysis could for example include a comparison between the LCC of the investment with the LCC of doing nothing or other investment proposals. The estimated economical life time (N) is limited by the technical life time, technical developments and expansions in the EDS (often giving a positive rest value). Equation (2) provides a general definition of the total LCC cost of an investment and includes following terminology:

- \( C_{\text{LCC}} \) is the total Life Cycle Cost of a project taking the interest into consideration,
- \( r \) is the interest rate determinate by the company (often per year),
- \( C_i \) is the investment cost year 0,
- \( C_i \) is the estimated sum of all increased costs compared with doing nothing during year \( i \) according to the project, e.g. increased costs of operation and maintenance,
- \( R_i \) is the estimated sum of all incomes from the projects during year \( i \) (i.e. decreased costs, revenues etc.), e.g. lower outage costs,
- \( RV^+ \) is positive rest values, i.e. incomes after the economical life time,
- \( RV^- \) is negative rest values, i.e. costs after the economical life time.

\[
C_{\text{LCC}} = C_i + \sum_{i=1}^{N} \left( \frac{1}{q^i} (C_i - R_i) \right) - \frac{1}{q^N} (RV^+ - RV^-), \quad q = \frac{1+r}{100} \quad (2)
\]

A benefit with LCC is the flexibility to settle the level of simplifications depending on the purpose. Typically, the costs are assumed to be gathered in the beginning of a year. Several equations are defined which could facilitate the calculations. For example, when calculating the sum of annual costs during a period; both possible with a constant returning cost and with an annual increasing cost. The approach within the research is to do optimizations of the total Life cycle cost (LCC). However,
there are several challenge when applying LCC integrated with analysis on EDS if every required aspect should be taken into consideration. For example, a there is
difficult to estimate the failure rate ($\lambda$) as a function of age and corrective maintenance when performing maintenance management using LCC.
Chapter 3

Regulations and Additional Incentives

A law, introduced in Sweden 2006, dictates that every DSO must annually report result from a risk- and vulnerability analysis regarding the reliability of the EDS to an authority determined by the government [10]. This includes an action plan of how the reliability in the EDS shall be improved in the future. The authority or the government is allowed to settle directions of how this law shall be applied. The guidelines on how to report are still under construction. However, new circumstances since the re-regulations in Sweden and introduction of some market conditions in 1996, such as new techniques, new laws, fear of more extreme climate, have increased the incentives of performing good risk management regardless the obligation. Because the electrical distribution systems operate as regulated local monopolies, the regulation itself is an important incentive. The impact of the regulation together with other incentives identified are described and analyzed in this chapter with focus on the impact of regulations.
3.1 Regulation of Distribution System Tariffs

3.1.1 The Network Performance Assessment Model

In Sweden, the regulator has a pronounced goal of forcing the DSOs to become more cost efficient [34]. The current regulation in Sweden uses a regulation model referred to as the Network Performance Assessment Model (NPAM). This was a paradigm shift [31]; from an earlier situation where the DSOs more or less got compensated for their costs, to a regulation trying to measure the customer performance of the electrical distribution [31]. The NPAM has been met by criticism and an ongoing legal process [35]. This process treats requirement motivated by the NPAM, that some of the DSOs must repay parts of prior received customer tariffs. Regarding to e.g. laws within the European Union, the use of the NPAM will be at least changed (perhaps replaced), see section 3.1.2.

The NPAM is based on reference networks; fictive electrical distribution systems defined from a set of conditions, such as location of customers and delivered electrical energy. This information is annually reported by every DSO to the regulating authority. The model performs a network performance assessment (NPA), expressed as norm costs to operate the reference network, and compare this value with the revenue, which gives a debiting rate [31]:

\[
\text{Debiting rate} = \frac{\text{Revenue}}{\text{NPA}}
\]  

A review of the tariffs, utilizing the NPAM, is annually performed by the regulating authority since 2003. The results from the NPAM are considered to be the primary tool for the regulating authority to judge the level of tariffs, and to decide if a DSO should be monitored for further review. Based on the model, several DSOs have been ordered to return a part of the revenue, if the debiting rate is higher than an acceptance level.

Paper I provides the first and only presentation with underlying theory for the Network Performance Assessment Model. It is based on interviews with the originator of the model (a short summary is provided in section 3.2.3). The underlying theory and developing work of the Swedish regulation model have a unique complexity; which includes technical assumptions of the power system, based on: years of discussions with the industry, performed Monte Carlo Simulations, reliability analyses etc. The understanding of this model is of great importance when developing future regulatory models, regardless of the future of the NPAM. The model has met difficulties and there is currently an ongoing law process investigating
the usage of the model. Furthermore, the robustness of the NPAM has been evaluated in two studies which indicate sensitiveness accessioned with small changes in the input data. The results are presented in Paper II and Paper IV (a summary is provided in section 3.3). Never less it is still an interesting and novel model and studies on the NPAM provides valuable learning for future work on developing regulation models.

3.1.2 Future Regulation in Sweden

The Swedish regulation will be changed in a close future, e.g. EU-laws force Sweden to go from an ex-post to an ex-ante regulation. Ex-ante is when the regulator judges the level of customer tariffs before they finally are settled and applied by the DSO, while the NPAM now is used within an ex-post regulation since the tariffs are reviewed afterwards. The NPAM could be used in an ex-ante regulation with only minor adjustments. Regardless if the new regulation is based on the NPAM in some parts or not, the future regulation will probably continue to focus on similar objectives as the current regulation, such as cost efficient, reliability of supply and customer values. Hence, the regulation will give incentives to more knowledge based and quantitative net planning and well performed risk management.
3.2 The Network Performance Assessment Model

Paper III provides a more comprehensive description of the Network Performance and its underlying theory. An overview of the results from Paper III is given in this section.

3.2.1 An overall summary of the NPAM

The Network Performance Assessment Model

Figure 1 – An overall picture of the NPAM

Figure 1 provides an overview of the NPAM. The NPAM builds up a radial fictive network, based on annual reported data. The fictive network is based on information in customer and production nodes. In a pure radial network, each component failure results in system outage. Consequently, electrical distribution systems often include component redundancy to improve system reliability. To capture this effect in the NPAM, a spare capacity feature has been included. The amount of spare capacity, i.e. component redundancy, corresponds to what the customers are willing to pay for (calculated from Monte Carlo simulations, see section 3.2.3). The model estimates this amount and the resulting required investment cost. This cost is then added to the estimated cost of the radial reference network, resulting in the complete reference network. Costs for operation and maintenance are added by template functions.
Finally, this total cost can be reduced, by a reliability cost function (see section 3.2.2). The resulting total cost is referred to as the Network Performance Assessment (NPA), see equation (4). The NPA is an assessment of the customer values of an EDS. The fundamental idea of the NPAM is that a DSO will be allowed to collect revenue that corresponds to these customer values. The allowed debiting rate for a DSO is defined by the quotient of the revenue and the NPA, as shown in equation (3). The results from the NPAM are considered to be the primary tool for the regulating authority to judge the level of tariffs, and to decide if a DSO should be monitored for further review.

NPA expresses the different customer values in terms of five different costs as follows:

1) The cost of the connection ($C_{\text{Connect}}$) corresponds to the capital cost of the fictive reference network, which includes the fictive radial network, spare capacity, operation and maintenance.
2) The cost of the administration ($C_{\text{Admin}}$) which includes an administrative template cost for each customer.
3) The cost of the delivery ($C_{\text{Deliv}}$) which is the energy loss in the system.
4) The cost of the services ($C_{\text{Service}}$) which is for example fees superior grids such as the transmission system. These are actual costs reported by the DSO.
5) The cost of reliability ($C_{\text{Rel}}$) provides a means for the DSO to reduce the allowed revenue by reducing the expected cost for the reference network by a maximum of the calculated cost for spare capacity that is worth investing in, see section 3.2.2.

$$NPA = C_{\text{Connect}} + C_{\text{Admin}} + C_{\text{Deliv}} + C_{\text{Service}} - C_{\text{Rel}}$$

(4)

### 3.2.2 The reliability cost function

The reliability cost function ($C_{\text{Rel}}$ in equation (4)) used by the NPAM is given by equation (5). $C_{\text{Rel}}$ aims to give incentives which are a good balance between high redundancy and cost effectiveness corresponding to the estimated cost the customer is willing to pay for to receive redundancy.

$$C_{\text{Rel}} = \begin{cases} 0 & \text{if } C_{\text{Outage}} - C_{\text{Expect}} \leq 0 \\ C_{\text{Outage}} - C_{\text{Expect}} & \text{if } 0 \leq C_{\text{Outage}} - C_{\text{Expect}} \leq C_{\text{Max}} \\ C_{\text{Max}} \Rightarrow C_{\text{Spare}} & \text{if } C_{\text{Outage}} - C_{\text{Expect}} \geq C_{\text{Max}} \end{cases}$$

(5)

The Expected outage cost ($C_{\text{Expect}}$) in the NPAM is the expected outage cost that the reference network would incur. The cost is calculated by algorithms using template functions in the NPAM, and depends on e.g. the subscriber density. This reduction is
made with a maximum ($C_{\text{Max}}$) corresponding with the template compensation for spare capacity given (a part of $C_{\text{Connect}}$ in equation (4)) by the NPAM. Furthermore, the NPAM does not give any reward for lower outage cost than $C_{\text{Expect}}$. Hence, the reliability cost function only regulates some values of the reliability of an EDS, which is illustrated in Figure 2. This could of course affect the incentives in different ways such as fusions of distribution system areas.

![Illustration of the regulation limited area of the reliability cost function](image)

Figure 2 – Illustration of the regulation limited area of the reliability cost function

The Customer outage cost ($C_{\text{Outage}}$) in the NPAM represents the cost that the customer experience. $C_{\text{Outage}}$ depends on delivered electrical energy, system reliability indices (SAIDI and SAIFI), and template functions of the customer interruption cost, see equation (6). The template functions depend on subscriber density and have been calculated based on a customer survey made by the association of Swedish DSOs, SwedEnergy in 1993 [36] including updated data in 2003. $C_{\text{Outage}}$ is calculated from both advertised, i.e. planned events, and unadvertised interruptions, i.e. stochastic events. Customers in an urban distribution system generally receive a higher amount of compensation (higher $x_i$ and $y_i$ in equation (6)) than customers in a rural distribution system due to the NPAM.

$$C_{\text{Outage}} = \frac{E}{8760} \sum_{i=a,b} \left( x_i \cdot SAIFI_i + y_i \cdot SAIDI_i \right) \quad (6)$$

Where:
- $E$ is delivered electrical energy for the area [kWh/yr],
- 8760 is the total number of hours per year [h/yr],
- the index \( i \) indicates if the interruptions are planned events, with \( a \), or stochastic, with \( b \),
- \( \text{SAIFI}_i \) [int/yr] and \( \text{SAIDI}_i \) [h/yr] are system reliability indices (see section 2.3.2),
- \( x_i \) [SEK/kW, int.] and \( y_i \) [SEK/kWh] are customer interruption cost functions depending on the customer density.

Note that the NPAM does not take into account the different loads for the individual customers when calculating the outage cost.

### 3.2.3 Study of the underlying theory

The NPAM model uses a set of template functions to assess the reliability cost function described in section 3.2.2. The template functions were defined during the development phase based on a set of simulation studies. Four different types of simulation studies (1-4) were made during the development phase with a sequential Monte Carlo simulation approach. The third simulation study is described in more detail in Paper III, which also shows the underlying logic. The other simulations have similar but simpler algorithms. A summary of the four algorithms:

1. **Assessment of outage costs for the fictive radial network**: Failure events were simulated, the generated outages were summarized, and a mean value was calculated. These simulations were input to calculation of the further development of the NPAM.

2. **Assessment of redundancy in transformers**: Simulations were made at each voltage level of the radial reference network. The resulting improvement in outage costs was compared with the required investment in redundancy for all transformers at the current voltage level. Consequently, the result from the simulations was either to have no redundant transformers or to have redundancy for all transformers. The results provide input data for the development of template function of the spare capacity.

3. **Assessment of the reference network – i.e. with feeder redundancy**: This algorithm used Monte Carlo simulation to identify an “optimal” (i.e. first profitable) investment in additional feeder length for the radial network. The resulting reference network provided input for the study presented in simulation 4, and also provided input data for calculating the development of template function of the spare capacity.

4. **Assessment of outage costs for the reference networks**: The Monte Carlo simulations for the reference network, i.e. with redundancy (calculated by simulation 3), were made in a similar way as simulation 1. The result is a template function used in calculation of the reliability cost function (see section 3.2.2).
3.3 Robustness Evaluations of Regulation Models

Studies assessing the robustness of regulation models as a part of the overall risk management could be motivated by:

1. If the model is sensitive and unpredictable, it could be a risk to use the model as a significant measure in the net planning process.
2. If the model gives unpredictable future revenues, this would become a risk itself, to take into consideration within the risk management.

3.3.1 An Overview of Two Performed Studies in Sweden

Two studies evaluating the robustness of the NPAM have been performed (referred to as S1 and S2) published in Paper II (S2) and Paper IV (S1) respectively. Both S1 and S2 use data of authentic Swedish EDS received by DSOs. S1 provides examples when a small realistic change in the input data results in significant divergences in the output data from the NPAM. For example, the reported location of one single low voltage customer is changed a few meters which should be compared with the fact that an uncertainty of 30 meter is allowed by the regulator. Within this study, the algorithms of the NPAM were also investigated to explain the received results. S1 (see section 3.3.2) shows examples of possible sensitiveness, but does not answer relevant questions such as how common these phenomena are. Therefore, S2 (see sections 3.3.4) continue with a more comprehensive and systematic approach using simulation methods and statistical theory. However, the method within S2 aims to be possible to use with some adjustments more generally on other models than the NPAM; the method is described in section 3.3.3. Finally, an approach to further judge the robustness by using statistical theory was performed within S2 to strengthen the conclusions. This last approach was not included in Paper II, only in the Swedish final report of S2 [37]; in this thesis a translation is provided in section 3.3.5.

3.3.2 The First Robustness Study of the Swedish NPAM

Several examples of small, non significant, divergences in input data which leads to significant divergences in the output from of the NPAM are provided in Paper IV. The Swedish final report of S1 [38] provides even more examples compared with Paper IV and also a more comprehensive theoretical explanation of the results. S1 could be seen as a “pre-study” and its conclusions indicates on possible sensitivity leading to an unpredictable regulation and motivates a further, more systematical, analysis of the robustness, i.e. S2.
Figure 3 – An example of the possible sensitiveness of an authentic system analyzed in S1

Figure 3 illustrates one of several examples from S1. The figure is received from the graphical interface of the NPAM (referred to as Netben, in this software it is possible to choose what to be illustrated) comparing the structure of the highest voltage level (135 kV of totally four possible voltage levels within the NPAM) of actual reference network including fictive transformer stations to 40 kV. Broken lines are connections to superior grids (for example the transmission system) trough existing stations available. In this example, one of the low voltage customer receive an increase of annual consumption to 34 365 kWh and 34 370 kWh respectively (original value is 19 375 kWh). Real data from an authentic EDS with 110 000 customers was used in this example. When the consumption was increased to 34 365 kWh, neither the structure of the reference network (left part of Figure 3) or the NPA received significant changes. When the consumption instead was changed to 34 370 kWh, the structure at the highest voltage level of the reference network was radically changed (right part of Figure 3). It is notable that the NPA decreases when the consumption increases.

The main conclusion from S1 was that a small realistic divergence in the input data could result in significant differences in the output data from the NPAM. A small change of input data at low-voltage could lead to “chain reactions” changing the whole fictive reference network at every voltage level. Changes in the input data which, in the reality, had given more expenses for the DSO, such as higher power demand or an additional customer, could result in lower NPA, which indirect leads to lower revenue allowed. The changes of NPA, depending on one small change of input
data did as most differ up to 7 million Euros (corresponds to 4.7 %) within S1 and in percent the NPA did as most differ more than 8 % (corresponds to 3.8 million) for the studied cases within S1. Paper IV provides more information of these particular examples.

3.3.3 A Simulation Method Evaluation Regulation Models

This section describes a simulation method evaluating the robustness of regulation models. This method has been applied on the Swedish NPAM, but can be used more generally with few adjustments.

Small variations of a category of input data are generated randomly. All other input data remain unchanged during the simulations. The variations are Normal Distributed with Expectation zero and with a small Standard Deviation (in S2, variation of the location or the individual energy consumption of low-voltage customers). The resulting output data are then collected. The simulation are repeated several times (100 times in S2), independent of earlier results assuming the original data before every new simulation. Original output (with unmodified data) and output from every performed simulation are then input to further analyses of the robustness.

Resulting output data (here debiting rate) from all simulations have been compiled in histograms to gain an overview of the result. This gives a picture of the overall robustness and the distribution of the results originating from the stochastic variations of the input data. The most important output data have been presented with maximum, minimum and original value, standard deviation etc.

In S2 the five different parts of the NPA was analyzed in greater detail by investigating the correlation. The NPA consists of five parts (see equation (4)): Connection, Delivery, and Administration, Services from superior grid and Reliability. The Variance (V) of the NPA is a function of the Variances of its parts and the Covariance (C) between its parts as follows:

\[
V(NPA) = \sum_{i=1}^{N} V(x_i) + 2 \sum_{1 \leq i < j \leq N} C(x_i, x_j)
\]  

(7)

Where \( x_1 = \) Connection (referred to as P1), \( x_2 = \) Delivery (referred to as P2) and \( x_3 = \) Reliability (referred to as P3). Administration and Services from superior grid are always constant during the simulations, which mean that Variances and all Covariance including these terms are always zero. Equation (7) can therefore be reduced to a function of the remaining three parts (P1, P2 and P3) of the NPA. To obtain an overview of how the different parts contribute to the sensitiveness of the NPA, the variances and covariance are in tables, structured as illustrated in Table 2,
based on equation (7). Because the covariance \( C(x, x) \) equals \( V(x) \) and \( C(x, y) = C(y, x) \) the sum of the nine resulting covariances in Table 2 becomes equal to \( V(NPA) \) according to equation (7).

Table 2 – Contribution of the different parts to the sensitiveness of the NPA

<table>
<thead>
<tr>
<th></th>
<th>C(P1, *)</th>
<th>C(P2, *)</th>
<th>C(P3, *)</th>
<th>Sum = C(NPA, *)</th>
</tr>
</thead>
<tbody>
<tr>
<td>C(*, P1)</td>
<td>V(P1)</td>
<td>C(P2, P1)</td>
<td>C(P3, P1)</td>
<td>Sum of row 1</td>
</tr>
<tr>
<td>C(*, P2)</td>
<td>C(P1, P2)</td>
<td>V(P2)</td>
<td>C(P3, P2)</td>
<td>Sum of row 2</td>
</tr>
<tr>
<td>C(*, P3)</td>
<td>C(P1, P3)</td>
<td>C(P2, P3)</td>
<td>V(P3)</td>
<td>Sum of row 3</td>
</tr>
<tr>
<td><strong>Sum of rows (1-3):</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>V(NPA)</strong></td>
</tr>
</tbody>
</table>

In addition to the individual results from the analyses of each EDS included, an overall comparison has been made between the different included simulations. Possible relations between the category of EDS and sensitiveness (e.g. number of customer or voltage level) and the frequency of measured phenomena were investigated in S2.
3.3.4 The Second Robustness Study of the Swedish NPAM

Figure 4 – An overview of one of the analysis within the second study of robustness

Figure 4 illustrates the overall result from S2: histograms of the debiting rate (the left axis together with the resulting differences of the NPA (the right axis). The divergence in the debiting rate differs from approximately 0.04 to 0.14 (most 11.2 %). The NPA differs up to 5 million Euros (10.4 %). Results from more analysis (for example NPA as a function of the energy demand) and results more in detail are presented in Paper II.

Results from S2 show that the NPAM can be sensitive with respect to small changes in input data and that these phenomena are unpredictable, not unusual and gives significant differences in result for the analyzed systems. Electrical distribution systems, both with a small and a large number of customers, could show significant divergences in output data as a result of small changes in input data. Even changes which should incur more expense for the DSOs, such as more distributed energy, could give lower NPA, i.e. indirectly lower revenues allowed. This is a strong
confirmation of the results received in S1. Hence, the main conclusion is that the NPAM is not robust toward small variations in input data.

The NPAM uses two algorithms which explain most of the sensitiveness shown in this paper. These are briefly introduced in this chapter in order to understand possible improvements in the NPAM or when to developing new methods. There are no available full descriptions of these algorithms, but further details on the underlying theory can be gained from the following publications [31], [37], [38], [39], and Paper III. The first algorithm in the NPAM that contributes to sensitiveness is how the fictive reference network connects with superior grids such as the transmission system or regional EDS owned by other DSOs. The second algorithm is related to the logic for placing transformers in the fictive reference network. In the NPAM, these are always located at the same coordinates as an existing customer. A “point of equilibrium” is calculated, based on the distance between the customers in a transformer area and their electrical consumption (corresponds to weight). The fictive transformer is then located at the same coordinates as the nearest customer to the “point of equilibrium”. The location of the fictive transformer is then used as input when the algorithm creates the next voltage level. A small change in input data could move the transformer several 100 meters and lead to “chain reactions” affecting all voltage levels. This could contribute to major sensitivity. If the transformers were allowed to be built everywhere, the NPAM would probably become less sensitive.

3.3.5 Theoretical Approach to Further Judge the Robustness

In equation (3), the calculation of the debiting rate (DR) is shown as a function of the revenue (R) and the NPA. The revenue could be seen as the sum of the revenues received from each customer (ri), but is however constant during the performed simulation within S2 (S2 is introduced in section 3.3.1). The NPA could be seen as the sum of the every contributed customer performance X_i, according to every single customer i. NPA is, unlike the tariffs, not constant during the simulations within S2 (see section 3.3.4). Hence, during S2, when the customer locations are stochastically changed, the debiting rate could be seen as a function of the stochastic variable NPA as shown in equation (8).

\[
DR = \frac{R}{NPA} = \frac{\sum_{i=1}^{n} r_i}{\sum_{i=1}^{n} X_i} = \frac{\overline{r}}{\overline{X}}, \quad r = \frac{1}{n} \sum_{i=1}^{n} r_i \quad \text{and} \quad X = \frac{1}{n} \sum_{i=1}^{n} X_i
\]  

(8)

The variance of the debiting rate could approximately be calculated with Gauss approximation as:
Equation (9) shows that the variance of the debiting rate is proportional to the variance of $\bar{X}$. Consequently, the focus is preferably on the variance of $\bar{X}$, which is an average of $n$ (here, $n =$ number of low voltage customers in the analyzed EDS) stochastic variables. The variance could be calculated as shown in equation (10):

\[
Var(\bar{X}) = \frac{1}{n^2} \left( \sum_{i=1}^{n} Var(X_i) + 2 \sum_{1 \leq i < j \leq n} Cov(X_i, X_j) \right) = \text{(if independent)} = \frac{1}{n^2} \sum_{i=1}^{n} Var(X_i)
\]

Furthermore, if the variances of $X_i$ are assumed to be independent with the same distribution ($\mathcal{N}(\mu, \sigma^2)$), the total variance could be calculated as

\[
Var(\bar{X}) = \frac{\sigma^2}{n}.
\]

If this assumption is correct, there will be a higher robustness of the results from the NPAM (lower standard deviation) the more customers the EDS have. If the variances of $X_i$ instead are positively correlated the variance could instead be calculated as $Var(\bar{X}) = \sigma^2$, i.e. the result is independent of the number of customers. Perhaps, none of these two extreme cases are directly applicable on the NPAM. However, this gives a good comprehension of which factors that affect the variance of the debiting rate and the requirements needed to receive a low variance (high robustness of the NPAM).

One argument used to defend the model and claim stability of the NPAM, is to state that the variance of the debiting rate becomes low since there are many customers in EDS. As shown, this argument is built on the assumption that the variances of $X_i$ are independent and has the same distribution, or at least has some of these characteristics. The results from S2, presented in Paper II, shows that this is not true, i.e. statistical theory could not be used as an argument to claim stability in this case. For example, one of the EDS studied in S2 (EDS1) has 111,600 customers, another EDS (EDS2) has 16,000 customers. According to the theory described above, EDS2 should be several times more sensitive according to small stochastically and independent changes in the input data compared with EDS1 (i.e. lower standard deviation which is the square root of the variance). However, S2 shows the opposite, EDS1 received three times higher standard deviation of the debiting rate compared with EDS2.
Accordingly, the hypothesis that all variances between $X_i$ are independent and have the same distribution could be discarded. Received results from S2 indicate that the robustness is unpredictable and independent of the number of customers. The conclusions from S2 are in detail provided in Paper II and [38] and summarized in section 3.3.4.
3.4 Additional Incentives

3.4.1 Customer Outages Compensations in Sweden

In Sweden, the customers are compensated with 12.5% of the annual tariff after 12 hours (minimum ~ 100 Euros\(^1\)) according to a recent law (referred to as Gudrun, see section 1.1). This compensation increases further after every additional period of 12 hours, 25% (minimum ~200 Euros) after 24 hours, and 50% after 48 hours (minimum ~ 300 Euros) and so on (see Table 3). This compensation model is a high level compared with e.g. UK. This law works in parallel and independent from the NPAM described in section 3.2 [10].

<table>
<thead>
<tr>
<th>Length of interruption, ( T )</th>
<th>Compensation to customer</th>
<th>Minimum * compensation</th>
</tr>
</thead>
<tbody>
<tr>
<td>( 12 \leq T &lt; 24 ) hours</td>
<td>12.5% of tariff ( \alpha )</td>
<td>2% of ( \beta )</td>
</tr>
<tr>
<td>( 24 \leq T &lt; 48 ) hours</td>
<td>+ 25% of tariff ( \alpha )</td>
<td>4% of ( \beta )</td>
</tr>
<tr>
<td>( 48 \leq T &lt; 72 ) hours</td>
<td>+ 25% of tariff ( \alpha )</td>
<td>6% of ( \beta )</td>
</tr>
<tr>
<td>Following 24 hour periods</td>
<td>+ 25% of tariff ( \alpha )</td>
<td>+ 2% of ( \beta )</td>
</tr>
<tr>
<td>Max compensation</td>
<td>300% of tariff ( \alpha )</td>
<td></td>
</tr>
</tbody>
</table>

\( \alpha = \{ \text{Individual customer’s annual network tariff} \} \)

\( \beta = \{ \text{Yearly set base amount} \} = \€4567 \)

* Is always set to 100 SEK values, rounded up

A few years ago there was no regulated customer compensation in Sweden. With the new legislation the cost for longer interruptions has significantly increased for the DSOs. For example, a DSO (reference application study) estimate this cost (excluding the damage of goodwill) to become 2/3 of the total outage cost in the event of major storms, while the other 1/3 mostly is repair and personnel costs. This new cost gives incentives of risk management to reduce the risks of interruptions longer than 12 hours.

3.4.2 A comparison between Sweden and UK

A study comparing the laws of customer compensations in Sweden and UK is presented in Paper V. The paper both compares the possible effects in both countries according to the laws, and presents results from a case study using historical data of an EDS. The approach was to assess how much the customer outage compensation

\(^1\) 1 Euro \(\approx 9\) SEK is assumed in this thesis
had become with each law during respectively between April 2004 to November 2006 for this EDS and also looking specific on the contribution from the storm Gudrun (8-9 January 2005). The EDS has 900 customers and the different laws was hypothetically applied respectively (this historical data was collected before the Swedish law took effect). The result was that it would had cost €474 000 (more than €500 per customer) with the Swedish compensation model and between €271 000 and €76 000 according to the UK model depending on the classification of the storm. A majority of the total compensation cost (more than 90 %) arises during extreme events such as severe storms. The major differences between the model of customer compensation settled by the law in Sweden and UK are:

- In Sweden the compensation level is higher compared with UK and the compensation cost starts after 12 hours compared with 18 hours in UK.
- In both countries, the outage cost compensation model is divided into intervals; in Sweden 12-24 hours, 24-48 hours, 48-72 hours and so on; in UK 18-30 hours, 30-48 hours and so on.
- The Swedish compensation is based on customer’s annual network tariff (with a minimum value of ~ 100 Euros) independent of customer category. In UK the compensation is based on customer category with the same levels within each category; two categories domestic- or non-domestic customers.
- The UK regulation has different policies and compensation levels for different weather conditions (more severe weather gives lower compensation cost for the same outage length), which is not included in Swedish model.

### 3.4.3 Additional Laws Affecting the Risk Management

Other recently updates done in the Swedish law [10] that gives incentives to the risk management are:

- The obligation of annual risk- and vulnerability analysis which is described and annotated in the introduction part of this chapter.
- Communication with customers and reporting to the regulating authority ave been more specified in the law. For example, the detailed level of outages reported and information to customers about their rights of compensations. Another example is that even shorter outages than 3 minutes (the old limit) must be reported.
- Functional requirement on distribution systems: no customer outages longer than 24 hours are allowed after January 1 2011.

### 3.4.4 Goodwill Effects and other Possible Incentives

Fear of more extreme climate and a higher general dependence of reliable electrical distribution have given increased attention in media of customer outages and highlighted the need of reliable distribution systems. The DSOs know that outages, in addition to repair costs and possible customer penalties, damage the goodwill of their
trademark. As a consequence of severe highlighted events such as the storm Gudrun, projects aimed at replacing overhead lines with cables increased rapidly in Sweden. Already in the mid-nineties the use of medium voltage overhead lines for renewal projects had been limited in favor of covered conductors and cable solutions. However, after Gudrun most DSOs with rural distribution areas initiated forced investment programs aiming to replace all weather sensitive overhead lines the next 5-15 years. Ageing characteristics of this technique can in itself become a future unknown risk, such as “water trees” was for the early generation of PEX cables [6].
Chapter 4

An Application Study on Risk Management

An application study investigating the risk management at a DSO has been made with results published in Paper I. This project will continue (see future work, Chapter 6) with the long term goal of developing a risk method. The approach has been to systematically describe the overall risk management process at a DSO (see section 4.1) and perform an evaluation which includes ideas of future developments (see section 4.2). In this thesis, further ideas, not included in Paper I, but as well concluded from the study, are provided (see section 4.3).
4.1 Description of Current Risk Management

The application study (see Paper I) describes and evaluates the risk management principles at Fortum Distribution. This company is one of the largest DSOs operating in Sweden. From 2006 to 2011, Fortum runs a large project in the Nordic countries referred to as the “Reliability Program”. The goal is to cost-efficiently reduce SAIDI to 60 minutes for rural and semi-rural areas by 2011. This corresponds to more than a 50 % reduction from historical SAIDI values of about 2-4 hours. To ensure cost-efficiency the work of developing a more knowledge based and quantitative network planning using e.g. risk management is necessary (and in fact crucial) for the success of the Reliability Program. Most likely the reliability program would be designed differently and implemented less rapidly without incentives such as compensation for interruption longer than 12 hour.

In Sweden, EDS could be divided into local (0.4-24 kV) and regional (>24 kV) EDS. There are large differences between these systems, both in terms of operation, but also in the risk management and network planning. At regional EDS the focus is on individual components (e.g. power transformers) and on the N-1 criterion, complemented by probabilistic measures such as EEAR while the risk management at local EDS more focuses on reliability (e.g. assessment of SAIDI) and volume (number of customers). Local EDS use historical outages data as an important input for project selection whereas regional EDS have more of a forward-looking approach, i.e., what can happen in the future if the system remains in today’s configuration? Local EDS are generally operated radially in rural areas which can include passive redundancy using normally open disconnectors (redundancy more generally used in urban areas) while regional EDS often operates with active redundancy. Depending on the voltage level, Fortum Distribution applies three levels of risk assessment policies for the EDS today:

1. Local EDS, low voltage (LV) [0.4 kV], see Paper I and section 4.3 (only an overall risk policy is applied at this level).
2. Local EDS, medium voltage (MV) [1.0-24 kV], see Figure 5 and Paper I.
3. Regional EDS [>24 kV], see Figure 6 and Paper I.

Risk policies and the project planning process for different voltage levels are described more in detail in Paper I. Figure 5 and Figure 6 illustrates an overview of the risk management at MV EDS (applied at rural areas) and regional EDS respectively. At MV EDS, a simple reliability analysis is performed as a part of the risk management. The current reliability model only estimates the consequences for one line at a time without the system perspective. Hence, a consequence of this simplification is that the model ignores dependencies in the systems such as taking passive redundancy into consideration if it existents. At regional EDS, risk matrices
are used as a part of the entire risk management (risk matrices are defined and discussed in section 2.1); an example of a used matrix is attended in Paper I together with a measure matrix used at MV.

Figure 5 – Overall illustration of the risk management at rural local EDS at MV
Overall goal: no outages above 12 hours

Incentives: regulations, "good-will", economic profit, laws etc.

1. Identification of possible scenarios that could give outages >12 h

System data

2a. Sorting out everything non-critical

For each "individual"

2b. Critical?
yes

3a. < 1-4 MW
yes

3b. < 12 h
no

Risk communication including internal "follow ups"

4. Risk matrix

5a. Preventive planning & project proposals

5b. Prioritited?

6a. Investment- (and maintenance) plans

6b. Implementation

No improvements for the present

next
4.2 A first Overall Evaluation of the Risk Management

Local- and regional EDS have different methods of network planning, motivated by different operation and categories of risks. At local EDS, the focus of the risk management is concentrated to a few areas which are the most important according to reliability statistics. These risks are however most obvious, but in the future these risks are mitigated due to the current strategy and new risks could instead appear (e.g. associated with the underground cables). Consequently, the current focus area is good, but a wider risk focus should be considered. Current risk management at medium voltage presented in Paper I is however not directly applicable to urban distribution systems, mainly due to the fact that more advanced methods to estimate the reliability benefit of projects are necessary. An essential part of the risk management at medium voltage is reliability analysis, which currently is based on significant simplifications. Hence, there is a potential to develop the reliability method further. Strong incentives to develop more quantitative methods of risk management to use in the network planning of electrical distribution systems was identified in this application study. However, differences between voltage levels in distribution systems are significant and justified. Experiences from this first part of the application study are input to a proposal of how to divide the risk assessment, see section 4.3.
4.3 Proposed Classification of Risk Management

The application study (presented in Paper I, summarized in section 4.1-4.2.) concludes that there are large differences between voltage levels of the EDS which motivate different risk management policies. In according to a risk perspective there is also significant differences between categories of systems, especially urban areas which have other characteristics compared with other EDS at the same voltage level. This project focuses on risks connected to the reliability of EDS (i.e. risk of customer outages); other risks will be handled separately as an own category. This motivates at least five separate policies of the risk management and a sixth policy to coordinate the risks at a central level at the company. The resulting classification with its six parts is provided below as a list which includes some first proposals of risk policy approaches.

Characteristics of the different proposed parts of the risk management classification:

1. **Risk of customer outages - Low voltage EDS** (secondary substations included): The probability of customer outages could vary a lot between low voltage systems; however, the consequences are relative low compared with other voltage levels. Failures at this level seldom affect more customers than the effected LV EDS because of protection equipments in the secondary substations. Hence, the resulting risk value is often small. Therefore, it could be profitable to have another risk policy for this level separated from the risk assessment at MV, to apply to e.g. move economic resources to other parts of the distribution system to maximize the cost effectiveness by doing less at this level. However, a general defined method applied on both this part and part 2 would probably give this result too for low voltage EDS.

2. **Risk of customer outages - rural and semi-rural local EDS** (low voltage excluded): Rural EDS at this voltage level contributes to a great majority of SAIDI (see Background). This fact is recently further founded by an interview within the application study (see Paper I). Consequently, medium voltage is the most important part of the EDS if the main objective is to reduce SAIDI. Reliability analysis could therefore be an important part of the risk assessment. Compared with regional EDS, the probability part of the risk is significantly higher, see equation (1). The consequence could vary, but are often less severe compared with regional EDS or local EDS in urban areas. However, an extreme event such as a severe storm could cause several damages at the same time, which lead to long interruptions. Such events could cause customer outages lasting several days, weeks or even up to month. These systems are often operated radially, but sometimes with passive redundancy (using normally open disconnectors), i.e. the outage last either during a repair time or a switching time. These systems have traditionally a great share of overhead lines contributing to a majority of the failures.
However, the tendency is a rapid replacement with cables. There could nevertheless continuously be significant risks; for example, underground cables have a longer repair time and the fast replacement could become an unknown risk itself in the future.

3. **Risk of customer outages - urban local EDS** (low voltage excluded): Urban EDS have a significant higher reliability compared with rural EDS at same voltage level. The redundancy is often good exclusively consisting of underground cables. However, the consequence, if a failure occurs, is often much more severe compared with rural system. Hence, the risk assessment should focus on handle and prevent extreme events with large consequences.

4. **Risk of customer outages - regional EDS**: These voltage levels are often operated with active redundancy, i.e. possibility to fulfill the N-1 criterion (see section 2.3.1). The probability of customer outages caused by this voltage level is small, but the consequence can become significant. Like the urban systems, the risk assessment should focus more on extreme events with large consequences. For example, in the application study (see Paper I), the risk management consists of identifying critical parts and then both developing preventive action plans to use if the identified events should become a reality and parallel work with long-term plans in order to solve the problem permanently by new investments.

5. **Other risks** (not reliability related): Within this category the most serious risks are included such as risk of human injury and breaking laws of e.g. safety and environment. Some of these risks could however been seen as absolute constraints (i.e. not in any case allowed to break) in cost optimizing analysis in other parts of the risk management.

6. **Overall risk management**: Risk management at a centralized level at the company could be used to cost efficiently divide resources available in the company between different areas, i.e. to optimize the investments centralized in the company. The alternative is to first divide the resources and then locally optimize the investment.
Chapter 5
Test Systems in the Development Work

This Chapter provides an introduction to an ongoing project of developing international test systems. The project is related to the other activities within this work (see also future work, section 6.2.4) and enables collaboration between researches in different countries. Test systems could for example be valuable within the development and evaluation of risk and reliability methods. Models of technical systems with adequate simplifications are needed in several situations. These test systems could be created with respect to a specific real EDS (useful in net planning) or like a general model, symbolizing a typical EDS (for example to compare methods and results), see further in section 5.1.
5.1 Benefits of using international test systems

The project itself of developing international test system could give valuable exchange and discussions between countries, researchers and companies. The exchange of ideas and knowledge is also an important part of the international work on test systems, as well as the development itself. There is a lot of work associated with creating good test systems satisfying every required aspect. Hence, one obvious benefit is that the use of a pre-defined test systems, if possible, saves time compared with creating an own model for each analysis or study. If no test system satisfy required aspects, it could still be easier to modify an existing system compared with creating a complete new. Moreover, if a locally developed model is used instead, all used data must be published, since all academic studies must be repeatable, while an international published test system could just be referred shortly. For academic projects, test systems provide the possibility to objectively compare research results, for example: comparison of methods or software. One example is a comparison between reliability results received from RADPOW (see section 2.3) and NEPLAN respectively [40]. NEPLAN is a commercial program with a graphical interface which could handle several categories of analysis, for example reliability analysis of EDS.
5.2 Development of Test Systems

In 1979, a test system was published by IEEE Subcommittee on the Application of Probability Methods, referred to as the IEEE Reliability Test System (RTS) [41]. This system was made to compare different reliability methods, only at the generation and/or transmission level according to the earlier focus. Originally, the idea was a system that could be used as a frame system, with possibilities to individually add parameters, modifications and improvements [3]. The original version held only data for the transmission level, divided into two parts separated by transformers (north 230 kV and south 130 kV). The system has, at this level, 24 buses (10 load buses) and an installed capacity of 3405 MW [40]. Until 1988, several developments of RTS were published for generation and transmission and 1988 data of the subsystems (distribution levels) for two of the load busses were given in a master dissertation [3].

During the 90s, a new test system was published called RBTS (Roy Billinton Test System) at University of Saskatchewan. It is smaller than RTS, but with every load bus defined at the distribution level [42], [43]. RBTS has two generators, six busses, five load busses, and an installed capacity of 240 MW. RBTS has five voltage levels (230/138/33/11 kV) and 18 288 customers, divided into several categories. In 1991 detailed data of load bus 2 and 4 and its sub systems was published [42] and in 1996 data of the load bus 3, 5 and 6 was done [43]. Figure 7 provides the structure of the RBTS at the transmission level and Table 4 provides data of characteristics of the five distribution systems included in RBTS (representing both urban and rural distributions systems).

An ongoing IEEE Power Energy Society (PES) Task Force (TF) on distribution system reliability has the scope of developing electrical distribution test system. Work within this TF will be input during future work, see for example section 6.2.4. One of the main motivations of developing test system despite the existence of e.g. RBTS is the fact that the electrical power industry has gone through fast worldwide changes since the previous test systems were updated. These changes both increase the needs of doing analyses on distribution systems and to investigate the needs of updating existing or create new test systems. A possible problem is to handle differences between EDS (e.g. between countries). A test system could both be well defined or act as a core system which could be supplemented by the users with additional data and modification depending of the purpose. One common used solution to handle differences between distribution systems is to have an overall high voltage system, which has sub-systems with different characteristics (urban, rural, industrial etc.); see e.g. Table 4 of the RBTS with this solution. See also suggestions of future work in section 6.2.4.
Figure 7 – The overall structure of RBTS at the transmission level [40]
### Table 4 – Overall description of the load busses in the RBTS

<table>
<thead>
<tr>
<th>Bus</th>
<th>Number of customers</th>
<th>Overall characteristics of the load bus</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>1,908</td>
<td>Typical urban and close to generation, 20 MW peak load</td>
</tr>
<tr>
<td>3</td>
<td>5,805</td>
<td>Typical industrial and other large customer, 85 MW peak load</td>
</tr>
<tr>
<td>4</td>
<td>4,779</td>
<td>Typical urban, 40 MW peak load</td>
</tr>
<tr>
<td>5</td>
<td>2,858</td>
<td>Typical urban, 20 MW peak load</td>
</tr>
<tr>
<td>6</td>
<td>2,938</td>
<td>Typical rural system, 20 MW peak load</td>
</tr>
</tbody>
</table>
Chapter 6
Closure

6.1 Conclusions
Incentives which motive the development of more quantitative methods applied on EDS have been identified and studied; laws and regulations, as well as more subjective measures such as possible damage on the trademark in case of severe events affecting customers. An increased knowledge of these incentives is valuable when developing risk methods or other quantitative methods performed by distribution system, operators (DSOs) in the future.

As a part of investigating incentives affecting the risk management, several studies of the Swedish regulation of customer network tariffs, referred to as the Network Performance Assessment Model (NPAM), have been performed. This Swedish regulatory model was created for one of the first de-regulated markets in the world and has a unique and novel approach which has met criticism. For the first time, an overall presentation of the NPAM has been performed within this thesis work to be used as future reference material. This includes insight into underlying calculations. Two studies evaluating the robustness of the NPAM have also been included in the thesis. The first study provides examples when a small realistic change in the input data results in significant divergences in the output data from the NPAM, while the second study continue with a more comprehensive and systematic approach using Monte Carlo simulation methods and statistical theory. The main conclusion from these two studies is that the NPAM not is robust toward small variations in input data. Theoretically explanation of the results has also been included. Experiences from all three studies of the NPAM provide experiences which contribute with valuable knowledge for the development of regulatory models worldwide.

This thesis aims to provide results which are useful in future development of risk methods. However, there is a challenge to find a good balance between the reality for DSOs on one hand and possible complex approaches with several theoretical benefits
on the other when developing new methods. To overcome this, an application study at a DSO has been performed to investigate current risk methods and future possibilities of development. According to a risk perspective, the study has concluded significant differences between categories of EDS and between voltage levels. A classification of the risk management divided into separate categories with different risk policies is proposed in the thesis. For example, quantitative reliability analysis methods are proposed as the main tool applied on rural local EDS. During the developing process, pre-defined international test systems are useful. Results from a pre-study of a project on developing international test systems are included in the thesis as a part of this work (see also future work, section 6.2.4). For example, possible benefits of using these systems such as an increased international exchange of knowledge as ideas are discussed in the thesis.
6.2 Future Work

The application study presented in Chapter 2 provides an input to the long term objective to develop a quantitative risk method (section 6.2.1 and 6.2.2) and the ongoing project on developing international test systems could be integrated with this work (section 6.2.4). Furthermore, risk associated with the introduction of RCAM-plans should be examined (section 6.2.3).

6.2.1 Further Evaluation and Implementation

The application study presented in Paper I should be continued, with the following proposed future steps (1-4):

1. Produce a proposal of possible developments to apply on the risk management at the DSO.
2. Discuss the proposal with the DSO and implement some of the suggestions on an authentic risk reducing project at the EDS.
3. Consider and compile the experience from step 2.
4. Use received knowledge from the application study as input when developing a risk method, see section 6.2.2.

6.2.2 Development of a Risk Method

Risk management applied on EDS is proposed to be divided into several categories (see section 4.3). The future development of a risk method aims to focus on reducing risks of customer outages caused by non urban medium voltage EDS. For other categories of EDS, the aim is to propose more general risk policies. The approach is to increase the use of quantitative reliability analysis methods within the risk management both in terms of taking mean values of the reliability into consideration (for example reducing SAIDI) and to reduce the risk of more severe events.

In section 2.1, a division of the risk analysis into three parts was suggested:

1) **Event**: This part includes identification and classification of possible risks. Scenarios that could lead to an event (here customer outages) should be identified (some minor risks could perhaps directly be sorted out and neglected).

2) **Probability** and 3) **Consequences**: Identified risks within step 1 should be analyzed further. Depending on the result of this analysis, the risk (if not considered to be neglected) should be proposed to be reduced or alternatively handled by developing strategies to decrease the consequence if the event occurs. Depending on the characteristic of the risk, different strategies have to be applied:

   a) Handle the general risk of customer outages in EDS: These risks are proposed to be assessed by using reliability analysis methods.
The approach is to taking more aspects into consideration than traditionally used by DSOs, such as redundancy and protection failures.

b) Handle more severe events in EDS: These risks (for example, severe storms and major outages in urban areas) have a significant lower probability but a significant higher consequence compared with a) and could therefore be difficult to properly assess using reliability tools. Strategies which include the use of risk matrices are a better alternative to management these category of risks.

6.2.3 Maintenance Management

Maintenance management using the RCAM approach is shortly introduced in section 2.3.1. An estimation of risks related to the introduction of optimal RCAM-plans is planned to be a part of the future work. The introduction of new techniques is generally connected with several risks (known as well as unknown). RCAM-plans are however intended to be optimal, but, there are embedded assumptions and approximations in the underlying models and the future could be difficult to predict. Hence, a risk analysis should be performed to identify and handle these future risks.

6.2.4 IEEE TF on Distribution System Reliability

The next suggested step within the IEEE task force on Distribution System Reliability (see section 5.2) is to evaluate previous test systems further with focus on RBTS and examine why test systems not are used so much today. Preferably, the work could be done with a closer collaboration with the industry than before and with organizations, such as Cigré, to better investigate the requirements of a test system. The overall long-term goal is to have a well define updated version of one or two existing test systems, easily available at a web-page using for example wiki-technique, to be used by several companies and universities. One challenge to overcome is to construct a general useful system despite of differences such as between European- and North American systems.

How to proceed as the next step:

- Use RBTS in the first place (see section 5.2)
- Make a review of previous work on for example RBTS and wind power
- List features expected for the test system, perhaps based on interviews
- Follow up on other activities of test systems

Examples of future development to consider:

- Include outage costs
• Common mode failures, i.e. a way of handle dependences of e.g. storms in distribution systems
• Protection system failures (already exists in some parts of RBTS)
• Including HVDC technique, but this would however be more relevant to introduce at the transmission level
• A greater amount of underground cables
• Distributed generation, e.g. wind power farms
• Load flow data, to handle capacity restrictions in EDS when performing reliability analysis
References


[35] Lawsuit 2076-05 to the county of Södermalms län, appeal against the Energy Market Inspection (EMI) handled by the law firm Advokatfirman Södermark.


