KTH Electrical Engineering

On Incentives affecting Risk and Asset Management of Power Distribution

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Abstract

The introduction of performance based tariff regulations along with higher media and political pressure have increased the need for well-performed risk and asset management applied to electric power distribution systems (DS), which is an infrastructure considered as a natural monopoly. Compared to other technical systems, DS have special characteristics which are important to consider. The Swedish regulation of DS tariffs between 1996 and 2012 is described together with complementary laws such as customer compensation for long outages. The regulator's rule is to provide incentives for cost efficient operation with acceptable reliability and reasonable tariff levels. Another difficult task for the regulator is to settle the complexity, i.e. the balance between considering many details and the manageability. Two performed studies of the former regulatory model, included in this thesis, were part of the criticism that led to its fall. Furthermore, based on results from a project included here, initiated by the regulator to review a model to judge effectible costs, the regulator changed some initial plans concerning the upcoming regulation.

A classification of the risk management divided into separate categories is proposed partly based on a study investigating investment planning and risk management at a distribution system operator (DSO). A vulnerability analysis method using quantitative reliability analyses is introduced aimed to indicate how available resources could be better utilized and to evaluate whether additional security should be deployed for certain forecasted events. To evaluate the method, an application study has been performed based on hourly weather measurements and detailed failure reports over eight years for two DS. Months, weekdays and hours have been compared and the vulnerability of several weather phenomena has been evaluated. Of the weather phenomena studied, heavy snowfall and strong winds significantly affect the reliability, while frost, rain and snow depth have low or no impact. The main conclusion is that there is a need to implement new, more advanced, analysis methods. The thesis also provides a statistical validation method and introduces a new category of reliability indices, R_T.

Keywords: *asset management, correlation studies, incentives, investment planning, maintenance planning, power distribution, reliability analysis, risk management, statistical validation, tariff regulation, vulnerability analysis, weather states.*

Sammanfattning

Distribution av elektricitet är att betrakta som ett naturligt monopol och är med stor sannolikhet det moderna samhällets viktigaste infrastruktur – och dess betydelse förutspås öka ytterligare i takt med implementering av teknik ämnad att minska mänsklighetens klimatpåverkan. I Sverige finns det fler än 150 elnätsbolag, vilka är av varierande storleksordning och med helt olika ägarstrukturer. Tidigare var handel med elektricitet integrerat i elnätsbolagens verksamhet, men 1996 avreglerades denna; infrastruktur för överföring separerades från produktion och handel. Införandet av kvalitetsreglering av elnätstariffer under början av 2000-talet och hårdare lagar om bland annat kundavbrottsersättning samt politiskt- och medialt tryck har givit incitament till kostnadseffektivitet med bibehållen god leveranskvalitet. En viktig aspekt är att eldistribution har, jämfört med andra infrastrukturer, flera speciella egenskaper som måste beaktas, vilket beskrives i avhandlingens första del tillsammans med introduktion av risk- och tillförlitlighetsteori samt ekonomisk teori. Två studier som kan ha bidragit till den förra regleringens fall och en studie vars resultat ändrat reglermyndighetens initiala idé avseende modell för att beräkna påverkbara kostnader i kommande förhandsreglering från 2012 är inkluderade.

Av staten utsedd myndighet övervakar att kunder erbjudes elnätsanslutning och att tjänsten uppfyller kvalitetskrav samt att tariffnivåerna är skäliga och icke diskriminerande. Traditionellt har elnätsföretag mer eller mindre haft tillåtelse till intäkter motsvarande samtliga omkostnader och skälig vinst, så kallad självkostnadsprissättning. Under slutet av 1990-talet började ansvarig myndighet emellertid arbeta mot en reglering av intäktsram som även beaktar kostnadseffektivitet och kundkvalitet. Vid utformande av en sådan reglering måste svåra avvägningar göras. Exempelvis bör elnätsföretags objektiva förutsättningar, såsom terräng och kunder, tas i beaktning samtidigt som modellen bör vara lätthanterlig och konsekvent. Myndigheten ansåg ingen existerande reglermodell vara lämplig att anpassa till svenska förhållanden, så en ny modell utvecklades: Nätnyttomodellen (NNM). För 2003 års tariffer användes denna och beslut om krav på återbetalning till berörda elnätskunder togs, vilka överklagades. En utdragen juridisk process inleddes, där modellen kritiserades hårt av branschen på flera punkter. Två, i avhandlingen inkluderade studier, underbyggde kritisk argumentation mot NNM. Beslut i första instans (Länsrätt) hade inte tagits 2008 då parterna kom överens avseende år 2003-2007. Ett EU-direktiv tvingar Sverige att gå över till förhandsreglering, och i stället för att modifiera NNM och fortsätta strida juridiskt för den, togs beslut att ta fram en helt ny modell. Nätföretagens tillåtna intäktsram kommer förenklat grunda sig på elnätsföretagens kapitalkostnader och löpande kostnader. Därtill, utifrån hur effektivt och med vilken kvalitet nätföretagen bedrivit sin verksamhet, kan tillåten intäktsram justeras.

En systematisk beskrivning av ett elnätsföretags nuvarande riskhantering och investeringsstrategier för olika spänningsnivåer tillhandahålles med syfte att stödja elnätsföretag i utvecklandet av riskhantering och att ge akademiskt referensmaterial baserat på branscherfarenhet. En klassificering av riskhantering uppdelat i olika kategorier och en sårbarhetsanalysmetod samt en ny tillförlitlighetsindexkategori (R_T) föreslås i avhandlingen, delvis baserat på genomförd studie. Sårbarhetsanalysens övergripande idé är att identifiera och utvärdera möjliga systemtillstånd med hjälp av kvantitativa tillförlitlighetsanalyser. Målet är att detta skall vara ett verktyg för att nyttja tillgängliga resurser effektivare, t.ex. förebyggande underhåll och semesterplanering samt för att bedöma om förebyggande åtgärder baserat på väderprognoser vore lämpligt. R_T är en flexibel kategori av mått på sannolikhet för kundavbrott $\geq T$ timmar, vilket exempelvis är användbart för analys av kundavbrottsersättningslagars påverkan; sådana har exempelvis införts i Sverige och UK under 2000-talet. En statistisk valideringsmetod av tillförlitlighetsindex har tagits fram för att uppskatta statistisk osäkerhet som funktion av antal mätdata ett tillförlitlighetsindexvärde är baseras på.

För att utvärdera introducerad sårbarhetsanalysmetod har en studie utförts baserat på timvisa väderdata och detaljerad avbrottsstatistik avseende åtta år för två olika eldistributionsnät i Sverige. Månader, veckodagar och timmar har jämförts vars resultat exempelvis kan användas för fördelning av resurser mer effektivt över tid. Sårbarhet med avseende på olika väderfenomen har utvärderats. Av de studerade väderfenomen är det blott ymnigt snöfall och hårda vindar, särskilt i kombination, som signifikant påverkar eldistributionssystems tillförlitlighet. Andra studier har visat på sårbarhet även för blixtnedslag (som ej fanns med som parameter i avhandlingen inkluderad studie). Temperatur (t.ex. inverkan av frost), regn och snödjup har således försumbar påverkan. Korrelationsstudier har utförts vilket bland annat visar på ett nästan linjärt samband i Sverige mellan temperatur och elförbrukning, vilket indirekt indikerar att även elförbrukning har försumbar påverkan på leveranskvalitet. Slutligen föreslås ett analysramverk som introducerad sårbarhetsanalys skulle vara en del av. Övergripande idé presenteras, vilket främst skall inspirera för fortsatt arbete; emellertid bör påpekas att introducerad sårbarhetsanalysmetod är en självständig och färdig metod oavsett om föreslagna idéer genomföres eller ej.

Acknowledgements

This doctoral thesis is based on results 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 the funders, whom 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 financial contribution comes from the Swedish Civil Contingencies Agency (initially the Swedish Emergency Management Agency which ended as an independent authority in 2009) distributed via the Swedish National Electrical Safety Board. Especially, I would like to thank the members of the reference group within this research program initially chaired by *Sven Jansson*, and also all members of my other reference group associated with RCAM. Some of the results included in this thesis are also based on two studies, one funded by Swedenergy and another funded by the Energy Market Inspectorate.

I deeply thank Professor *Lina Bertling*, my former main supervisor who initiated this project and also my current supervisor Doctor *Patrik Hilber*; both have provided valuable support throughout the project. I also thank my former supervisor Professor *Roland Eriksson* for his great support throughout the work and my current main supervisor Professor *Rajeev Thottappillil*. Furthermore, I acknowledge Doctor *Hans Edin* for "kvalitetsgranskning" (quality review), current and former colleagues for valuable collaborations and being nice travel partners at conferences, especially *Julia Nilsson* and *Johan Setréus*, but also *Johanna Rosenlind*, Doctor *Tommie Lindquist*, *François Besnard* Doctor *Nathaniel Taylor*, Doctor *Daniel Månsson* and several others. *Peter Lönn* for e.g. IT support.

I also acknowledge all those others that have contributed to this work and I could unfortunately not mention all of them, but a special thanks to: *Olle Hansson*, *Jörgen Hasselström* (now at Sweco), *Henrik Rinnemo* and *Per Bengtsson* at Fortum Distribution for sharing their knowledge, providing input data and proofreading publications; *Matz Tapper* at Swedenergy for all his support; *Mats B-O Larsson*, originator of the NPAM, for sharing his knowledge, *Herlita Bobadilla Robles* at the Energy Markets Inspectorate (previously at Gävle Energi AB) for all her support from the very beginning when I performed my masters project in 2005 until now.

And not to be forgotten, all the support from *family* and *friends*...

Carl Johan Wallnerström
Stockholm, August 2011

List of Publications

Appended Papers

		Sections in which the paper is essentially reported in:
Paper I	C. J. Wallnerström, L. Bertling and L. A. Tuan, "Risk and reliability assessment for electrical distribution systems and impacts of regulations with examples from Sweden," International Journal of Systems Assurance Engineering and Management, to be published (accepted 2010)	1.1 2.2 5.3
Paper II	C. J. Wallnerström and P. Hilber, "Vulnerability Analysis of Power Distribution Systems for Cost-effective Resource Allocation", IEEE Transaction on Power Systems, Accepted for Future Publication (2011)	2.5 4.4 6.3 6.4 6.5
Paper III	C. J. Wallnerström and L. Bertling, "Learning from Experiences of the prior Swedish Electrical Distribution System Regulation – Reference Material when Developing the Future Regulatory Incentives", Conference on Innovative Smart Grid Technologies (ISGT) Europe 2010, Göteborg, Sweden, October 2010	3.1 3.3
Paper IV	C. J. Wallnerström and L. Bertling, "Laws and Regulations of Swedish Power Distribution Systems 1996-2010 – Learning from novel approaches as less good experiences", CIRED Workshop, Lyon, France, June 2010	3.1 3.3 4.2 4.4
Paper V	C. J. Wallnerström and L. Bertling, "A Sensitivity Study of the Swedish Network Performance Assessment Model Investigating the Effects of Changes in Input Data", the 19th International Conference on Electricity Distribution (CIRED), Vienna, 21-24 May 2007	3.2
Paper VI	C. J. Wallnerström and L. Bertling, "Investigation of the Robustness of the Swedish Network Performance Assessment Model," IEEE Trans on Power Systems, vol. 23, pp. 773-780, May 2008	3.2
Paper VII	C. J. Wallnerström, A. Isenberg, J. Setréus and P. Hilber, "The Potential of Using Equivalent Comparison Standards to judge Effectible Costs in Electrical Distribution Tariff Regulation", CIRED 2011, June 6-9 2011, Frankfurt, Germany	4.3

Paper VIII	C. J. Wallnerström, J. Hasselström, P. Bengtsson and L. Bertling, "Review of the Risk Management at a Distribution System Operator", 10th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), May 25-28 2008, Rincón, Puerto Rico	5.1 5.2
Paper IX	C. J. Wallnerström and L. Bertling, "Risk Management Applied to Electrical Distribution Systems", CIRED, Prague, 2009	5.1 5.2
Paper X	C. J. Wallnerström, J Setréus, P. Hilber, F. Tong and L. Bertling, "Model of Capacity Demand under uncertain Weather", PMAPS, Singapore, June 2010	6.2

Author's contributions in appended papers

Professor Lina Bertling and Doctor Patrik Hilber have contributed as supervisors, which for example include input of ideas and reviews of draft versions. The author of this thesis has written and contributed to the major parts of all appended papers with these three exceptions:

- L. A. Tuan has written Chapter 5 in Paper I.
- All authors of Paper VII have collectively worked on a project resulting in a Swedish technical report [1] on which Paper VII is based.
- Paper X is mostly based on a Master of Science thesis by F. Tong, supervised by the author of this thesis, who also performed the major parts of the "conversion" work.

Paper VIII is partly based on interviews with Jörgen Hasselström and Per Bengtsson.

Additional information on appended papers

- Paper V, Paper VI, Paper VIII and a previous version of Paper III (entitled "Review of the Swedish Network Performance Assessment Model", modified and updated during 2010) were appended to the licentiate theses [2] together with [3].
- Paper I is partly based on parts of [4] which the author of this thesis has written and on material from the licentiate theses that have never been included in any papers.
- Paper V is mostly based on [5].
- Paper VI is mostly based on [6].
- Paper III is partly based on [7], [8] and [5].
- Paper VII is mostly based on [1].
- Paper VIII and Paper IX are quite similar. Both are, however, appended since Paper VIII is twice as large (more details, theory and examples), while Paper IX is more updated.

Additional publications not appended

Papers:

- H. Rinnemo, C. J. Wallnerström, M. Abdul-Rasool and P. Hilber, ”An Example of Investment Planning of Power Distribution using Quantitative Reliability and Cost Analyses” [9]
- J. Setréus, C. J. Wallnerström, P. Hilber, C. Böös and R. Göransson, “RACalc – a Power Distribution Reliability Tool A student project towards an open source reliability software for electrical distribution systems” [10]
- P. Hilber, C. J. Wallnerström, J Rosenlind, J Setréus and N. Schönborg, “Risk analysis for power systems - overview and potential benefits” [4]
- J. Setréus, C. J. Wallnerström and L. Bertling, “A Comparative Study of Regulation Policies for Interruption of Supply of Electrical Distribution Systems in Sweden and UK” [3]
- L. Bertling, M. Larsson and C. J. Wallnerström, “Evaluation of the customer value of component redundancy in electrical distribution systems” [11]

Other publications in English:

- C. J. Wallnerström, “On Risk Management of Electrical Distribution Systems and the Impact of Regulations” [2]
- L. Bertling and C. J Wallnerström, “Exercises on reliability assessment of electric power systems” [12]
- L. Bertling, P. Hilber, J. Jensen, J. Setréus and Carl Johan Wallnerström “RADPOW development and documentation” [13]

Other publications in Swedish:

- C. J. Wallnerström, “En jämförande studie av tillförlitlighetsmodeller för elnät – en utvärdering av Nätnyttomodellens tillförlitlighetsmetod” (~“A comparative study of reliability assessment models for electrical distribution systems and evaluation of the method in the Network Performance Assessment Model”) [7]
- P. Hilber, C. J. Wallnerström, J. Setréus and A. Isenberg, “Potentiell användning av standardkostnader i regleringen av elnätsföretagens löpande påverkbara kostnader”, (~“The Potential of Using Equivalent Comparison Standards to judge Effectible Costs in Electrical Distribution Tariff Regulation”) [1]
- L. Bertling and C. J Wallnerström, “Nätnyttomodellens tillförlitlighet med avseende på små förändringar i indata”, (~“Evaluation of the reliability of the Network performance assessment model”) [6]

- C. J. Wallnerström, "Algoritm för uppskattning av den maximala effekten i eldistributionsnät - med avseende på Nätnyttomodellens sammanlagringsfunktion", (~"An algorithm for the maximal simultaneity power through power lines with regard to the method in The Network Performance Assessment Model") [8]
- C. J. Wallnerström and L. Bertling, "Känslighetsanalys av Nätnyttomodellens indata", (~"Sensitiveness analysis of input data for the Network performance assessment model") [5].

Contents

TILLÄGNAD

Tommy Hjorth

*13. 3. 1980

†17. 2. 2004

"Guds gåva är evigt liv"

”Av dessa äro två egenskaper hos etern och två egenskaper hos elektronen. Dessa naturkonstanter bilda ett i dimensionshänseende fullständigt system och jag vill kalla dem de fyra världskonstanterna.

[…]

De fysikaliska grundenheterna måste vara minst fyra. Däremot torde man ej med samma stränghet kunna veta att fyra i framtiden, då kanske många nya fysikaliska upptäckter gjorts, skola visa sig till fyllest. Efter vad man nu vet synes dock intet skäl föreligga att tro att mer än fyra behövs.”

Erik G. Hallén, ”Elektricitetslära”, 1953

”Enligt en […] utredning skola Sveriges vattenfall efter reglering av vattenföringen kunna tillsammans lämna […] mer än fem gånger den effekt, som för närvarande uttages. Tack vare de »vita kolen», synes det alltså vara väl sörjt för vårt lands framtida energibehov.”

[…]

”Till grund för sådana tariffer ligger bl. a. det förhållandet, att kostnaderna för den elektriska strömmens framförande till abonnenten kunna anses vara av två slag, nämligen dels amorteringen av det kapital, som åtgått för verkets anläggning och ledningsnätets framdragande, dels de direkta driftkostnaderna. Men även andra faktorer spela in. Sålunda måste man taga hänsyn till konkurrensen från andra energikällor, t. ex. kol och ved, varför den till industrin […] brukar åsättas ett relativt lågt pris, medan man anser sig kunna begära mer för den ström, som åtgår till belysning – ett område, där elektriciteten ju redan utträngt alla konkurrenter.”

Herlin E., ”Elektricitet till husbehov”, Stockholm 1930

vvvvvv

Chapter 1

Introduction

1.1 Background

Several risks are associated with electric power distribution systems (DS). This thesis focuses on risks related to customer outages. Reliability analysis methods have been proposed in several studies as the primary tool to handle this category of risks [14], [15]. Traditionally, the research and the development of reliability analysis methods have focused on generation and transmission [16]. However, several studies have shown that most of the customer outages are due to failures at the distribution level [17], [18], [19]. Furthermore, there is an international tendency towards adopting new performance-based tariff regulation methods [20], [21]. Hence, the focus on customer outages has increased and consequently the interest in introducing reliability assessment applied to DS. An increased fear of more extreme weather events in the future, following from the current climate-change debate, focuses additional attention on reliability and risk analysis in DS, which are often vulnerable to weather conditions. An example of an event which had a large impact on the public opinion in Sweden is the severe storm called Gudrun (by the Norwegian Meteorological Institute) or Erwin (by the German Weather Service) [22]. This storm struck the southern part of Sweden on January 8-9 2005 and caused the interruption of supply for approximately 450 000 customers. About one year after this event, a Swedish law on the compensation for power supply outages lasting longer than 12 hours was established [23]. Other countries, such as the UK, have also adopted new laws on customer compensation that work in parallel with the regulation of customer network tariffs [24].

To meet current and future requirements, new methods and tools to perform good risk analyses are needed [25], [26]. Risk management is commonly used, e.g. for studies of nuclear power plants, air pollution and dams. However, the use of quantitative approaches to DS is limited, if existing at all. A solution could be to introduce comprehensive reliability analysis methods as input to the development of the risk management adopted by the distribution system operators (DSOs). For all types of methods with underlying models, there is a need to balance the complexity of the details with necessary input data, and the resources needed to put the models into practice. In the end there is always a need for the right incentive to make available needed resources in person-hours and data. Hence, experience both from the industry and from more theoretical academic methods could be valuable to incorporate into the development work. A first step is to examine possible risks and different incentives within the risk management (such as regulations). One specific reason in Sweden for developing risk methods applied to DS is a law applied from 2006 which obliges every DSO to report annually on performed risk and vulnerability analyses. However, regardless of this obligation, there is still a strong motivation to develop quantitative and knowledge-based methods.

1.2 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 [27]. High costs associated with maintenance, combined with extreme demands for safety, motivated the development of a more systematic maintenance planning. This method has then spread to other industries, for example the electric power industry [28]. At KTH, School of Electrical Engineering, research into developing RCM has been conducted for about ten years. The aim is to develop a more analytical (quantitative) RCM-method, adjusted to electric power systems, referred to as RCAM (Reliability Centered Asset Management) [29]. The development of RCAM includes generation [30], [31], power distribution [1], [32] and transmission systems [33], [34]. Component life time modeling [35] [36], system reliability analysis methods and component priority methods [37] are studied and further developed. This research is collected in the RCAM research group [4]. The theory presented in Chapter 2 of the thesis intends to supplement other theses within the RCAM research group:

- **Lina Bertling**, "Reliability Centred Maintenance for Electric Power Distribution Systems", Doctoral Thesis 2002 [19].
    - RCM and other maintenance management in general
    - Modeling of life distribution functions
    - Reliability modeling of urban power distribution systems
- **Patrik Hilber**, "Maintenance Optimization for Power Distribution Systems", Doctoral Thesis 2008 [32].
    - Component reliability importance indices
    - Maintenance optimization (multi-objective approach)
- **Tommie Lindquist**, "On reliability and maintenance modelling of ageing equipment in electric power systems, Doctoral Thesis 2008 [35].
    - Reliability modeling of power system components
    - Bayes' Theorem
- **Johan Setréus**, He presented his Licentiate Thesis 2009 [34] and he plan to defend his PhD thesis in October 2011 entitled "Identifying Critical Components for System Reliability in Power Transmission Systems".
    - Risk and reliability methods applied to power transmission systems
    - Roy Billinton / Reliability Test System (RBTS)
- **Julia Nilsson**, "On Maintenance Management of Wind and Nuclear Power Plants", Licentiate Thesis 2009 [30].
    - Failure Mode and Effect Analysis (FMEA)
    - RCM
    - Production (nuclear and wind power)

- **François Besnard**, "On Optimal Maintenance Management for Wind Power Systems", Licentiate Thesis 2009 [31].
    - Basic reliability theory, including Markov theory
    - Mathematical optimization
    - Wind power
- **Johanna Rosenlind**, Licentiate Thesis planed during 2012.
    Reliability modelling of transformers

1.3 Objectives and scientific contribution

1.3.1 Objectives

The overall objective is to investigate risks followed by incentives affecting the risk and asset management of power distribution systems (DS) such as tariff regulation. Furthermore, the thesis also aims to propose the first step of developing a quantitative analysis method, integrated with investment and maintenance planning in DS.

1.3.2 Scientific contribution

The scientific contribution of this thesis can be divided into four parts:

1. Analyses and documentation of the previous Swedish tariff regulation.
    a. A comprehensive description of the Network Performance Assessment Model (NPAM) and its underlying theory; knowledge to be used in future developments of regulatory models, both by learning from novel approaches of the NPAM and from other experience of this model.
    b. Development of a statistical method evaluating the robustness of regulation models applied on the NPAM.
2. An investigation on current and known future incentives for the Swedish DSOs, for examples studies related to the upcoming tariff regulation from 2012 and the law on compensation for long outages.
3. A review of current investment planning and risk management at a DSO.
4. A quantitative vulnerability analysis method including statistical validation analysis framework applied to DS.

1.4 Thesis outline

Chapter 2 introduces theory associated with risk and asset management applied to DS.

Chapter 3 and Chapter 4 investigate Swedish laws and regulations between 1996 and 2012 which affect DSOs to learn from history as well as to analyze existing incentives.

Chapter 5 investigates current project planning and risk management at a Swedish DSO.

Chapter 6 proposes vulnerability analysis method including investigation of correlations and characteristics of DS, a comprehensive case study and examples of how to use results from the method in practice.

Chapter 7 concludes the thesis and proposes ideas for the future.

Chapter 2

Risk Methods and Asset Management

 Jonas Merian, http://www.jonasdesign.net

Chapter 2 provides an introduction to risk and asset management applied to power distribution. This includes: (a) identified characteristics of power distribution systems which are important to take into consideration (section 2.1), (b) aspects of input data (section 2.2), (c) definitions and an overview of existing risk assessment approaches (section 2.3), (d) reliability analyses applied to power distribution (section 2.4), (e) introduction of a new reliability analysis index framework and a statistical evaluation model (section 2.5), (f) cost analysis methods useful to combine with e.g. reliability analyses (section 2.6) and asset management applied to power distribution (section 2.7).

2.1 Power distribution systems

2.1.1 The Swedish power system

The Swedish Power system is divided into three main levels: transmission, regional (sub-transmission) and local power distribution systems (DS). Informally, these three levels are often defined differently in different contexts. However, by Swedish law [23], a regional power line is formally defined by two criteria that must be fulfilled: (a) <220 kV and (b) subject to line concession. Hence, local power distribution systems are power systems <220 kV which are not subject to line concession (i.e. subject to area concession) and transmission systems are all power systems ≥220 kV.

In many contexts, the transmission system is defined as everything operated by the Swedish national grid (Svenska Kraftnät) which is almost consistent with the formal definition. At local DS level, there are about 160 DSOs in Sweden, while almost every regional (sub-transmission) DS is owned by Vattenfall, Eon or Fortum (2-3 more DSOs own regional DS). Several voltage levels (e.g. 33 and 70 kV) can formally be defined as either regional or local DS. Often, however, the voltage level is more important than formal legal definition in analysis. The following additional informal definition is often used by Swedish DSOs (see e.g. Paper VIII):

- Low voltage (LV), 0.4 kV.
- Medium voltage (MV), 1-25 kV (in Sweden 6, 11 or 22 kV).
- High voltage (HV), >25 kV (many DSOs do not own regional DS, but DS at these voltage levels).

2.1.2 A historical review of the Swedish power system

Transmission and distribution of electricity is considered a natural monopoly, i.e. an infrastructure unreasonable to open for competition from an economic perspective (as in e.g. road, water and sewage). For historical reasons, there are several DSOs of varying size and ownership structure (state, municipal or private), which have a concession for the distribution of defined areas (local DS) or specific lines (regional DS). The concession means a privilege with rights, but also with several obligations, which are governed by laws and regulation. Energy Markets Inspectorate (EI) monitors that the legislations are followed, i.e. that customers have access to the DS and that the service meets quality requirements with reasonable non-discriminatory tariff levels. Previously, the trading of electricity was integrated into the operation of DS, but in 1996, the Swedish electricity market was deregulated; the transmission and distribution infrastructures were hence separated from production and trade.

The Swedish national grid (Svenska Kraftnät) took over ownership, operation and responsibility for the transmission system (from having been a part of the state-owned Vattenfall), while the concession for the lower voltage levels continued as before, to be divided among a few hundred companies with completely different circumstances. The result was that electricity customers could choose freely between suppliers, but not DSO.

2.1.3 Characteristics to consider in risk management

Compared with other technical systems, electric power distribution systems (DS) have special characteristics (not all of them are unique for DS) affecting the risk management that must be taken into consideration when developing new methods:

- The entire society including almost all infrastructures are dependent on reliable distribution of electricity [38].
- An event could affect a greater area of the system than the locally affected part, since failures have to be disconnected according to the safety aspect for humans and equipment (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 by one event.
- Some components such as overhead lines are significantly exposed and vulnerable to weather events (e.g. lightning, snow and wind), and this has an effect along the system when failure occurs, and those effects need to be dealt with.
- DS are operated as local regulated monopolies. The incentives for new investments in risk reduction could become different compared with non-monopolies, i.e. strongly dependent on the regulation.
- DS are connected to other electric 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.

2.1.4 Overall risk categories

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

1. Risks of breaking any environmental or safety law.
2. Risks of customer outages which lead to repair costs, but also direct and indirect costs related to the outage such as customer compensation.
3. Risks of other events that imply a repair cost, but no customer outages.

These categories are based on severity. This thesis additionally proposes a classification of risk policies based on DS category (e.g. on voltage level), see section 5.3.

2.2 Input data, standard costs and test systems

Regardless of analysis method, the results never can be more reliable than the input data allows. Good and comprehensive data are, however, often expensive or sometimes even impossible to collect. Different analysis strategies based on the input data available are proposed in section 2.2.1 together with an example of reliability data which are based on empirical material from the application study presented in section 6.4. Section 2.2.2 exemplifies a comprehensive cost directory (*EBR*) used by Swedish DSOs since the 1960s as input in investment- and maintenance planning. In some kinds of analysis, predefined test systems with predefined input data can be advantageous, which is treated in section 2.2.3.

2.2.1 Details of reliability data

This section is based on Paper I and [4].

Good, comprehensive input data is expensive, and sophisticated analysis based on detailed data demands even more resources. A common solution is to use mean values, which is the case in, for example, the calculation of well-established indices such as SAIDI [17]. However, there are significant disadvantages connected to the use of mean values in the analysis. For example, using mean restoration time does not take into account all possible behaviors of a consequence. Four different approaches to handling mean values, with advantages and disadvantages, are shown in Table 1 to illustrate this fact.

Table 1 – Approaches to handling mean values in reliability analyses

Strategy/approach	Advantages	Disadvantages
1. Only use one mean value	Easily manageable and well-established models.	Does not consider all possible events, only the mean value.
2. Estimate a statistical distribution based on a single mean value	Captures all consequences, data easy available.	More complex than1; the distribution is not always a suitable description of the real behavior.
3. Dividing the failures into categories	Relatively simple, easy to adjust the complexity according to purpose.	More work with data collection and processing, discrete model, not spanning all possible events.
4. Estimate the better suiting distribution	Gives results close to the reality.	Complex, costly and time consuming.

Table 2 provides an example of the third approach, dividing outages into two failure categories. The failure rates are based on over 50 000 historical outages over eight years at 0.4 kV and 11 kV levels. The longer-than-12-hour values stem from rare events, affecting system reliability indices to a small extent. The result is that the events causing these longer outages could be missed when the DSO works towards better reliability indices based on average values. When looking at average values at the 0.4 kV level, it might be assumed that underground cables cause more longer-than-12-hour outages, but as can be seen in Table 2, the overhead lines are more problematic. This illustrates the value of applying the third approach, *i.e.,* if our main concern is long outages, then we should focus on overhead lines.

Table 2 – Failure rates divided into short (0.05-12 hours) and long outages (>12 hours)

Component	Failure rate[1]	[%][3]	Failure rate[2]	[%][3]
Overhead line 0.4 kV	0.0668 ±0.0025	0.8	0.0150 ±0.0012	3.4
Overhead line 11 kV	0.1169 ±0.0027	61.3	0.0086 ±0.0008	92.2
Underground cable 0.4 kV	0.0395 ±0.0014	1.1	0.0034 ±0.0004	0.5
Underground cable 11 kV	0.0281 ±0.0020	7.0	0.0002 ±0.0002	0.4
Secondary substation	0.0107 ±0.0007	3.8	0.0006 ±0.0002	0.2
Other/unknown	-	26.1	-	3.3

[1]Number of outage 0.05-12 hours/year, km/station with 95 % confidence interval.
[2]Num. of customer outage ≥12 hours/year, km/station with 95 % confidence interval.
[3]Contribution to total outage time caused by the category of failure.

2.2.2 Annually published standard costs

This section is based on Paper VII.

Since the 1960's, Swedenergy has annually published an EBR (elbyggnadsrationalisering, ~electrical construction rationalization), aimed to rationalize planning, investments and maintenance of power systems [39], i.e., to provide rational "standards" when constructing power systems. One important part of the EBR publication is the calculated costs for different activities. EKM (ekvivalenta ledningsmått, ~equivalent line measures) units are entirely based on costs in EBR. Consequently, to investigate EKM, the underlying EBR calculations must be reviewed. This study has included both interviews with EBR at Swedenergy and studies of EBR materials. EBR consists of six aggregation levels (P1-P6), affecting each other from bottom to top; see Figure 1. P1-P3 and parts of P4 are reported in the annual EBR publications.

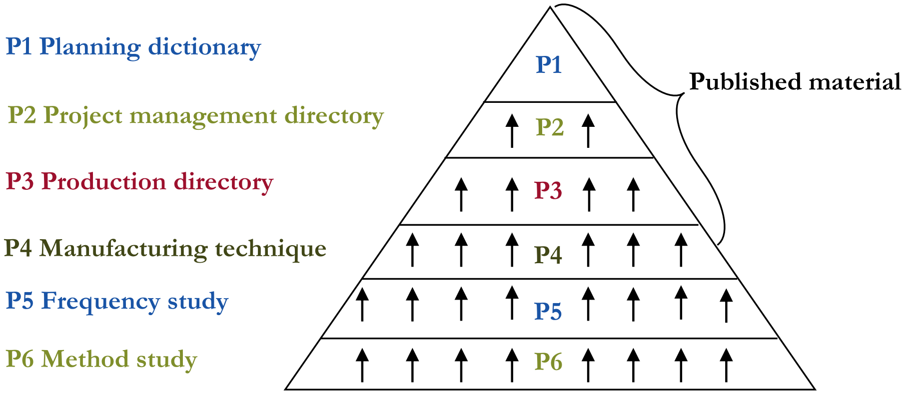


Figure 1 – The structure of EBR

Underlying frequency and time studies (P5 and P6) are partly based on interviews with different DSOs, partly on methodological studies in which Swedenergy conducted field studies. The number of underlying studies differs, but is often only a few. According to interviews with Swedenergy [1], the reason is the difficulty finding voluntary DSOs because it is both time- and resource consuming. In EBR, the costs are divided into the following categories: (a) work, (b) material, (c) machine, (d) equipment and (e) other. "Other" includes building permit costs [8]. EBR does not include common costs such as overall administration and research. The recommendation is to add 3-8 %.

2.2.3 Benefits of using test systems

This section is partly based on Paper I.

Using common international test systems could be useful for valuable exchange of ideas and knowledge among countries, researchers and companies. There is a great deal of work involved in creating good test systems satisfying many requirements. Hence, one obvious benefit is that the use of a pre-defined test system, if possible, saves time compared with creating a new model for each analysis or study. If no test system satisfies the required aspects, it could still be easier to modify an existing system than to create a completely new one. Moreover, if a locally developed model is used instead, all data used must be published, since all academic studies must be replicable, while an internationally published test system could simply be referred to. For academic projects, test systems provide the possibility to objectively compare research results, e.g., comparisons of different methods or different software.

One of the best-known and most widely used test systems in power system engineering is the IEEE Reliability Test system (IEEE-RTS) which was developed in 1979 by the IEEE Subcommittee on the Application of Probability Methods [40]. This system was created to compare different reliability methods, but only at the generation and/or transmission level. The system was later enhanced in 1996 to reflect changes in evaluation methodologies and to overcome perceived deficiencies [41]. Another well-known test system is the Roy Billinton (or ReliaBility) Test System (RBTS), which was developed during the 90s. It is smaller than the IEEE-RTS, but with every load bus defined at the distribution level [42], [43] (included voltage levels: 230/138/33/11 kV). An overall picture of RBTS at the transmission level is provided through Figure 2 and Table 3.

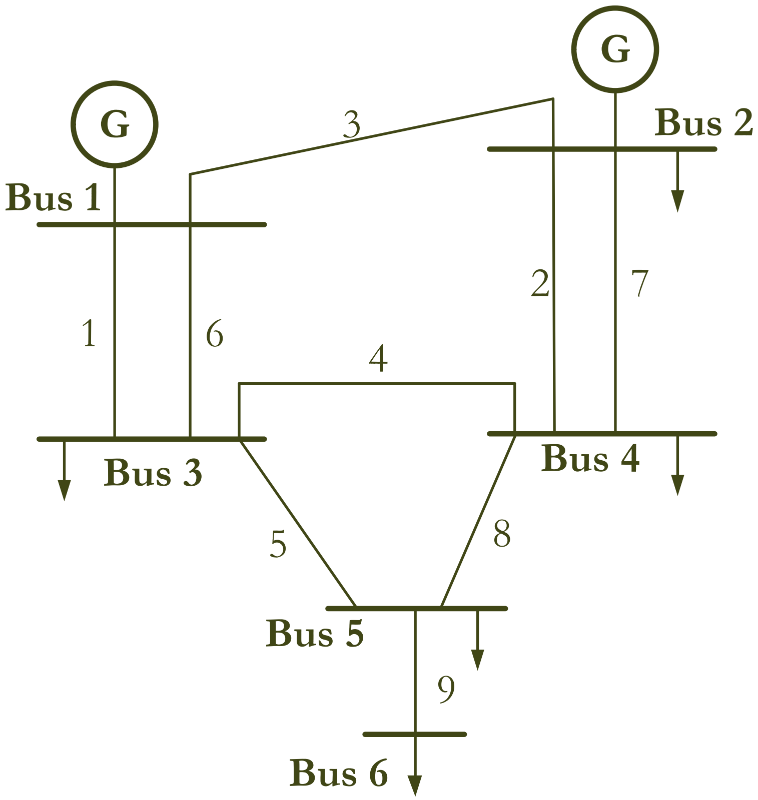


Figure 2 – The overall structure of RBTS at the transmission level [44]

Table 3 – Overall picture of RBTS

Bus	Number of customers	Overall characteristics of the load bus
2	1 908	Typical urban and close to generation, 20 MW peak load
3	5 805	Typical industrial and other large customer, 85 MW peak load
4	4 779	Typical urban, 40 MW peak load
5	2 858	Typical urban, 20 MW peak load
6	2 938	Typical rural system, 20 MW peak load

The future development of power systems is characterized by changes on both the supply and the demand side. On the supply side, the power system is integrating more power generation from renewable sources, both small-scale and large-scale. On the demand side, the load characteristics are changing with more nonlinear loads, and the demand side can also function as both consumers and as small producers, e.g., ideas of how future hybrid electric vehicles could be used as energy reserves based on the electricity price. The changes in the supply and the demand side would definitely force changes in the transmission level. High voltage DC system (HVDC) development is among the most discussed topics in the field today. The whole power system is moving in the direction of what is referred to as the "Smart Grid". With these changes, the requirements for the test system would also need to change.

The major disadvantage of international test systems is that there are often significant differences between countries, between areas within countries or even sometimes between two DS with similar objective conditions. Hence, when DSOs perform analyses, unlike researchers, for instance, they prefer their own input data if it exists, or at least input data from a DS with similar conditions. Recently, two test systems were developed adjusted to typical Swedish conditions: urban and rural [45].

2.3 Risk and vulnerability assessment

2.3.1 Definition of risk and vulnerability

This section is partly based on Paper I and Paper VIII.

Risk

According to a current ISO and IEEE standard [46] 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 [46] could be used as an overall framework in the development of risk methods applied to DS, but they are, however, broad. For example, [15] discusses the risk concept in DS and shows 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 (see section 2.1.1). Another paper, [14], proposes using reliability assessment within risk management. A risk analysis could be performed using three questions [25]:

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

Vulnerability

Vulnerability is related to risk, but is a more relative concept, often used in comparative studies of different infrastructure designs or states. Moreover, the vulnerability concept is widely used in other, significantly different contexts than analyzing important infrastructures, for example in environmental research [47] and computer security research [48]. The latter is an example of analyzing targeted attacks that indirectly can severely affect power systems, while vulnerabilities of random events are investigated in this thesis. Vulnerability has no commonly accepted definition [49]. A definition of system vulnerability suitable to use in this thesis is provided in [50]: "the system's inadequate ability to withstand an unwanted situation, limit the consequences, and recover and stabilize after the occurrence of the situation".

2.3.2 Risk communication

This section is partly based on Paper VIII and Paper IV.

Risk communication – general definition

Risk communication is an important part of the risk management to internally motivate projects, for instance, and to receive higher acceptance and good-will effects from other stakeholders such as customers. Risk communication could be defined as "exchanging or sharing of information about risk between the decision maker and other stakeholders" [25]; where a stakeholder is "any individual, group or organization that can affect, be affected by, or perceive itself to be affected by, a risk" [46].

Risk communication – examples of incentives affecting DSOs in Swedish

According to risk management used by Swedish DSOs, risk communication could be divided into three categories:

1. **The regulating authority:** According to Swedish law, every DSO must perform annual risk and vulnerability analyses including an action plan. Other kinds of information-sharing are also partly regulated [23].
2. **Internal:** The projects have to be motivated with regard to decreased risks and to cost-effectiveness. Goodwill effects must sometimes internally be estimated and included to make single project profitability.
3. **Customers:** It is important, both during the project planning and afterwards, to increase acceptance and goodwill.

From 2008, information about extensive outages has to be reported to the Swedish regulator within 14 days. The aim is to allow the quality of electricity supply to be assessed. Outages are defined as extensive if any one of the following criteria is fulfilled:

- >24 hours and involves more than 1 000 customers or 25 % of the customers.
- >12 hours and involves more than 10 000 customers or 50 % of the customers.
- >2 hours and involves more than 100 000 customers.

2.3.3 Examples of risk analysis methods

The examples in this section exemplify methods used in probabilistic risk assessment, but these are neither complete nor consistent (some could be considered as a sub-category to another listed method or in some other way related to each other). Often combinations of these are used.

- Overall risk charting / expert assessments see section 2.3.4.
- Risk matrix, see section 2.3.4.
- Reliability analysis, see section 2.4.
- Methods using Bayes' Theorem, e.g. [26], [51].
- Markov analysis, e.g. [52], [53].
- Fault tree analysis; see section 2.3.5.
- Event tree analysis; see section 2.3.5.

- Failure mode and effects analysis (FMEA), e.g. [53].
- Simulation methods, e.g. [26], [54].

Together with requirements and time horizon, the amount of input data often determines the preferred risk analysis method. This is illustrated in Figure 3 and differs, of course, greatly between areas and context, but often methods which require low amounts of input data are used by the industry, such as overall risk charting based on expert assessments.

Figure 3 – Illustrative example of methods used in risk assessment

2.3.4 Overall risk charting and risk matrix

A simple, but commonly used definition of the risk value [53] is exemplified in equation (2.1), where *P* is a number associated with a determined probability category, while *C* is a number associated with a determined 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).

$$Risk\ value = P * C \tag{2.1}$$

A common approach to assessing a risk or comparing and prioritizing risks is the use of *risk matrices* [55]. This approach has been used by the electric power industry in Sweden, for example as part of the risk management of regional distribution systems at a DSO (see Chapter 5). The probability and the consequence are first estimated and divided into settled categories. The categorization could be made by either 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 risk matrix is exemplified in Table 4 (which illustrates that the *risk value* is not necessarily defined as in equation 2.1). This risk matrix was used as part of an RCM (see section 1.2) method applied to hydro power generators in Sweden. If the risk value is 3 or more, a preventive maintenance strategy will be recommended; see [56].

Table 4 –A risk matrix exemplified from the RCM of hydro power generators [56]

Consequence / **Probability**	A Minor	B Average/Serious	C Severe/Catastrophic
Failures occur more often than once a year	2 / 3 Safety, Efficiency loss, Environmental	4	5
Failures occur in intervals of between 1 and 20 years	2	3	4
Failures occur in intervals of between 20 and 50 years	1	2 / 3 Safety	3
Failures occur in intervals of over 50 years	0	1	2 / 3 Interrupted production, flooding

A risk category based on the characteristic of its consequence could be an additional valuable input to the prioritizing of risks and their further management. It is not always obvious that two risks with the same resulting location in the matrix should be handled equally. This is exemplified in Table 4, where, for example, safety risks are sometimes prioritized higher and handled differently 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 are not always) 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 for handling them (e.g. low risk value → no action; high → investment needed). Measures like cost per reduced risk value could be defined and used; 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.

2.3.5 Fault and event trees

Fault trees are used to estimate the probability of a risk, while the event tree investigates the consequence [53]. The fault-tree approach is to define an unwanted event (e.g. system outage) and then figure out possible steps towards this event connected with logical operators, "creating a tree growing upside down". At the bottom, the tree ends with base events, which are all assigned a probability. Following the tree up, using the logical operators together with simplified probability theory, a probability of the "top event" is calculated straight-forwardly. This is exemplified in Figure 4. One benefit is that risk-reducing action can easily be evaluated, i.e. how they affect the base events in the tree (eliminate, replace or reduce the probability). A drawback is that complex analyses result in large trees that are difficult to handle; however, computer programs exist that make large fault trees more manageable.

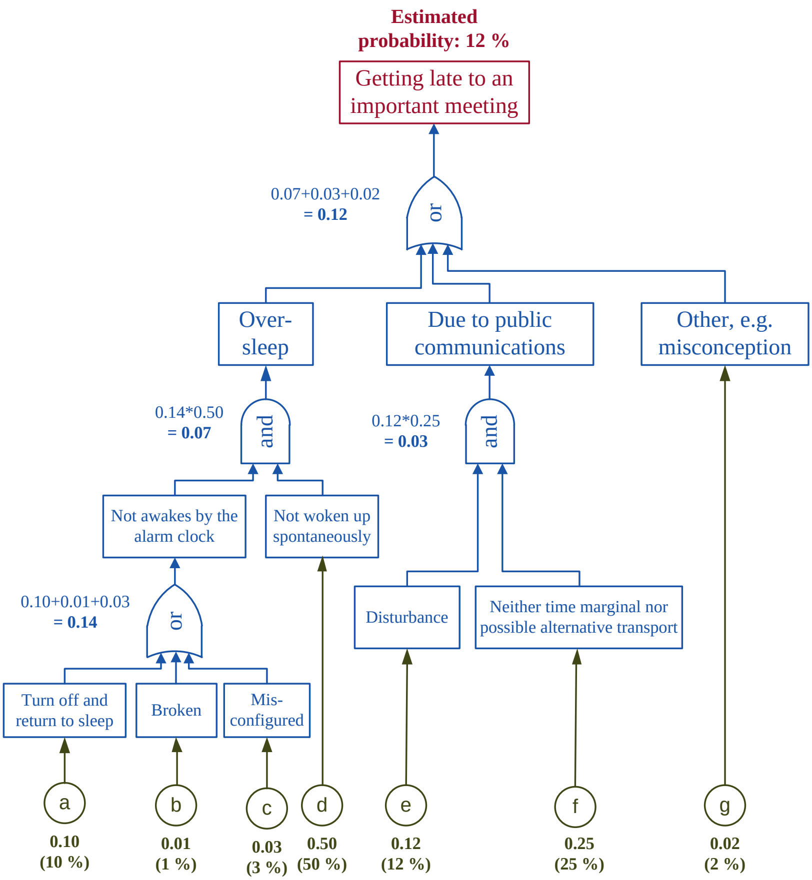


Figure 4 – Example of a fault tree

Block diagrams, often used in reliability analysis, are directly related to fault tree analyses; fault trees could easily be transformed to block diagrams and vice versa; see Figure 5.

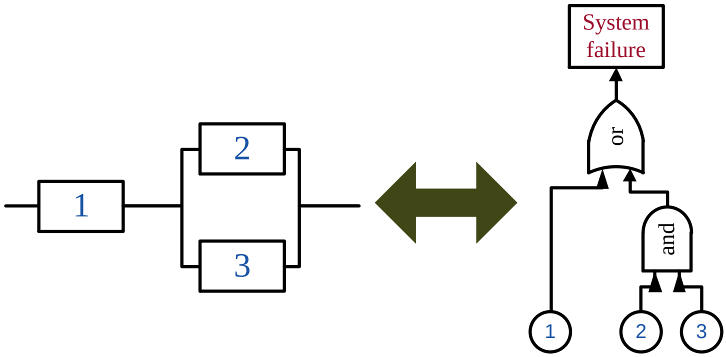


Figure 5 – Connection between failure trees and block diagrams e.g. in reliability analysis

Event trees assume that an unwanted event has occurred (i.e. not considered the probability) and analyzes possible effects by sorting out different possible sequences of events using questions with only "yes"- and "no-answers" [57], e.g. if a protection is working properly. All "yes"- and "no-answers" are assigned probabilities. Different "end events" can then be calculated. Figure 6 illustrates an example of an *event tree*.

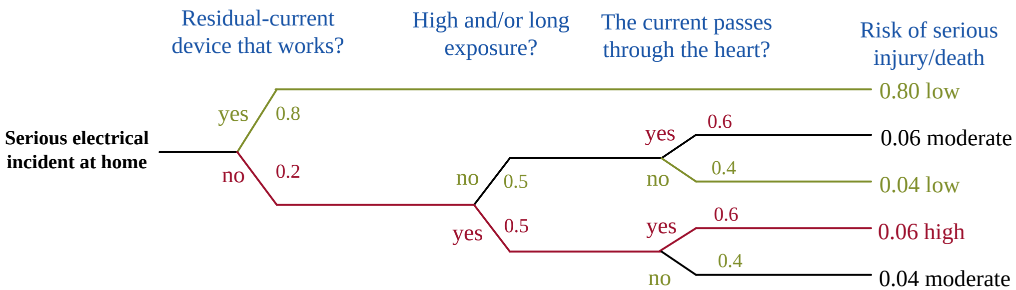


Figure 6 – Example of an event tree

Fault trees and *event trees* could be connected to each other, where the former analyzes the probability of an event, and the latter its possible consequences, see Figure 7.

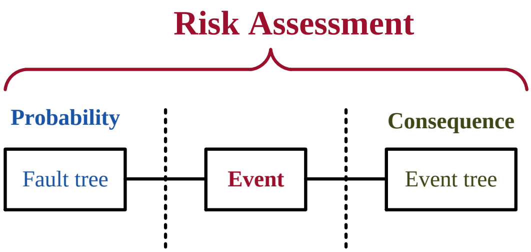


Figure 7 – Fault tree in relation to event tree within risk assessment

2.3.6 Common cause failure

In analyses, failures are often assumed to be independent. In reality, this is not always the case [58]. Assumed redundancy is not appropriate to use in all contexts. A fire in a double transformer station could affect both transformers; a severe storm could affect several feeders at the same time in a DS and so on. Actually, it is often more likely that a dependent event affects both parts of a redundant system compared with the probability of two independent events which occur simultaneously [59]. A method for handling these kinds of dependent events is to introduce "common cause failures" [53], which are assigned their own probabilities. Figure 8 exemplifies how this can be integrated into a simple reliability model. If β % of the failures is considered as common cause, then the resulting failure rate of a system consisting of two equal parallel components can be calculated as:

$$\lambda_S \approx \left(\frac{100-\beta}{100}\lambda\right)^2 + \frac{\beta}{100}\lambda, \text{ where } \lambda \text{ is the failure rate of a single component.} \quad (2.2)$$

A common approach (but unconventional) if no other contradicting data exists, is to assume β equals 20 % [53].

More generally, a redundant system of N components, with individual failure rates λ_i and a common cause failure rate of λ_{cc}, gives:

$$\lambda_{system} \approx \prod_i^N (\lambda_i - \lambda_{cc}) + \lambda_{cc} \quad (2.3)$$

Note, "$restouration\ time \ll \frac{1}{\lambda}$" is always assumed.

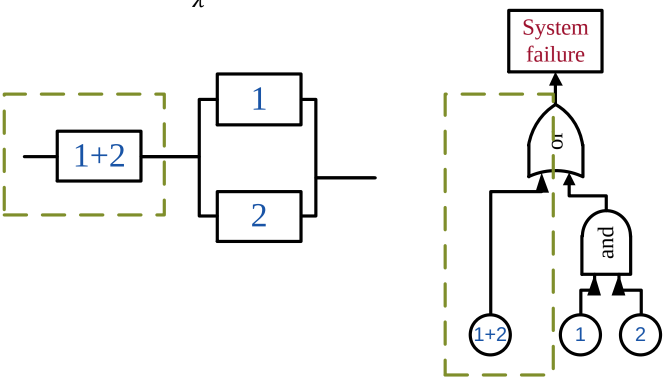


Figure 8 – Example of modeling common cause failures

2.4 Reliability analysis applied to power distribution

Trustworthy reliability analysis demands many historical fault events and is therefore not applicable in many risk analysis contexts such as flight and nuclear, with low probabilities and major consequences. A commonly used solution is to study *incidents* and assume the dependency between incidents and "real" events. Customer outages in power supply are less severe but more likely to occur than in many other fields; hence, reliability analysis is a possible approach. Reliability analysis methods applied to power distribution are introduced in this section, but are treated in more detail in several other publications, e.g. [60], [61] and [52]. In this thesis, analytical reliability analysis is used. An alternative approach is to use Monte Carlo simulation [54], where stochastic events are simulated, for example, to simulate dependency between failure rates and weather conditions [62].

2.4.1 Definitions

- *Reliability* is "the ability of a component or system to perform required functions under stated conditions for a stated period of time [63]".
- *Redundancy* is "more than one independent opportunity for a piece of equipment to carry out a desired function [64]"; 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 [60].
- *Failure* is "the termination of the ability of a component or system to perform a required function [63]". However, there are sometimes more than the two states (failure and function) needed to be modeled. For single components, Markov analysis can be used, for instance, while reliability indices (introduced in section 2.4.2) consider that parts of a system can be in failure mode.
- A *customer outage* is traditionally defined in Sweden as an interruption of the electric supply ≥0.05 hours (3 minutes) affecting one or more customers. 0.05 hours is defined according to the earlier Swedish regulations [65]. However, recently outages <0.05 hours have also been reported to the regulator, but these will probably not be included in the first version of the quality function used within the new tariff regulations from 2012 (see section 4.2.2) and are separately reported (and probably in the future separately handled in laws and regulations).

2.4.2 Reliability terms and theory used in this thesis

In Sweden, power distribution is often operated radially. Sometimes switching to alternative feeders is possible, but the normal operation is still radial with *open point*s [28]. The average outage time is significant smaller than the average time between outages (i.e. when customers receive electric energy). This characteristic is used to approximate the reliability calculations to deduce useful indices appropriate to apply on DS. Markov theory (see e.g. [60]) is used to deduce approximate derivations, resulting in the following equation of the unavailability of load *point i* (LP_i):

$$U_i^{serial}[hours/year] \approx [r \ll \tfrac{1}{\lambda}] \approx \textstyle\sum_j \lambda_{ij} r_{ij}, \tag{2.4}$$

λ_{ij} is the failure rate that component j affects LP_i with a customer outage; r_{ij} is the average restoration time:

$$\lambda_i^{serial}[1/year] \approx [r \ll \tfrac{1}{\lambda}] \approx \textstyle\sum_j \lambda_{ij}, \tag{2.5}$$

$$r_i[hours] = \frac{U_i}{\lambda_i}. \tag{2.6}$$

In reliability calculations, component failures are often assumed to be independent from each other (section 2.3.6 introduces an approach to handling dependences). When a component fails, 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 weighted according to number of customer affected or electric power affected). A selection of these reliability measures is provided here, with a focus on those which are commonly used in regulations and by DSOs [61], see Table 5.

Table 5 – System indices

$System\ Average\ Interuption\ Duration\ Index\ (SAIDI)$	$\frac{\sum_i U_i N_i}{\sum_i N_i}$	$[\frac{hrs}{yr}, cust]$	(2.7)
$System\ Average\ Interuption\ Frequency\ Index\ (SAIFI)$	$\frac{\sum_i \lambda_i N_i}{\sum_i N_i}$	$[\frac{int}{yr}, cust]$	(2.8)
$Customer\ Average\ Interruption\ Duration\ Index\ (CAIDI)$	$\frac{SAIDI}{SAIFI}$	$[\frac{hrs}{int}, cust]$	(2.9)
$Energy\ Not\ Supplied\ index\ (ENS)$	$\sum_i (U_i\, L_{a(i)})$	$[\frac{kWh}{yr}]$	(2.10)
$Average\ Energy\ Not\ Supplied\ index\ (AENS)$	$\frac{ENS}{\sum_i N_i}$	$[\frac{kWh}{yr}, cust]$	(2.11)
$Average\ System\ Availability\ Index\ (ASAI)$	$\frac{8760 \sum_i N_i - \sum_i U_i N_i}{8760 \sum_i N_i}$	$[prob.]$	(2.12)
$Average\ System\ Unavailability\ Index\ (ASUI)$	$1 - ASAI$	$[prob.]$	(2.13)
An additional index used by a DSO (see Chapter 5) is: $Customer\ outage\ minutes$	$\sum_i U_i N_i = (60\ SAIDI \sum_i N_i)$	$[minutes\ /year]$	(2.14)

N_i is equal to number of customers in LP_i

λ_i is failure rate in LP_i

$L_{a(i)}$ = average load connected to LP_i

Protection equipment such as fuses and breakers can have a stuck probability. This can be considered in the calculation when required by modifying failure rates:

$$\lambda_i = \lambda_i^{if\ normal} * P(normal) + \lambda_i^{if\ hidden\ failure} * P(stuck) \qquad (2.15)$$

For example, if a breaker with the probability of 95 % fully protects *LPx* from failures of overhead line Y which has a failure rate of 0.20 failures/year; then: $\lambda_{that\ Y\ affect\ LPx} = 0 * 0.95 + 0.20 * 0.05 = 0.01 failures/year$.

If an alternative feeder can only sometimes be used (e.g. depending on load), this can be considered by calculating the average restoration time:

$$r_{average} = r_{scenario\ 1} * P(scenario\ 1) + r_{scenario\ 2} * P(scenario\ 2) + \cdots \qquad (2.16)$$

For redundant systems:

$$\lambda_i^{redundant}[1/year] = \frac{(\prod_j \lambda_{ij})(\sum_j r_{ij})}{1+\sum_j \lambda_{ij} r_{ij}} \approx \left(\prod_j \lambda_{ij}\right)\left(\sum_j r_{ij}\right) \qquad (2.17)$$

$$U_i^{redundant}[hours/year] \approx \prod_j \lambda_{ij} r_{ij} \qquad (2.18)$$

$$r_i^{redundant}[hours] \approx \frac{\prod_j r_{ij}}{\sum_j r_{ij}} \qquad (2.19)$$

The equation of unavailability for the special case of two components, 1 and 2 (e.g. double transformer stations), is consequently:

$$\lambda_i^{parallel}[1/year] \approx \lambda_1 \lambda_2 (r_1 + r_2) \qquad (2.20)$$

$$U_i^{parallel}[hours/year] \approx \lambda_1 \lambda_2 (r_1 + r_2) \qquad (2.21)$$

$$r_i^{parallel}[hours] = \frac{r_1 r_2}{r_1 + r_2}. \qquad (2.22)$$

2.4.3 Protection failures

Protection equipment, e.g. breakers, fuses and disconnectors, should improve the reliability, protect components and/or ensure the safety laws. However, these components can fail in different ways, which make reliability analysis much more extensive [57]; sometimes, therefore, these components are assumed as perfect.

Categories of protection failures:

- *Hypersensitive*, i.e. a breaker, for example, opens when not required. It can be modeled to include an extra failure rate with a restoration time. The consequence is often less severe than “normal” failures,; unlike these, they do not affect other protection equipment and the restoration time is often (not always) lower.
- *Stuck probability (a kind of hidden failure)*, i.e. it does not perform its task when demanded (stuck). It can be modeled with a probability, see *equation 2.15*.
- *Information and control system failures* (not included in this thesis).

In addition, these components can, of course, be affected by ordinary failures (e.g. short circuit) like other component categories (e.g. cables and transformers), which are modelled in the same way as these.

2.4.4 Example of reliability calculation

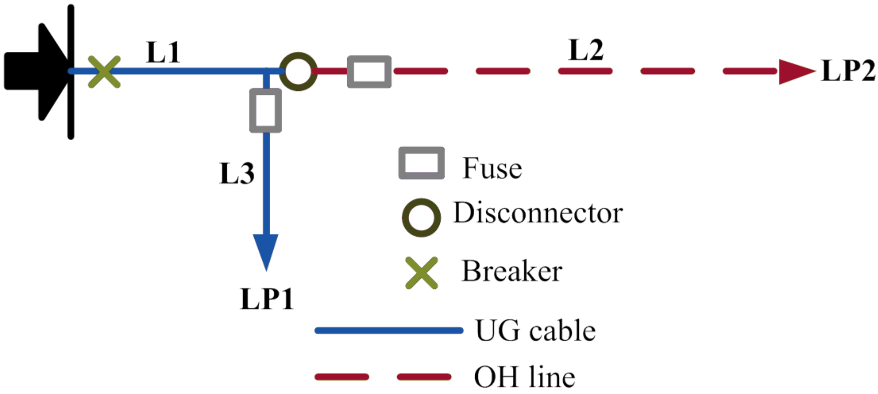


Figure 9 – System model within example of reliability calculation

Input data to system model in Figure 9:
OH line: 0.15 failures/year, km; repair time 5 hours.
UG cable: 0.06 failures /year, km; repair time 8 hours.
Breaker: hypersensitive 0.01 times/year on average (30 minutes recovery time)
Disconnector: 0.01 failures/year; repair time 10 hours; can disconnect 95 % failures within 1 hour.
Fuses: blows with the probability of 40 % (when short circuit – and not in case of ground fault); hypersensitive 0.01 times/year in average (90 minutes recovery time).

Feeders (OH lines and UG cable):

Feeder	L1	L2	L3
Length [meter]	500	1 500	1 000

Load points:

	Number of customers	Average annual consumption
Lp1	4 500	10 000 kWh/customer
Lp2	1 000	50 000 kWh/customer

Task:
Calculate SAIDI, SAIFI, CAIDI, ENS, AENS, ASAI and ASUI.

Solution:

Calculate and arrange feeder data:

Feeder	λ_{Li} [failures/yr]	r_{Li} [hours]
L1	0.030	8
L2	0.225	5
L3	0.060	8

Calculate and arrange possible categories of incidents leading to outage:

NO	*Component*	*Consequences*
1	L1	Outage in all load points 8 hours
2	L2	Outage in LP2 5 hours; probability of 60 % for outage in LP1, i average 0.95*1 + 0.05*5 = 1.2 hours
3	L3	Outage in LP1 8 hours; probability of 60 % for outage in LP2 8 hours
4	Disconnector	Outage in all load points 10 hours
5	Fuse (L2)	Outage in LP2 1.5 hours
6	Fuse (L3)	Outage in LP1 1.5 hours
7	Breaker	Outage in all load points 0.5 hours

Calculate annual average consumption per load point:

LP1 = 45 GWh and LP2 = 50 GWh

Calculate for each load point:

	LP1				**LP2**		
	λ_{L1} [f/yr]	r_{L1} [h]	U_{L1} [h]		λ_{L2} [f/yr]	r_{L2} [h]	U_{L2} [h]
1	0.030	8.0	0.240	1	0.030	8.0	0.24
2	0.135	1.2	0.162	2	0.225	5.0	1.125
3	0.060	8.0	0.480	3	0.036	8.0	0.288
4	0.010	10.0	0.100	4	0.010	10.0	0.100
5	-	-	-	5	0.010	1.5	0.015
6	0.010	1.5	0.015	6	-	-	-
7	0.010	0.5	0.005	7	0.010	0.5	0.005
Σ	**0.255**		**1.002**	**Σ**	**0.321**		**1.773**

Calculate reliability indices:

$$SAIFI = \frac{4500*0.255+1000*0.321}{5500} \approx 0.267 \text{ outages/year, customer}$$

$$SAIDI = \frac{4500*1.002+1000*1.773}{5500} \approx 1.142 \text{ hours/ year, customer}$$

$$CAIDI = \frac{4500*1.002+1000*1.77}{4500*0.255+1000*0.321} \approx 4.278 \text{ hours/outage}$$

$ASAI = \frac{5500*8760-(4500*1.002+1000*1.773)}{5500*8760} \approx 0.9998696$ (i.e. ~99.987 % availability)

$ASUI \approx 1 - 0.9998696 \approx 0.0001304$ (i.e. ~0.013 % unavailability)

$ENS = \frac{45\,000*1.002+50\,000*1.773}{8760} \approx 15.27$ MWh/year

$AENS = \frac{45\,000*1.002+50\,000*1.773}{8760*5500} * 1\,000 \approx 2.78$ kWh/year, customer

2.4.5 Reliability analysis of regional and transmission systems

Compared with local DS, transmission and in some cases regional DS have fewer outages, but often much more severe possible consequences. Furthermore, these systems are seldom operated radially as are local DS (see also section 5.3 where different risk strategies are proposed). Therefore, other kinds of measures are more suitable than the reliability indices introduced in section 2.4.2:

- Expected Energy At Risk (EEAR) [MWh] is the expected amount of demanded energy that cannot be delivered without overloading transmission equipment. [66]
- *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 [67]. This is a commonly used criterion applied to transmission systems, but could also be applied as an internal goal or requirement to regional DS (see, for example, Chapter 5). The 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.) [64]".
- *N-m criterion:* the N-1 criterion can, of course, be generalized to an optional requirement of number of components.
- Johan Setreus, a member of the RCAM research group, has developed a method whereby each transmission component is assigned a risk and vulnerability measure which is based on three separate indices that include the system impact on (i) transmission security, (ii) load and (iii) generation. The associated impact of the component on (ii) and (iii) is determined by its contribution to well-established system reliability indices. The impact on (i) is determined by the component's contribution to causing small margins or overloads in critical transfer sections. A small margin or overload in transfer congestion does not necessarily result in customer disconnections, or blackout, but stresses the security margin towards system collapse. This method will be presented within his PhD thesis which is planned to be defended during 2011. An early version of the method has been published [33].

2.5 Introduction of a new reliability analysis framework

2.5.1 Introduction of a new reliability index framework – R_T

This section is based on results from Paper II.

A new reliability index category, R_T, is introduced (see equation 2.18), flexible enough to adjust to different laws regarding long outages (see e.g. section 4.4.1) or DSO policies (see e.g. Chapter 5) of long outages. R_T is the average number of outages above T hours during one year and 1 000 customers (the last-mentioned motivated to avoid values <<1).

$$R_T = 1\,000 \frac{\sum_i (\lambda_{\geq T,i} N_i)}{\sum_i N_i} \; [int./year \;\; 1\,000\, cust.], \tag{2.23}$$

where $\lambda_{\geq T,i}$ is the sum of customer outages/year in LP_i caused by outages $\geq T$ hours and N_i is number of customers in LP_i. The Swedish and the UK customer compensation laws are compared in [3] (see section 4.4.2). The Swedish customer compensation does not take customer category or weather condition into consideration, while in the UK, the customers are separated into two categories (domestic and non-domestic) and different compensation levels are used for different weather conditions. Examples of R_T related with costs are provided in Chapter 6.

In Sweden, 12 and 24 hours are important time limits, i.e. R_{12} and R_{24}, while 18 hours, i.e. R_{18}, is the limit of the first compensation level in the UK. If an outage interval, T1 to T2, is of interest (e.g. 12-24 hour outages which is the first compensation level in the Swedish legislation), this is provided by calculating $R_{T1} - R_{T2}$. See section 4.4.1.

2.5.2 Example of using R_{12} and R_{24}

This example is taken from [4] (constructed by the author of this thesis) based on the same input data as used in Paper II.

Sweden has legislation regarding outages longer than 12 hours and a functional requirement of 24 hours. Consequently, 12 and 24 hours are important limits for Swedish DSOs in maintenance and investment planning, see section 4.4.1. Figure 10 presents results from an ongoing application study showing the expected number of outages longer than 12 hours as a function of changed mean outage time. The current expected number of long outages (>12 hours) per year is 136, affecting 1 000 customers, i.e. R_{12} = 136 (see equation 2.23). If an investment is estimated to reduce the average outage time by 1 hour, R_{12} will decrease to 121, while the opposite will increase R_{12} to 151 long outages per year and 1 000 customers. The figure shows how the probability of long outages could be affected by investments (or savings). This could, for example, be a valuable input to asset management of investment and maintenance planning.

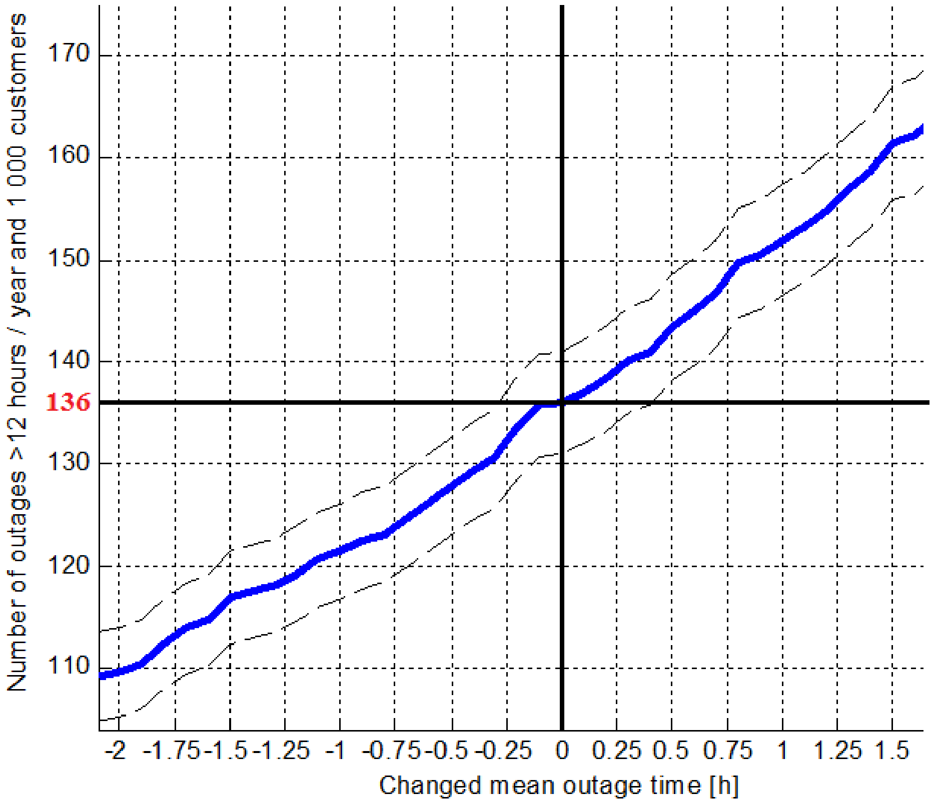


Figure 10 – Number of outages longer than 12 hours as a function of changed average outage time including 95% confidence interval.

The results presented are based on statistics of failures between 2001 and 2008 which occurred in a Swedish DS with approximately 150 000 customers. Other results from this study are presented in Chapter 6.

2.5.3 Statistical validation

This section is based on a section in Paper II.

Using reliability indices applied to DS is well-established in different contexts. However, these indices could be based on few measurements followed by a high statistical uncertainly, especially the new category of indices introduced in section 2.5.1, which depends on extensive outages (hence often with less historical data to rely on). Therefore, a statistical model is proposed for evaluating reliability indices as a function of amount of input data. During a defined period, a stochastic number of reported outages occur and the reliability indices can thus be written as:

$$Z = c\sum_{i=1}^{X} Y_i = cX\sum_{i=1}^{X} Y_i/X = cX\bar{Y}. \text{ where:} \tag{2.24}$$

- Z is a stochastic variable representing an index.
- c (>0) is a constant.
- X is a stochastic variable representing the number of measurements.
- Y_i is a meter-reading (i.e. numerical value) from the i[th] measurement in which all Y_i are assumed to be mutually independent, equally distributed stochastic variables with expected value μ_Y>0.and $\bar{Y}$ is the mean value of all Y_i.

Suppose that the outcome of X becomes m reported outages of a certain category; then the following can be assumed:

$$X \in Po(m). \text{ where } E(X) = m \text{ and } \sigma_X = \sqrt{m} \tag{2.25}$$

For large m. the following approximations can be made:

$$X \in N\left(m.\sqrt{m}\right) \text{ and } Z \approx c\mu_Y X \tag{2.26}$$

$$\text{Define } \mu_Z = c\mu_Y m \rightarrow Z \in N\left(\mu_Z.\ \frac{\mu_Z}{\sqrt{m}}\right) \tag{2.27}$$

One appropriate measure of uncertainty for stochastic variables is the coefficient of variation [68], c_V, which is defined as the ratio of standard deviation and expected value:

$$c_V = 100\frac{\frac{\mu_Z}{\sqrt{m}}}{\mu_Z} = \frac{100}{\sqrt{m}}[\%] \tag{2.28}$$

Statistical analysis can be performed; for instance, a 95 % confidence interval can be calculated as:

$$\mu_Z \pm 1.96 c_V \mu_Z \tag{2.29}$$

2.6 Cost analyses

The theory introduced in this section is largely based on Swedish course material for"EG209U Technology for Distribution of Electric Power" – part 3 at the Royal Institute of Technology, in which the author of this thesis gave lectures between 2007 and 2010.

2.6.1 Costs and incomes

Investment costs are balanced against risk reduction in the cost analyses proposed in this thesis. Incomes can be handled as negative costs and risk reduction can either directly or indirectly be translated into costs (see e.g. section 4.4). Examples of costs to consider in risk- and asset management applied to DS are:

- *Investment and capital costs*, e.g. depreciation and cost of restricted capital.
- *Outage costs*: This category of costs includes customer outage compensations (see section 4.4.1) and repair costs.
- *Cost of operation and maintenance*: Costs within this category could increase or decrease followed by an investments. For example, new components such as redundant lines can entail more costs in maintenance and operation, but replacement of overhead lines with underground cable could instead lead to lower maintenance costs.
- *Costs and incomes after the economic life time (residual values and/or residual costs)*: Potential incomes are, for example, the value of the raw material such as copper, and potential 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 in the goodwill.
- *Other costs*: For example, electric power losses and reactive compensations needed in the DS if the amount of underground cable increases.

2.6.2 Economic lifetime

A typical economic life time for DS components is often above 30 years for feeders and transformers, for instance, but could vary a great deal. It is important to distinguish between "*Economic lifetime*", "*technical life time*" and "d*epreciation*".

Factors that determine the economic lifetime:

1. Technical life time, which often depends on age, but also on maintenance, usage, load etc.
2. A technical development, i.e. the component becomes "outdated", leading to, or example, shortage of spare parts.
3. Changed usage pattern such as increased load (e.g. a transformer becomes too small); however, this often gives the old component a residual value

It is often allowed and economically advantageous to apply a shorter depreciation time than economic lifetime.

2.6.3 Discount interest rate

The *discount interest* rate is set by the company board in order to compare investments separated in time. Typical questions:

- What is the interest rate on loaned capital?
- What is the financial return on alternative investments?
- How risky is the investment?

The discount interest rate can significantly vary among companies and lines of business; often, high risk → higher interest [69]. If an investment is expected to provide too low a financial return, the same money could just as well be used for other things (e.g. paying off debts). A commonly used approach is the *weighted average cost of capital WACC*, where a weighted average between the interest on debt and the demanded return on shareholders' capital are produced; shareholder demands depend on the financial risk and taxes.

2.6.4 Considering inflation

Real calculations: discount interest rate (Z_r) [%] at which inflation (i) [%]is not considered.
Nominal calculations: discount interest rate (Z_i) [%] at which inflation (i) [%] is considered.
The relationship between Z_r and Z_i is:

$$\left(1+\frac{Z_n}{100}\right)=\left(1+\frac{Z_r}{100}\right)\left(1+\frac{i}{100}\right) \tag{2.30}$$

Sometimes, the following approximation is adequate:

$$\frac{Z_n}{100}\approx\frac{Z_r}{100}+\frac{i}{100} \tag{2.31}$$

2.6.5 Capital cost calculation – example

If an investment is 1 million SEK, the discount interest rate is 5% and a straight-line depreciation (which is most common) is set at 10 years, the capital cost is: 150 000 SEK the first year ($\frac{1\,000\,000}{10} + 1\,000\,000 * 0.05$), 145 000 SEK the second year ($\frac{1\,000\,000}{10} + (1\,000\,000 - 100\,000) * 0.05$), 140 000 SEK the third year ($\frac{1\,000\,000}{10} + (1\,000\,000 - 200\,000) * 0.05$) and so on over ten years.

2.6.6 Net present value method

Note that the interest *Z* has the unit percent. To shorten equations in this thesis, *q* and *p* are defined as:

$$q = 1 + \frac{Z1}{100},\ p = 1 + \frac{Z2}{100}, \tag{2.32}$$

The basis of the net present value [70] method is discounting, i.e. moving incomes and costs in time. This could be illustrated by the following question: *"How much money should be put in the bank today, with the interest z %, to obtain C, in n years?"*

$$C_{net\ present\ value}(z_1, n) = q^{-n} C_n = NPF(z_1, n) C_n \tag{2.33}$$

Equation 2.23 provides the answer to this question,; where, C_n is an economic value year *n*, $C_{net\ present\ value}$ is the net present value, $NPF(z_1, n)$ is the net present factor as a function of year *n* and *interest* z_1. Figure 11 exemplifies net present value calculation.

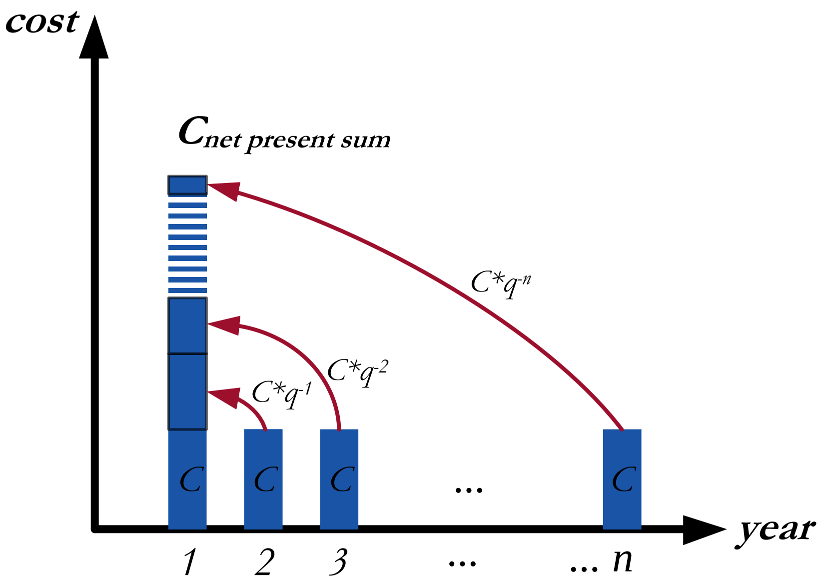


Figure 11 – Illustration of net present value calculations

Often, an annual constant cost or income is associated with an investment analyzed, e.g. a revenue or a rent. Instead of calculating the net present value for each year, equation 2.34 can be used to calculate the net present sum over *n* years.

$$C_{net\ present\ sum}(z_1, n) = \frac{q^n}{\frac{z1}{100}q^n} C_{annual\ value} = NPS(z_1, n)C_n \tag{2.34}$$

$C_{annual\ value}$ is the annual cost (income can be modeled as a negative cost) during *n* years, $C_{net\ present\ sum}$ is the sum of all net present values regarding *n* years, $NPS(z_1, n)$ is the net present sum as a function of year *n* and *interest* z_1. Figure 11 exemplifies net present value calculation.

The assumption of a constant annual value (cost, income...) is not always appropriate, e.g. it is often valid to assume an annual price increase (Figure 12). Equation 2.35 can be used to calculate the net present sum of a cost, which increases by z_2 % each year during *n* years, with the interest z_1.

$$C_{net\ present\ sum}(z_1, z_2, n) = \frac{p*(p^n - q^n)}{q^n(p-q)} C_{year\ 1} = NPS(z_1, z_2, n)C_n \tag{2.35}$$

$C_{year\ 1}$ is the value the first year.

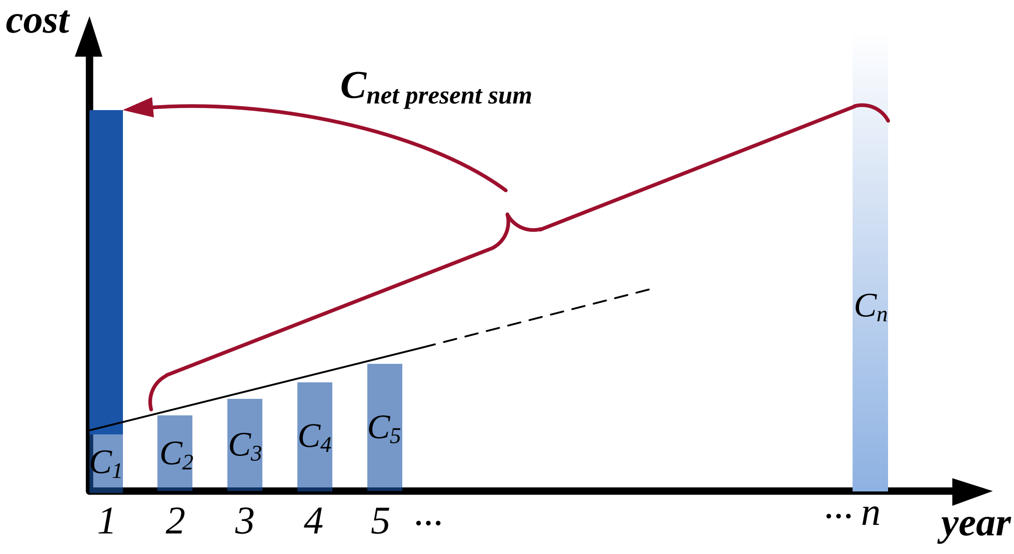


Figure 12 – Net present sum assuming annual constant cost/income increment

A constant annual encasement of current (z_2 %) in a power line gives a quadratic annual increase of the losses. The cost of future losses (possible changes in the electricity price are not considered) can be calculated by using the following equation:

$$C_{net\ present\ sum}(z_1, z_2, n) = \frac{p^2*(p^{2n} - q^n)}{q^n(p^2-q)} C_{year\ 1} \tag{2.36}$$

Assume an investment during the first year and a first operation cost model during *year 1* to *year* n_k; a reinvestment during *year* n_k and a new second operation cost model (e.g. decreased losses after reinvestment) during *year* n_k to *year* N, where N is the economic lifetime. These kinds of problems can be solved by first discounting costs and incomes during *year* n_k to *year* N, to the *year* n_k, and then discounting received value to *year 1* together with the sum of incomes and costs between *year 1* and *year* n_k as shown in Figure 13.

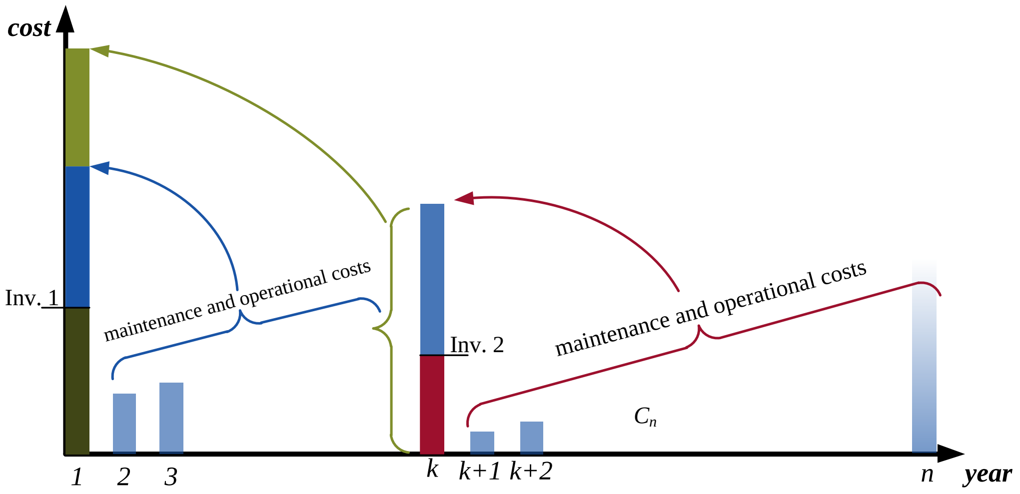


Figure 13 – LCC example with several investments during the time period

2.6.7 Equivalent annuity method

Annuity is a periodic amount to cover the repayments and interest costs during a specified period of *n years*. The equation for constant annuity is:

$$a^{constant}(z1,n) = \frac{\frac{z1}{100}}{1-q^{-n}} \tag{2.37}$$

This gives an annual cost consisting of annuity of the investments costs and operational costs (and any other costs):

$$C_{annual} = a^{constant}(z1,n)C_{investment} + C_{operation} \tag{2.38}$$

Example:
If the investment cost is 50 000 SEK and the interest rate is 7 %, then the annuity factor for a period of ten years is: $a^{constant} \approx 0.1424$. If the annual operational cost is 5 000 SEK, then the total cost is (0.1424*50 000 + 5 000) SEK/year; see Figure 14.

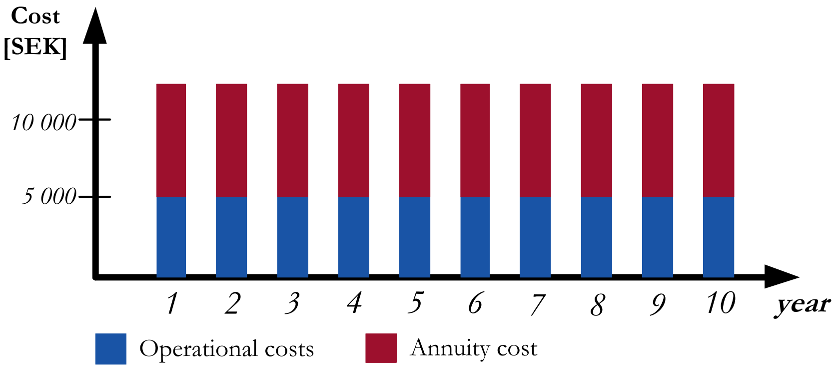


Figure 14 – Example of annuity calculation

2.6.8 Payback method

The *payback method* (also referred to as "the payoff method") is appropriate as an overall estimation of how rapidly an investment pays off. A *payback period* (i.e. repayment time) is the number of years until the accumulated surplus (receipts - payments) becomes equal to or larger than the initial cost. If the payback period is estimated to be shorter than the economic lifetime, the investment is considered as profitable. This method does not consider interest and therefore fits best on relatively short-term projects in a first overall estimation.

Assume that the payback period is T and the investment cost is C_I. If the annual payment surplus is considered constant $C_{surplus}$, the following equation can be used:

$$T = \frac{C_I}{C_{surplus}} \tag{2.39}$$

If the surplus, $C_{surplus\ i}$, varies between years, T has to be estimated from the following equation, where C_I is included in $C_{surplus,1}$ as a cost (negative surplus):

$$\sum_{i=1}^{T} C_{surplus,i} = 0 \tag{2.40}$$

2.6.9 Internal rate of return

The *internal rate of return* is related to the *present value method*. The *internal rate* is defined as the interest rate that gives the sum of all total net present values equal to zero. $C_{surplus\ i}$ is defined in the same way as the *payback method* (see section 2.6.8).

$$\sum_{i=1}^{N} \frac{C_{surplus,i}}{\left(1+\frac{internal\,rate\,[\%]}{100}\right)^i} = 0 \tag{2.41}$$

2.7 Asset management

Asset management can be summarized as the art of finding a balance between *risk*, *cost* and *performance*. [51]

2.7.1 LCC analysis

Life Cycle cost (*LCC*) is the annualized cost of an investment during its entire economic lifetime. This often includes costs of investments, outages, maintenance, interests and possible incomes (i.e. negative costs). An *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 economic lifetime (*N*) is limited by the technical lifetime, technical developments and expansions in the DS (often giving a positive residual value). Equation 2.42 provides a general definition of the total *LCC* of an investment and includes the following terminology:

- C_{LCC} is the total *Life Cycle Cost* of a project, taking the interest into consideration.
- z is the interest rate in percent determined by the company (often per year).
- C_I is the investment cost during the first year.
- C_i is the estimated sum of all costs during *year i*, which are associated with the project and which includes incomes etc. modeled as negative costs (e.g. revenues).
- *R* is the sum of all residual values after the economic lifetime including residual costs (which are modeled as negative residual values).

$$C_{LCC} = C_I + \sum_{i=1}^{N} \frac{C_i}{q^i} - \frac{R}{q^N},\ q = \frac{1+z}{100} \qquad (2.42)$$

One benefit of LCC is the flexibility it allows to set the level of simplifications depending on the purpose. Typically, the costs are assumed to be gathered at the beginning of a year. Several equations are defined which could facilitate the calculations; see e.g. section 2.6.6.

The overall aim of the RCAM research group (see section 1.2 and section 2.7.3) is to perform cost optimizations of the entire lifetime of an investment. However, there are several challenges when applying LCC integrated with other analyses of DS if every required aspect is to be taken into consideration. For example, it is difficult to determine accurate estimations of the failure rate (λ) as a function of age and corrective maintenance when performing maintenance management using LCC.

2.7.2 Example of LCC calculation

Problem:

The owner of a power distribution system is considering investing in a new power line to improve the reliability in an area with high outage cost. During the past years, the average outage cost was 150 000 SEK/year, which is assumed to be representative of a normal year. An LCC analysis is to be performed (using nominal discount rate) to roughly estimate the maximum investment cost allowed (unprofitable projects are not performed). Expect a real discount rate of 8 % and an inflation of 4 %. Expect a lifetime of 35 years and a residual value of 10 % of the investment cost. The new power line will generate an increased maintenance cost of 100 000 SEK every 10th year (not in the first year) and a reduction in the outage cost by 90 %. The cost differences in service and loss are considered negligible. Assume the following (fictional) factors affecting the outage cost:

- *50 % of the total outage cost is expected to increase by 5 % each year during the next 35 years.*
- *The remaining 50 % of the total outage cost is expected to remain unchanged over the next 15 years, then a doubling of this cost will occur (i.e. from year 15 this cost increases from 75 000 to 150 000 SEK if no new investment is made and from 7 500 to 15 000 SEK with the investment).*

Solution:

LCC_1 = LCC cost without any investment
LCC_2 = LCC cost with proposed investment

Requested: The critical investment cost (I) which gives $LCC_1 = LCC_2$.

Calculate the nominal interest rate ($z_{nominal}$):

$$z_{nominal} = (1 + 0.08)(1 + 0.04) - 1 \approx 0.1232\ (12.32\ \%)$$

Calculate net present factors (NPF) and sums (NPS) needed using equations 2.33-2.35 in section 2.6.6:

$$NPF(10,\ 0.1232) = \frac{1}{1.1232^{10}} \approx 0.313$$
$$NPF(15,\ 0.1232) = \frac{1}{1.1232^{15}} \approx 0.175$$
$$NPF(20,\ 0.1232) = \frac{1}{1.1232^{20}} \approx 0.098$$
$$NPF(30,\ 0.1232) = \frac{1}{1.1232^{30}} \approx 0.031$$
$$NPF(35,\ 0.1232) = \frac{1}{1.1232^{35}} \approx 0.017$$
$$NPS(15,\ 0.1232) = \frac{1.1232^{15}-1}{0.1232*1.1232^{15}} \approx 6.70$$
$$NPS(20,\ 0.1232) = \frac{1.1232^{20}-1}{0.1232*1.1232^{20}} \approx 7.32$$
$$NPS(35,\ 0.1232) = \frac{1.1232^{35}-1}{0.1232*1.1232^{35}} \approx 7.98$$

$NPS^{(a)}(35,\ 0.1232,\ 0.05) = \frac{1.05*(1.05^{35}-1.1232^{35})}{1.1232^{35}(1.05-1.1232)} \approx 13.43$
(a) net present sum with a constant annual increment of 5 %.

Net present cost calculations:

- $R = rest\ value = 0.1\ NPF(35,\ 0.1232)I = 0.0017I$
- $M = sum\ of\ increased\ maintenance\ during\ all\ 35\ years = 100\ 000\big(NPF(10,\ 0.1232) + NPF(20,\ 0.1232) + NPF(30,\ 0.1232)\big) = 44\ 200\ SEK$
- $OC_1 = 74\ 000 NPS(35,\ 0.1232\ \ 0.05) = 1\ 007\ 470\ SEK$
- $OC_2 = \begin{Bmatrix} year\ 1-15 = 75\ 000NFS(15,\ 0.1232) \\ year\ 15-35 = NFS(15,\ 0.1232)(2*75\ 000NFS(20,\ 0.1232)) \end{Bmatrix} = 502\ 500 + 192\ 150 = 691\ 650\ SEK.$

$LCC_1 = OC_1 + OC_2$
$LCC_2 = I + 0.1(OC_1 + OC_2) + M - R = 0.9983I + 0.1(OC_1 + OC_2) + M$
$LCC_1 = LCC_2 \rightarrow I = \frac{0.9(OC_1+OC_2)-M}{0.9983} = \frac{0.9(1\ 007\ 470+691\ 650)-44\ 200}{0.9983} \approx \mathbf{1\ 487\ 500}$

The maximum accepted investment cost is **1 487 500 SEK**.

2.7.3 Reliability-centered asset management

Reliability-centered asset management (*RCAM*) is based on Reliability Centered Maintenance (RCM [27]). The major difference compared with traditional RCM is the use of quantitative methods. The aim of the approach is to find a relationship between reliability and the effect of asset management actions. The overall goal is to develop plans that are *optimal* according to the total cost of the system by creating a good balance between corrective maintenance (i.e. waiting to act until the consequence occurs), condition-based maintenance (e.g. inspections of equipments investigating the condition or measuring methods of the cables' condition) and predetermined maintenance (i.e. scheduled maintenance).
The process of **RCAM is divided into three stages** [29]:

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, e.g. *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.

2.7.4 How to handle uncertainties

A common solution is to have a margin, e.g. to increase the cost of capital. A margin can, however, affect the cost effectively of an investment.

Relevant questions to consider [69]:
What is the impact if the investment totally fails?
What are the relevant costs to liquidate or change the direction of unsuccessful projects?

Methods to handle uncertainties:

1. **Apply margins**, e.g. increased discount interest rate.
2. **Sensitivity analyses**; see examples in e.g. section 3.2 and [71].
3. **Risk Analyses**; see section 2.3.

Traditionally, the DSOs have been allowed to cover their costs by customer tariffs, regardless of cost efficiency. In such a regulation, applying margins in investments is a relatively easy and possible solution. However, from the late 90s, the Swedish regulator has tried to implement incentives of cost efficiency and reliability by re-regulations and additional laws which are described in Chapter 3 and Chapter 4. To manage this new paradigm, the DSOs need to apply more advanced analysis methods. These methods can be based on theory introduced in this chapter. In Chapter 5 and Chapter 6 analysis methods applied to DS are investigated.

"Black swans": Before the Europeans discovered Australia, the term was used to describe something impossible; then it was realized that such existed. Now the term has been adopted by current risk theory to describe surprising events with major impact, in which risks not previously predicted occur. How to handle black swans is perhaps the most important challenge within risk management.

Chapter 3

Learning from the previous Swedish Tariff Regulation

 Cleas Böös and Tom Ericsson

Chapter 3 investigates the Network Performance Assessment Model (NPAM) that was a model used by the Swedish regulator of DS tariffs. This includes the background and underlying theory (section 3.1), studies of the robustness (section 3.2) and the "fall" of the model (section 3.3). The model was novel and complex as well as criticized (e.g. by studies included in this thesis) and finally abandoned. Therefore, this chapter hopefully provides valuable lessons (from novelties as well as drawbacks) when developing future incentives of power systems.

3.1 The Network Performance Assessment Model

This section is mainly based on Paper III and Paper IV.

3.1.1 Background

Following the deregulation of the Swedish electricity market in 1996, a new regulating authority, the Swedish Energy Agency (STEM), was established in 1998. However, the distribution was still operated as regional natural monopolies, with responsibilities as well as privileges. Earlier, the DSOs were more or less allowed to compensate for all their costs by setting tariff levels regardless of the effectiveness and quality. Following the deregulation, STEM identified the problem of increasing tariff levels. Despite several attempts to keep the tariffs down, e.g. through price freezing, no solution was effective. It was therefore necessary to find a new regulation paradigm [11]. In 1998, a project was initiated by STEM to propose a new regulatory model resulting in the Network Performance Assessment Model (NPAM). This was a paradigm shift from an earlier situation where the DSOs were more or less compensated for their costs to a regulation trying to measure the customer performance of power distribution [65].

The NPAM was a unique and innovative regulatory tool. The model evaluated tariffs ex-post by entering several system data into a computer program which produces a fictive network, with the aim of having the same objective conditions as the real system [65]. *Ex-post* means that the final tariff levels are determined after the end of the regulatory period, whereas the opposite is entitled *ex-ante*. Following the use of this regulatory tool, STEM demanded repayments from several DSOs each year from 2003, based on results from the NPAM. The Energy Markets Inspectorate), a division of STEM, became an independent authority in 2008 whose responsibility included regulating electric power distribution system (DS) tariff levels. The tariff regulation using the NPAM as the primary tool was, however, strongly criticized by stakeholders followed by proceedings. For example, the NPAM was heavily criticized for not taking historical circumstances into consideration (such as previous investments in areas with decreased need of electricity as a result of abandoned industries, for example) and for not being robust enough to fulfill the criterion of objectivity (i.e. equal judgment between different companies). This criticism was partly based on analyses included in this thesis (see section 3.2). In the later part of 2008, the parties made an agreement for 2003-2007, which included fewer DSOs and significantly lower levels of repayments than the original demand. In January 2009, the regulator decided to abandon the NPAM, partly motivated by the fact that it was not an ex-ante regulation though theoretically it can be used in this way [2].

3.1.2 An overall summary of the NPAM

The NPAM is based on *reference networks*, fictive DS defined from a set of "real" conditions, such as location of customers and delivered electric energy. This information was 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 compares this value with the revenue, which gives a debiting rate [65]:

$$Debiting\ rate = \frac{Revenue}{NPA} \tag{3.1}$$

A review of the tariffs, utilizing the NPAM, was annually performed by the regulating authority regarding tariffs between 2003 and 2007 (in January 2009 the NPAM however was formally abandoned). The results from the NPAM were 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 were ordered to return part of their revenue, if the debiting rate was higher than an acceptance level. Paper III provides a presentation with underlying theory of the NPAM. It is based on interviews with the originator of the model.

The underlying theory and development of the Swedish regulation model have a unique complexity, which includes technical assumptions of the DS, based on years of discussions with the industry, the performance of Monte Carlo Simulations, reliability analyses, etc. The understanding of this model is of importance when developing future regulatory models if one is to learn from its drawbacks and novelties. An overview of the results from the NPAM is given in this section, while Paper III provides a more comprehensive description.

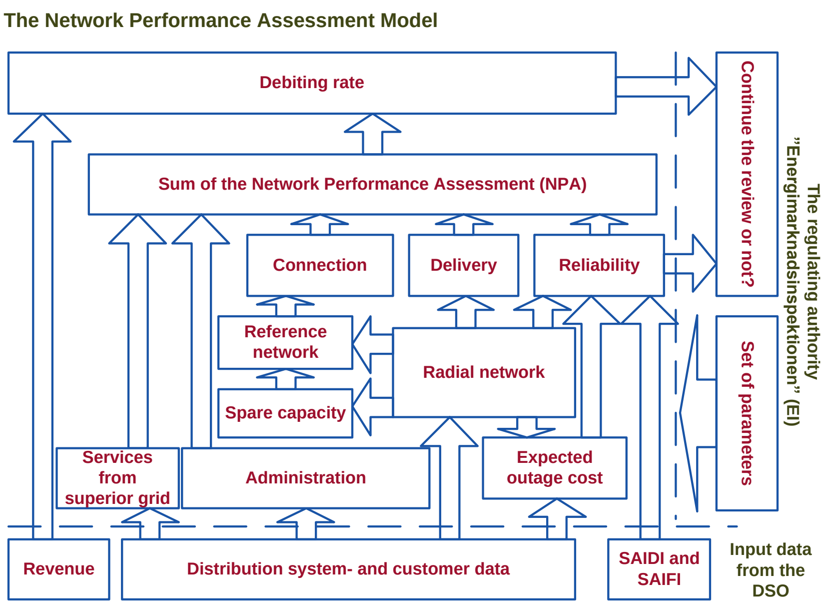


Figure 15 – An overall picture of the NPAM (2003-2008)

Figure 15 overall illustrates 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, DS often include component redundancy to improve the 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). 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. The resulting total cost is referred to as the Network Performance Assessment; see *equation 3.2*. The NPA is an assessment of the customer values of a DS. 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 3.1*. The results from the NPAM were considered to be the primary tool for the regulating authority to judge tariff levels, and to decide if a DSO should be monitored for further review.

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

1) The *cost of the connection* ($C_{Connect}$) 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_{Admin}) which includes an administrative template cost for each customer.
3) The *cost of the delivery* (C_{Deliv}) which is the energy loss in the system.
4) The *cost of the services* ($C_{Service}$) which is, for example, fees for superior grids such as the transmission system. These are actual costs reported by the DSO.
5) The *cost of reliability* (C_{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 3.1.3.

$$NPA = C_{Connect} + C_{Admin} + C_{Deliv} + C_{Service} - C_{Rel} \tag{3.2}$$

3.1.3 The reliability cost function

The reliability cost function (C_{Rel} in *equation 3.2*) used by the NPAM is given by *equation 3.3*. C_{Rel} aims to give incentives which are a good balance between high redundancy and cost effectiveness corresponding to the estimated cost the customers are willing to pay to receive redundancy.

$$C_{Rel} = \begin{cases} 0 & if\ C_{Outage} - C_{Expect} \leq 0 \\ C_{Outage} - C_{Expect} & if\ 0 \leq C_{Outage} - C_{Expect} \leq C_{Max} \\ C_{Max} \Leftrightarrow C_{Spare} & if\ \leq C_{Outage} - C_{Expect} \geq C_{Max} \end{cases} \tag{3.3}$$

The Expected outage cost (C_{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 such factors as the customer density. This reduction is made with a maximum (C_{Max}) corresponding to the template compensation for spare capacity ($C_{Spare} = C_{Max}$) given (a part of $C_{Connect}$ in *equation 3.2* by the NPAM. Furthermore, the NPAM gives no reward for lower outage cost than C_{Expect}. Hence, the reliability cost function only regulates some values of the reliability of a DS, which is illustrated in Figure 16. This does, of course, affect the incentives in different ways such as fusions of distribution system areas.

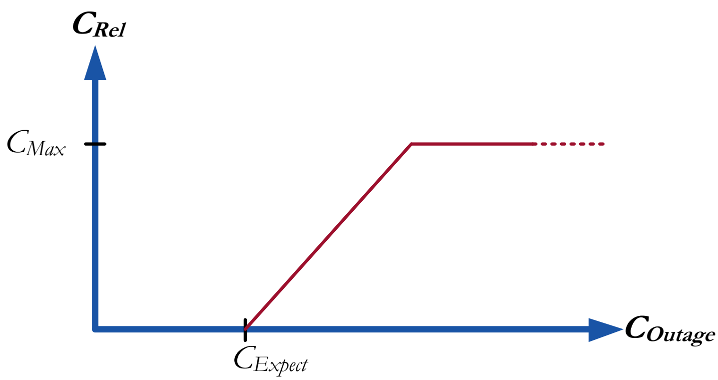


Figure 16 – Illustration of the regulation limited area of the reliability cost function

The Customer outage cost (C_{Outage}) in the NPAM represents the cost that the customer experiences. C_{Outage} depends on delivered electric energy, system reliability indices (*SAIDI* and *SAIFI*), and template functions of the customer outage cost; see *equation 3.4*. 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 [72] including updated data in 2003. C_{Outage} is calculated from both advertised (similar but not always identical to planned events) and unadvertised outages, i.e. stochastic events. Customers in an urban DS generally receive a higher amount of compensation (higher x_i and y_i in *equation 3.4*) than customers in a rural distribution system due to the NPAM.

$$C_{Outage} = \frac{E}{8760} \sum_{i=a,b} (x_i SAIFI_i + y_i SAIDI_i) \quad (3.4)$$

where:

- E is delivered electric energy for the area [kWh/yr],
- *8760* is the total number of hours per year [h/yr],
- the *index i* indicates if the outages are announced events, with *a*, or unadvertised, with b,
- $SAIFI_i$ [int/yr] and $SAIDI_i$ [h/yr] are system reliability indices (see section 2.4.2),
- 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.

3.1.4 Estimation of maximal aggregated power

The probability that all load points connected to a feeder simultaneously demand maximal power (P^{max}) is neglected and consequently there is no motivation to dimension the system regarding this theoretical maximal demand. Hence P^{max} has to be multiplied by an "aggregate factor" S:

$$P^{max}_{aggregated} = P^{max} * S \quad (3.5)$$

$$P^{max} = \frac{\sum_{i=1}^{N} E_i}{1\,900} \quad (3.6)$$

$$S = e^{-\left(0.1849 * \ln\left(s^{-1}\right) + 0.0172\right) * \ln(N)} \quad (3.7)$$

The definitions of P^{max} and S are based on Monte Carlo simulations and discussions with the DSOs. N is the total number of load points, E_i is the annual electrical energy consumption of load point i and s is a variable determined by EI, which depends on the *Net Level (NL)* defined in Paper V, for instance:

$$s = \begin{cases} 0.50\ NL1\ (0.4\ kV) \\ 0.90\ NL2\ (10\ kV) \\ 1.04\ NL3\ (40\ kV) \\ 1.06\ NL4\ (135\ kV) \end{cases} \quad (3.8)$$

Despite the fact that the NPAM is abandoned, the model presented in this section can be used as well in other contexts.

3.1.5 Study of the underlying theory

The NPAM model used a set of template functions to assess the reliability cost function (*equation 3.4*). 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 with a sequential Monte Carlo simulation approach. The third simulation study is described in more detail in Paper III, which also shows the underlying method. The other simulations had similar but simpler algorithms. A summary of the four algorithms is:

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; the conclusion was that redundancy is motivated at all voltage levels except transformers between low voltage (0.4 kV) and medium voltage (in the NPAM 10 kV) where single transformers are preferable.
3. **Assessment of feeder redundancy in the reference network**: 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 the template function for 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 to that in simulation 1. The result is a template function used in calculation of the outage cost.

3.2 Robustness evaluations of regulation models

Studies assessing the robustness of regulatory models can, besides acting as a critical review, be motivated as:

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, which has to be taken into consideration within the risk management.

3.2.1 An overview of two performed robustness studies

Two studies evaluating the robustness of the NPAM have been performed (referred to as *S1* and *S2*) published in Paper V (*S1*) and Paper VI (*S2*) respectively. Both *S1* and *S2* use data of authentic Swedish DS 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, such as when 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 meters is allowed by the regulator. Within this study, the algorithms of the NPAM were also investigated to explain the received results. *S1* (see section 3.2.2) shows examples of possible sensitiveness, but does not answer relevant questions such as how common these phenomena are. Therefore, *S2* (see sections 3.2.4) continues 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 3.2.3. Finally, an approach to further judging the robustness by using statistical theory was performed within S2 to strengthen the conclusions. This last approach was not included in Paper IV, only in the Swedish final report of S2 [6]; in this thesis a translation is provided in section 3.2.5.

3.2.2 The first robustness study of the Swedish NPAM

Several examples of small, non-significant, divergences in input data which lead to significant divergences in the output from the NPAM are provided in Paper V. The Swedish final report of S1 [5] provides even more examples and also a more comprehensive theoretical explanation of the results. S1 could be seen as a "pre-study" and its conclusions indicate possible sensitivity leading to an unpredictable regulation and motivate a further, more systematical, analysis of the robustness, i.e. *S2*.

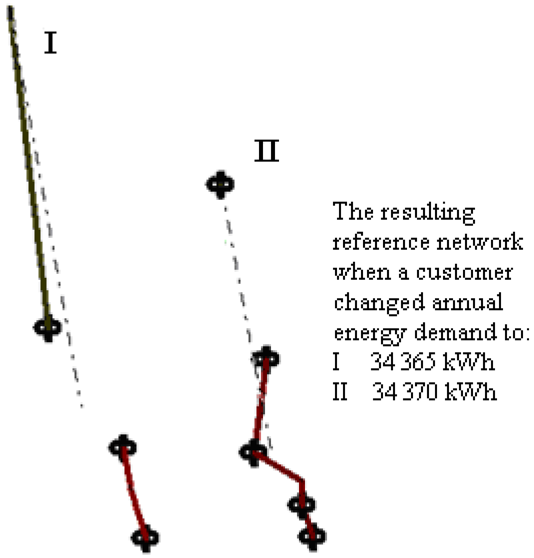


Figure 17 – An example of the possible sensitiveness analyzed in *S1*

Figure 17 illustrates one of several examples from S1. The figure is received from the graphical interface of the NPAM (referred to as Netben) comparing the structure of the highest voltage level (135 kV of totally four possible voltage levels) of actual reference network including fictive transformer stations to 40 kV. Broken lines are connections to superior grids. In this example, increased annual consumption of a single low voltage customer resulted in that the structure at the highest voltage level of the reference network was radically changed (see Figure 17). Furthermore the NPA decreased when the consumption was increased. 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. Changes in the input data which, in the reality, had incurred more expenses for the DSO can result in lower NPA, which indirectly leads to lower revenue allowed.

Paper V provides more information of these particular examples.

3.2.3 A method evaluation regulation models

This section describes a method evaluating the robustness of regulatory models. This method has been applied to the Swedish NPAM, but can be used more generally. Small variations of a category of input data are generated randomly. All other input data remain unchanged during the simulations. The variations (can be any input data) 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 is repeated several times (100 times in *S2*), independent of earlier results, i.e. 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 were analyzed in greater detail by investigating the correlation. The NPA consists of five parts (see *equation 3.2*): 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:

$$V(NPA) = \sum_{i=1}^{N} V(x_i) + 2\sum_{1\le i<j\le N} C(x_i, x_j) \tag{3.9}$$

In *S1,* the following x_i are included in *equation 3.9*: 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 equal to zero. *Equation 3.9* 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 6, based on *equation 3.9*. Because the covariance *C(x, x)* equals *V(x)* and *C(x, y)* equals *C(y, x)*, the sum of the nine resulting covariances in Table 6 becomes equal to V(NPA) according to *equation 3.9*.

Table 6 – Contribution of the different parts to the sensitiveness of the NPA

	C(P1, *)	**C(P2, *)**	**C(P3, *)**	**Sum = C(NPA, *)**
C(*, P1)	V(P1)	C(P2, P1)	C(P3, P1)	**Sum of row 1**
C(*, P2)	C(P1, P2)	V(P2)	C(P3, P2)	**Sum of row 2**
C(*, P3)	C(P1, P3)	C(P2, P3)	V(P3)	**Sum of row 3**
			Sum of rows (1-3):	**V(NPA)**

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

3.2.4 The second robustness study of the Swedish NPAM

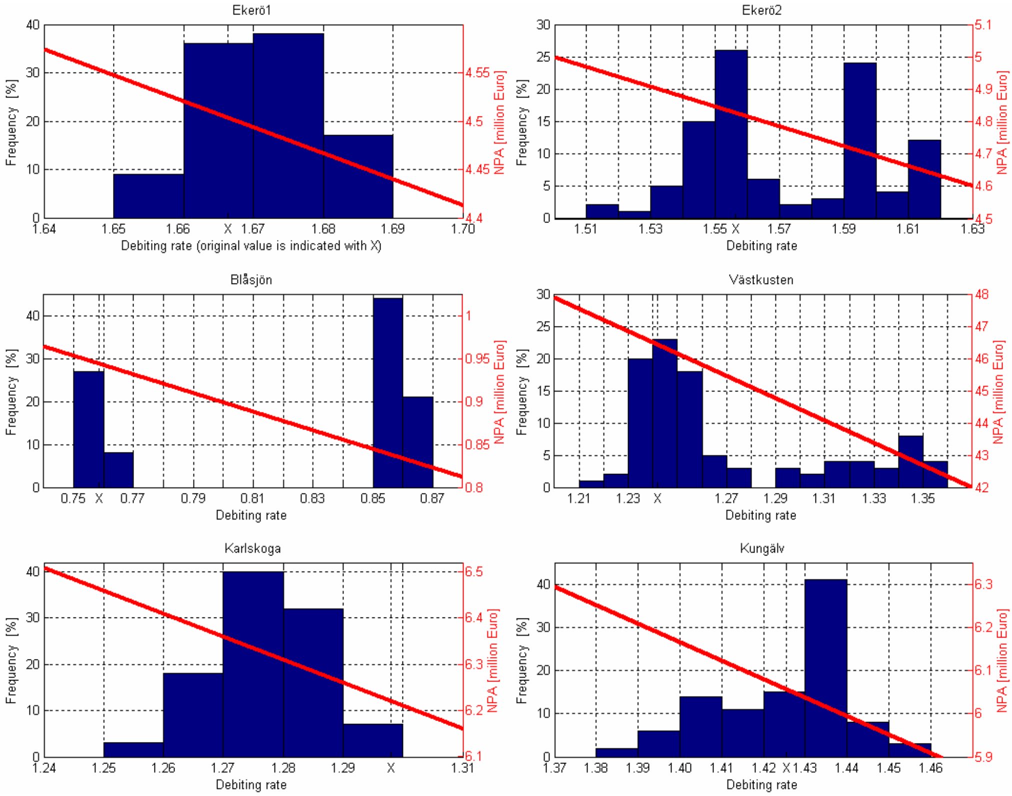


Figure 18 – An overview of one of the analyses within the second study of robustness

Figure 18 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 debiting rate before any changes is marked by "X" at the x-axis at each histogram. The divergence in the debiting rate differs from approximately 0.04 to 0.14 (at 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 in more detail are presented in Paper VI.

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 can lead to significant differences in result for the analyzed systems. DS, 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 to small variations in input data. The

NPAM uses two algorithms which explain most of the sensitiveness shown in this study. The first algorithm is how the fictive reference network connects with superior grids and the second algorithm is related to the logic for placing transformers in the fictive reference network. More information is provided in Paper III (see also [6], [7], [8], [11], [65] for more information on underlying theory).

3.2.5 Theoretical approach to further judging the robustness

In *equation 3.10*, 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 (r_i), but is, however, constant during the performed simulation within *S2* (*S2* is introduced in section 3.2.1). The NPA could be seen as the sum of every contributed customer performance X_i, according to every single *customer i*. Unlike R, NPA is not constant during the simulations within *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 3.10*.

$$DR = \frac{R}{NPA} = \frac{\sum_{i=1}^{n} r_i}{\sum_{i=1}^{n} X_i} = \frac{\frac{1}{n}\sum_{i=1}^{n} r_i}{\frac{1}{n}\sum_{i=1}^{n} X_i} = \frac{\bar{r}}{\bar{X}} \tag{3.10}$$

The variance of the debiting rate could be calculated approximately with Gauss approximation as:

$$V(DR) = V\left(\frac{\bar{r}}{\bar{X}}\right) \approx \left(\frac{\bar{r}}{\mu^2}\right)^2 V(\bar{X}), there\ \mu\ is\ the\ expectation\ of\ \bar{X} \tag{3.11}$$

Equation 3.11 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 DS) stochastic variables. The variance could be calculated as shown in *equation 3.12*:

$$V(\bar{X}) = \frac{1}{n^2}\left(\sum_{i=1}^{n} V(X_i) + 2\sum_{1\le i<j\le n} C(X_i, X_j)\right) = \{if\ independent\} = \frac{1}{n^2}\sum_{i=1}^{n} V(X_i) \tag{3.12}$$

Furthermore, if the variances of X_i are assumed to be independent with the same distribution (→ $V(X_i) = \sigma^2$) the total variance could be calculated as:

$$V(\bar{X}) = \frac{\sigma^2}{n} \tag{3.13}$$

If this assumption is correct, there will be a higher robustness of the results from the NPAM (lower standard deviation), the more customers the DS have. If the variances of X_i are instead positive correlated (=1), the variance could instead be calculated as:

$V(\bar{X}) = \sigma^2$, i.e. the result is independent of the number of customers. (3.14)

Perhaps neither of these two extreme cases is directly applicable to the NPAM. However, this gives a good comprehension of which factors affect the variance of the debiting rate and the requirements needed to receive a low variance (high robustness).

One argument used to defend the model and claim the stability of the NPAM was to state that the variance of the debiting rate becomes low since there are many customers in DS. As shown, this argument is built on the assumption that the variances of X_i are independent and have the same distribution, or at least has some of these characteristics. The results from *S2*, presented in Paper VI, show that this is not true, i.e. statistical theory cannot be used as an argument to claim stability in this case. For example, one of the DS studied in *S2* (DS1) has 111 600 customers, another DS (DS2) has 16 000 customers. According to the theory described above, DS2 should be several times more sensitive to small stochastically and independent changes in the input data than DS1 (i.e. lower standard deviation which is the square root of the variance). However, *S2* shows the opposite: DS1 received a standard deviation of the debiting rate three times higher than that for DS2. Accordingly, the hypothesis that all variances between X_i are independent and have the same distribution can be discarded. Results obtained from *S2* indicate that the robustness is low and hence results from the NPAM are unpredictable and independent of the number of customers. The conclusions from *S2* are provided in detail in Paper V and [6] and summarized in section 3.2.4.

3.3 The fall of the NPAM

This section is mainly based on Paper III and Paper IV.

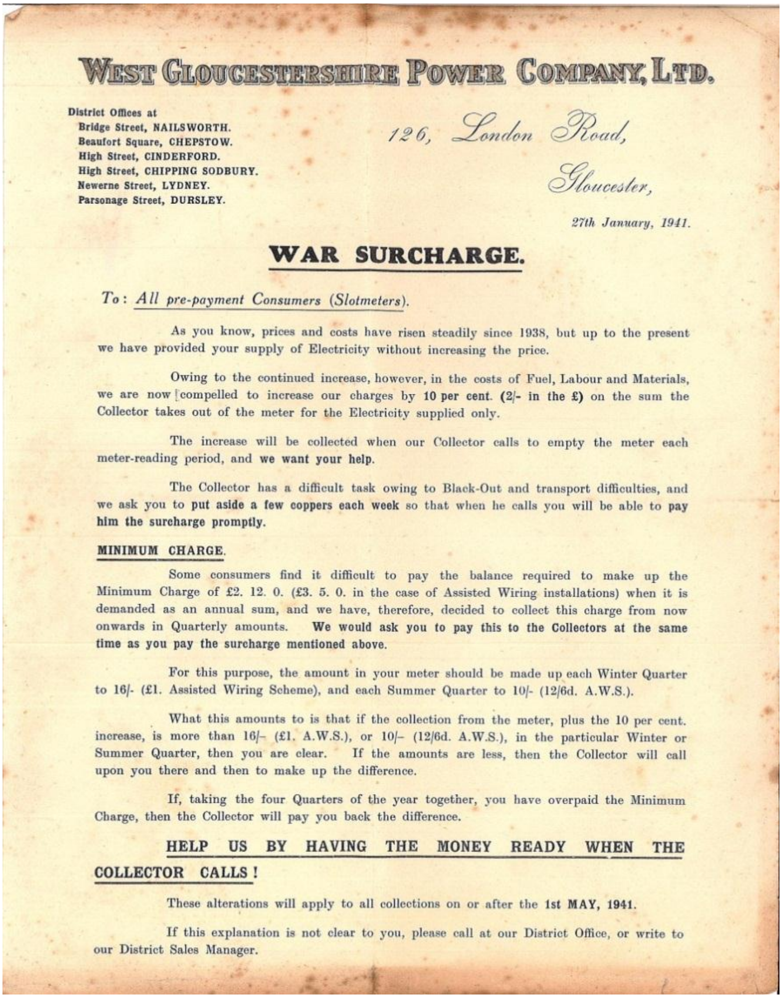
Following the use of this regulatory tool, the authority demanded repayments from several DSOs each year from 2003, based on results from the NPAM. The tariff regulation using the NPAM as the primary tool was, however, strongly criticized by stakeholders following the legal proceedings. These legal proceedings would have taken several years and cost a lot of time and resources only to treat 2003, while new legal proceedings were added each year. For example, the NPAM was heavily criticized for not taking historical circumstances into consideration (such as previous investments in areas with decreased need of electricity as a result of abandoned industries, for instance) and for not being robust enough to fulfill the criteria of objectiveness (i.e. equal judgment between different companies). In the later part of 2008, the parties made an agreement for 2003-2007, which included fewer DSOs and significantly lower levels of repayments than in the original demand. In January 2009, the regulator decided to abandon the NPAM, although the model was working, partly motivated by the fact that it was not an ex-ante regulation (though theoretically it can be used in this way).

Two studies evaluating the robustness of the model have been summarized in this chapter (see Paper V and Paper VI). The main conclusion from these two studies is that the NPAM is not robust to small variations in input data. These studies were a contributing factor to its demise. The studies were planned to be used as evidence in the legal proceedings. The experiences from Sweden demonstrate the importance of having a constructive dialogue with the DSOs without being too compliant.

What happened after "the fall" of the NPAM is described in section 4.2.

Chapter 4

Tariff Regulations and Additional Incentives



WEST GLOUCESTERSHIRE POWER COMPANY, LTD.

District Offices at
Bridge Street, NAILSWORTH.
Beaufort Square, CHEPSTOW.
High Street, CINDERFORD.
High Street, CHIPPING SODBURY.
Newerne Street, LYDNEY.
Parsonage Street, DURSLEY.

126, London Road,
Gloucester,

27th January, 1941.

WAR SURCHARGE.

To: All pre-payment Consumers (Slotmeters).

As you know, prices and costs have risen steadily since 1938, but up to the present we have provided your supply of Electricity without increasing the price.

Owing to the continued increase, however, in the costs of Fuel, Labour and Materials, we are now compelled to increase our charges by **10 per cent. (2/- in the £)** on the sum the Collector takes out of the meter for the Electricity supplied only.

The increase will be collected when our Collector calls to empty the meter each meter-reading period, and **we want your help.**

The Collector has a difficult task owing to Black-Out and transport difficulties, and we ask you to **put aside a few coppers each week** so that when he calls you will be able to **pay him the surcharge promptly.**

MINIMUM CHARGE.

Some consumers find it difficult to pay the balance required to make up the Minimum Charge of £2. 12. 0. (£3. 5. 0. in the case of Assisted Wiring installations) when it is demanded as an annual sum, and we have, therefore, decided to collect this charge from now onwards in Quarterly amounts. **We would ask you to pay this to the Collectors at the same time as you pay the surcharge mentioned above.**

For this purpose, the amount in your meter should be made up each Winter Quarter to 16/- (£1. Assisted Wiring Scheme), and each Summer Quarter to 10/- (12/6d. A.W.S.).

What this amounts to is that if the collection from the meter, plus the 10 per cent. increase, is more than 16/- (£1. A.W.S.), or 10/- (12/6d. A.W.S.), in the particular Winter or Summer Quarter, then you are clear. If the amounts are less, then the Collector will call upon you there and then to make up the difference.

If, taking the four Quarters of the year together, you have overpaid the Minimum Charge, then the Collector will pay you back the difference.

HELP US BY HAVING THE MONEY READY WHEN THE COLLECTOR CALLS!

These alterations will apply to all collections on or after the **1st MAY, 1941.**

If this explanation is not clear to you, please call at our District Office, or write to our District Sales Manager.

Chapter 4 investigates current risk management incentives in power distribution. This includes the current and the upcoming tariff regulation from 2012; an overall description (section 4.2) and results from a project evaluating a possible model for reviewing effectible costs (section 4.3); additional incentives (section 4.4) such as mandatory risk and vulnerability analysis, customer outages compensation laws for long outages, functional requirement of 24 hours and possible effects on the goodwill.

4.1 Overview

From the perspective of the DSOs, there are costs for investments, operation and maintenance to balance against the requirements for the system reliability and the profit for the stakeholders. In a perfect market environment, a balance would be reached when customers select the DSO with the best price for the required customer value. However, the infrastructures are natural monopolies. It is the task of the authorities to judge if this tariff is reasonable. A law, introduced in Sweden in 2006, dictates that every DSO must annually report results from a risk- and vulnerability analysis regarding the reliability of the DS to an authority determined by the government [23]. This includes an action plan of how the reliability in the DS will be improved in future. In addition, 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 to practice good risk management regardless of the obligation. Because DS are operated 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 a focus on the impact of regulations.

4.2 Current regulation of distribution system tariffs

This section is mainly based on Paper IV.

4.2.1 The years between NPAM and 2012

During these years, 2008 and 2011, much of the focus is on the preparedness for the new ex-ante regulation from 2012. The regulator, *EI*, has the difficult task of both avoiding relapsing into great conflicts and legal proceedings and on the other hand of fulfilling their task to protect electricity customers, while the regulation has to be fair and motivate the right incentives. In some way, the tariff levels are self-regulated during the period. The DSOs have the incentive to be careful, because too high increments of the tariffs could affect the regulator in the process of defining the details of the regulation, i.e. motivate harder regulation. An official mid-term regulation, however, exists. According to the law, the regulator has the mandate to review the fairness of the tariff levels and provide sanctions if needed although without quantitative results from the NPAM. The mid-term regulation has similar overall principles to those of the upcoming regulation such as reviewing several years at a, time and EI aims to create some sort of tariff levels before 2012. DSOs with suspected high tariffs and/or with low reliability are manually reviewed and have the possibility of "self-regulating" by 2012. Any tariff adjustments concerning 2008-2011 are then decided in connection with the decisions on tariff levels for 2012-2015 [6].

4.2.2 Introduction of a new tariff regulation from 2012

The major parts of the new regulation are established, but details remain to be determined and not everything will be included in the first version. The new regulation aims to give a stable prediction of the revenue which hopefully will facilitate investment and maintenance planning performed by the DSOs. Historical data from recent years gives a preliminary revenue framework for a period of four years. Changes in conditions compared with the forecast can be later adjusted.

The revenue framework is based on the following parts:

- **Capital costs:** The capital cost of a component consists of depreciations and the cost of tied-up capital. The regulator intends to apply capacity conservation principles by using real annuity. A constant annuity is calculated based on the estimated net present value and economic life time. The constant annuity value is used despite actual age, which makes it easier for both parties. If a component is older than its estimated economic lifetime, the compensation will be the same (DSOs who maintain their components well are thus rewarded). The required rate of return is calculated with the WACC method (weighted average cost of capital).

- The operating costs is divided into:
  - **Effectible costs**: See section 4.3.
  - **Not effectible costs:** These are fully compensated.
- **Quality function**: The quality function could, unlike the NPAM, both be negative and positive. All customers may collectively obtain revised tariff levels regardless of the individual reliability. In order not to "punish" a DSO twice, outages ≥12 hours are excluded (see section 4.4.1). The quality function is limited to not reduce the revenue framework more than either 3 % or as much as the compensation for cost of restricted capital (i.e. the lowest of these limits is used).

EI has by law the ability to integrate more quality aspects in the upcoming regulation, but these will probably not be included in the first phase. However, EI already has the possibility to impose sanctions on DSOs to correct major weaknesses. The additional quality aspects that will be considered in the future are:

- **Administrative deficiencies**: Customer service, information etc. Customer services could be overloaded during severe disturbance.
- **Voltage Quality**: transients, waveform, deviation from the normal voltage value etc.
- **Very short outages (<0.05 h)**: These have traditionally not been included in the Swedish regulations. Even short outages can cause high impact on certain categories of customers.

4.3 Evaluating a model to review effectible costs

This section (except 4.3.1) is based on Paper VII.

4.3.1 Examples of effectible costs models in other countries

This subsection is not included in Paper VII, but translated from [1].

Examples of how the operation and maintenance costs are handled in different countries' regulation of electricity tariffs:

- **Norway**: Annually a revenue frame work (ceiling) is set ex-ante. The main principles for the calculation of revenue limits are revised at least every five years. Gradually, the tendency has been to go from the actual costs to standard costs (In 2007, 60 % were based on standard costs). The standard cost is based on data from all companies, but with individual adjustments based on objective conditions. [73][74]
- **Finland**: Methods are ex-ante determined individually for pricing over periods of four years. The Authority uses various models to examine the effectiveness of the DSO and develop efficiency objectives of effectible costs such as operation and maintenance. Evaluation takes place after each regulatory period and any remarks can affect the next period. [73][74][75]
- **Denmark**: Ex ante regulation which decides revenue frameworks in terms of revenue per kWh. The starting point is the tariff levels of 2004, which are adjusted due to inflation and efficiency adjustment. The demands of efficiency are individual and are calculated based on a model which takes into consideration, for example, the structure of the DS and reliability (outages above 1 minute). [73][76]
- **UK**: The regulation is based on five-year periods. In the UK, there are only 14 DSOs (Sweden has more than 160 DSOs), which has allowed deeper individual analysis of each company concerned, e.g. including investigation of historical performance and forecasts of future needed investments. [74][77]

4.3.2 Project description

A project initiated by the Swedish regulator was performed by the RCAM research group during the fall of 2010. The aim was to review the potential of using equivalent comparison standards to judge effectible costs. The regulator's initial concept was to use units based on a standard cost model entitled EKM, where the operating cost of 1 km 0.4 kV overhead line is defined as 1 EKM. The overall idea is to calculate the total amount of EKM for each DSO and to estimate a cost for one EKM. The DSO will then be compensated in proportion to its EKM. The model has the intention to be a "zero-sum game" for the DSOs, i.e. to award cost effective DSOs by taking from less efficient DSOs.

The study includes interviews and surveys distributed to every Swedish DSO. However, no proposal for EKM units appropriate to use in the first regulatory period could be provided, due to large variations in response from the DSOs. The study provides several results such as enabling all parties to contribute their views before implementation, indication of how current EKM should be modified, increased knowledge for parties involved, and an action plan for future work. Based on this study, the regulator will not use EKM-like units in the first regulatory period (the initial idea was to apply it to 25 % of the effectible cost part during the first period and eventually increase this share to 100 %).

The overall idea is to calculate a total amount of EKM for each DSO and to estimate a cost for EKM =1 (based on actual effectible costs reported from the Swedish DSOs). The DSOs will then be compensated for effectible costs in proportion to their EKM. The aim is for the model to be a "zero-sum game" for the DSOs, i.e. to reward cost-effective DSOs by taking from less efficient DSOs.

4.3.3 EKM – A cost comparative model

Definition of EKM

The EKM model aims to describe operation and maintenance costs (reinvestments excluded) of power distribution system entities and to facilitate comparisons between DSOs. EKM_i is defined as [1]:

$$\frac{annual\ effectible\ costs\ of\ entity\ i}{annual\ effectible\ costs\ of\ 1\ km\ overhead\ line} \tag{4.1}$$

Background to EKM

EKM measures are developed by Swedenergy, an association representing companies involved in the production, distribution and trading of electricity in Sweden. Since the 1960s, Swedenergy has annually published EBR; see section 2.2.1. Each EKM_i is based on costs in EBR and a list of EKMs is included in the EBR publication. Every ~4th year, an expert group investigates if technical means or societal requirements have changed for any of the operation and maintenance activities included in EKM during the past years. If required, changes are introduced for the calculation of the actual EKM entities; otherwise the measures are updated only based on changes in EBR costs.

Current EKM

The latest EKM version during the project time (2010) was from 2006 (EKM units are presented in Table 8). During 2011 a new version will be published. According to an interview with SwedEnergy, there will probably not be any significant changes on local voltage levels, but 36 kV to 145 kV will be carefully revised [1]. Furthermore, EKM units of customer and market services will be updated thoroughly.

Possible use of an EKM-like unit in tariff regulation

Initially EI considered using a model based on units similar to EKM to reallocate 25 % of the effectible costs in the first four year regulatory period with the long-term aim of increasing this amount to 100 %. To integrate such a model, there are several issues that have to be addressed, for example:

- EBR and EKM are only based on few studies, especially for higher voltage levels, and therefore currently do not provide reliable information.
- Customer-related costs must be clearly defined and investigated (not done in this study, suggested as future work).
- EI could not rely entirely on units developed by Swedenergy, which is represented by the same DSOs whose tariffs are regulated. Consequently, EI has to review the entities carefully and modify if necessary.

4.3.4 EKM – Surveys

All Swedish DSOs were invited to answer a survey. Approximately 50 % of 170 companies with a good spread between small and big DSOs answered. More components than those existing were included, based on discussions with EI and with DSOs. Figure 19 and Figure 20 and Table 7 - Table 9 summarize some results from the survey.

Figure 19 – Do you prefer a regulation that takes many conditions into consideration, with more comprehensive reporting?

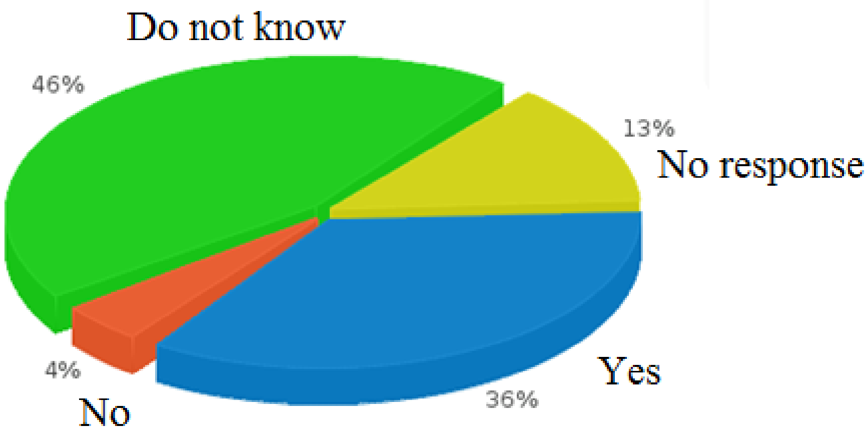


Figure 20 – Is EKM a suitable model to use in the upcoming regulation?

Table 7 – The conditions that most affect your operation and maintenance cost

Proportion of forest	40 %
Proportion of rural vs. urban areas	37 %
Proportion of rough terrain	6 %
Other category answered	10 %
No answer	7 %

All DSOs were asked to estimate EKM values and to estimate their costs (the latter indirectly give EKM units). More entities than existing where included, based on discussions with EI and with DSOs. Unfortunately, too few DSOs answered the survey at a detailed level needed to estimate EKM statistically well enough to propose sharp EKM units. However, the analyses gave a number of indications for each entity; see Table 8 (existing EKM) and Table 9 (entities not included in EKM 2006). Other entities than presented in Table 8 and Table 9 were also within the survey, but without any answers, e.g. sea cable categories.

Table 8 –Analyses of existing EKM

Entity	**Indication**	**EKM 2006**
OH line 0.4 kV	Defined as 1.00	1.00
UG cable 0.4 kV rural	No significant changes needed	0.70
UG cable 0.4 kV Urban	No significant changes needed	0.70
UG cable 0.4 kV City	High spread between responses	0.70
OH line 12-24 kV	Current EKM too low	1.20
Covered OH line 12-24 kV	Current EKM too low	0.90
UG cable 12 kV rural	No significant changes needed	0.60
UG cable 24 kV rural	Current EKM too low	0.60
OH cable 12 kV	Current EKM too low	0.90
OH cable 24 kV	Current EKM too low	0.90
UG cable 12 kV Urban	High spread between responses	0.60
UG cable 24 kV Urban	No significant changes needed	0.60
UG cable 145 kV Urban	Current EKM too low	0.40
UG cable 12 kV City	No significant changes needed	0.60
UG cable 24 kV City	High spread between responses	0.60
Pole mounted transformer	Current EKM too low	0.00
Sec. substation rural	Current EKM too low	0.10
Sec. substation City/Urban	Current EKM too low	0.30
Sec. substation double	Current EKM too low	0.50
Subst. 52-72.5/12-24 kV [1]	Current EKM too low	1.90
Substation 145/12-24 kV [1]	Not included in the survey	1.90
Substation 145/52-72.5 kV [1]	Not included in the survey	1.90
Subst. feeder bay 12-24 kV	No significant changes needed	1.40
OH line 36-72.5 kV	Current EKM too low	1.50
OH line 84-170 kV	Current EKM too low	1.50
UG cable 36-72.5 kV rural	(2)	0.30
UG cable 36-72.5 kV urban	(2)	0.40
UG cable 36-72.5 kV city	(2)	0.60
UG cable 84-170 kV rural	(2)	0.30
UG cable 84-170 kV urban	(2)	0.40
UG cable 84-170 kV city	(2)	0.60
Transf. 52/12-24 kV	Current EKM too low	4.60
Transf. 123-170/12-24 kV	Current EKM too low	4.60
Transf. 123-170/52-72.5 kV	No answers	5.10
Subst. feeder bay 145 kV	No answers	1.60
Subst. feeder bay 52-72.5 kV	No answers	1.60
Customer related costs	Analyzed in survey B	0.06

(1) Excluding apparatus
(2) Could not be compared because of different detail levels

Table 9 – Entities not included in EKM 2006

Entity	number of answers	mean value
Disconnector 36-170 kV	2	1.14
Disconnector 245 kV	1	1.30
Transformer substation 24-36 kV	1	8.00
Transformer substation 52-72.5 kV	3	3.89
Transformer substation 84-170 kV	3	3.89
Transformer 24/12 kV (note 1)	3	1.72
Transformer 72.5-84/12-24 kV	1	4.00
Transformer 123-170/36-52 kV	2	5.58
Substation switching bay 12-24 kV	4	1.29
Substation switching bay 36-72.5 kV	3	1.74
Substation switching bay 84-170 kV	3	1.74
Capacitor bank 12-84 kV	4	0.52
Capacitor bank 123-170 kV	1	1.00

(1)Voltage regulation transformer included.

Correlations between the different questionnaires have been calculated. The aim is both to examine whether certain types of companies are over-represented and see the connection between objective conditions and different responses. Examples of indications:

- The desired detail level and assessment is basically uncorrelated with the category (e.g. size or urban versus rural) of DSO.
- The more knowledge, the more positive toward EKM.
- Nothing indicates that the network companies have responded to the survey "tactically".

A need of investigating customer-related costs further was identified. An additional survey was made, where all DSOs in the first survey that stated an interest in continued participation were invited. DSOs have indicated in interviews that all customer-related costs could be divided into three categories: (a) billing cost, (b) customer service costs, (c) electric meter cost. Only a few companies answered the survey. Estimated cost per customer and percentage distribution between cost categories differ significantly between companies; the choice may depend on several factors such as objective differences, cost effectiveness and how different cost categories are defined (reported in the organization). However, all companies indicated a much higher customer-related cost EKM in the survey (0.10, 0.19 and 0.46) than EKM 2006 (0.06).

4.3.5 Outcome of the study

Conclusion

Current EKM has carefully been investigated and there are doubts about the reliability of existing measures for direct use in a tariff regulation. The recommendation (if EI decides to use an EKM-like model) was: Update all entities and/or reduce the portion governed by the EKM model in the first regulatory period.

Examples of key results

- Knowledge: Initiation of activity among the DSOs to increase knowledge and awareness of EKM and future ex ante regulation.
- Problem Identification: Only a few DSOs have a sufficient current state of knowledge to be able to contribute "sharp" suggestions for EKM values. Two identified areas with extra need of further studies are: 1) Customer-related costs, 2) EKM at higher voltage levels.
- Suggested action plan, i.e. future work
- Indications: The survey provides some indications of EKM levels.
- Modeling: There is a wide spread between survey responses regarding EKM. Whether this is due to objective differences is not possible to ascertain. It is therefore possible that the values of EKM should depend on more conditions than component category.

Consequence

Based on this study, EI will not include EKM-like units in the first regulatory period from 2012 (which was the intention before this study).

4.4 Additional incentives

This section summarizes parts of Paper II and Paper IV.

4.4.1 Customer outage compensations in Sweden

Sweden has a legislation regarding outages above 12 hours and a 24-hour functional requirement [23]. Consequently, 12 and 24 hours are important limits for Swedish DSOs in maintenance and investment planning [2]. Table 10 summarizes the model for determining customer outage compensation and damages to affected customers [3].

Table 10 – Consequences of outages longer than 12 hours

Outage length [hours]	Customer compensation [SEK[1]]	Minimum comp.[4] [SEK]
<12 hours	input to the tariff regulation	-
12-24 hours	12.5 % of α^2	2 % of β^3
24-48 hours	37.5 % of α	4 % of β
Following 24 hour periods	+ 25 % of α + γ^5	+ 2 % of β
…	…	…
Max	300 % of α + γ	-

[1]SEK = Swedish crowns, 100 SEK ≈ €11.0 (EUR) or ≈ $14.5 (USD)
[2]α = Individual customer's annual network tariff
[3]β = Yearly set base amount (42 400 SEK 2010)
[4]Set to even 100 SEK values, rounded up → 2 % of β is rounded up to 900 SEK
[5]γ = Risk of additional consequences of breaking the law of 24 hour functional requirement.

Note that outages longer than 24 hours could lead both to compensation according to the customer compensation model and to additional consequences. The consequence of breaking the functional requirement has not yet been examined because the law has only been in force for a short time, but EI has indicated that well-performed risk and vulnerability analysis could affect the consequences. That is to say, if the identified weakness that led to an outage longer than 24 hours were included in the action plan for improvements (based on performed risk and vulnerability analysis), the outage would probably be tolerated to a greater extent than if the weakness had not been identified as important to handle.

4.4.2 A comparison between Sweden and the UK

A study comparing the laws of customer compensations in Sweden and the UK is presented in [1]. 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 a DS. The approach was to assess how much the customer outage compensation had amounted to with each law respectively, between April 2004 and November 2006 for this DS, also looking specifically at the contribution from the storm Gudrun (8-9 January 2005). The DS studied has 900 customers and the different laws were hypothetically applied respectively (this historical data was collected before the Swedish law took effect). The result was that it would have 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 than in the UK and the compensation cost starts after 12 hours compared with 18 hours in the 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, 30-42 hours, 42-54 hours and so on.
- The Swedish compensation is based on customer's annual network tariff (with a minimum value of € ~100) independent of customer category. In the UK the compensation is based on customer category with the same levels within each category; two categories exist: domestic and 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 the Swedish model.

4.4.3 Compulsory risk and vulnerability analysis

A law [23] introduced in Sweden in 2006 dictates that every DSO has to annually report the results from the risk and vulnerability analysis regarding the reliability of their DS. The risk analysis has to include an action plan of how the reliability will be improved [2]. An initial difficulty with this analysis was that Swedish law requires records of Swedish authorities to be open and available to the public. Hence, analysis results are potential "terrorist manuals", which subsequently led to a revision of the law. The regulator would receive the information that the analysis had been done, and if needed, read the results locally, at the DSO, without collecting the documents.

4.4.4 Reporting of severe outages

From 2008, information about extensive outages has to be reported to EI within 14 days. The aim is to make it possible to assess the quality of the electricity supply. Outages are defined to be extensive if any of following criteria is fulfilled:

- Longer than 24 hours and involves more than 1 000 customers or 25 % of the customers in a DS.
- Longer than 12 hours and involves more than 10 000 customers or 50 % of the customers in a DS.
- Longer than 2 hours and involves more than 100 000 customers in a DS.

4.4.5 Goodwill effects and other possible incentives

Fear of more extreme climate and a higher general dependence on reliable electrical distribution have resulted in increased attention in the media to customer outages and highlighted the need for reliable DS. The DSOs know that outages, in addition to repair costs and possible customer penalties, damage the goodwill of their trade mark. As a consequence of severe highlighted events such as the storm Gudrun, projects aimed at replacing overhead (OH) lines with underground (UG) cables increased rapidly in Sweden. Already in the mid-nineties, the use of medium voltage OH 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 OH lines in the next 5-15 years. Ageing characteristics of this technique can in themselves become a future unknown risk, just as "water trees" was for the early generation of PEX cables [19].

Communication with customers and reporting to the regulating authority has been more comprehensive followed by recent changes in the law: for example, the detailed level of outages reported and information to customers about their rights of compensations. Other examples are that even shorter outages than three minutes (the old limit) must be reported and reporting of severe outages described in section 4.4.4.

Several DSOs have introduced more advanced analysis methods followed by incentives investigated in this chapter. In Chapter 5 this is exemplified by the description of risk management policies at different voltage levels at a DSO.

Chapter 5

Risk Management Policies at a DSO

Chapter 5 provides a description of the current project planning and risk management at a DSO (section 5.1), a short evaluation (section 5.2) and finally, a proposed classification of risk management policies partly concluded from this study (section 5.3).

5.1 Description of current risk management at Fortum

This section summarizes parts of Paper VIII and Paper IX.

An application study investigating the risk management at a DSO has been performed. The application study describes and evaluates the risk management principles at Fortum Distribution, one of the largest DSOs operating in Sweden. From 2006 to 2011, Fortum has been running 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 (the outcome can be calculated during 2012). This corresponds to more than a 50 % reduction from historical SAIDI values of about 2-4 hours. To ensure cost-efficiency, work on developing a more knowledge-based network planning, is necessary (and in fact crucial) to 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 hours (see section 4.4).

Depending on the voltage level, Fortum Distribution applies three levels of risk assessment policies for the DS today (note that the definition of local- and regional DS differs from the formal definition presented in section 2.1.1):

1. Local DS, low voltage (LV) [0.4 kV], see Paper VIII/Paper IX and section 5.3 (only an overall risk policy is applied at this level).
2. Local DS, medium voltage (MV) [1.0-24 kV], see Figure 21 and Paper VIII/Paper IX.
3. Regional DS [>24 kV], see Figure 22 and Paper VIII/Paper IX.

Table 11 – Overall comparison of risk policies between local- and regional DS

	Local DS	**Regional DS**
Reliability focus	On customer outages and volume (number of affected customers).	On individual components (e.g. power transformers) and on the N-1 criterion (see section 2.4.5), complemented by probabilistic measures such as EEAR (see section 2.4.5)
Project priority approach	Use of historical outages data as an important input for project selection.	A forward-looking approach, i.e., "*what can happen in the future if the system remains in today's configuration?*"
Redundancy	Operated radially in rural areas which can include passive redundancy using normally open disconnectors (redundancy more generally used in urban areas).	Active redundancy (see section 2.4).

Risk policies and the project planning process for different voltage levels are described in more detail in Paper VIII and Paper IX. Figure 21 and Figure 22 illustrate an overview of the risk management at MV DS (applied in rural areas) and regional DS respectively. At MV DS, a reliability analysis is performed as 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 exists. Reliability models which take the entire system perspective into consideration are proposed in sections 2.4. Furthermore, a new reliability framework which can handle outages above 12 hours is introduced in section 2.5. At regional DS, risk matrices are used as a part of the entire risk management (risk matrices are defined and discussed in section 2.3.4); an example of a matrix used is appended in Paper VIII together with a measure matrix used at MV.

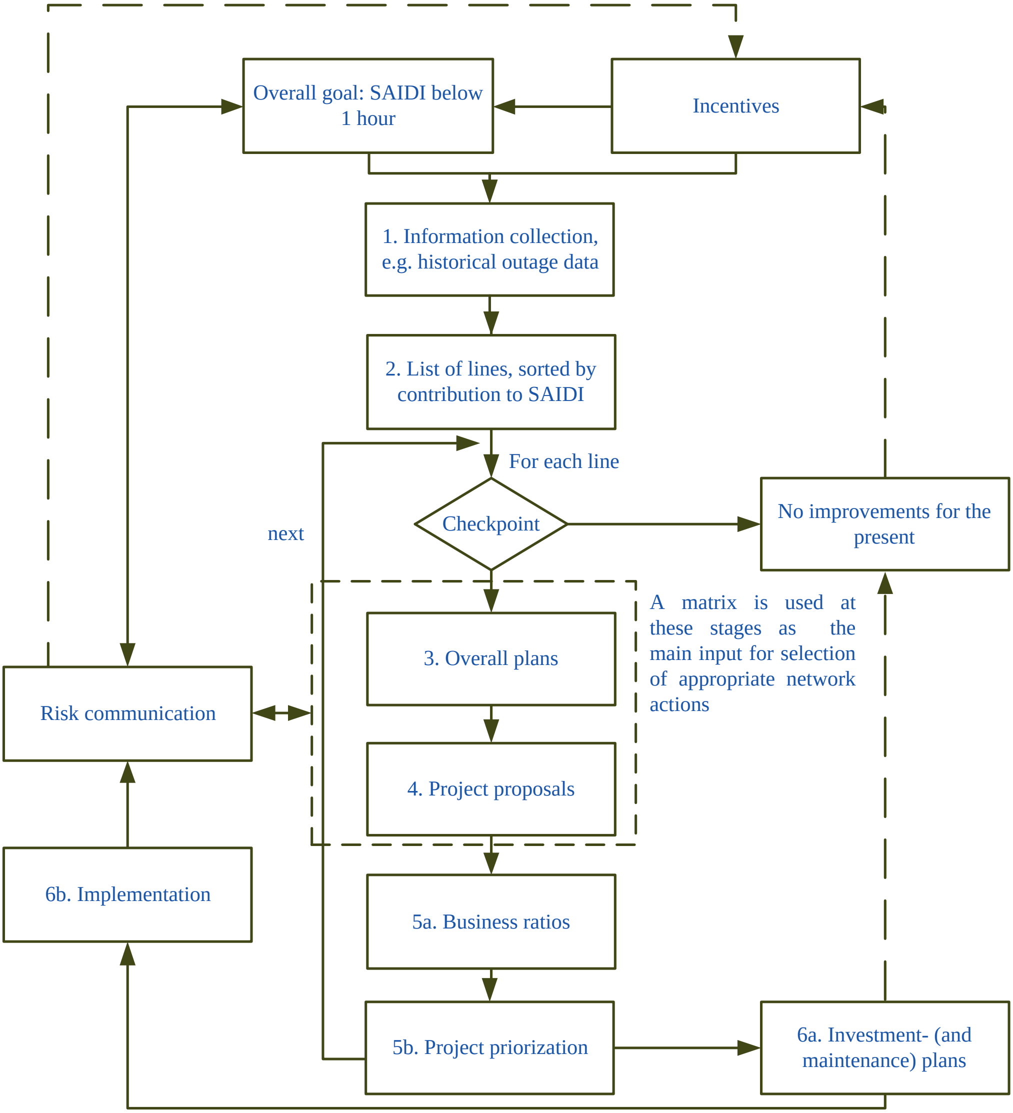


Figure 21 – Overall illustration of the risk management at rural local DS at MV

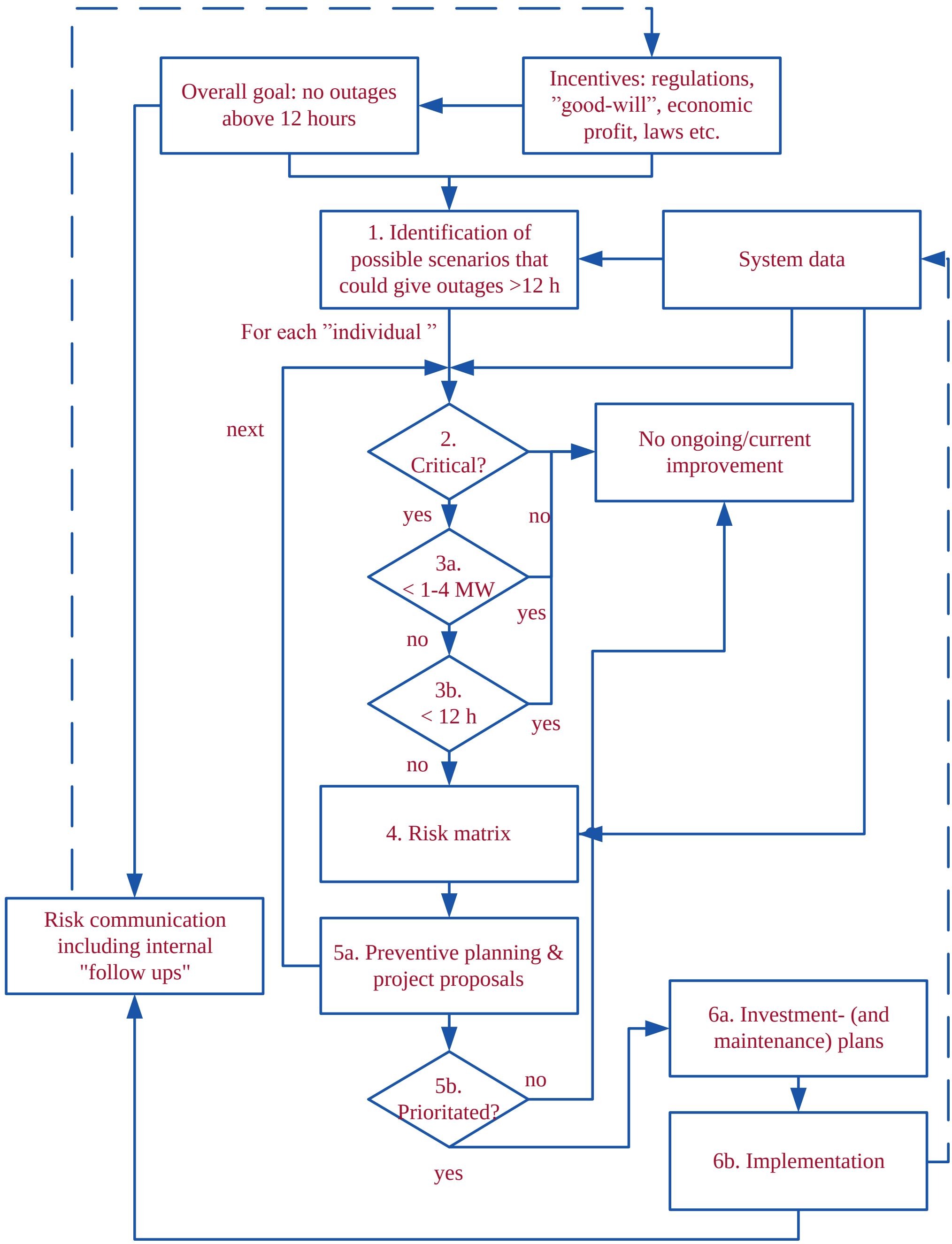


Figure 22 – Overall illustration of the risk management at regional DS

5.2 Evaluation of the risk management at Fortum

This section summarizes parts of Paper VIII and Paper IX.

Local- and regional DS have different methods of network planning, motivated by different operation and categories of risks. At local DS, the focus of the risk management is concentrated in a few areas which are the most important according to reliability statistics. These risks are, however, most obvious, but in the future probably mitigated due to the current strategy, and new risks could instead appear (e.g. associated with underground cables). Consequently, the current focus area is good, but a wider risk focus should be considered. An essential part of the risk management at medium voltage is reliability analysis, which is currently based on significant simplifications. Hence, there is a potential to develop the reliability method further. Strong incentives to develop more comprehensive methods of risk management to use in the network planning of DS were identified. However, differences between voltage levels in distribution systems are significant and justified. Experiences from the application study are input to a proposal of different risk policies; see section 5.3.

5.3 Proposed classification of risk management

This section summarizes parts of Paper I.

There are large operational differences between different voltage levels of the electrical power distribution systems (DS) and between urban and rural areas, which prompt different risk management policies:

- ***Risk of customer outages***
  - ***Low voltage (0.4 kV) DS*** (secondary substations included): Failures at 0.4 kV seldom affect more customers than the local area because of protection equipment in the secondary substations. Hence, the resulting risk value is often small. Therefore, it can be profitable to reallocate economic resources to other parts of the DS in order to maximize the cost effectiveness by doing less at this level.
  - ***Rural and semi-rural local DS***: Rural DS often contribute to more than 80 % of system average SAIDI (see section 2.4.2). Reliability analysis could therefore be an important part of the risk assessment. The consequences of outages are, however, often less severe than in higher voltage levels or urban systems. Nonetheless, an extreme event such as severe storms could cause several impairments at the same time, which could lead to long outages.
  - ***Urban local DS***: These systems have a high reliability compared with rural parts. The redundancy is often good, consisting exclusively of underground cables. However, the potential consequences are often more severe. Hence, the risk assessment should focus on how to handle and prevent extreme events with large consequences.
  - ***Regional DS***: These voltage levels are often operated with active redundancy, i.e. possibility to fulfill the *N-1 criterion*. The probability of customer outages caused by this voltage level is small, but the consequences can become significant. Like the urban systems, the risk assessment should focus more on extreme events with large consequences.
- ***Other risks*** (not reliability related): Within this category, risk of human injury and breaking safety and/or environment laws are included, which can have more severe consequences than customer outages. Some of these risks could, however, be seen as absolute constraints (i.e. not permitted under any circumstances) as a part of the risk management of customer outages.

This chapter has shown current risk management policies at a DSO and proposed a risk management classification partly based on this study. Quantitative analyses methods for cost-effective resource allocation applied to rural and semi-rural local DS are proposed in Chapter 6. This focus area is motivated by the fact that this part of the electrical power system often contributes to more than 80 % of system average SAIDI.

Chapter 6

Vulnerability Analyses for Cost-effective Resource Allocation

Photo Courtesy of U.S. Army

Chapter 6 proposes a vulnerability analysis method (section 6.3) including investigation of correlations and characteristics of power distribution (section 6.2), a case study (section 6.4) and examples of how to use results from the method in practice (section 6.5). This vulnerability analysis includes an approach to statistical analyses of reliability based on the amount of input data. Section 6.6 proposes the overall idea of an analysis framework.

6.1 Introduction

Present-day society is dependent on the reliable distribution of electricity (further background is provided in section 1.1), and the demand for cost efficiency has increased since new incentives have appeared (see e.g. Chapter 4). Hence, there has to be a balance between the aims of increasing the reliability (see e.g. section 2.4) and becoming more cost-efficient (cost analysis theory is provided in section 2.6-2.7). An analysis method using quantitative reliability assessment is proposed in this chapter where the DS generally can be divided into several system states such as different weather conditions.

Quantitative methods using reliability indices for cost-effective asset management in power distribution are not a new concept [78], [79]. Furthermore, reliability models which divide power systems into two or three weather states have been proposed [80]. For example [81] describes a model dividing power distribution systems into the states: "normal weather", "adverse weather" and "major adverse weather". Weather conditions and vulnerability differ considerably among regions, but wind, lightning and icing/snow are often identified as the most critical conditions [82]. Weather phenomena can be correlated to each other (e.g. hard wind combined with precipitation), but also to power consumption (e.g. low temperature and heating or high temperature and air conditioning). This fact complicates the analyses because it is not always clear what is causation. This is investigated in section 6.2 together with power characteristics to provide valuable input to further analyses.

Vulnerability analysis of power systems using reliability and risk-based methods have earlier been proposed, but these methods often focus on a higher system/voltage level [83], [84]. The impact on distribution system reliability indices from single storms has been analyzed earlier in e.g. [85]. Paper II proposes a vulnerability method where the DS can be generally divided into several system states - not necessarily weather-related, i.e. a flexible analysis method. The vulnerability analysis is performed by comparing the results of quantitative reliability analyses from each state. Possible legal consequences for distribution system operators (DSOs), i.e. companies with a regional concession, are presented in Paper II (in this thesis summarized in Chapter 4). A vulnerability model is suggested (see section 6.3), which is then evaluated in a case study (see section 6.4). The aim of the method is to allocate resources more cost-effectively in power distribution systems, including both human and economic resources and equipment. Section 6.5 approaches an illustrative example of potential use of received results. Finally, section 6.6 proposes an overall idea of an analysis framework, of which the vulnerability method earlier presented in this chapter, constitutes a part, while the rest of this framework is suggested as future work.

6.2 Correlations and power demand characteristics

Section 6.2.1 is based on both Paper II and Paper X. Section 6.2.2 and 6.2.3 are based on Paper X – a study of a single Swedish power distribution system (DS). Note, Paper II and Paper X are based on different studies and different DS.

6.2.1 Correlation investigations of weather and power demand

When performing analyses using weather parameters, it is important to establish whether any results are due to actual causation. A first step is to calculate the correlation between parameters, which is shown in Table 12 and Table 13. Some weather parameters also correlate with the power consumption. In Sweden, a strong (in a large temperature span almost linear), negative correlation between temperature and power demand has been identified in several studies [86] and in the study presented in Paper X, illustrated in Table 12. Hence, any temperature-related correlation might as well depend on the load. There is a risk to underestimating the total energy not supplied if mean values are used because outages are more likely to occur during high load in winter, whatever the cause (higher risk of storms, high load, frost etc.)[87]. However, in countries with warmer climate, the power consumption instead often increases with temperature due to the need for air conditioning. Table 13, illustrating results from a study presented in Paper II, shows several weather correlations in two Swedish areas (see Figure 27, section 6.4) based on ~70 000 measurements (hourly data during eight years) of each weather parameter and area. A low correlation does not automatically mean independency. For example, temperatures around 0°C increase the likelihood of strong winds, while both low and high temperatures often occur during high pressure with low wind speeds, i.e. high dependency but low correlation.

Table 12 – Correlations between different parameters (from Paper X)

	Wind direction	Wind speed	Cloudiness	Sun radiation	Power demand
Temp.	-0.02	0.13	-0.08	0.52	-0.90
Wind d.		0.27	-0.03	0.09	0.06
Wind s.			0.14	0.25	0.02
Cloud.				-0.24	0.16
Sun r.					-0.39

Table 13 – Correlations between weather events (from Paper II)

	Temperature	Wind speed	Precipitation
[1]Power demand	-0.90[3]	0.02	not available
[2]Wind speed	0.14 / 0.20		
[2]Precipitation	0.03 / 0.07	0.09 / 0.11	
[2]Snow depth	-0.58 / -0.50	0.00 / 0.20	0.00 / 0.07

[1]These statistics are from the study published in Paper X
[2]{area DS1} / {area DS2}see Figure 27
[3]The negative correlation drops below -20°C (probably all heating available is then maximally utilized)

6.2.2 Power demand characteristics of one Swedish DS

The characteristics of the electrical energy consumption of a Swedish DS have been analyzed in Paper X and its consumption pattern is illustrated in Figure 23. The power consumption in this example has obviously seasonal properties; for example, the peak load usually occurs when the temperature goes down. The change of power demand also depends on human behavior and reaches its bottom value at night (but does not significantly change between weekdays and weekends) in this example; see Figure 24.

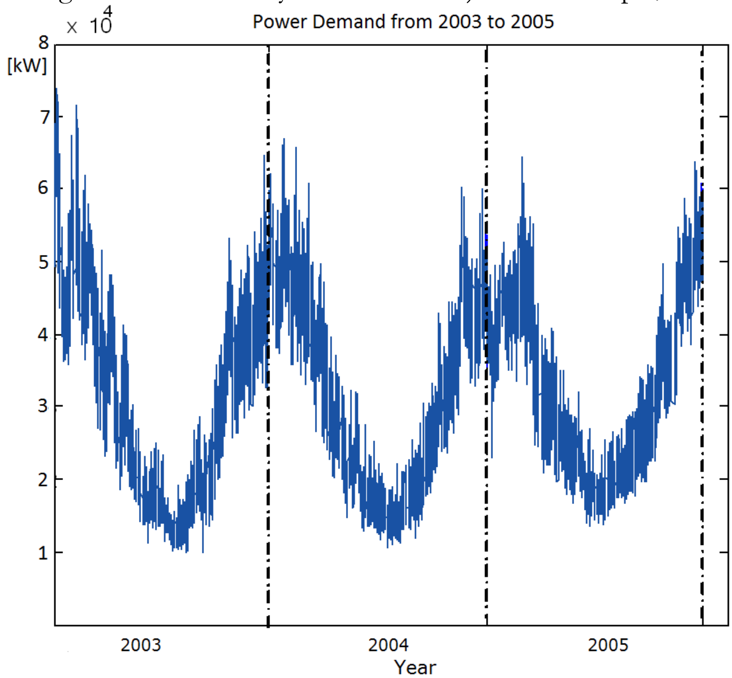


Figure 23 – Total power demand during 2003-2005.

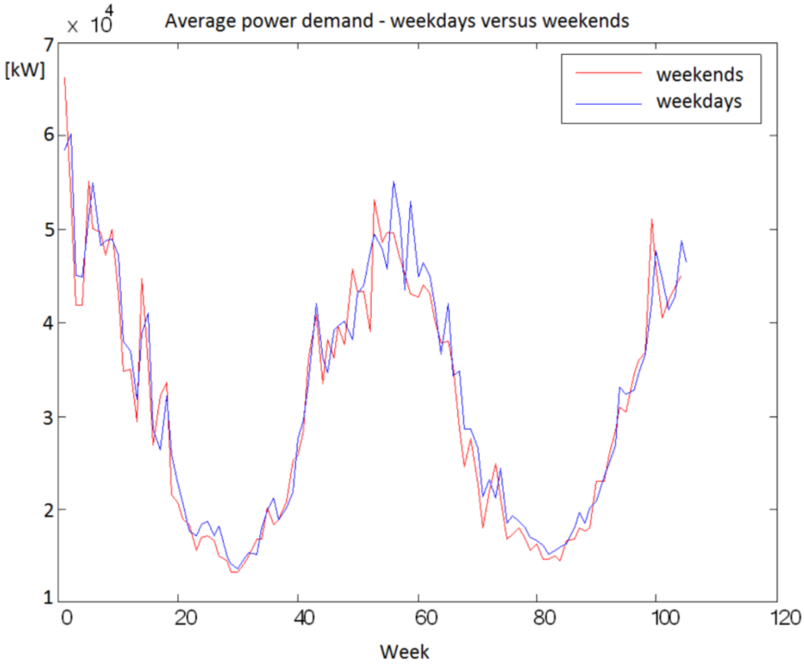


Figure 24 – Average power demand for weekdays/weekends

6.2.3 Power demand prediction models of one Swedish DS

The aim of the study presented in Paper X was to develop prediction models of energy demand (hourly/annual) and peak load (daily). Based on the load data of a DS and on detailed weather data, linear regression models are developed. The regression models are based on input data from 2003 and then validated by using input data from 2004 and 2005:

- For prediction of **power demand** (see Figure 25), a regression model using only temperature as input parameter is more accurate than using several input parameters.
- For prediction of **daily peak load** (see Figure 26) a regression model using several weather parameters had lower error than with using just temperature as input.

Proposed models and more information are provided in Paper X.

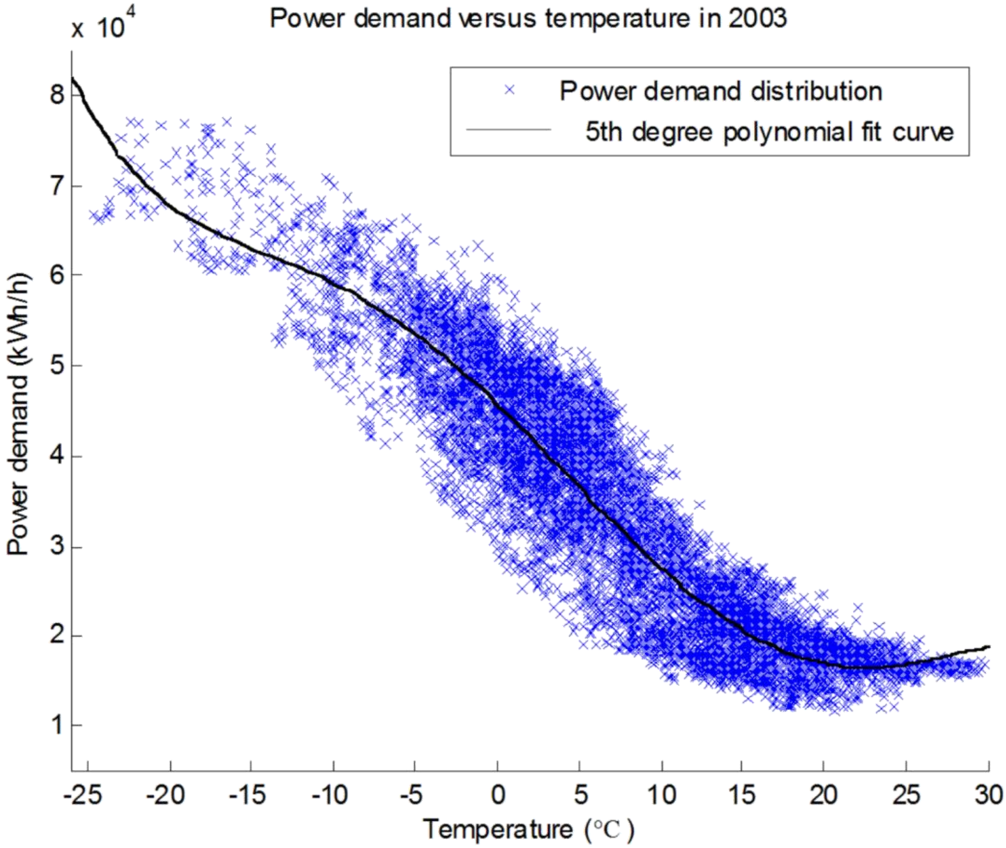


Figure 25 – Power demand vs. temperature and 5th degree polynomial fit curve

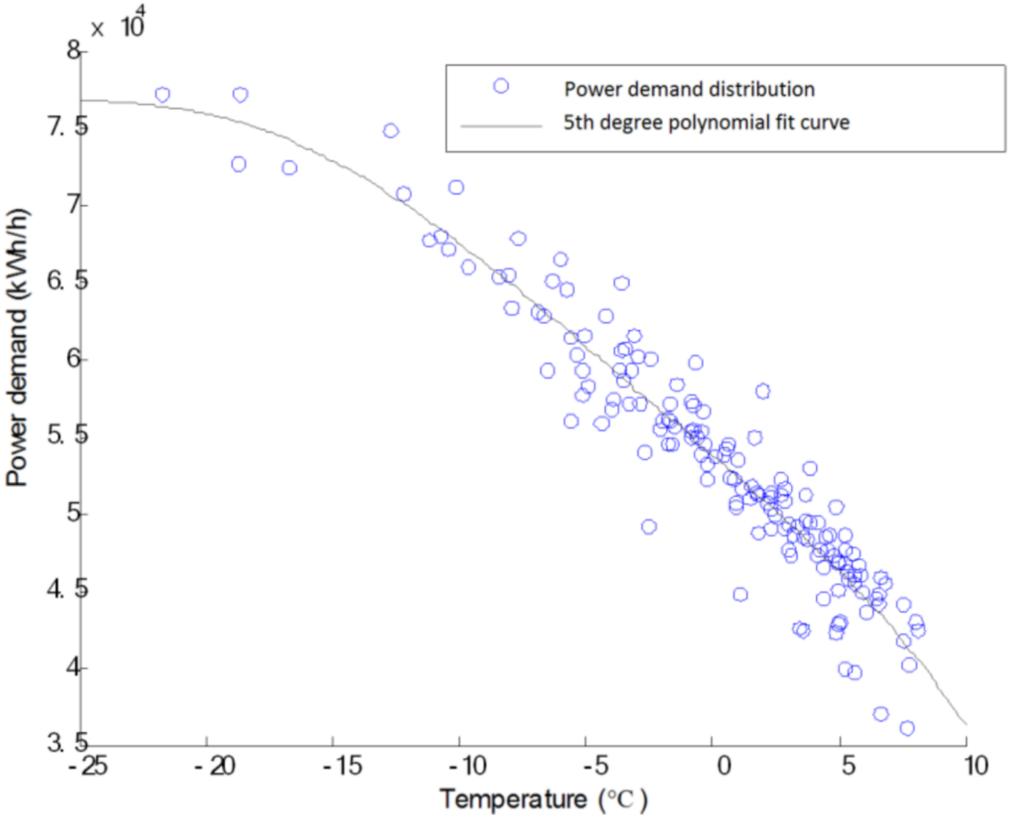


Figure 26 – Daily peak power versus daily average temp

6.2.4 Concluding remarks

In the study presented in Paper X, a specific Swedish DS (Ekerö) situated close to Stockholm, Sweden is analyzed, consisting of both urban and rural areas; however, the power demand characteristics in this system are probably, at an overall level, representative of most of Sweden. Regression models proposed are specific for this DS, but the aim is to demonstrate possible methods of developing regression models of power consumption and peak load specific for any DS.

Correlation analyses have been performed based on two studies (presented in Paper II and Paper X) and three DS. The results are valuable when developing quantitative analysis methods.

6.3 Vulnerability analysis method

This section summarizes parts of Paper II. A vulnerability method is proposed where the DS generally can be divided into several system states. The vulnerability analysis is performed by comparing the results from each state using quantitative reliability indices.

6.3.1 Method overview

1. Determine the accuracy and extent of the analysis.
2. Identify system states (section 6.3.2).
3. Calculate conditional risk/reliability indices for each state (section 6.3.3).
4. Perform a statistical validation (section 2.5.3).
5. Use the result for cost-effective resource allocation in the investment and maintenance plans (example presented in section 6.5 and ideas of more comprehensive economic analysis are proposed in section 6.6).

6.3.2 Categories of system states

From the case studies, three categories of system states have been identified as important to study separately:

- Time states (see section 6.4.2)
- Weather states (see section 6.4.3)
- Reductions in system performance, for example when a spare transformer is set aside for maintenance.

For systems in other environments, different categories might need to be defined.

6.3.3 Conditional reliability indices

Well-established reliability indices, SAIDI, SAIFI, CAIDI and AENS (see section 2.4.2) and a new introduced category of indices R_T, (see section 2.5.1), are used to analyze one system state at a time, "conditional" reliability indices are calculated:

$$[reliability\ index]^{[S]} = [reliability\ index|state\ S] \tag{6.1}$$

For example: $SAIDI^{wind\ speed\ \geq\ 8\ m/s}$ represents the average outage time per year and customer, given one theoretical full year of wind speed above 8 m/s. In reality, this state is rare and ought to be calculated based on input data from several years. If Y % of *SAIDI* can be traced to state *S*, then: $SAIDI^{S}[hours/year,\ customer\ |\ State\ S] = \frac{0.01Y*SAIDI}{P(S)}$, where *P(S)* is the probability of state *S*.

6.3.4 Examples of how to estimate costs based on indices

Translated into economic measures, R_{12} (see section 2.5.1) could roughly be estimated at \$ 0.5/customer, year. This value is based on the model presented in section 4.4.1 (the outages are assumed to be 12-24 hours and the customers are assumed to be of normal domestic size in average).

R_{24}, however, is difficult to translate into cost because of its double legal consequences – both customer compensation and additional consequences of breaking the law of 24 hour functional requirement (see Table 10).

For the UK system (see 4.4.2), R_{18} can roughly be translated into *\$ 0.1/domestic customer, year* and *\$ 0.2/non-domestic customer, year* (normal weather and 12-42 hours outages are assumed).

The DSOs could also have their own policies motivated by goodwill, for instance. A template cost, based on the quality function in the Swedish tariff regulation (other costs such as goodwill not included), is:

$$\textit{Outage cost} \approx 18 * SAIDI * \textit{Number of customers } [\$/year] \qquad (6.2)$$

Using *equation 6.2* and the assumption of R_{12} introduced in this section, the cost reduction of different reliability improvements could be estimated, e.g. input to the analysis framework proposed in section 6.6.

6.4 Case study

This section summarizes parts of Paper II.

6.4.1 Empirical data

Two electrical power distribution systems (DS) and their associated weather statistics are included in the case study. The first DS (*DS1*), situated in the Swedish region of Gästrikland (see Figure 27), is owned by Gävle Energi AB. The second DS (*DS2*), situated in the Swedish region of Värmland (see Figure 27), is owned by Fortum Distribution. Outage data have been collected for 2001-2008. Hourly weather measurements (snow depth every 24 hours) for the two areas were obtained from the Swedish Meteorological and Hydrological Institute (SMHI), at the weather stations Film and Sunne respectively, (Figure 27), selected in consultation with SMHI based on quality and proximity. The weather differs somewhat within each area, especially between coastal and inland areas for DS1 and between the western upland and the east for DS2.

For DS1, 1 851 outages above 0.05 hours were reported and for DS2 the number was 60 050. DS1 has about 50 000 and DS2 about 150 000 customers. During the studied period, two severe weather events occurred in Sweden:

- The storm "Gudrun" 8-9 January 2005: Seven days in this study are linked to the storm to capture delayed reported outages.
- The storm "Per" and additional severe weather events in January 2007: Ten days in this study are linked to this weather event.

Figure 27 – Southern Sweden.

By applying the cost model presented in section 6.3.4, the economic consequences are: estimated at:

$$C_{DS1} \approx 900\ 000 * SAIDI + 25\ 000 * R_{12} + \dagger * R_{24} \quad [\$/year] \tag{6.3}$$

$$C_{DS2} \approx 2\ 700\ 000 * SAIDI + 75\ 000 * R_{12} + \dagger * R_{24} \quad [\$/year] \tag{6.4}$$

The consequences, $\dagger$, of R_{24} are difficult to estimate since these outages are forbidden by Swedish law from 2011.

6.4.2 Time categories

Reliability analyses have been performed to determine how the outages are distributed over different periods of time. Figure 28 exemplifies results from the case study for DS2 for unplanned outage durations. The contribution from the two major weather events that occurred during the analyzed period is shown in the figure. Figure 28 clearly illustrates how individual weather events can affect the average values of several years. See Paper II for the results in detail.

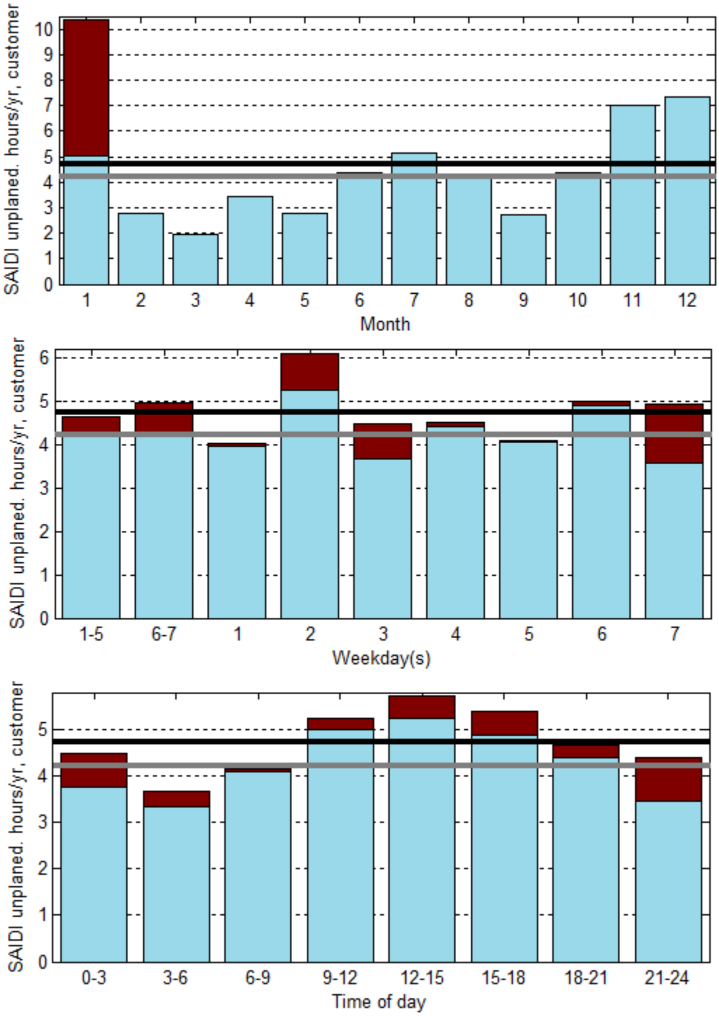


Figure 28 – SAIDI for DS2, unplanned outages divided into months, weekdays and time of day for 2001-2008. The combined contributions of Per and Gudrun are illustrated with a different color at the top of each bar. The black line is average SAIDI, gray line is average SAIDI with Per and Gudrun excluded.

Knowledge of differing expected reliability parameters between time periods can be used to evaluate whether a DSO has an adequate level of preparedness for inconvenient working hours and when it is appropriate to schedule preventive maintenance. An example of how the results could be used in practice is provided in section 6.5.

Month

Knowing the expected reliability on a monthly basis is useful for the planning of maintenance and holidays. The differences between months are probably explained by weather and human activities, for example highest probability of lightning during summer, while the probability of hard wind is highest during autumn and winter. Both systems have the lowest probability of outages during spring and in September. In DS2, the risk is elevated during November to January. See Paper II for the results in detail. An example of how to use this result is presented in section 6.5.

Weekday and hour of the day

Knowing the expected reliability of weekdays or time of day may, for example, to be useful in determining the readiness needed during shifts. The differences between weekdays showed in Paper II might be explained by human activities and the security level. If the reliability differs between days, the DSO could consider reallocating existing resources. For interruption during non-"normal" working hours, the lowest probability of interruption is between approximately 03-06 AM (see Paper II for the results in detail). The causes of the differences have not been studied in detail, but load and human activity are likely explanations based on experience (i.e. discussions with DSOs).

6.4.3 Weather categories

Clarification of Figure 29-Figure 32

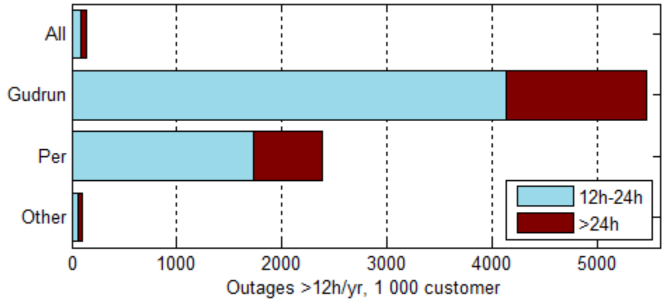
The upper part of the figures illustrates the number of outages ≥12 hours during a "hypothetical" full year with each state respectively. These values can therefore seem high, especially for states with low probability and high vulnerability. The lower part illustrates the contribution from each state to different reliability indices. Here, the contribution can be low from a vulnerable state because of its low probability.

Dependencies and correlations

For the analysis of weather conditions, it is important to establish whether any results are due to actual causation when identifying risk reduction proposals. A first step is to calculate the correlation between weather parameters, which is shown in section 6.2, Table 13. Some weather parameters could also correlate with the electrical consumption, which is shown in section 6.2, Table 12.

Effects on major weather events

The two severe weather periods listed in section 6.4.1 have only marginally affected the results of DS1, but the contribution in DS2 is large. The results are outlined in Figure 29; see Paper II for the results in detail. About 20 % of all outages ≥12 hours in DS2 occurred during Gudrun. Per also contributed to a significant share of the long outages, but, compared with Gudrun, had more impact on SAIFI, which might be explained by better preparedness, as an effect of experience gained from Gudrun.



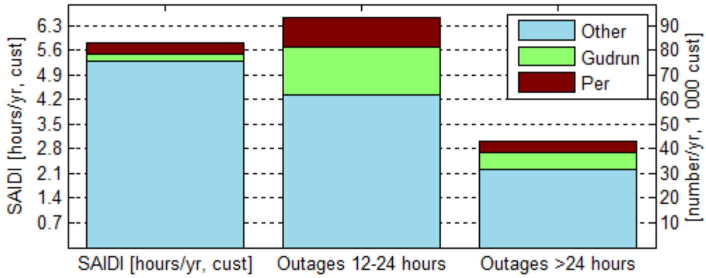


Figure 29 – DS2, the contribution from two single major weather events during a period of eight years. The upper figure presents conditional values given a specific state. The lower figure is in absolute average values.

Wind speed

The overall results for DS2 are illustrated in Figure 30; see Paper II for the results in detail for DS1 and DS2. Wind speed ranges are determined in accordance with the Beaufort scale [88]. The results show that the vulnerability of the system is in principle independent of wind speed most of the time except due to strong winds.

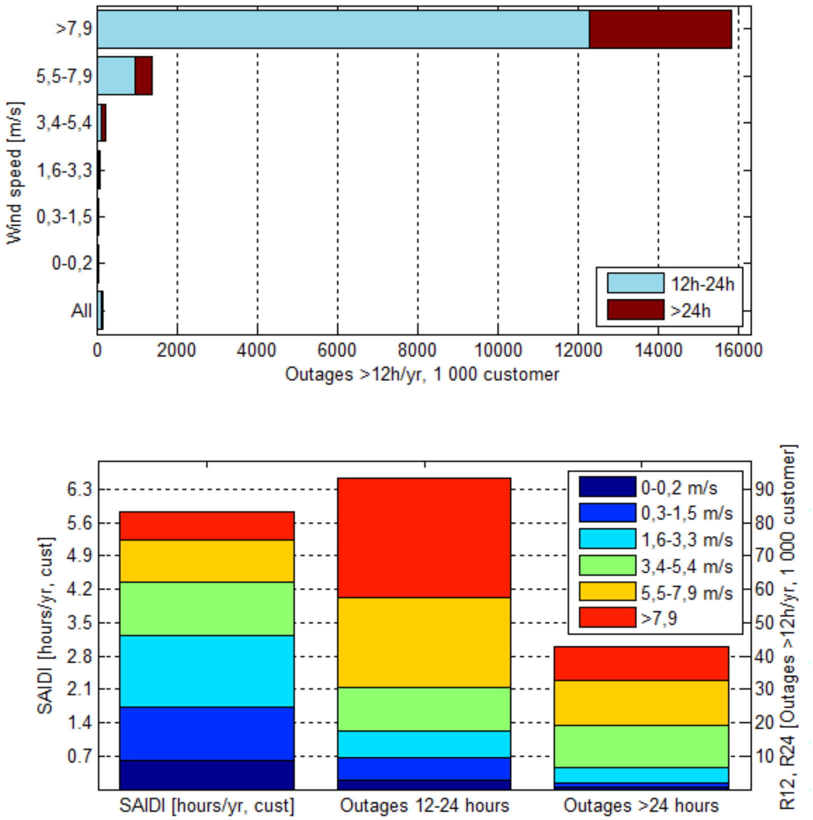


Figure 30 – DS2, indication of the vulnerability of strong wind.

Temperature and high load

The results presented in Paper II show no clear connection between reliability and temperature or power consumption. The outage variations between temperature intervals that exist might be explained by some weather events being more likely at certain temperatures and human activities; for example, digging depends on temperature in subarctic areas. In Sweden, underground cables currently account for a relatively small percentage of all outages, but in the future, this share will increase as a result of increased amount of such investments (see e.g. Chapter 5), which motivates more futures studies on the vulnerability of underground cables.

Snow depth

See Paper II for the results in detail. The results of DS2 indicate an increased risk, primarily due to increased CAIDI (which is natural) while the results of DS1 indicate negligible impact.

Precipitation

Measurements of precipitation of the last 24 hours are used in this study. This is motivated by the fact that outages could occur from a chain of events (e.g. snowfall) longer than one hour. The accumulated 24h-value is established for every hour. The results (see Paper II) show that large amounts of fresh snow increase the risk of outages in both DS1 and DS2. Less snow than ~15 cm/24 hours and probably* rain have basically no effect at all.

*The results from DS2 first indicated an increased vulnerability followed by rainfall. To investigate the cause, the system state was divided into two sub-categories, based on the wind situation, showing that the increased risk due to rain is often combined with strong winds.

Weather related risk categories

The studied DS are vulnerable to excessive snow and high wind speeds. To analyze the influence of these risk categories and causality, a number of system states have been analyzed further (see Paper II for the results in detail). The results show that only strong winds or heavy snowfall alone increases the vulnerability and that the combination of the two is more critical than the sum of the individual states. The results of DS1 and DS2 are illustrated in Figure 31 and Figure 32 respectively.

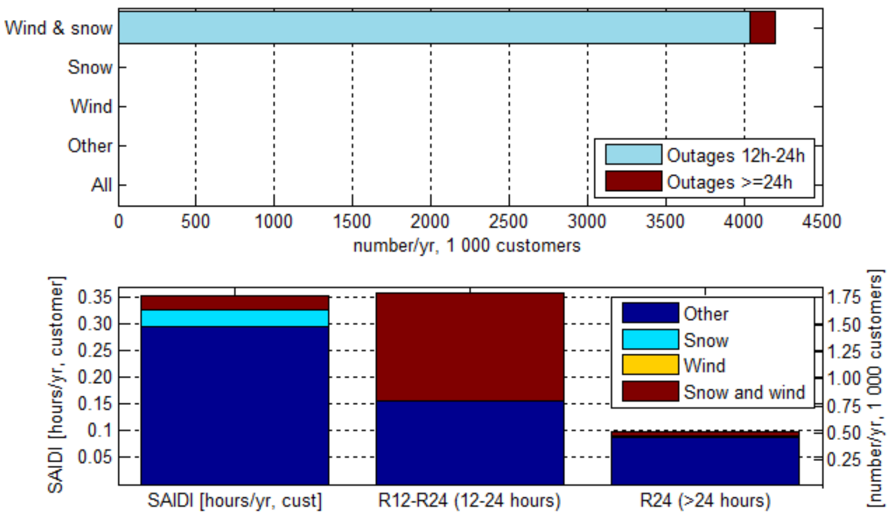


Figure 31 – DS1, vulnerability categories with respect to identified weather categories that provide the highest risk for customer outages.

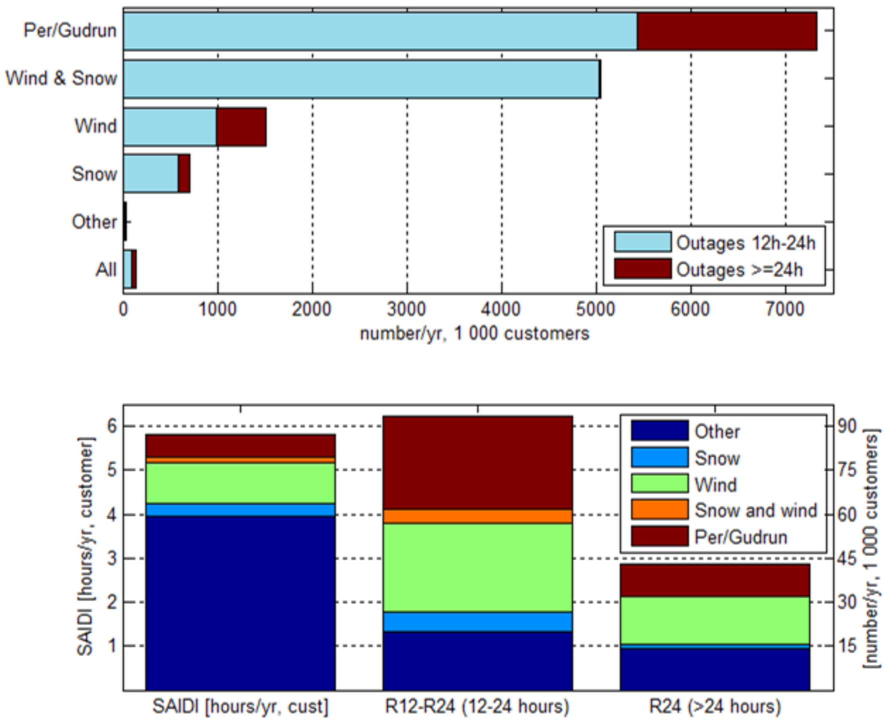


Figure 32 – DS2, vulnerability categories with respect to identified weather categories that provide the highest risk for customer outages.

6.5 Examples of how to use the results in practice

This section summarizes parts of Paper II.

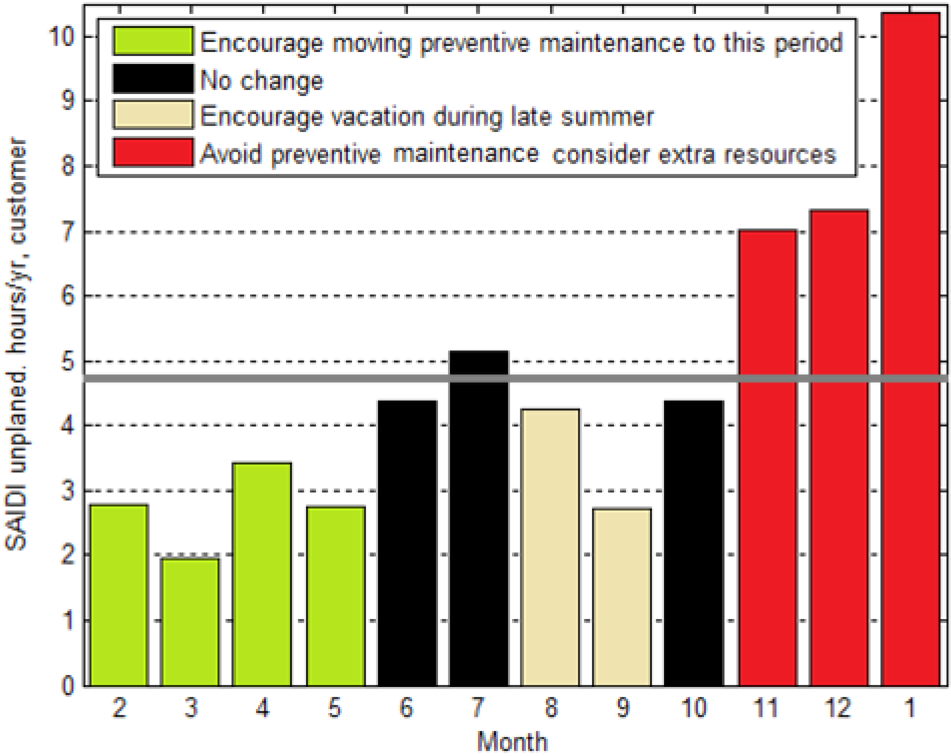


Figure 33 – DS2, example of how results from the proposed vulnerability method could be used in practice.

The vulnerability analysis method gives indications of effective resource allocation. With respect to the vulnerability analysis results of different months (see section 6.4), preventive maintenance should be performed during spring (see Figure 33); vacations should be concentrated in late summer; increased manning, i.e. more human resources, should be considered for October-January. This gives a more balanced level of resource utilization throughout the year and also decreased risk level in general.

No cost analysis is performed here. Analysis results from the method can, however, be used to evaluate asset management actions and to improve the utilization of existing resources. In future work, more detailed cost analysis methods should be added; see section 6.6.

6.6 Cost-effective resource allocation

6.6.1 Introduction

Risk- and vulnerability analyses of electrical power distribution systems (DS) can be performed by using quantitative reliability methods (see section 2.4). Reliability analysis is a risk analysis category which demands a great deal of historical statistics as input and consequently is inappropriate to apply to several other technical fields (more information in section 2.1 and section 2.3). Nevertheless, reliability analyses are mostly based on average input data; a disadvantage with such approach is for example that unacceptable risks and long outage compensation models (see section 4.4) are not captured (this problem is discussed in section 2.2). By dividing the DS into different system states (see section 6.3.2); much information can be gained about system behavior in different situations which with traditional reliability approaches had been missed (see section 6.4). This information can be used to address resource allocation and investment planning (see section 6.5). The presented method can be viewed as a step toward quantifying the good practice of today.

6.6.2 The potential use of the model

The resource allocation model aims, for example, to be used to:

- Develop cost effective investment and maintenance plans.
- Evaluate whether extra preparedness (e.g. more personnel) ought to be considered as a consequence of some categories of weather forecasts.
- Estimate the appropriate amount of reserve components and resources that could be shared with other DSOs (a problem is that weather events often affect DSOs simultaneously). A potential consequence of such long outage compensation and functional requirement as that in Sweden (see section 4.4) is fear of lending/renting resources to other DSOs.
- Estimate preparedness motivated during inconvenient hours.
- Investigate how planned maintenance could be scheduled when the system is as little vulnerable as possible.
- Identify unacceptable vulnerabilities/risks.

6.6.3 Model overview

The approach is to divide comprehensive projects into minor analyses and then compile the results. Different resource allocation alternatives (e.g. project and maintenance plans), are first analyzed with respect to different system states as earlier exemplified in section 6.3-6.4. The aim is to identify strategies, as profitable as possible, taking the entire economic life times into account (e.g. "savings" could in the long run be costly), i.e. it is recommended to perform life cycle cost (LCC) analyses (see section 2.7). The resource allocation model can be described as a matrix as illustrated in Table 14. Each column of the matrix represents a system state (S_j), previously published in Paper II. Each row of the matrix represents a resource allocation alternative (e.g. an investment or saving).

Table 14 – Proposed resource allocation model

System state:			S_1"*normal*"	S_2	...	S_N
Res alloc.	$\boldsymbol{\Delta Cost}$	$P(\ldots)$ $\boldsymbol{Aver.}$	$1-\sum_{j=2}^{N} P(S_j)$	$P(S_2)$	...	$P(S_N)$
1 "no"	0	A_1	A_{11}	A_{12}	...	A_{1N}
2	$\boldsymbol{\Delta C_2}$	A_2	A_{21}	A_{22}	...	A_{2N}
3	$\boldsymbol{\Delta C_3}$	A_3	A_{31}	A_{32}	...	A_{3N}
⋮	⋮	⋮	⋮	⋮	↘	⋮
M	$\boldsymbol{\Delta C_M}$	A_M	A_{M1}	A_{M2}	...	A_{MN}

Each ΔC_i is the cost differences between keeping current status and applying analyzed resource allocation. These values can, of course, be positive as well as negative (for example when comparing savings needed). Traditionally, one analysis is performed for each investment alternative and then compared based on a system average (A_i) or on a normal system state (A_{i1}). If an optimization is performed considering the average or normal case, important effects can be neglected such as costs compensation for long outages. Each square in the matrix (A_{ij}) illustrates a minor analysis (compared with A_i), which could be performed separately. The connection between the minor analyses and a traditional analysis is hence given by:

$$A_i = \sum_{j=2}^{N}\left(A_{ij}P(S_j)\right) \tag{6.5}$$

Chapter 7

Closure

Carl Johan Wallnerström

Chapter 7 concludes the thesis and proposes ideas for the future.

7.1 Conclusions

This thesis investigates incentives which promote the development of more advanced analysis methods applied to electrical power distribution systems (DS). The structure of the thesis can be summarized as follows: (a) an introduction to risk/asset management applied to DS, (b) studies of incentives (both learning from the history and an inventory of current and future incentives), (c) a case study describing risk management and investment planning at a distribution system operator (DSO) and (d) proposals based on (a)-(c). The regulator has the role of providing incentives for cost-efficient operation with acceptable reliability and reasonable tariff levels. Because DS are considered as natural monopolies, with several different owners, the regulation must also be objective and fair. The experiences from Sweden show the importance of having a constructive dialogue between parties involved. A difficult task for the regulator is to settle the complexity, i.e. the balance between consider many details and the manageability.

The Swedish regulation of DS tariffs between 1996 and 2012 together with complementary laws are investigated. The aim is to learn from both novel approaches and from drawbacks. Three studies of the previous regulation of customer network tariffs, referred to as the Network Performance Assessment Model (NPAM), have been performed. The NPAM had a unique and novel approach which, however, prompted a great deal of criticism. The main conclusion from two studies appended is that the NPAM is not robust to small variations of input data. Hence, these studies were possibly a contributing factor to its fall. Moreover, a project initiated by the regulator has been performed, aimed at reviewing a potential model to judge effectible costs. Based on results from this project some initial plans concerning the upcoming regulation were changed.

The main conclusion from the first part of the thesis is that there is a need to implement new, more advanced, analysis methods applied to DS because of increased incentives. The second part of the thesis continues with investigations and proposals of analysis methods. To find a suitable level of analysis complexity, an application study investigates current risk analysis methods at a DSO. Significant differences between categories of DS and between voltage levels are concluded. Partly based on these results, a classification of different risk policies is provided. A vulnerability analysis method is proposed and demonstrated. The method can be used to allocate resources more cost-effectively. The idea is to divide analyses into minor parts and then compile the results. An application study, evaluating the proposed method is presented including how weather parameters and power demand affect the system reliability. Heavy snowfall and strong winds have great impact, while the impact of temperature, rain, snow depth and power demand are relatively small. A new reliability index approach (R_T) is introduced, flexible so as to adjust to different laws or DSO policies of long outages. Furthermore, a statistical model is proposed for evaluating reliability indices as a function on amount of input data.

7.2 Future work

Continue to investigate the progress followed by changed incentives and by new techniques and methods*, as well as develop more advanced analysis methods*. A specific example is to develop the analysis framework presented in section 6.6 further, while the ongoing work on RCAM (see section 1.2) can be seen as an overall research vision. The entire infrastructure of electrical power has to undergo significant developments and large investments to meet future requirements. Both the supply and the demand side will be changed. On the supply side, the power system is integrating more and more power generation from renewable sources, on both a small- and a large-scale. On the demand side, some nodes can function as both consumers and as small producers. *Who is to pay for an upgrade of the infrastructure needed?* It is not obvious which companies will make money on a smart grid concept; DSOs have a monopoly on construction, while their authorized business activities are strictly regulated. The power system is moving in the direction of what is referred to as the *smart grid*. Existing tariff regulation models do not to any significant extent support *climate incentives* such as rewarding low losses, which will be a future challenge; however, the upcoming Swedish tariff regulation encourages DSOs to increase component life times (see section 4.2.2), which decrease the climate impact.

Investigation of how to model "common cause failures": Failures are often, in analyses, assumed to be independent. In reality, this is not always the case (see section 2.3.6). Assumed redundancy is not appropriate to use in all contexts. A fire in a double transformer station can affect both transformers; a severe weather event often affects several components at the same time in a power system, and so on. Actually, a common cause failure is often more likely to occur, than two simultaneously independent failures. A method to handle these kinds of dependent events is to introduce "common cause failures", which are assigned their own probabilities. In order to evaluate the possible impact of common cause failures, *correlation studies* is an important issue and it is not always clear what is real causation (see section 6.2).

Further investigation of approaches to handling mean values in reliability analyses: Good and comprehensive input data is expensive, and sophisticated analysis based on detailed data demands large resources (see section 2.2). A common solution is to use mean values of failure rates, for example. However, there are significant disadvantages tied to the use of mean values in the analysis; for example, using mean restoration time does not take into account all possible consequences. One approach is to estimate a more comprehensive, better suiting, distribution which yields results close to reality but is, on the other hand, complex, costly and time consuming. A less costly approach that still encompasses a large range of consequences is to divide an unwanted event into sub-categories with their own probabilities and consequences.

Abbreviations and vocabulary

Abbreviations

C	Covariance
Cust	Customers
DS	(electrical power) Distribution System
DSO	(electrical power) Distribution System Operator
EBR	See section 2.2.1.
EI	Energimarknadsinspektionen (Energy markets Inspectorate)
EKM	See section 4.3.
ENS	Energy Not Supplied
hrs(s)	hour(s)
HV	High Voltage (i.e. all voltage levels above MV)
int	interruption(s)
LCC	Life Cycle Cost
LV	Low Voltage (i.e. 0.4 kV in Sweden)
MV	Medium Voltage (i.e. 1, 6, 11 or 22 kV in Sweden)
NL	Net Level
NPA	Network Performance Assessment
NPAM	the Network Performance Assessment Model
NPF	Net Present Factor
NPS	Net Present Sum
OH [line]	Over Head [line]
RBTS	"Roy Billinton"/ReliaBility Test System
RCAM	Reliability Centered Asset Management
RCM	Reliability Centered Maintenance
RTS	IEEE Reliability Test system
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEK	Swedish krona, the currency of Sweden. The Swedish currency, SEK, is often translated into Euro and/or American dollar. However, because the thesis is based on studies over several years, assumed exchange rates may slightly differ between appended papers, but are given within papers concerned (\$ 1 ≈ 6.5 SEK, € 1 ≈ 9 SEK in June 2011).
SMHI	Swedish Meteorological and Hydrological Institute
STEM	Swedish Energy Agency (STatens EnergiMyndighet)
UG [cable]	Under Ground [cable]
V	Variance
WACC	Weighted Average Cost of Capital
yr(s)	year(s)

English-Swedish Dictionary

English	Swedish
Disconnector	(last)frånskiljare
capacitor bank	kondensatorbatteri
covered overhead line	belagd luftledning
debiting rate	debiteringsgrad
network performance assessment	nätnytta
overhead cable	hängkabel
pole mounted transformer	stolptransformator
secondary substation	nätstation
Substation	fördelningsstation
substation feeder bay	linjefack
substation switching bay	ställverksfack
The Network Performance Assessment Model	Nätnyttomodellen
line corridor	trädgata

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