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Abstract

The objective of this report is to provide state of the art in theory and practice of reliability assessment in power systems, including socio-economic impact assessment. The results are based on literature surveys and a questionnaire survey among TSOs providing information on reliability management in practice. The responses cover 9 TSOs in total from the Nordic countries and the Continental Europe, representing different system sizes, characteristics and control zones.

The results of the literature survey on reliability assessment are presented for two main areas: reliability indicators and reliability methods. The literature survey on socio-economic impact assessment mainly deals with value of lost load, and how to estimate such costs.

The synthesis of the literature surveys and responses to the questionnaire indicates that there is a gap between the existing research literature and what is practiced by TSOs. Probabilistic methods, including socio-economic impact assessment, seem to be used to some extent in long-term planning and in mid-term planning and asset management, while almost absent in the short-term operation of the power system. The TSOs are, however, already collecting reliability data for primary equipment. A few lessons can be learned, from air traffic management and sectors such as nuclear power, gas supply, water supply, and railway, regarding amongst other need for novel probabilistic assessment methodologies.

The report provides a common basis for the development of new reliability criteria for power systems.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

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EXECUTIVE SUMMARY

This report describes state of the art in theory and practice of reliability assessment methodologies including socio-economic impact assessment. The report provides a common basis for the development of new reliability criteria for power systems.

The results are based on literature surveys covering a total of about 130 publications. In addition, a questionnaire survey was performed among TSOs providing information on reliability management in practice. The responses cover 9 TSOs in total from the Nordic countries and the Continental Europe. These represent different system sizes, characteristics and control zones. Despite the limited number, the responses are regarded sufficiently representative for Europe.

Assessing power system reliability is a complex and comprehensive task involving a multitude of factors, dimensions and uncertainties. Due to the complexity and different needs in different decision contexts and time horizons, it is necessary to decompose the problem into sub problems. Various methodologies for reliability assessment have been developed over decades, each solving a specific part of the overall problem and there are different indicators in use to describe reliability.

The results of the literature survey on reliability assessment are presented for two main areas: reliability indicators and reliability methods. Indicators are separated in deterministic and probabilistic reliability indicators. In the area of reliability analysis, a distinction is made between the two main approaches to probabilistic reliability assessment, namely analytical and Monte Carlo simulation methods. Both online and offline tools found in the literature are also presented.

The literature survey on socio-economic impact assessment mainly deals with value of lost load (VOLL) or customer interruption costs, and how to estimate such costs. A lot of different methods exist for estimation of VOLL. Examples of applications of VOLL estimates are given in the report, such as, cost-benefit studies of probabilistic reliability criteria compared to the N-1 criterion and the use in quality of supply regulation of the network companies.

Most of the TSOs in the questionnaire survey reported that they use the N-1 criterion strictly. However, the majority also reports that they sometimes apply the N-0 criterion, meaning that they accept more severe consequences when the probability is regarded small.

The synthesis of the literature survey and responses to the questionnaire indicates that there is a gap between the existing research literature and what is practiced by TSOs. Probabilistic methods, including socio-economic impact assessment, seem to be used to some extent in long-term planning and in mid-term planning and asset management, while almost absent in the short-term operation of the power system. The TSOs are, however, already collecting reliability data for primary equipment.

A few lessons can be learned from air traffic management and sectors such as nuclear power, gas supply, water supply, and railway, amongst other: reliable infrastructures result from complex interactions between multiple human operators, procedures and technical systems. Traditional indicators fall short in covering these complex interactions. Thus, there is a need for novel probabilistic assessment methodologies.

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1 INTRODUCTION

This report is the first deliverable from work package 1 (WP1) in the GARPUR project. The 4-year GARPUR research project designs, develops and assesses new probabilistic reliability criteria and evaluates their practical use while maximising social welfare [1].

WP1's overall objective is to analyse the approaches currently used by TSOs to ensure power system reliability and assess similarities and differences in how the N-1 criterion is implemented.

The objectives of this work package are to
1) Revisit current and proposed methodologies for reliability assessment and management, including socio-economic impact assessment
2) Provide a common basis for the development of new reliability criteria and motivation for change.

There are three tasks to meet these objectives:
- T1.1 Revisiting methodologies and definitions of concepts and metrics
  - Reliability assessment methodologies
  - Socio-economic impact assessment
  - Lessons learned from other sectors
- T1.2 Current reliability management approaches
  - Current practices and priorities for improvement
  - Coming grid codes and state of the art on development of reliability criteria
- T1.3 Drivers and barriers for new reliability standards for the European Power System
  - What can be abandoned and which concepts must be preserved?
  - Improvement options offered and the risks of replacing past practices related to the N-1 criterion. Possible risks in terms of overall system reliability.

The work in WP1 (tasks 1.1 - 1.3) is performed by triangulation, i.e., different methods and approaches are used to meet the objectives, such as literature surveys, questionnaire survey among TSOs and expert evaluations/ interviews/ discussions.

This deliverable presents the results from the first task (T1.1) on state of the art in theory and practice of reliability assessment methodologies and socio-economic impact assessment, including some lessons learned from other sectors. The report provides a common basis for development of new reliability criteria.

The report is organized as follows: First, the main terms and definitions used in this report are described in Chapter 2. The reliability concept and framework are described in Chapter 3, as a background for structuring the reliability methodologies. The results on state of the art from literature surveys and the questionnaire survey are given in Chapter 4 and 5, respectively, regarding reliability and socio-economic impact assessment. In Chapter 6, a short description is given of some approaches where these two aspects are combined. Lessons learned from other sectors are given in Chapter 7, before a summary and the conclusions are drawn in Chapter 8. Finally, the list of references is provided in Chapter 9.

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2 TERMS AND DEFINITIONS

The main terms used in this report are listed in this chapter. The definitions are grouped according to fundamental reliability concepts and reliability analysis, respectively.

2.1 Reliability concepts

Power system reliability

Power system reliability means the probability that an electric power system can perform a required function under given conditions for a given time interval [2].

Note 1: Reliability quantifies the ability of an electric power system to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time [2].

Note 2: The definitions above (from [2]) describes the reliability from the power system perspective. From the end-user perspective, reliability of supply is frequently used as a term describing how reliability is perceived at a local delivery point. See note 3 for how reliability of supply may be measured:

Note 3: The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service [3].

Note 4: Reliability of a power system can be divided into power system security and power system adequacy [3]:

> **Power system security** is the ability of the power system to withstand sudden disturbances such as short circuits or un-anticipated loss of system components. Security refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without the interruption of customer service [3, 4]. Another aspect of security is system integrity, which is the ability to maintain interconnected operations. Integrity relates to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of specified severe disturbances [4].
>
> **Power system adequacy** is the ability of the system to supply the aggregate electric power and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of the system components [3].

Reliability management

Power system reliability management means to take a sequence of decisions under uncertainty. It aims at meeting a *reliability criterion*, while minimising the socio-economic costs of doing so.

Reliability criterion

A reliability criterion is a principle imposing a basis to determine whether or not the *reliability* level of a power system is acceptable. Such a principle can be expressed as a set of constraints that must be satisfied by the decisions taken by a TSO.

N-1 criterion

The N-1 criterion is a principle according to which the system should be able to withstand at all times a credible contingency - i.e., unexpected failure or outage of a system component (such as a line, transformer, or generator - in such a way that the system is capable of accommodating the new operational situation without violating operational security limits. (Partly based on [5, 6]).

Note 1: The N-1 criterion is a deterministic *reliability criterion*.

Note 2: There is no common definition of N-1 in literature. It is defined in several different ways which are more or less similar. To show the variety, some of the definitions are provided in Appendix 1.

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Reliability indicator
A reliability indicator is an observable or computable quantity that provides insight into the level of reliability of a system in a particular context. It can be used, ex-ante, to formulate a *reliability criterion* used for *reliability management* or alternatively to assess, ex-post, the *reliability* level of a system.

Note: a reliability indicator is a measure of *reliability*.

2.2 Reliability analysis

Reliability analysis of power systems traditionally attempts to answer three fundamental questions (in analogy to risk analysis [7]):

1. What can go wrong?
2. How likely is it to happen?
3. What are the consequences?

Terms used in relation to these questions are grouped and described in the following.

2.2.1 What can go wrong, and how likely is it to happen?

Threat
Threat can be defined as any indication, circumstance, or *event* with the potential to disrupt or destroy a system, or any element thereof. This definition includes all possible sources of threats, i.e., natural hazards, technical/operational, human errors, as well as intended acts such as terror and sabotage [8]. Threat can also be defined as anything that might exploit *vulnerability* (*remark: i.e., susceptibility*) [7].

Note 1: Threat is external to the power system [9].
Note 2: The threat may lead to an *unwanted event* understood as a disruption of the system, such as power system *failures* [9].

Vulnerability
Vulnerability is an expression for the problems a system faces to maintain its function if a threat leads to an *unwanted event* and the problems the system faces to resume its activities after the *event* occurred [9]. Vulnerability is an internal characteristic of the system, composed by *susceptibility* and (lack of) *coping capacity*:

> **Susceptibility**
> The susceptibility of the infrastructure describes how likely it is that a *threat* leads to a disruption in the system and is depending, e.g., on the technology, the working force and the organization. A system is susceptible towards a *threat* if it leads to an *unwanted event* in the system [9].
>
> **Coping capacity**
> Coping capacity describes how the operator and the system itself can cope with an *unwanted event*, limit negative effects, and restore the function of the system to normal state [9].

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Event
The general term event is defined as occurrence of a particular set of circumstances [10]. In [7, 11], it is distinguished between hazardous and initiating events, and accident scenarios (sequence of events). Often in power systems, terms like *failure* events and extraordinary (or exceptional) events are used.

Unwanted event
An unwanted event is here defined as an event involving power system *failure*(s) leading to a disruption or disturbance in the power system (i.e., a *contingency*). Unwanted event is often used synonymously with undesired event [11]. The unwanted event 'power system failure' may result in power supply *interruption*.

Contingency
A contingency is the unexpected *failure* or *outage* of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages [5].

Disturbance
Disturbance is an unplanned *event* that produces an abnormal system condition [5].

Failure/fault
A failure is the termination of the ability of an item to perform a required function. After failure, the item has a fault [12].

Fault rate (frequency)
The fault rate is the number of faults of a continuously required function (of a component), per unit of time exposed to such faults = number of faults of a particular type per unit exposure time [13].

Note: Fault rate (or frequency) is in this report used synonymously with failure rate or failure frequency.

Outage
An outage is the state of a component or system when it is not available to properly perform its intended function due to some *event* directly associated with that component or system (IEEE Std. 493-1997, see, e.g., [14]).

2.2.2 What are the consequences?

Consequence
Consequence is the outcome of an *event* [10].

Note: There can be different types of consequences: technical (like *interruption*), economic or environmental consequences, consequences on personnel/ consumers safety, etc.

Interruption
Electric service interruption denotes the involuntary loss of electricity supply to one or more end-users. In technical terms, a supply interruption is a condition in which the voltage at the supply terminals is lower than 5 % of the reference voltage [15]. Supply interruptions are classified in terms of duration as 1) long interruptions (longer than 3 min) or 2) short interruptions (up to and including 3 min).

Note: An interruption may also be partial, if a contingency leads to reduced capacity to supply the load such that the electricity supply is only partially interrupted.

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Interrupted power
Interrupted power is the estimated power that would have been supplied to end-users at the time of interruption if no *interruption* and no transmission restrictions had occurred (Based on [14] and ENS below).

Note: Often, terms like load curtailed, lost load and load shed are used with a similar meaning.

Energy not supplied (ENS)
Energy not supplied is the estimated energy which would have been supplied to end-users if no *interruption* and no transmission restrictions had occurred [16].

Criticality
Criticality refers to the extent of the *consequences* for the users of the infrastructure when a system does not carry out its intended function [9]. The criticality describes how severe the consequences are for users who are dependent on the system.

Interruption costs
Interruption cost is the socio-economic cost of *interruptions* to customers/end-users, measured, e.g., in terms of *value of lost load* (VOLL).

Cost of energy not supplied (CENS) [17, 18]
Costs of energy not supplied represent *interruption costs*. CENS is a similar concept as *value of lost load* (VOLL) and both concepts are used in this text.

Value of lost load
Value of lost load (VOLL) is defined as a measure of the cost of unserved energy (the energy that would have been supplied if there had been no outage) for consumers [19]. This is in principle the same concept as the *cost of energy not supplied* (CENS).

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3 POWER SYSTEM RELIABILITY FRAMEWORK

The purpose of this chapter is to describe the basic reliability concepts and framework for reliability management, providing a context for the state of the art on reliability and socio-economic impact assessment methodologies. The chapter is to a large extent based on the GARPUR Description of work part B (DoW, [1]) and [9].

3.1 Reliability and vulnerability

Society is critically dependent on a reliable electricity supply to cover basic needs such as food and water supply, heating, safety, financial and ICT services. This dependency is increasing as a consequence of more use of ICT and new uses like electrical vehicles and distributed electricity storage. Failing to provide a reliable electricity supply has far reaching consequences for individuals, society and the economy.

Power system reliability means the ability to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time [1, 2]. This ability to perform the required function is occasionally terminated by failures in the power system, most often with minor consequences. Such failures may be caused by threats external to the power system itself. The power system is designed and operated according to the N-1 criterion and severe consequences will most likely be caused by combinations of failures. Extraordinary events involving multiple failures and devastating impacts are usually regarded to have (very) low probability (high impact, low probability events).

Figure 3-1 illustrates the link between the power system's exposure to external threats and the levels of criticality for society. The strength of this link depends on the power system vulnerability, as illustrated by the figure. A system is vulnerable if it fails to carry out its intended function, the capacity is significantly reduced, or the system has problems recovering to normal function. Vulnerability is composed of susceptibility to threats and (lack of) coping capacity, which are internal characteristics of the system [9].The power system is susceptible towards a threat if it leads to a disruption in the system. Susceptibility depends e.g., on the technology, the working force and the organization. An example is a poor technical condition of a component due to ageing. The coping capacity on the other hand, describes how the operator and the system itself can cope with the situation, limit negative effects, and restore the function of the system after a disruption (unwanted event).

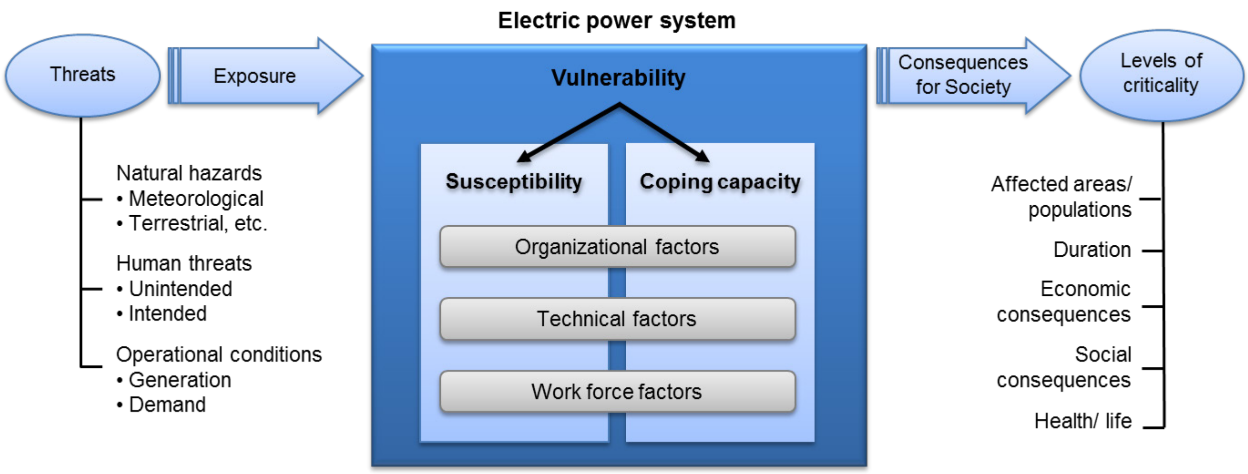

Figure 3-1: Electric power system vulnerability [9]

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While vulnerability is an internal characteristic of the system, reliability can be explained by the combination of its vulnerability to external threats that can lead to failures, and the implied loss of electricity supply for the end-users. In broad terms, power system reliability covers all dimensions of the picture, except the consequences (criticality) for society.

The criticality of the consequences is a combined measure of the loss of electricity supply and the society's dependence on electricity. As illustrated in the figure, the criticality is for instance directly dependent on factors like affected area, duration, type of customers, economic and social consequences, and consequences for life and health.

Threats are evolving outside the vulnerable system and can be related to nature, humans or the operational conditions as shown in the figure. This framework allows for all kinds of hazards or threats to be taken into account, representing an all-hazard approach.

There are numerous factors that have an influence on the vulnerability (both susceptibility and coping capacity) and, as such, on the power system reliability. These can be sorted in the three categories technical, work force and organizational, as indicated by the figure. Examples of internal system factors with influence on susceptibility and coping capacity in the pan-European power system are given in Table 3.1. More examples can be found in [9].

Table 3-1: Examples of factors with influence on susceptibility and coping capacity, based on [1, 9]

Influencing factor	Susceptibility	Coping capacity
Organizational	Structure of the TSOs Coordination between operators Availability of information Regulations of the electricity market	Contingency plans Coordination of restoration Availability of communication systems Regulations of the electricity market
Technical	Reliability criterion Technical condition of components Redundancies Operational stress Existence of pre-fault preventive actions	Reliability criterion Equipment for repair Spare parts Redundancies Existence of post-fault corrective actions
Work force	Operative skills Availability of skilled personnel Human errors	Skills in system restoration and repair of critical components Availability of personnel

The reliability criterion and how we manage reliability is in itself an example of factors in Table 3.1 that may influence on both the susceptibility and coping capacity. For example, if the current reliability criterion N-1 is not fulfilled, the power system is more susceptible to threats than if it is fulfilled. On the other hand, if N-1 is fulfilled, it represents a reserve which is important for the capacity to cope with an unwanted event and quickly restore the electricity supply.

3.2 Reliability management

Power system reliability management means to take a sequence of decisions under uncertainty. The overall objective is in principle, to ensure an adequate level of reliability while minimizing total socio-economic costs. In practice, reliability management is decomposed in three types of time horizons and activities, namely long-term system development, mid-term planning including asset management and short-term system operation. This is illustrated in Figure 3-2.

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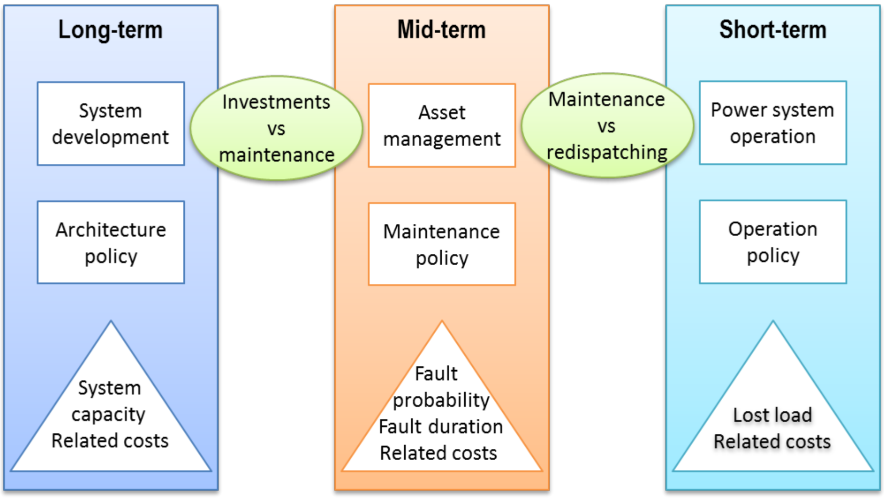

Figure 3-2: Decomposition of reliability management in three different time horizons [1]

The reliability management in the different time horizons follows some kind of principles known as the reliability criteria. On the European level, the power system is divided in various control zones where the respective TSO is responsible for the reliability management according to the regulations set by the corresponding regulatory authority. The current N-1 criterion is partly differently interpreted and implemented by the TSOs. Current reliability management practices are addressed in the second deliverable (D1.2) from this work package.

This report focuses on reliability and socio-economic assessment methodologies. Assessing power system reliability is a complex and comprehensive task involving a multitude of factors, dimensions and uncertainties. As illustrated by Figure 3-1, the reliability of electricity supply is affected by a variety of external threats and internal vulnerabilities, as well as the possible consequences to society. Due to the complexity and different needs in different decision contexts and time horizons, the problem needs to be decomposed into sub problems. Depending on the specific context and needs, various methodologies for reliability assessment have been developed over decades, each solving parts of the overall problem. There is no single methodology suitable for an all-encompassing reliability analysis. This is shown by the state of the art description of methodologies in the succeeding chapters. The following section describes a conceptual framework for the reliability assessment.

3.3 Reliability assessment

Reliability assessment is divided into reliability analysis and reliability evaluation [7]. In this report, we mainly focus on the analysis part.

In a given power system, the reliability depends on the threats, vulnerabilities, and the consequences, as illustrated by Figure 3-1. Instead of trying to analyse and assess the overall probability of functioning, reliability analysis of power systems traditionally attempts to answer three fundamental questions (in analogy to risk analysis [7]):

1. What can go wrong?
2. How likely is it to happen? (if a probabilistic approach is used)
3. What are the consequences?

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On a high level, the so-called bow tie model has been accepted as a good conceptual model to assist risk and vulnerability analysis in general [11]. This model can also be used to provide a framework for reliability analysis as it is suitable for describing some basic principles and important relationships even for highly complex problems.

The bow tie model is a concept for helping to structure and visualize the causes and consequences of unwanted events. An unwanted event is here defined as the event 'power system failure' leading to a disturbance in the power system. Figure 3-3 gives an example where the main unwanted events to be considered are power system failures potentially leading to interruptions of the electricity supply. The figure shows the main categories of threats, which include natural hazard, technical/ operational, human errors and intended acts such as terror or sabotage.

The threats might lead to power system failures through a set of causes, while failures might lead to different consequences through a set of circumstances.

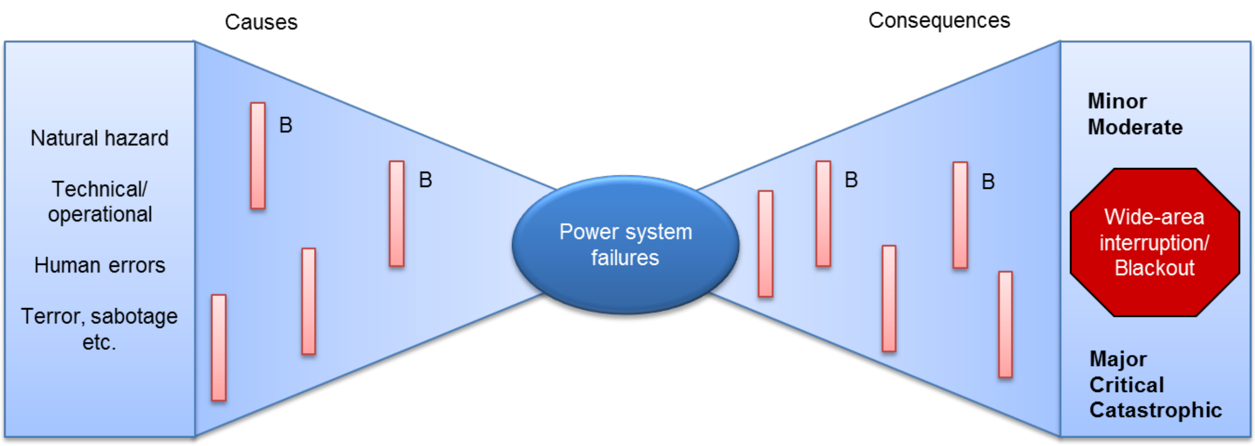

Figure 3-3: Bow tie model: Threats, power system failures, consequences and barriers (B) [9]

To the left in the bow tie model, possible causes behind the unwanted event are listed. The potential consequences are shown to the right. The starting point for the analysis is the unwanted event (power system failures). An important part of the causal analysis is to establish the relationship between the unwanted event and the basic causes. In general, this is often performed using fault tree analyses, while the consequences might be analysed by using event tree analyses [7]. In power system reliability analysis, usually more advanced models like power flow analyses are needed for the consequence analysis.

As indicated in the figure, a number of barriers (B) exist to prevent threats from developing into unwanted events and to prevent or reduce the consequences of unwanted events. A system is more vulnerable towards the relevant threats if the barriers are weak or malfunctioning. Examples of barriers to avoid the unwanted event are: adequate vegetation management, the N-1 criterion is fulfilled, protection settings are tested and correct, and adequate system protection schemes are in place. System protection schemes can also be barriers to reduce the consequences of the unwanted event. Other examples are: work force and communication systems are available for restoration/repair. More examples can be found in [9]. Comparing these examples with the vulnerabilities (susceptibility and coping capacity) exemplified in Table 3.1, it can be noticed that the vulnerabilities are closely related to the barriers.

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The consequences of power system failures are often quantified according to the amount of interrupted power and interruption duration, or energy not supplied. The consequences can be further classified from minor to catastrophic [20]. This classification will depend upon the system size and area under study, if it is a city or a community, a larger control zone or on the pan-European level.

One basic input parameter to the probabilistic reliability analysis is the fault frequency, while the output is measured in terms of reliability indicators like those mentioned above. The relationship between these indicators and the framework presented in Figure 3-1 is as follows: fault frequency describes the result of exposure to threats and the susceptibility to these threats. Energy not supplied adds information about the coping capacity, i.e., the consequences of the unwanted event measured as interrupted power and interruption duration. The duration is determined from the switching times and component repair times, which are included in the coping capacity and also basic input parameters to the reliability analysis. Expected interruption costs add information about the societal consequences for different end-users. The reliability indicators are illustrated in Figure 3-4.

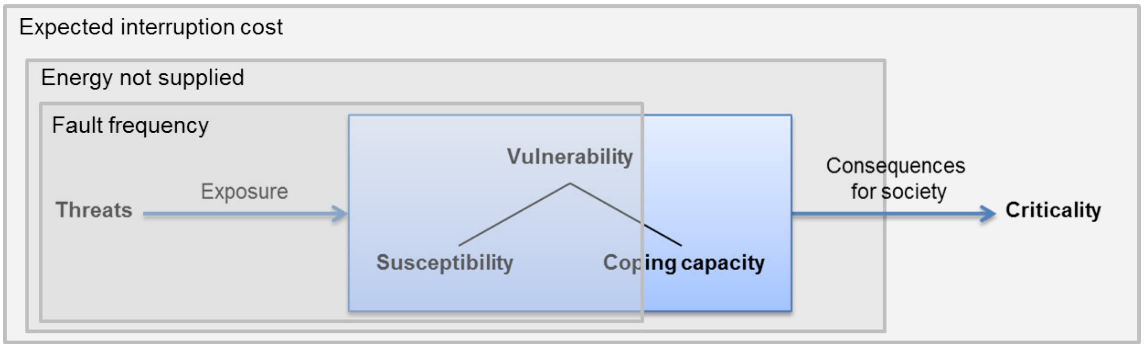

Figure 3-4: Examples of reliability indicators and relationship with vulnerability [9]

Based on the results of the reliability analysis, the next step of the reliability assessment is to perform reliability evaluation, e.g., to evaluate the results against the reliability criterion, analyse reliability improving measures such as to protect against or reduce (if possible) certain threats, identify and assess vulnerability reducing measures, or measures to limit the consequences. In practice, this means to identify and assess the right barriers on both the cause and the consequence side of the bow tie (Figure 3-3).

The context will be different for the reliability analysis in the different time horizons and there are different indicators in use to describe the reliability, which are outlined in the next chapter. Nevertheless, the main principles remain the same as described in this chapter. The framework serves as a background for structuring the methodologies in the succeeding chapters.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

4 STATE OF THE ART ON RELIABILITY ASSESSMENT

4.1 Literature survey

The aim of the literature survey on reliability assessment methodologies was as far as possible to cover the multitude of dimensions and aspects that are addressed in the GARPUR project, i.e. the two main aspects of reliability (security and adequacy), the three time horizons described in Chapter 3, and the various alternatives as described in DoW [1] regarding renewables, exogenous threats, corrective control and high impact low probability events, etc. Hence, the search for literature has partly been general and partly targeted to research literature and reports found by general requests and through different sources, such as, IEEE Xplore, CIGRE-, ENTSO-E and NERC-publications. The literature is surveyed and described in this chapter according to the two main topics reliability indicators and reliability methods, as follows:

- **Reliability indicators[1]:** What we measure.
- **Reliability methods:** How do we measure it:
    - What can go wrong?
    - How likely is it to happen?
    - What are the consequences?

In addition, a structured overview is given in this chapter of the literature covered by the survey.

Note that reliability is here divided in security (short-term reliability) and adequacy (long-term reliability).

4.1.1 Reliability indicators

In this section, the state of the art reliability indicators are presented. The following categorization is chosen for the indicators in this report:

- **Deterministic adequacy indicators:** Indicators measuring the historical performance of the power system.
- **Probabilistic adequacy indicators:** Indicators forecasting the performance of the power system over time.
- **Deterministic security indicators:** Indicators concerned with the system's security.
- **Probabilistic security indicators:** The same as the previous one, but the indicator also takes probabilities into account.
- **Component reliability indicators:** Indicators on power system components' reliability.

4.1.1.1 Deterministic adequacy indicators

According to ENTSO-E's network code on operational planning and scheduling [21], each TSO shall contribute to an annual report on the system's performance containing the following indicators:

- OPS 1A: number of events in which an incident in the contingency list led to a degradation of system operation conditions.
- OPS 1B: number of events counted by indicator OPS 1A, in which the degradation of system operation conditions occurred as a result of unexpected discrepancies of demand and generation forecast.

[1] Often in literature, terms like 'reliability metric/metrics' and 'reliability index/indexes/indices' are used. Here, the term 'reliability indicator' is used to explain and sort the different measures that are used to present the reliability level in a given context and time frame. This is to avoid using too many different terms and to ensure coherence with the terminology used in other work packages in GARPUR.

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- OPS 2A: number of events in which there was a degradation of system operation conditions due to an Out-of-Range contingency.
- OPS 2B: number of events counted by indicator OPS 2A, in which the degradation of system operation conditions occurred as a result of unexpected discrepancies of demand and generation forecast.
- OPS 3A: number of events leading to degradation in system operation conditions due to lack of active power reserves.

The indicators that ENTSO-E specifies are the minimum requirement for the TSOs, and some of the TSOs do have a more thorough reporting of faults. The Nordel group has for instance had common guidelines for reporting faults in their transmission systems since 1971 [16, 22]. Since 2006, the Nordic transmission system operators (previously under Nordel, now under ENTSO-E Operational Committee have published the common fault statistics for the Nordic grid in English [23]. The fault statistics contain information on the number of disturbances, energy not supplied, faults in power system components, failure causes, outages and HVDC statistics [16, 24].

Perhaps the most comprehensive framework for monitoring the performance of the bulk power system is that of the North American Electric Reliability Corporation NERC. The framework consist of a definition of an adequate level of reliability (ALR), which the system can be said to have if it possesses the following characteristics [25]:

- **ALR1:** The system is controlled to stay within acceptable limits during normal conditions
- **ALR2:** The system performs acceptably after credible contingencies
- **ALR3:** The system limits the impact and scope of instability and cascading outages when they occur
- **ALR4:** The system's facilities are protected from unacceptable damage by operating them within facilities rating
- **ALR5:** The system can be restored promptly if it is lost
- **ALR6:** The system has the ability to supply the aggregate electric power and energy requirements of the electric consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

NERC's assessment methodology also consist of a framework for selecting indicators [26]. The assessment is done in annual reports, which have been published since 2009 [26-31]. The number of indicators has increased since the first report. In the latest report [31], the following ALR indicators were reported:

- ALR1-3: Planning reserve margin.
- ALR1-4: Bulk power system transmission related events resulting in loss of load
- ALR1-5: System voltage performance.
- ALR1-12: Interconnection frequency response
- ALR2-3: Activation of underfrequency load shedding
- ALR2-4: Average percent non-recovery disturbance control standard events
- ALR2-5: Disturbance control events greater than most severe single contingency
- ALR3-5: Interconnected reliability operating limit/system operating limit exceedances
- ALR4-1: Automatic transmission outages caused by failed protection system equipment
- ALR6-1: Transmission constraint mitigation
- ALR6-2: Energy emergency alert 3 (firm load interruptions due to capacity and energy deficiencies)
- ALR6-3: Energy emergency alert 2 (deficient capacity and energy during peak load periods)
- ALR6-11: Automatic AC transmission outage initiated by failed protection system equipment
- ALR6-12: Automatic AC transmission outages initiated by human error

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- ALR6-13: Automatic AC transmission outages initiated by failed AC substation equipment
- ALR6-14: Automatic AC transmission outages initiated by failed AC circuit equipment
- ALR6-15: Element availability percentage
- ALR6-16: Transmission system unavailability.

The name of the indicators contains two numbers, where the first corresponds to the ALR addressed, and the second to when it was proposed. Some indicators have been discarded, as can be seen from the fact that the second number is not continuous. In the latest report [27], two additional indicators are reported in addition to the ones addressing ALR.

- **SRI:** Severity risk indicator, which is used to assess the system's reliability performance over time with regards to multiple ALRs [32]
- **KCMI:** Key compliance monitoring indicator, which indicates the system's compliance with requirements in the NERC standard [27].

Examples of adequacy monitoring found outside of the large interconnected areas, such as ENTSO-E and NERC, can also be found. One example is the adequacy monitoring enforced in Brazil [33].

4.1.1.2 Probabilistic adequacy indicators

The above mentioned adequacy indicators are all deterministic indicators in the sense that they merely give a measure or indication on how the system has performed in the past (ex-post). In the literature there exist proposals for many probabilistic indicators, aiming at estimating (quantifying ex-ante) the probability of the system's adequacy. An extensive list of probabilistic indicators reported in the literature is given in [34]:

Load point indicators:

- Basic values:
  - Probability of failure
  - Expected frequency of failure [f/yr]
  - Expected number of voltage violations
  - Expected load curtailment [MW]
  - Expected energy not supplied [MWh]
  - Expected duration of load curtailment [h]
- Maximum values:
  - Maximum load curtailed [MW]
  - Maximum energy curtailed [MWh]
  - Maximum duration of load curtailment [h]
- Average values:
  - Average load curtailed [MW/curtailment]
  - Average energy not supplied [MWh/curtailment]
  - Average duration of load curtailment [h]
- Bus isolation values:
  - Expected number of curtailments
  - Expected load curtailed [MW]
  - Expected energy not supplied [MWh]
  - Expected duration of load curtailment [h].

Power system indicators:

- Basic values:
  - Bulk power interruption indicator (BPII) [MW]
  - Bulk power supply average curtailment indicator (BPSACI) [MW/curtailment]
  - Bulk power energy curtailment indicator (MBPECI) [minutes]

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- Average values:
  - Average number of curtailments
  - Average load curtailed [MW]
  - Average energy curtailed [MWh]
  - Average duration of load curtailed [h]
  - Average number of voltage violations
- Maximum values
  - Maximum system load curtailed under any contingency condition [MW]
  - Maximum system energy not supplied under any contingency condition [MWh].

For the above given list of probabilistic adequacy indicators it is worth noticing the following:
- The list is not exhaustive,
- the indicators have to be calculated for given time horizons, and
- the indicators have to be calculated for given operating conditions.

One potential problem with the above given probabilistic adequacy indicators is that they do not take the N-1 criterion into consideration [34-36], as they are only concerned with the cases where loads are curtailed. From a more traditional deterministic point of view it would be beneficiary to also quantify the probability of being in a state where the N-1 criterion is not fulfilled. To address this issue, a set of security constrained adequacy indicators is proposed [35, 36]. The indicators are the probabilities of being in a certain system operating state. Rather, than using the system states normally found in the literature [6, 37], the following simplified states are used:
- **Healthy:** The system is at least N-1 secure.
- **Marginal:** The system is no longer N-1 secure; however, it is still operating adequately.
- **At risk:** System or equipment constraints are violated and loads may be curtailed.

4.1.1.3 Deterministic security indicators

According to ENTSO-E's network code on operational security article 8 [6], TSOs shall classify the state of their system in the following categories.

a) Normal state
b) Alert state
c) Emergency state
d) In-extremis
e) Restoration.

The network code gives strict criteria for determining which state the system is in. To give an idea of the criteria without going into details from the network code, the system states found in the literature [37], are presented.
- **Normal state:** In this state, the system is stable, no constraints are violated, and the system is able to withstand any single credible contingency.
- **Alert state:** In this state, the system is still stable and no constraints are violated, however, the reserve margins are not sufficient to guarantee that the system is robust to any single credible contingency. Depending on the operation rules, actions can take place to bring the system to the normal state.
- **Emergency state:** In this state, the system is still intact; however, some system constraints are violated. The system can be restored to the normal state (or at least to the alert state), if the suitable corrective actions are taken.
- **In-Extremis:** In this state, both generation-load system balance and voltage and power limits are violated. The system loses synchronism, there are cascading outages and possibly shutdown

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of a major portion of the system. Control actions, like load shedding or controlled system separation are used for saving as much of the system as possible from a widespread blackout.
- **Restoration:** In this state the equipment is reconnected or energized to restore lost loads.

These states correspond to the ones used in the ENTSO-E network code, but with a less strict definition. To determine which state the system is in, the following values shall be monitored by the TSOs [6]:
- Busbar voltages
- Active power flows
- Reactive power flows
- Frequency
- Generation and consumption.

4.1.1.4 Probabilistic security indicators

In [38], a method is proposed which addresses the issue of the probability of contingencies occurring. The idea is to calculate the risk of system constraint violations given a specified operating state. The general formulation of such an indicator can mathematically be described as:

$$Risk(X_{t,f}) = \sum_i \mathrm{P}(E_i)(\sum_j P(X_{t,j}|X_{t,f}) \times Sev(E_i, X_{t,j}))$$

Where:
- $X_{t,f}$ is the forecasted system condition at time *t*
- $X_{t,j}$ is the j^{th} possible system condition at time *t*
- E_i is the i^{th} contingency
- $Sev(E_i, X_{t,j})$ is the severity of contingency *i* happening at loading condition *j* at time *t*.

The different indicators within this class of indicators are distinguished by the choice of severity function. Proposals for severity functions addressing different security issues are presented in [38]. They argue that technical severity functions are the most useful for operators and give examples on how discrete or continuous severity functions can be defined. The methodology is further extended upon in [39], where a proposal for risk indicators for transient stability is proposed, and in [40], where severity functions for high currents are introduced. In [40], an aggregated indicator called loss of load (LOL) is also suggested. A summary of the identified indicators are given below:
- **Low voltage risk indicator**
- **Overload risk indicator**
- **Voltage instability risk indicator**
- **Cascading risk indicator**
- **Overloading risk indicator**
- **High current risk indicator**
- **Transient stability risk indicator**
- **Loss of load risk indicator.**

The suggested risk indicators are examples of means to quantify the risk, which a system is subjected to. For the grid operators it is also of importance to be able to correctly assess a certain level of risk, meaning that it should be clear to the operators when the risk level is unacceptable. A suggested solution to this is presented in [41]. The suggestion is to classify the risk level within the identified acceptable region, into three different risk levels. By doing this, a framework is obtained for assessing how critical is the system's risk level. An example to the approach is given, in which the risk levels associated with overload on a transmission line is classified.

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4.1.1.5 *Component reliability indicators*

The reliability of the system is not only dependent on how it is loaded in comparison to its limits. It is also dependent on the reliability of each of its individual components. Consequently, there is a need for quantifying the reliability of the system's components to obtain a more complete picture of the system's reliability.

The most important basic indicators of component reliability are given as [42, 43]:

- Failure rate
- Repair rate
- Mean time to failure (MTTF)
- Mean time to repair (MTTR = 1/repair rate)
- Mean time between failures (MTBF).

It is worth noting that the failure rate, which is one important input to reliability assessment, has different names in the literature. Among these are force of mortality (FOM), rate of occurrence of failures (ROCOF), hazard rate and fault rate.

In the application guide [44], it is shown how the failure rate can be calculated from statistical failure data, giving an average value over all the components in the system. The failure rates can also be estimated from manufacturer data and later updated by failure data from statistics as suggested in [45, 46]. For many applications it is of value to know the failure rate of one particular power system component. How to estimate failure rate is shown in, e.g., [42].

Another type of components which influences the system's reliability is protection systems, which have been identified as one of the leading causes of blackouts [31, 47]. This is reflected in some of the adequacy indicators reported in the NERC reliability reports, like ALR4-1, which measures the reliability of protection equipment. Similar indicators are proposed in [12, 48], defined as:

- The probability of not having a failure to operate
- The ability of not having an unwanted operation
- The probability that a protection can perform a required function under given conditions for a given time interval.

In [49], these indicators are calculated and compared, using data from Norway and Finland.

4.1.2 Methods and tools for reliability assessment

Historically there have been similarities between short-term and long-term assessment of the bulk power system. In [37], traditional off-line security assessment is described as a process, where one tries to identify all relevant system limits in advance of operation. Similarly, reference [50] describes the deterministic approach to long-term planning as simulating the performance of the system for given time periods, loading conditions and contingencies to identify solutions to possible violations of a given performance criterion. Consequently, the simulation of the power system given all relevant operating conditions can be identified as paramount to both the long- and short-term time horizons. Among the various aspects which should be considered for such simulations are:

- Shall probabilities be considered?
- The extent of the simulation.
- How to model internal and external elements and factors relevant for the simulation.
- What should be the output of the simulation?

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It is not possible to cover all these topics exhaustively within one report. Consequently, we aim at giving an adequate overview of the available possibilities, instead of giving an extensive overview of each paper. The presentation is structured in topics. The rationale is that a reliability assessment has to consider how to model different aspects of the power system; to be able to calculate different reliability indicators. It is therefore deemed reasonable to present the view in literature on different aspects of the reliability assessment.

Before moving on to the presentation of the methods and tools for reliability assessment, a distinction is made between the two main approaches to probabilistic reliability assessment: analytical and Monte Carlo simulation methods [43, 51]. The difference lies in how the contingencies are selected. In analytical methods, like the contingency enumeration approach, the contingencies are first selected by screening techniques and then based upon a failure criteria [52]. Monte Carlo simulations select the contingency based upon random sampling [43, 51]. It is also possible to construct hybrid models as demonstrated in [53, 54]. Using this approach, non-outage states that are not N-1 secure can be identified, by the contingency enumeration approach.

4.1.2.1 Modelling weather, corrective control and market related issues

To perform a full reliability assessment, one would ideally want to model all relevant aspects of the power system and the external factors influencing it (cf. Ch. 3). Typical external factors (threats) to consider include [9]:

- Natural hazard
- Technical/operational aspects
- Human errors
- Terror, sabotage.

There are various methods for modelling the relation between threats and power system failures. Common for many of these methods is the use of component failure frequency. This concept is already mentioned in section 4.1.1.5 Actually, most of the probabilistic reliability assessment methodologies in the literature use failure frequencies as important input data. To get a general introduction on how failure frequencies are used in probabilistic assessment, a good reference is [43].

There are different proposed approaches to modelling natural hazards; the most common is to model weather effects. In references [55, 56], an approach to model the influence of different weather conditions on the security within the operational time frame is given. The idea is that fault statistics are based upon average data, and that one with relatively high certainty can know the weather conditions for the operational time frame. Given these assumptions, one can calculate components' failure frequencies for the given weather relative to the average failure frequency. Reference [57] compares one, two, and three state Markov weather models, this approach might be better suited for long-term studies as it takes the probability of the weather types into account. This is in contrast to references [55, 56] where the weather is assumed to be constant over the operational time frame. An approach where the weather is indirectly taken account of is demonstrated in the OPAL methodology [14]. Instead of calculating the influence of weather, the influence of the time of occurrence is taken into account. In this way seasonal variations are captured. The resolution of this approach might not be sufficient for operational purposes, but it should suffice for long-term planning.

Among the technical and operational issues faced in reliability assessment of a power system, is preventive and corrective control. The problem can be viewed as either technical or operational depending on whether the actions are performed automatically or manually by operators.

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Protection system's influence on the reliability can be assessed using the probabilities of the components' different failure modes as described in [14]. More on protection system's influence on the power system's reliability is presented in the sections on cascading faults (4.1.2.2 and 4.1.2.5 .

In this paragraph, a few examples related to corrective actions like rescheduling, and disconnection of power system units are presented. Typically, like in the planning tools reported in [14, 50], load shedding is based upon optimal power flow solutions. Similarly, reference [54] uses a minimum load curtailment approach, in which the minimization problem aims at minimizing the curtailed load instead of the costs. Other authors like [55], acknowledge the fact that it might be unreasonable to assume that the operators will be able to perform as an optimal power flow. They argue that it might be more reasonable to assume the operator to shed blocks of load close to the contingency. Another example is presented in [58], where uncertainty is considered not only with respect to the occurrence of a contingency but also with respect to the effectiveness of corrective control. On this basis, an explicit probabilistic reliability management framework is proposed.

With the introduction of deregulated markets, the inclusion of a market model might be necessary to get a complete picture of the system's reliability. This is reflected in ENTSO-E's network code on operational planning and scheduling [21], where it is explicitly stated that the TSOs shall perform intraday adequacy analysis taking forecasted market data into account. On a longer time scale, the need for detailed forecasts are not as prudent, regardless it would be beneficiary to model the market to some extent. One methodology acknowledging this fact is the OPAL methodology, which can take load and production forecasts from the market model EMPS as input [14]. The most common handling of market issues seems to be the use of economic dispatch, which is used by many of the tools reported in [50], and also other reports like [54, 59]. A model representing load increase, transmission upgrades and daily load fluctuations for blackout studies is presented in [59]. The model is based upon simple rules determining how the demand and transmission capacity will gradually increase. Nevertheless, it represents a useful approach for incorporating such effects into the assessment.

4.1.2.2 Contingency selection methods relevant for all time horizons

In the ENTSO-E network code on operational security [6], it is stated that the TSOs within ENTSO-E shall define a contingency list containing internal and external contingencies. External contingencies are contingencies outside of a TSO's responsible area with a high influence on its area [6]. The contingency list shall contain ordinary contingencies and may contain exceptional contingencies, if their probability is high enough. Ordinary contingencies are N-1 situations, whereas exceptional contingencies are higher order contingencies. The situation is similar in the US, where the US electricity industry is considering if it should become mandatory to monitor higher order contingencies [60]. It could be noted that although guidelines are given, the definition of "exceptional" is not exactly specified in the ENTSO-E network code, neither is the "high influence" clarified.

By adding more contingencies to the contingency list, more intricate methods for selecting a relevant contingency list may be needed. Traditionally, contingency lists have been constructed based upon expert knowledge [61] or automatic contingency screening algorithms [61, 62]. The automatic contingency screening algorithms typically perform fast approximate methods to identify the most important contingencies for further assessment [61, 62]. Examples on fast approximate methods are DC power flow, fast decoupled power flow, partial solutions of the power flow, geographical bounding of the problem, and combinations of these methods [61, 62].

The contingency selection methods described in [61, 62], are mainly methods where approximate power flow is performed to identify the critical N-k contingencies, without considering the importance of protection and switching equipment. It is, however, of importance to consider this type of equipment for reliability assessment. This need is demonstrated in [63], where the importance of hidden failures for the development of power system outages were presented. A hidden failure is defined as a "permanent defect that will cause a relay or a relay system to incorrectly and inappropriately remove a circuit element(s) as a direct consequence of another switching sequence" [63]. Hidden failures may in other words lead to the outage of multiple components due to one single initiating event. The idea that one initiating event might lead to cascading outages were further investigated in [64], where substation faults were simulated using event trees. The idea is that the probability of an N-k fault can be determined constructing event trees for the chain of events leading to the faults. Using this method facilitates the identification of N-k faults with probabilities of occurring in the same order of magnitude as that of N-1 faults. The rationale is that the consequences of N-k faults are inherently more severe than those of N-1 faults. Consequently, these N-k faults with a high probability of occurring should be included in the contingency list. Similarly, references [65, 66] also calculates the consequences at the end of each branch, which is used to calculate the risk associated with the end branches [65]. Reference [66] uses event trees to calculate the following indicators, which can be used to identify components' contribution to the system's risk:

- Fussel-Vesely importance
- Risk decrease factor
- Risk increase factor.

References [65, 66] extends both the idea of cascading faults from merely giving an indication on which contingencies to consider. Their use of risk indicators give an indication on the system's risk associated with certain initiating events, paths of events, and equipment failures. Information that could be useful beyond identifying critical contingencies, as it also gives information on the system's security towards the same contingencies.

4.1.2.3 Online tools for measuring security

As earlier mentioned, the ENTSO-E network code on operational security [6] requires each TSO to classify its system according to the system operating states. The classification should be done by on-line static contingency analysis at least every fifteen minutes, and as a minimum requirement a dynamic analysis shall be performed off-line [6].

To monitor that the system is within its limit, determined either online or offline, the primary measurement tools are SCADA systems and post processing by a state estimator [67]. In recent years with the increased available computational power, further attention has been put on developing online dynamic security assessment tools [37]. In [37], there are reported 19 tools for dynamic security assessments in use, under testing and under development. A review of 15 of these tools shows a wide variety of implementations. The TSOs have identified different stability issues as the most important for their system, and have different intended uses of the installed tools. Generally, the issues identified were the robustness and reliability of the tools, the solution speed, and how to present the results. All the tools reviewed in [37] were deterministic tools, however, commercially developed online risk tools do exist. One example is Promaps Online [68]. The methodology, extensively facilitating Markov chain models using the Kronecker product, is further described in [69].

Within the research community, there also exist other proposals for tools capable of performing online risk based security assessment. One example of such a methodology is presented in [38]. The methodology uses data from the state estimator to obtain the current state, and evaluates the risk as the sum of the risks associated with possible near future states and selected possible near future contingencies. A description of a prototype tool implementing the methodology can be found in [70]. The prototype tool for assessing and controlling risk proposed in [71] is also fast enough to perform

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online assessment for a number of contingencies in the range of some tens of contingencies for a realistically sized power system [71].

4.1.2.4 Offline tools for measuring short- and long-term reliability

Most methods and tools for reliability assessment of power systems found in this review have been intended for offline applications. The tools span a wide range with time horizons ranging from long-term system development to operational planning; and complexity ranging from collection of data on disturbances to simulation and prediction of the reliability of future power systems. The NERC state of reliability reports [26-31] present a relatively simple framework for assessing the bulk power systems' adequacy through monitoring certain adequacy indicators on an annual basis. Similarly, the Nordic countries publish yearly reports on the faults and disturbances in their network [16, 22]. An example of a tool used to collect such data is the tool FASIT used for registration of faults and disturbances in the Norwegian grid [72]. This type of statistical reliability data can be used by experts as a support to qualitatively predict the future reliability of the system, or as an input to other probabilistic reliability assessment methods. Additionally, there exist a need for quantifying the reliability of the system in the future, both with regards to security and adequacy. In the technical brochure [50], a short description of 18 tools for probabilistic planning is given. The capabilities of the tools vary; some are specialized on long-term planning, whereas other can also be used for operational planning, or blackout studies. The technical brochure also provides examples on case studies, where some of the tools have been used for planning purposes.

4.1.2.5 Methods and tools for assessing blackouts

The technical brochure [50], reports on work done within two fields of blackout studies, statistical studies, i.e., probability distributions of time between blackouts and size of blackouts, and studies on modelling of blackouts. There are different means of modelling blackouts. Report [73] focuses on the power system's structural vulnerability to blackouts independent of its operating conditions, whereas [60, 74-76] focus on cascading outages' role in blackouts. Cascading failures are defined as a sequence of dependent failures of individual components that successively weakens the power system [74]. Paper [77] presents a method, where cascading blackouts are modelled as a two-level process. The first level contains the initiating event, which might be severe enough to lead to a blackout immediately or through slow processes. The first level is in other words dominated by slow processes like operator actions and thermal processes, and this level gives the probability of the initiating event leading to a cascading blackout. The second level is initiated if the slow processes in the first level lead to electrical instabilities, in which case the goal of the assessment is to assess the severity of the blackout. In the recent studies [60, 76], state of the art methodologies on risk assessment of cascading outages are presented. The methodologies are divided into two main categories: detailed modelling and simulation methods and bulk analysis methods. This categorization corresponds to methods in need of a topological model of the grid, and those which only rely on statistical data. Each of these main categories can be further subdivided as follows [60, 76]:

- **Detailed modelling and simulations:**
    - Cluster-based approach
    - Enumeration of likely cascade paths
    - Uniform sampling
    - Enumeration technique including operator intervention and automatic protection
- **Bulk Analysis methods:**
    - Historical blackout data
    - High-level statistical models.

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The amount of data and simulation effort needed to assess cascading outages is enormous. Thus, good tools are needed to utilize the suggested methodologies. An overview of the current available commercial and research tools can be found in [75].

4.1.2.6 Overview of offline reliability assessment tools reported in the literature

To provide a good insight into what can be done in terms of reliability assessment today, both commercial and research grade tools are presented. Additionally, the research grade tools give a quick reference on how reliability assessment can be constructed.

In Table 4.1, an overview of probabilistic reliability assessment tools is given. It consists mainly of tools aimed at long-term system development and short-term operational planning. The table is constructed from similar tables from the reports [14, 50, 75]. The report [50] focuses on planning issues and has the most extensive list. Report [75] describes tools for cascading outages. The main focus of [14], unlike the two other reports, is not to give a presentation of methodologies and tools, it is rather to give a presentation of the probabilistic adequacy assessment tool OPAL. However, a quite detailed comparison of analytical tools is also given.

Table 4-1: Overview of probabilistic reliability assessment tools

Tool	Developer	Methodology	Power flow	Reported in
TRELSS & TransCARE	EPRI	Analytical	AC or DC	[50, 75]
TRANSREL	GR USA	Analytical	AC	[50]
OSCAR	Kinectrics	Analytical or Monte Carlo	AC or DC	[50]
PROCOSE	Hydro One	Analytical	DC	[50]
TPLAN	Siemens PTI	Analytical	AC	[50]
CREAM	EPRI	Monte Carlo	DC	[50]
MECORE	University of Saskatchewan and BC Hydro Canada	Hybrid analytical and Monte Carlo	AC or DC	[14, 50]
NH2	CEPEL Brazil	Monte Carlo	AC or DC	[50]
CORAL	PSR Inc.	Monte Carlo	DC	[50]
PowerFactory	DIGSILENT	Analytical	AC	[14, 50]
ASSESS	RTE France and NGT UK	Monte Carlo + analytical	AC or DC	[50, 75]
REMARK	RSE	Monte Carlo	DC	[50]
CAT	Commonwealth Associates Inc., USA	Analytical	AC	[75]
POM-PCM	Energy Systems Research Inc., USA	Analytical	AC	[75]
HIDDEN FAILURE	Chen and Torp	Monte Carlo	AC	[75]
MANCHESTER	The University of Manchester	Monte Carlo	AC	[75]
OPA	ORNL-PSERC-Alaska	Monte Carlo	DC	[75]
PSA	LOS Alamos National Laboratory	Monte Carlo	AC or DC	[75]
TAM	Texas A&M University	Monte Carlo	AC	[75]
OPAL	SINTEF Energy Research	Analytical	AC or DC	[14]
Sincal	Siemens	Analytical	AC	[14]

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From Table 4.1 one can see that the number of tools capable of performing analytical assessment or Monte Carlos simulation is the same. With regards to the power flow solution algorithm, there is a slight overweight of tools capable of performing AC power flow compared to DC, with 16 and 12 reported tools respectively. More detailed descriptions of the tools and their capabilities can be found in the references where they have been reported.

4.1.2.7 Methods and tools for mid-term asset management

A review of asset management strategies are given in [78], where the most common strategy was identified to be scheduled maintenance, meaning that the assets' reliability is evaluated based upon experience, expert knowledge and manufacturer data. The other most used asset management strategies were reported to be evaluating the assets' physical condition based upon scheduled inspections, followed by continuous monitoring. A review of the state of the art monitoring and inspection methods in use are given in [79], where a broad variety of tests and inspection methods are reviewed for overhead lines, cables, transformers, switching equipment, capacitors, surge arresters, insulators, instrument transformers, and gas insulated substations. The methods are classified according to if they can be performed online or offline, and if they are destructive or not.

The approach is not really concerned with measuring the reliability. However, there also exist mathematical methods for asset management [78, 80-83], where assessing the reliability is a part of the method. One method reported in use particularly in the US is Reliability Centred Maintenance (RCM) [78]. RCM is a method for deciding a cost optimal maintenance strategy given a certain level of reliability [78, 84, 85]. An extension to the RCM methodology called Reliability Centred Asset Maintenance (RCAM) is proposed in [85], in which the effect of the system's reliability due to certain maintenance strategies are evaluated.

In [81], a Markov process is proposed to model different maintenance strategies and evaluate their effect on the state transition times. This is demonstrated in a tool named AMP [81, 86]. A similar approach is presented in [80], where the state's residing times are estimated using a Bayesian approach and gamma distributed residing times. For this application, the residing times can be interpreted as the time a component resides in a particular condition. The methodology also proposes a methodology to determine through expert judgment and monitoring, in which of the Markov states a component resides. A tool-box based upon the methodology has been developed as described in [87].

4.1.3 Overview of literature

This section aims at giving an overview of which topics are covered in the different references. The idea is to provide a quick indication on where one can read about different topics. An exhaustive list of the topics covered in the papers is not provided. The rationale behind the sorting used in the tables is to follow the structure of the document. This approach was chosen as it was deemed slightly easier to interpret. A rather strict sorting criterion was used when constructing the tables. In other words, when it is reported that seven papers consider modelling of weather effects, the true number might be higher. The reason for this is that only papers, which to a certain degree, explicitly state how they implement the modelling are considered.

From the tables it can be seen that most of the topics have been well covered, except for modelling of markets and renewables. The reason for this might be that most of the literature reviewed is concerned with the more technical aspects of measuring reliability. The importance of modelling these issues is, however, not forgotten in the literature. For instance the report [50], has an extensive list of case studies of probabilistic planning, where market and renewable related issues are touched upon.

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Many of the aspects covered by the literature is also covered in the guide [44]. Although the guide is dated it is considered as a good introduction to the basic concepts presented.

Table 4-2: Overview of papers reporting reliability indicators

Type	References	Count
Deterministic security indicators	[6],[37],[55],[56],[67],[66],[53]	7
Probabilistic security indicators	[38],[39],[40],[41],[55],[56],[65],[70],[71],[68],[88],[50],[54]	13
Deterministic adequacy indicators	[21],[22],[16],[23],[24],[26],[27],[28],[29],[30],[31],[32],[33],[72]	13
Probabilistic adequacy indicators	[37],[34],[35],[36],[43],[9],[57],[14],[50],[51]	10
Component reliability indicators	[48],[49],[82],[83],[78],[79],[80],[86],[81],[45],[46],[87]	12

Table 4-3: Overview of papers covering different time horizons

Type	References	Count
Online security assessment	[37],[38],[39],[64],[70],[68]	6
Offline security assessment	[40],[50],[53],[54],[55],[56],[65],[66],[67],[71],[73],[74],[75],[76],[77], [88],[89]	17
Mid-term asset management	[78],[80],[86],[81],[45],[46],[82],[83],[84],[85],[87]	11
Long-term planning	[34],[35],[36],[50],[51], [57],[14]	7

Table 4-4: Overview of modelling considerations in different papers

Type	References	Count
Protection systems	[50],[37],[47],[48],[54],[55],[56],[18],[60],[63],[64],[65],[66],[71],[69], [76],[75],[77]	18
Cascading	[50],[38],[47],[54],[55],[56],[60],[63],[64],[65],[71],[74],[76],[75],[77]	15
Weather	[50],[55],[56],[57],[18],[69],[75],	7
Remedial control actions	[50],[37],[38],[39],[41],[54],[55],[56],[58],[60],[63],[76],[75],[77]	14
HILP	[50],[47], [60],[74],[76],[75],[77]	7
Renewables	[50],[34]	2
Market modelling	[50],[54],[18],[89]	4

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4.2 Questionnaire survey

4.2.1 About the questionnaire survey

A questionnaire was prepared to provide information about the status of reliability management in practice and the views of the TSOs regarding:

- Current reliability management approaches (N-1 criterion etc.)
- Reliability methods, tools and data (including socio-economic impact)
- Drivers and barriers for new reliability standards
- The functional description of necessary methods and data for new reliability standards.

The questionnaire contains 52 different questions of which some are partly overlapping. The questions are included in Appendix 2.

In this report, only results from the second part on reliability methods, tools and data (including socio-economic impact) are reported. The other three parts are reported in the second deliverable D1.2 from this work package.

The responses cover 9 TSOs in total, from the Nordic countries and Continental Europe, representing different system sizes, characteristics and control zones. Despite the limited number, the responses in are regarded sufficiently representative for Europe due to the variety revealed through the answers.

4.2.2 Reliability indicators in use

Figure 4-1 shows the various long-term reliability indicators in use. There are several indicators in use that are reported by between three and five respondents. It should be mentioned that there is a high variation in the number of indicators in use by the different respondents. In fact, three of the respondents have reported two or less indicators in use. And the number of indicators in use ranges from zero indicators to nine. Furthermore, there are some indicators in use not captured by the given response alternatives, which the respondents identified to be:

- Curtailment of wind energy production
- Congestions
- Losses
- ENTSO-E indicators.

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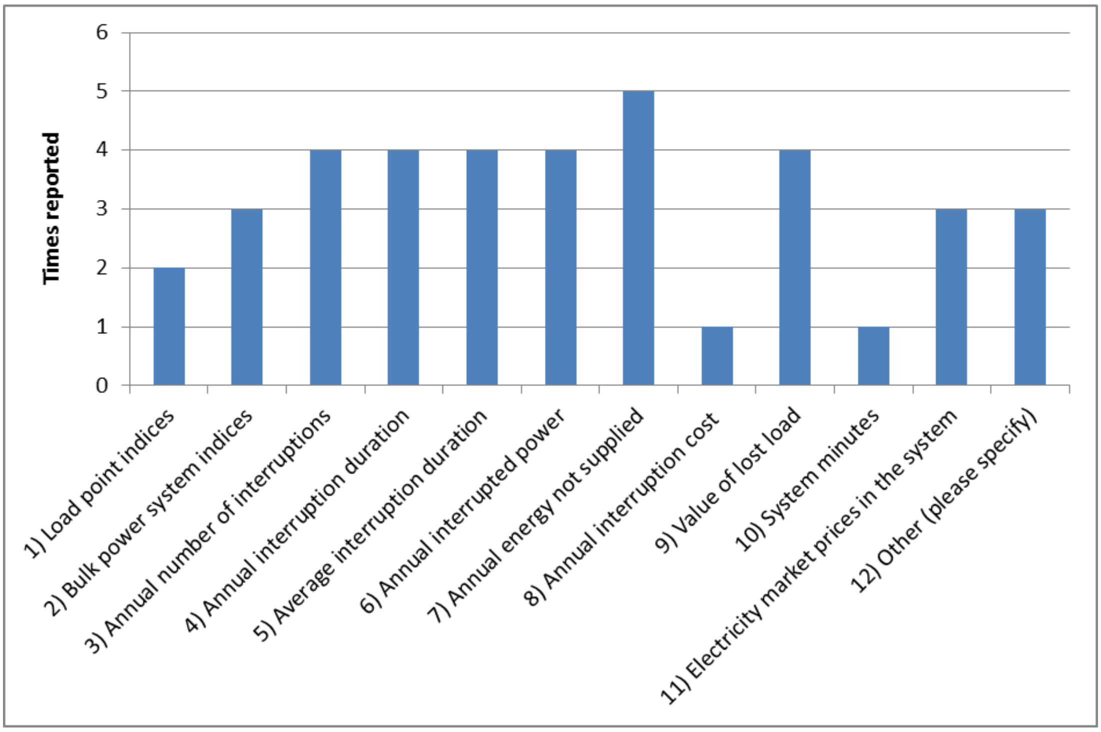

Figure 4-1: Reliability indicators for assessing the effect of planned grid developments on the system reliability

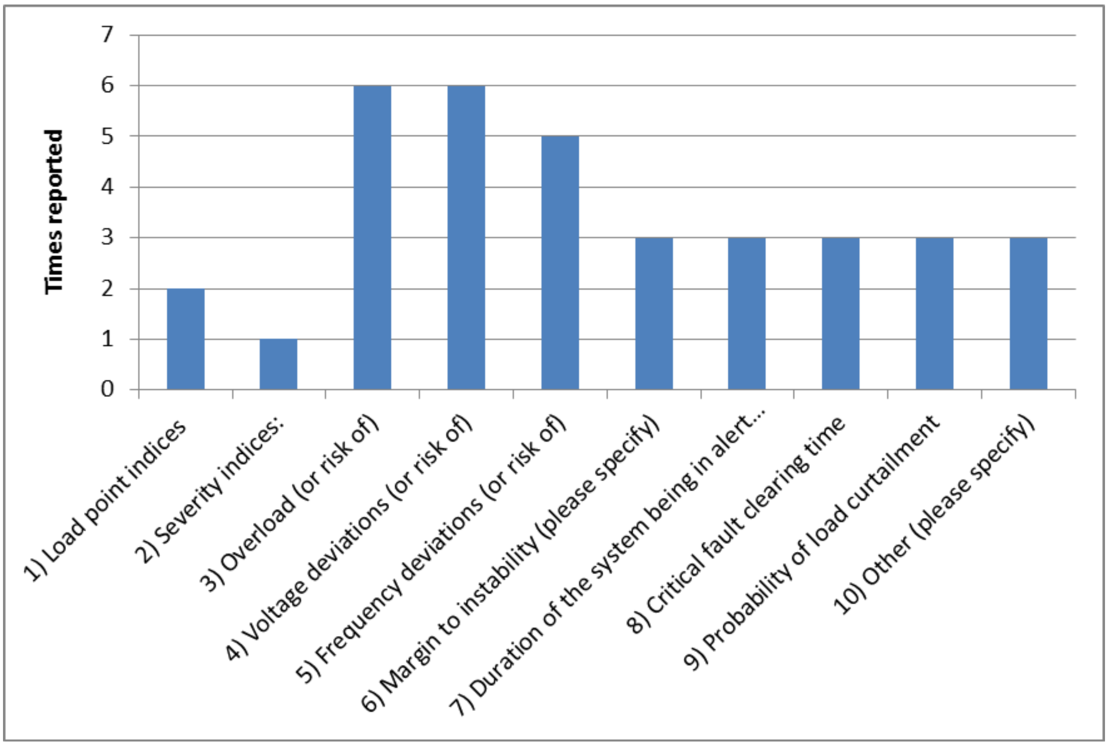

Figure 4-2: Reliability indicators for assessing operational reliability (security)

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To get a complete picture of the power system's reliability, security indicators are required together with adequacy indicators. In Figure 4-2, a graphical presentation of the security indicators in use are given. The additional indicators identified by the TSOs were:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Customer Average Interruption Frequency Index (CAIFI)
- Amount of reserves
- Congestion duration.

It could be noted that the three first additional indicators reported are originally distribution indicators [34]. A potential explanation is that these indicators are used for customer delivery points, rather than end users.

The respondents were also asked if they felt that there are aspects that the current available indicators fail to measure in any way, in which case they were requested to elaborate on this. From the answers received, it seems that most respondents are quite confident in the indicators available: six out of nine answered no, two out of nine answered yes, and one respondent did not answer. Maybe just as interesting is the fact that two of the respondents answering no to this question, also commented on it. Their responses were as follows:

- Indicators for overinvestment.
- Indicators for weather issues in particular with respect to renewable energy sources (RES).

It might be reasonable to assume that the first commenter above did feel that the indicators actually sufficiently indicate the system's reliability, and that the lack of a proper indicator for overinvestments was a minor issue. The second comment, received above, is more related to potential future issues, in the case where the penetration of renewables reaches a certain level. The comments on the shortcomings of the currently available indicators were:

- The end users' perception of the value of energy not supplied (ENS)
- Lack of N-1 on reactive compensation devices.

4.2.3 Reliability data

To be able to calculate reliability indicators, either through simulations or through statistical methods, one will need data. To get an overview of the availability of data in the industry and the current practices, the TSOs were asked various questions regarding their data collection approaches.

The first question, with respect to reliability data, was related to which type of data that are measured. A rather uniform answer was received to this question, as all respondents reported that they measure the following data on component faults:

- Number of faults
- Outage times
- Failure causes.

Additionally the following fault data, not specifically asked for in the questionnaire, were reported:

- Interrupted power
- Fault owner
- Consequences for power production
- Protection equipment response during outages.

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Data on human errors and faults on remedial actions are also collected by the majority of the respondents, however, mostly with respect to system faults. This means that faults on remedial actions, which does not result in power system interruptions, are in most cases not collected.

The use of Phasor Measurement Units (PMUs) was also reported by most of the respondents, with the highest penetration at the highest voltage levels. The PMUs were by most reported used for reliability assessments, but not for detecting unstable voltage situation. Some of the respondents also reported that the PMUs were new equipment mostly installed for testing purposes.

All the respondents reported that they to some extent record faults in their system. In general, the respondents report faults on most primary equipment, as can be seen in Figure 4-3. Not all TSOs have HVDC lines in their systems, so naturally, not all the TSOs record faults on HVDC lines. Another interesting observation is the comparatively lower reporting of generator faults, a result that might be credited to the deregulation of the electricity industry. The comments received indicate that some TSOs distinguish between the following types of transformers in their fault statistics:

- Voltage transformers
- Current transformers
- Power transformers
- Phase shifting transformers (PST).

Additionally, some TSOs also collect fault statistics for reactive power compensation devices.

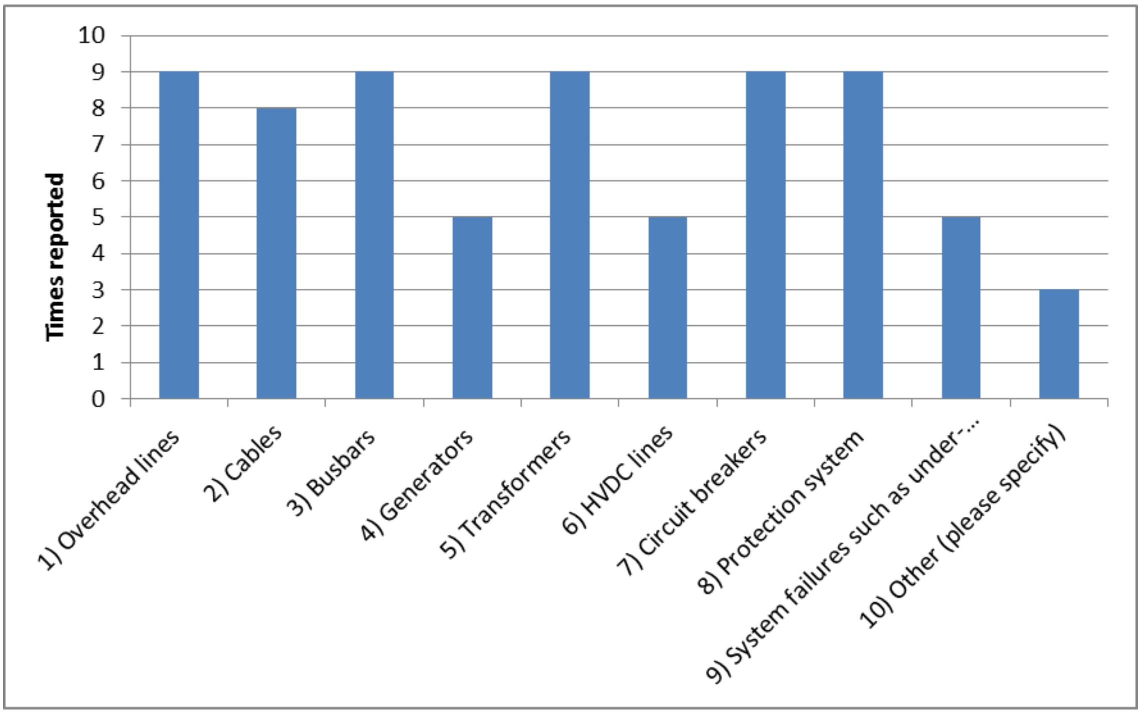

Figure 4-3: Components that are included in part of the fault statistics

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The data collected by the TSOs can be used for various purposes. Consequently, the TSOs were also asked what they use the statistics for. There was little variation in the responses, actually apart from grid performance statistics which was reported by all the respondents. The other uses reported were all given by seven out of nine respondents. A summary of the reported purposes are given below:

- Grid performance statistics
- Asset management
- Maintenance planning
- System development, grid investment planning.

To get an impression on how the data is used for asset management, the respondents were asked to elaborate, in the case that they use the collected data for this purpose. The received comments are summarized below:

- The data is used to calculate probabilities in risk evaluations on some specific high impact low probability (HILP) events, which can be used to change operational rules to mitigate risks.
- Asset management takes action after a fault.
- When there is a clear indication that components have an elevated failure rate compared to similar components, actions are taken.
- Failure statistics are used for investment purposes.
- Replacement of component populations based on failure rate.

The findings above correspond well with the results presented in Figure 4-4, which clearly shows that all the respondents use the collected data to calculate the components' failure frequency. Additional comments received, indicate that the following indicators also are reported:

- Energy Not Supplied (ENS)
- Cost of Energy Not Supplied (CENS)
- Customer Average Interruption Duration Index (CAIDI)
- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI).

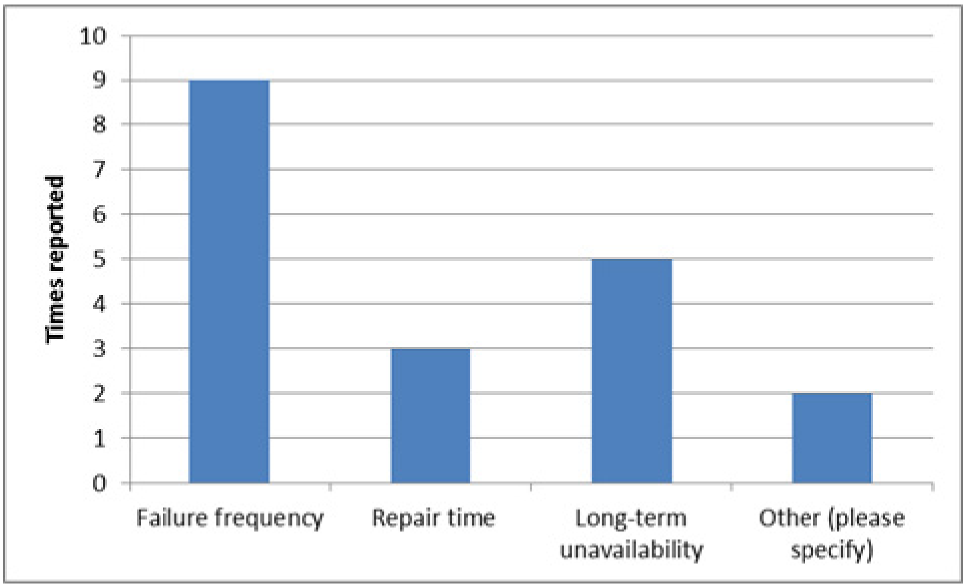

Figure 4-4: Reliability data calculated from the collected data

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The need for good reliability data has been identified as one of the barriers towards widespread utilization of probabilistic assessments [14, 50]. Thus, it is of high importance that TSOs are willing to share reliability data with each other. In this aspect, the responses to the questionnaire give room for optimism, as all the respondents were positive towards data sharing. As expected, most of them emphasized that it would depend on the sensitivity of the data.

4.2.4 Reliability assessment methodologies

Different types of analyses can be run to assess the reliability of the power system. Whichever analyses that are relevant, depend on the various aspects, relevant for the different TSOs. Consequently, a scalable and general methodology must be able to perform different analyses. An overview of analyses currently in use for the long and short-term time horizons is presented in Figure 4-5. As expected, power flows are used by all the respondents for both time horizons. The largest variation between the short- and long-term time horizons can actually be found in the reported use of probabilities. Although a rather high percentage of the respondents reported the use of probabilities in their long-term studies, most of them also stated that this was only used in special cases. In other words, probabilistic planning is not their main approach to planning.

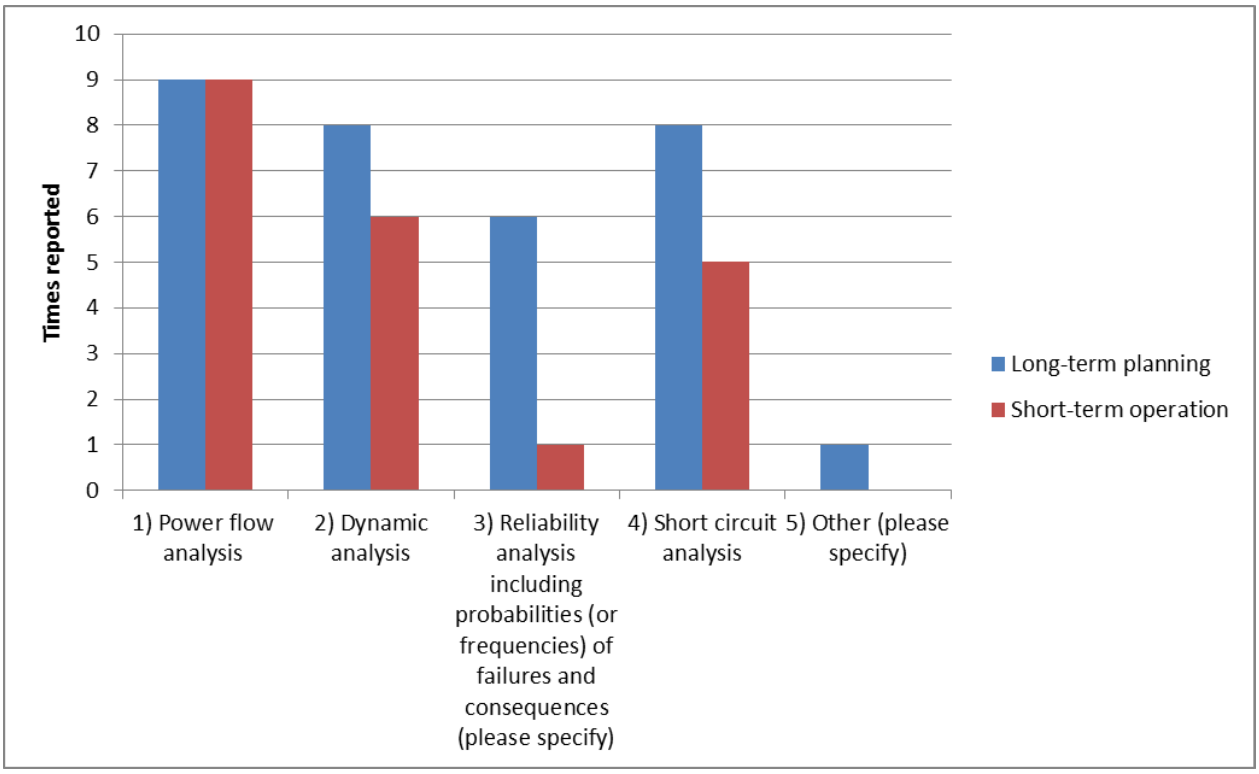

Figure 4-5: Reliability assessment methodologies in long-term planning and short-term operation

The question regarding how the reliability is assessed with respect to the mid-term asset-management was interpreted quite differently by the TSOs. Consequently, the results obtained from this question might not be reliable. Nevertheless, the results are presented in Figure 4-6, as they provide some useful information, namely the reported use of methodologies such as Reliability Centred Maintenance (RCM), and Failure Mode Effect Analysis (FMEA), together with useful comments provided by the respondents. From the comments, it seems that the most used reliability assessment is to evaluate the reliability

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towards the N-1 criterion. Moreover, the age of the components were also used as a measure of reliability.

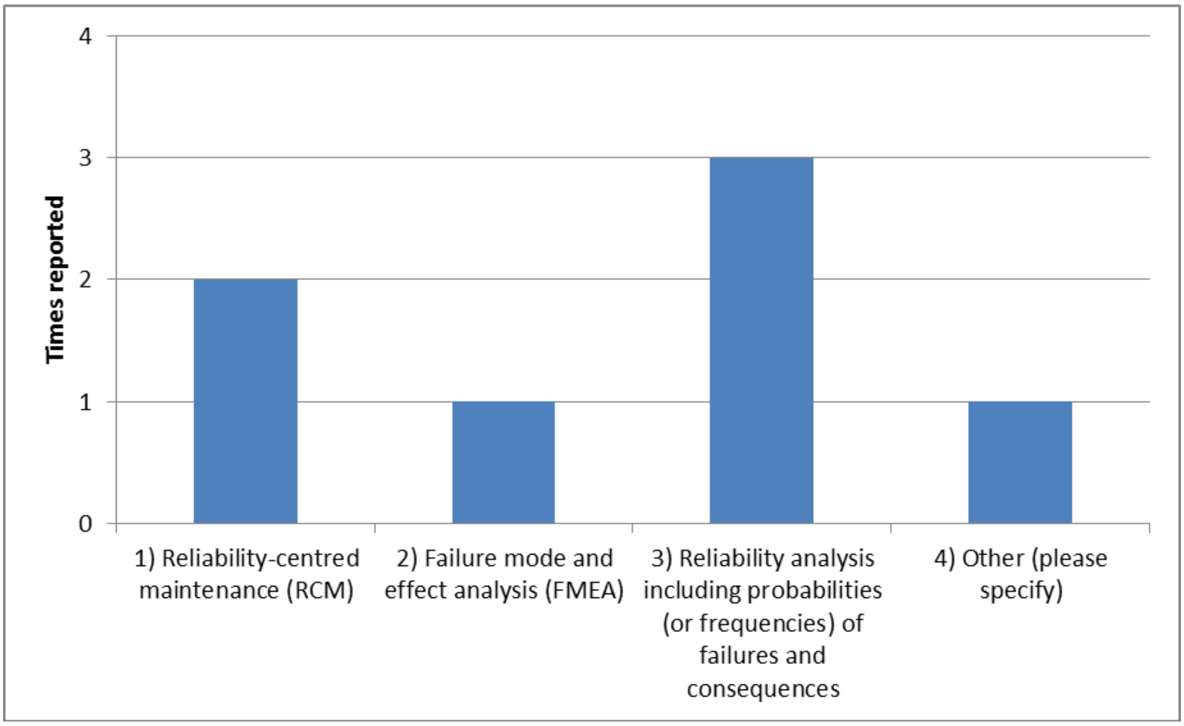

Figure 4-6: Reliability assessment methodologies for mid-term asset-management

To gain insight in how the current practice is for modelling different aspects related to the GARPUR objectives, the TSOs were asked how they model or take into account the following aspects:

- External threats (e.g., weather, human errors etc.)
- Remedial actions and their probability of failure
- Demand side management and energy storage
- High impact low probability events.

Amongst the TSOs, different external threats are taken into consideration, the most common one being weather effects. This effect is taken into account by two main approaches that were reported to be:

- Weather forecasts typically used for the operational time frame
- Statistical data typically used for the planning time frame.

The weather forecasts are used as an indication of the operational security of the system, meaning that reports on imminent extreme weather are interpreted as a reduction of the system's security. Statistical methods, which account for the weather, are typically used for:

- Component fault rates
- Seasonal variation
- Extreme situations like avalanches or landslides.

Additionally, the TSOs also reported that such events are evaluated on the basis of discussions, rather than through modelling. Weather effects were clearly the main concern with respect to external threats, as it was the only issue explicitly mentioned, apart from one respondent that mentioned the modelling of human errors to be assumed captured through the fault statistics.

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The importance of remedial actions are reflected in the fact that all respondents except one reported that they model such actions. However, there were few reports on how they actually implement the modelling. Furthermore, only one respondent reported that the probability of remedial action failure was taken into account.

The modelling of demand side management and energy storage is to some extent considered by most of the respondents, with modelling of hydro power being the most reported mean for modelling of energy storage. The respondents that reported this aspect to be of any importance, all used industrial customers for this purpose. And only two different modelling approaches were reported, namely, to model customers participating in the demand side management as:

- Interruptible loads, or
- flexible loads.

On the case of high impact low probability (HILP) events, the respondents were quite in line with each other. The general approach seems to be the use of expert evaluations on a case to case basis, similar to what they reported for their handling of extreme weather conditions. Additionally, a few respondents reported that they evaluate the probabilities of such events in a few cases.

When asked if they feel that the available methods fail to cover some areas, the opinion of the respondents was divided. Five out of nine respondents reported that, in their opinion, the available methods fail to cover the following areas:

- Growing uncertainties in the power system
- Probabilistic assessment
- HILP
- Correct assessment of consequences
- Interdependencies of faults in large power systems
- Describing the sample space.

4.2.5 Reliability tools

Performing a reliability assessment of a large power system by hand is not really feasible; consequently good tools are needed to assist the assessment. A conclusion on the most used software tools throughout the industry cannot be drawn from this questionnaire, due to the limited number of respondents. The questionnaire is rather meant to give a reasonable overview of what is available and in use.

The TSOs were asked to name the tools they use to assess the reliability for the different time horizons. In Figure 4-7, it can clearly be seen that PSS/E and in-house developed software are the most used software for long-term planning. It should also be noted that long-term planning is the time horizon with the highest reported variety of tools.

In house-developed software seems to be the most popular tool for mid-term asset-management. Additionally, it is worth noting that some respondents reported the same tool used for both the mid-term- and short-term time horizons. This might indicate that the respondents have interpreted the mid-term horizon differently. The time horizons were not explicitly defined in the questionnaire.

For short-term operation, PSS/E and in-house software once again seem to be the most commonly used tools, together with SCADA software.

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The respondents also provided feedback on what the current available tools in their opinion fail to cover. Naturally, their view was not uniform as they face different challenges. The main points from the feedback are given below:

- Forecasting errors of generation and load
- Possible failure of corrective actions
- Probabilistic assessment in general
- Congestions in neighbouring countries
- Flexible tools for assessing system related and reliability issues
- Integrate market modelling and reliability analyses.

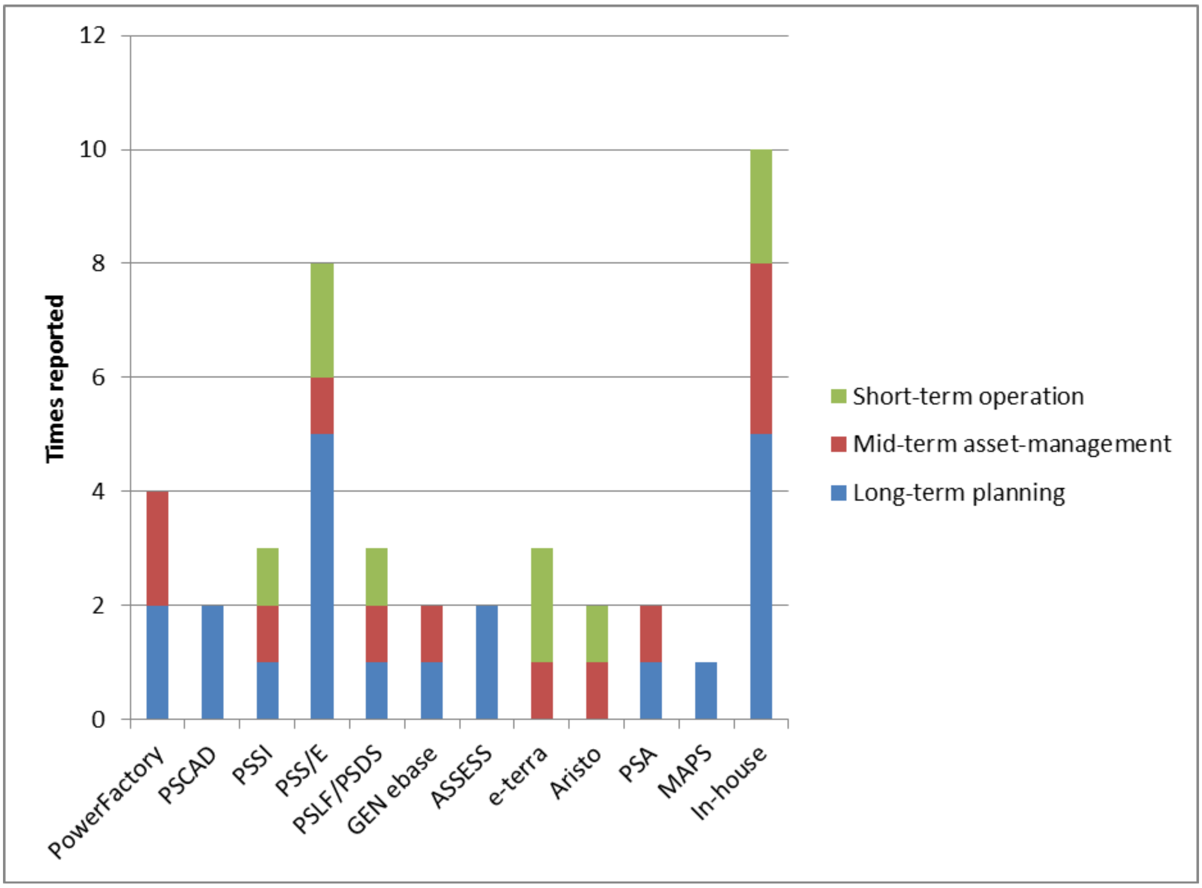

Figure 4-7: Power system reliability tools

4.3 Synthesis of reliability assessment methodologies in theory and practice

Thus far, this report has presented both a literature survey and a questionnaire survey on power system reliability assessment. A reasonable next step is to investigate these in relation to each other.

4.3.1 Synthesis of reliability indicators and reliability data in theory and practice

Although the literature survey identified a lot of papers regarding probabilistic security indicators, the questionnaire revealed that these are generally not in use. It seems that the current industry practice is closer to what is required by ENTSO-E's network codes, than what is presented in the literature. Of course there are some similarities, as many of the same input data needed for calculation of the more traditional

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security indicators are needed to calculate the probabilistic indicators. In general, it can be claimed that the literature suggests that a probabilistic element also should be included in the security indicators.

One might argue that the picture is similar for the long-term reliability indicators; however, the indicators in use are not that fundamentally different from the ones reported in the literature. On one hand it seems that the industry tends to use deterministic indicators, and the literature on the other hand operates with probabilistic indicators (expected values). The important observation from the literature is that the probabilistic methods aim at predicting (ex-ante) certain indicators, whereas the deterministic methods try to measure the same kind of indicators (ex-post). In general, the following indicators were identified as important for both probabilistic and deterministic approaches:

- Annual number of interruptions
- Average interruption duration
- Annual interrupted power
- Value of lost load.

With regards to collection of reliability data there is no general variation between the industry and what is presented in the literature. The reason for this is most likely that most of the papers, regarding reliability data reviewed, are describing methodologies in use.

4.3.2 Synthesis of methods and tools in theory and practice

The methods and modelling issues identified as the most relevant seem to be the same in both theory and practice. One of the exceptions is the fact that most papers argue for a probabilistic assessment of the power system; In contrast to the industry, where deterministic assessments are the most used approach. It seems that if the industry uses probabilistic assessment, it is for case studies. A discovery not only supported by the questionnaire, but also by previous reports like [50]. This challenge will be discussed in the next deliverable (D1.2) from this work package.

There is also a degree of similarities between the literature survey and the questionnaire survey with respect to methods used in mid-term asset-management. The largest difference between the literature survey and the results from the questionnaire within this field is that the respondents explicitly mention the N-1 criterion. This difference might just as well be a result of the way the question was phrased, than as an actual difference between theory and practice.

The tools reported in the literature were mainly probabilistic tools, so it is no surprise that many of them are not found in the answers to the questionnaire. It would also be quite surprising if none of the TSOs use tools capable of performing probabilistic assessment, given that some of them reported that they do probabilistic studies. The tools reported in the questionnaire, are:

- ASSESS
- PowerFactory.

It is also worth mentioning that the commercial software used by the highest numbers of respondents, PSS/E, has a module named TPLAN. This module is mentioned as standalone software in the literature survey. In other words, respondents to the questionnaire might have reported it together with PSS/E.

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5 STATE OF THE ART ON SOCIO-ECONOMIC IMPACT ASSESSMENT

5.1 Literature survey

The results from the literature survey on socio-economic aspects of reliability in power systems cover the following topics:

1. Microeconomic framework for the analysis of reliability and valuing lost load
2. Estimation of value of lost load (VOLL) in practice, i.e., empirical studies that estimate the value (or cost) of loss of electricity supply to end users
3. Cost-benefit studies (CBA) and other applications of VOLL estimates to the analysis of reliability and security of supply in electricity markets
4. Studies of the cost of intermittent energy sources (e.g. wind and solar) and related reliability issues
5. Cost of reliability
6. Interconnector studies – to a very limited extent concerned with reliability issues.

The focus varies within these categories and some of them overlap to a certain extent.

Below we provide a brief overview of each of the categories above.

5.1.1 Microeconomic framework for valuing lost load

The microeconomic framework for analysis of reliability in electricity markets has first and foremost been concerned with defining the value of lost load (VOLL) or customer interruption costs. VOLL is "a measure of the cost of unserved energy (the energy that would have been supplied if there had been no outage) for consumers" [19].

Reference [90] develop a formal microeconomic framework, which includes a precise mathematical definition of VOLL in terms of consumer surplus. Under certain simplifying assumptions regarding functional forms, VOLL turns out to be equivalent to average consumer surplus lost due to interruption of service, which agrees with the verbal definition given in the previous paragraph.

5.1.2 Estimation of value of lost load

5.1.2.1 Factors affecting value of lost load

VOLL will typically vary due to several factors. These include (see e.g., [91, 92]):

- Type of customer
- Perceived reliability level,
- Time of occurrence of power interruption,
- Duration of interruption, and,
- Pre-notification of the interruption, or not.

Types of customers are, e.g., the manufacturing sector, the service sector, agriculture and households. These categories, however, can be disaggregated further. Companies can be disaggregated by industrial sector, regions, size, etc. Households can be disaggregated by income, region, size etc. The degree of disaggregation undertaken will of course depend on data availability.

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The perceived reliability level and experiences with interruptions will influence the degree to which customers prepare for the loss of power and how they value the lost load [93]. For instance, high experienced frequency of interruptions has been found to lower the valuation of lost load, while long interruption durations have been found to increase it. Various preventive measures can be undertaken by customers to avoid costs of outages so – somewhat counterintuitively – a lower perceived reliability level may lead to lower measured VOLL. Here, it should be noted that lower perceived reliability is likely to have negative long-term effects on welfare since certain investments, production and activity will not be undertaken unless reliability is sufficiently high.

The time interruptions occur will typically have an impact on the related costs, see, e.g., [17]. For households it is much more of a nuisance to lose power during leisure time than during working hours. The opposite is valid for businesses, e.g. in the service sector, where costs will primarily occur during hours of production.

The duration of an interruption also matters [17, 91, 92]. For some sectors, the cost is highly non-linear as a function of duration. Sometimes costs per unit time fall with the length of an interruption (at least for relatively short time intervals). In other cases, however, the opposite may occur, e.g., if production material or equipment is damaged after a certain time has passed without electricity supply.

Finally, pre-notification of a power interruption, e.g., due to maintenance work, gives consumers the opportunity to prepare for the loss of power. Such interruptions are therefore usually assumed to carry lower costs than those that occur without advance warning. This assumption is, however, not always supported by the results of household surveys [94].

5.1.2.2 Methods for estimating the value of lost load

If demand functions for electricity, depending on the factors listed above and probably several others (such as income), were known, it would be easy to assess VOLL: consumer surplus, defined as the difference between the consumers' willingness to pay for a commodity and the actual price paid by them, would simply be estimated by integrating the demand function. From a microeconomic point of view this would be the most satisfying approach to measuring VOLL. This is one of the approaches employed by the authors of [95] in a case study of a major power failure in Cyprus. This, however, is the only example known to us of such an approach. The reason is probably that, especially in the short term, price elasticity of demand for electricity is extremely low and also imprecisely measured. In fact, the functional form of the demand function itself – usually assumed to be of the constant elasticity form – is hard to specify. Estimating the integral of the demand function is therefore likely to be a highly speculative exercise. Other, less direct, methods are therefore usually employed.

There is a large literature that is concerned with the estimation of the value of lost load. This literature consists both of published papers in international academic journals as well as reports published by TSOs, regulators and others, including best-practice guidelines such as [91, 96]. There exist recent reviews of this literature: The paper [97] is a concise overview of the literature in this area published up to 2007. Reference [93] is an extensive report, which reviews cost estimation methods for VOLL and, more generally, for how to measure valuation of different quality of supply deviations in electricity supply: interruptions, voltage disturbances and rationing. Reference [91] describes advantages and disadvantages of the various methods. Literature up to 2010 is surveyed. We will only give a brief overview here.

Methods for estimating interruption costs (as well as costs of voltage disturbances and other quality deviations) include the following approaches (we use the classification of [93]):

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- **Stated preference**, i.e. how customers say they value power interruptions; based on surveys or interviews
- **Revealed preference**, where valuation is based on observed market behaviour
- **Indirect analytical methods**, including **proxy methods** and the so-called **production function approach**
- **Case studies**, which analyse actual blackouts.

Each of these approaches has its advantages and disadvantages. Stated preference methods have the advantage of eliciting customers' valuations by surveys but are quite costly to undertake and may lead to skewed estimates, e.g., due to strategic answering and cognitive biases. The revealed preference approach, indirect analytical methods and case studies are based on available data, which reduces the cost of valuation. Due to the top-down nature of these methods, various non-monetary costs are not included in the estimates, which may bias them downwards. But there may also be an upward bias due to lack of flexibility in assumed response possibilities for businesses and households.

Stated preference methods are the most common approach to estimate costs of interruptions. In the survey of [93], 20 out of 29 cost estimation studies employ this approach. However, in a literature search for this review of recently published papers in academic journals or working paper series, many studies employed the production function approach. One reason for this might be that academic studies must usually rely on smaller resources than those commissioned by regulators and the electricity industry, and therefore the production function approach, which is less costly and time-consuming, is preferred. Even if survey studies are expensive and time consuming to undertake, they appear to be the favoured approach for purposes of regulation. Regulators also typically require more granularity, e.g., on costs for different types of customers, than the production function approach, which relies on national accounts statistics, allows for in practice.

5.1.2.3 Stated preference methods

Stated preference methods estimate costs of power interruptions from the statements of customers. This can be done directly or indirectly. There are several different approaches within this class of methods. These include:

- The **direct worth method**, where customers are asked to estimate direct costs resulting from an interruption.
- **Contingent valuation**, where customers are asked for their estimate of what they would require in payment for accepting a lower level of reliability of electricity supply or willingness to pay for a higher level of reliability.
- **Preparatory action** where customers are asked to choose actions they would undertake from a menu of possibilities; each action is associated with a given cost.
- **Conjoint analysis**, which takes an indirect approach and solicits valuation by asking customers to rank varying combinations of electricity prices and availability. Utility functions are then derived from regressions with the survey data as input.

In addition to the studies cited in [93], which use one of the stated preference methods, a Norwegian study of costs of power supply interruptions and voltage disturbances [98] has recently been completed in preparation for changes in the Norwegian CENS regulation. The authors in [17] documents an earlier Norwegian study of such costs and how they are used in the CENS regulation. Both direct worth and contingent valuation methods are used. A survey-based study of interruption costs for Belgian households is presented in [99]. Reference [94] is a mixed study where costs of interruptions for households are elicited by contingent valuation methods. And reference [100] is an example of a study of this kind which employs conjoint analysis.

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5.1.2.4 Revealed preference

In the **revealed preference** approach it is studied by observing market behaviour how customers value the cost of power interruptions in reality by, e.g., installation of backup power or by entering into interruptible power contracts. See reference [93] for references to studies that use this approach.

5.1.2.5 Indirect analytical methods

Indirect analytical methods are also described in [93]. Here, interruption costs are estimated indirectly from variables assumed to be linked to electricity consumption. In the case of businesses, costs are usually estimated by the production function approach and assumed closely correlated with loss of output. Valuation is then based on a model for the loss of value added associated with power interruption. Such models will typically disaggregate by sectors, time, countries, regions etc.

For households, the value of lost load is usually tied to loss of leisure activity. Typically, the marginal value of labour (i.e., the after-tax wage rate) is taken as price variable.

In addition to the production function approach other **proxy methods** have been employed. The simplest of these is the cost of electricity which may be assumed to give a lower bound for the value of lost load.

As noted above, the production function approach is commonly used in the academic literature. In addition to the publications cited in [93], studies that employ this approach include:

- [94]; Austrian non-household users (household costs were assessed by survey)
- [101]; Ireland
- [102]; Germany
- [103]; Spain
- [104]; Germany (disaggregated by states)
- [105]; Germany (disaggregated by counties)

5.1.2.6 Case studies

Case studies require collecting data and facts right after a large-scale power outage. Based on such data, costs of power interruptions can be quantified. See reference [93] for references to studies that use this approach.

5.1.3 Cost-benefit studies and other applications of VOLL estimates to the analysis of reliability and security of supply

VOLL estimates are mostly of interest as input to studies or decision making in the electricity sector. They are used by network owners, TSOs and regulators as input to aggregate cost estimates for control areas and for decision making. A number of published studies document how VOLL estimates can be used for this purpose (see, in particular, [91, 92]). We largely confine our attention to such publications, which have often resulted from policy analysis in the authors' countries.

Two of the first published papers in this area are [106, 107]. These papers consider a probabilistic security criterion for determining transmission constraints based on minimizing total grid operating costs, consisting of (TSO) congestion costs and expected interruption costs (based on "preliminary but credible" VOLL estimates). The approach is illustrated by examples from the Norwegian transmission grid and it is shown that substantial cost savings can be achieved as compared to the N-1 criterion.

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Reference [108] further refines the approach of the two aforementioned papers, but also considers other objective functions than expected costs, such as utility, regret and TSO-penalty functions. It is shown that some of the objective functions may favour security criteria close to the N-1 criterion.

The authors of [18] describe how VOLL estimates from customer surveys are applied in the so-called CENS (cost of energy not supplied) regulation in Norway. In the CENS regulation, network companies' revenue cap is dependent on the quality of electricity supply as regards power interruptions. This regulation therefore introduces implicitly a penalty for power interruptions based on VOLL estimates and gives the TSO economic incentives to minimize costs, including socioeconomic costs of power interruptions.

Following a change in the Dutch electricity regulation in 2005 – which allows deviation from the N-1 criterion if costs of strictly upholding it exceed the benefits – there has been a spate of research on social cost-benefit analysis of reliability as applied to the Dutch electricity market. Thus, the authors of [109] study how to curtail electricity efficiently in the case of blackouts. They compare random load curtailment by regions to load curtailment in regions with low costs of lost load first and find that by using the latter approach social costs of load curtailment can be reduced by 42-93 %.

In reference [110], an approach to network regulation similar to that in [106, 107] is considered. In the Dutch context, a social cost-benefit framework is developed for the application of the flexible N-1 criterion in Dutch regulation. In addition to VOLL estimates, the framework requires input on failure probabilities and the cost of investments. The framework is applied to a case from the Dutch electricity grid and it is shown that investing so as to ensure N-1 during maintenance would be inefficient. Even if reliability would be slightly reduced, the expected costs substantially exceed expected benefits. They point out, however, that these results may not be applicable elsewhere.

The authors of [111] have studied probabilistic approaches to network operation and standards. Instead of adhering strictly to a deterministic rule, expected congestion and interruption costs (based on VOLL estimates) are minimized. They base their approach on smart grid concepts and assume generation, transmission, and demand corrective actions can be coordinated both pre- and post-fault. The approach is illustrated in a case study of future operation of the England-Scotland interconnector. A particular challenge in this case is posed by some 10 GW of wind generation that is expected to be connected in Scotland until 2020. The study compares probabilistic, N-1 and N-2 criteria and argues strongly for the probabilistic approach as the most efficient one.

The authors of [95] study the costs of major power shortages in Cyprus following an explosion that destroyed 60 % of the island's power generating capacity. As noted above, this paper employs demand functions to estimate consumer surplus lost, but estimation using VOLL estimates derived by the output function approach are also employed. The results differ considerably. The paper concludes that emergency actions taken by national energy authorities were generally appropriate and in line with international best practices. In particular, economic losses avoided by the emergency response are greater than the costs of the latter.

5.1.4 Studies of the cost of intermittent energy sources (e.g. wind and solar) and related reliability issues

The author of [112] studies the impact of increased renewables' generation on the German electricity market. In particular, it is analysed how the development of renewable energy sources will, other things being equal, reduce the reliability of electricity supply. It is therefore necessary to invest in the grid to maintain present levels of reliability of electricity supply. (Here it should be noted that investments in the low- and medium-voltage network only are included in the analysis – investments in the transmission grid

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are not taken into consideration.) The costs of grid investments are then compared to the benefits which they yield, i.e., of maintaining the present level of reliability rather than allowing it to diminish. In net present value terms, the costs far exceed the benefits of maintaining a constant reliability level. Potential benefits associated with lower CO_2 emissions are not included in this comparison, but it is argued that these are doubtful in any case.

Reference [113] presents an analysis of the Arizona electricity market where large-scale solar energy generation is present and more is planned. The paper develops a detailed empirical model based on the microeconomic model of [90]. The model is estimated using generator characteristics, solar output, electricity demand, and weather forecasts for an electric utility in south-eastern Arizona. It concludes that a 20 % solar photovoltaic mandate is quite costly in welfare terms. This cost is, however, primarily due to the high investment cost of solar: the fact that the energy output of solar panels is irregular and very difficult to forecast yields lower welfare losses than expected. Given a $21/ton social cost of CO_2, a 65 % reduction in the cost of solar generation is needed for the aforementioned mandate to be welfare neutral.

5.1.5 Cost of reliability

Our literature search found only one published study of the cost of reliability [114]. The paper estimates the capital elasticity of reliability and applies this estimate to evaluate a capital spending program proposed by a Wisconsin electricity utility to improve reliability. In general, a 1 % increase in real capital cost results in a 0.285 percent reduction in the System Average Interruption Duration Indicator (SAIDI). The investment program they evaluate is expected to result in substantially greater reduction in SAIDI and is therefore found to be highly cost effective.

5.1.6 Interconnector studies

Improved reliability and security of electricity supply is one of the benefits of interconnectors [115]. Published policy studies of interconnectors usually take this aspect into account, e.g., by estimating the benefits from the need for lower reserve capacity, although the focus is more on the impact on overall supply, demand and prices in the electricity markets that are brought closer together (in market terms) by the interconnector. Reference [116] is a critical appraisal of CBA analyses of two recent interconnectors, i.e., the NorNed cable between Norway and the Netherlands [117] and the East-West interconnection between Ireland and the UK [118]. Reference [116] claims that without quantification (as in [117]), welfare effects of security of supply may easily get too much attention.

The authors of [119] present an approach for assessing the benefits of interconnector investments in the presence of intermittent sources like wind. Their model, which covers thirty European countries, allows for endogenous power plant investments, also optimizing generation dispatch and utilization of transmission lines. The model is used to evaluate the benefits of further line extensions between the European mainland and northern European countries.

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5.2 Questionnaire survey

Most TSOs (six out of nine) say they use the N-1 criterion strictly. Only three, however, have estimated the costs and benefits of applying this criterion compared to other reliability criteria. Most TSOs (six out of nine) sometimes apply the N-0 criterion. The main reason given for deviating from the (dominant) N-1 criterion is that it is too expensive to apply the latter. A couple of TSOs say they do this to use the grid more efficiently. Interestingly, three say they apply the N-0 criterion, meaning that they accept more severe consequences in cases where the probability of a fault is small

As for how socio-economic benefits and costs are included in the transmission system today, most TSOs (eight out of nine) see increased transmission capacity as a benefit. One TSO did not explicitly mention increased transmission capacity. It rather uses concepts, such as: congestion, rent, produces surplus and consumer surplus, which are used to evaluate the socio-economic benefits and costs. Reduced expected loss of load is also a commonly given benefit item. Increased security margins are less frequently mentioned as a benefit. On the cost side, costs of reserves are most often mentioned (seven out of nine). Congestion costs and re-dispatch costs are also mentioned by more than half of the respondents. One TSO think the categories given in the questionnaire were not quite satisfactory and say their approach is that of quantifying congestion rent, producer and consumer surplus in a market model also taking the value of losses and other items into account. One TSO indicate that different approaches are used for interconnector investments (social welfare) and internal investments (increased transmission capacity and reduced expected loss of load). Furthermore, while CAPEX and OPEX are considered on the cost side for planning, other costs (congestion and reserves) are only included on the operations time-horizon.

All respondents say they assess socio-economic impacts in planning of grid developments, i.e., on the longest time-horizon, particularly related to the market. On shorter horizons, there is less emphasis on this aspect, about half the participants assess such impacts on shorter time-horizons. The use of software tools for socio-economic impact assessment varies considerably. TSOs use both in-house developed software (on platforms such as Matlab and Excel) and specialized commercial/external software (PROMOD, EMPS, BID, Samlast, SOS Tool Suite, PPSI).

There is limited use of socio-economic or market indicators to assess the effect of planned grid developments on system reliability. As Figure 4-1 shows, the most frequently used metric is annual energy not supplied (ENS). Six TSOs use ENS alone or together with value of lost load or/and annual interruption costs. Three TSOs use electricity market prices. When socio-economic impact assessment is performed, however, different cost rates are used; most commonly cost rates are differentiated by function of interruption duration and customer groups.

To sum up, all the respondents consider socio-economic impacts at the planning stage of grid developments, but there is less emphasis on this aspect on shorter time-horizons. When asked about costs and benefits, reduced expected loss of load is the most important specific benefit item, while on the cost side the significant items are reserves, congestion and re-dispatching. The degree of sophistication in this respect varies. In particular, one TSO applies a more sophisticated approach considering all important costs and benefits in a holistic manner. TSOs use different software tools for their analysis in this area – ranging from Excel to suites of market models. The most commonly used type of data for socio-economic impact assessment are different cost rates for value of lost load or cost of energy not supplied, differentiated to varying degrees. Finally, N-1 is the dominant criterion in use and few TSOs have compared the costs and benefits of using that criterion to other possible criteria. Yet, most TSOs deviate from the N-1 criterion on occasion allowing for N-0 operation. In most cases, the reason is the cost of applying the N-1 criterion strictly. Interestingly, three TSOs apply the N-0 criterion meaning that they accept more severe consequences in cases where the probability of a fault is regarded small.

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5.3 Synthesis of socio-economic impact assessment methodologies in theory and practice

The liberalisation of electricity markets led to increased demand for socio-economic impact assessment of investments in the power system. Whereas before, the approach was usually purely from the engineering point of view, the push for lower costs of delivered electricity brought the need to study the trade-off between increased reliability benefits of investments in electricity grids and the costs of those investments. Furthermore, while before all necessary information resided within one vertically integrated utility which also made most important decisions on the supply side, the unbundling of the different sectors of the electricity market created a need for more sophisticated analysis of market participants' behaviour under imperfect information. More recently, increased emphasis on electricity generation from renewable sources, such as wind and solar which are frequently variable, has created increased demands on transmission system capacity. There is therefore a need to weigh all these aspects together in a unified approach.

Methods for estimating the benefits of reliability – or their mirror image, the costs of electricity interruptions – are by now well developed: as the literature survey above shows there exists by now a large literature on how to measure the value of lost load or interruption costs. There is a good theoretical foundation for these methods of measurement and several existing methods. While regulators and TSOs usually rely on survey-based methods for measuring the cost of electricity outages – many such studies are published as reports (see [93] for examples) – methods that rely on existing aggregate data, e.g., from national accounts, are also common in recent research literature, in particular in recent articles published in international academic journals. Although this aspect is adequately covered in the literature, the different methods described here give quite different results for the value of lost load. Similarly, the survey of methods and tools for reliability assessment shows that the theme is more than well covered, but typically neither methods, tools nor data available are capable of covering the full range of complexity of the matter. Hence it can be concluded that there is a considerable uncertainty in the reliability part of assessing socio-economic impacts of power system investments. The results of such assessments should be handled with care, keeping an eye on the uncertainty.

Value of lost load estimates are mostly of interest as input to studies or decision making in the electricity sector. There is a small academic literature that is concerned with socio-economic aspects of decisions related to reliability in the electricity sector. This literature has usually grown out of policy work in the countries concerned, e.g., Norway [18], the Netherlands [109], the UK [111] and Germany [112]. In particular, the recent German literature has resulted from the Energiewende, i.e., the transition to a renewable energy supply sector in that country. Only a handful of studies consider probabilistic reliability criteria [105, 106, 109, 110].

As for practice, the survey of TSOs indicates that socio-economic impact assessment is widely used in the planning of electricity grids, but to a very limited extent on shorter time-horizons. The sophistication of assessment methods varies, especially as concerns the value of lost load. For example, while reduced loss of load is considered an important benefit of grid investments, only half the participating TSOs use value of lost load or cost of energy not supplied as a metric in their reliability studies. Cost items of maintaining reliability that are easier to measure, such as cost of reserves, congestion, and redispatching, are, however, widely used among TSOs in their assessment of socio-economic impacts. Hence, it appears – and is perhaps to be expected – that there is some gap between the existing research literature and what is practiced by TSOs in the area of socio-economic assessment.

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6 RELIABILITY ASSESSMENT INCLUDING SOCIO-ECONOMIC IMPACT

In the literature review on socio-economic impact assessments, various studies and definitions of socio-economic impact are presented. And, in the literature review on reliability assessment, various technical indicators and means for calculating them are presented. This chapter aims at giving a review of the literature on methodologies and tools combining these two aspects. The need for combining these aspects has been identified by many, examples are the Norwegian CENS [18] regulation and the concept of optimal reliability and value-based planning [43].

6.1 Methods and tools for combined reliability and socio-economic impact assessment with respect to short-term operation

In the literature, there exist different proposals for how to incorporate socio-economic impact into the reliability assessment. In the paper [88], a subjective weighting of socio-economic impact is proposed for a technical risk index. The purpose of this approach was not to define the best method for quantifying the socio-economic impact associated with a certain event. It was more a question of demonstrating that two events with seemingly the same impact, from the technical point of view, might have substantially different impacts if the socio-economic impact is taken into account. A monetary risk index is also proposed by [65], where the cost of energy not supplied is calculated for the events at the end of a cascading process. It is also shown how this cost can be calculated for a set of contingencies, thus enabling the calculation of the total expected cost associated with one initiating contingency. The papers [55, 56] show that the expected interruption costs can be calculated taking various time dependent phenomena into account. Furthermore, reference [55] shows how the calculation of expected interruption costs can be incorporated into their adaptive deterministic security boundaries' methodology. To our knowledge, the only commercial online security tool, which calculates the interruption cost is the previously mentioned tool Promaps Online [68].

6.2 Methods and tools for combined reliability and socio-economic impact assessment with respect to long-term planning

A method for incorporating a more complete picture of the total cost for probabilistic planning is proposed in [36], where the expected overall reliability cost is calculated (EORC), which is defined by the following equation:

$$EORC = ECOST + \ EPIC$$

Where ECOST is the "Expected Customer Interruption Cost" and EPIC is the "Expected Potential Insecurity Cost". Compared to for instance [55, 56], the added value in this formulation is the consideration of EPIC, which is the expected cost incurred by the system being in an N-1 insecure state. Such costs are typically related to system operator preventive actions, like but not limited to procuring balancing power, starting up reserve capacity, and re-dispatching. In short they argue that the overall cost of reliability (EORC) is the sum of customer interruption costs, and the cost of operating the grid without fulfilling the N-1 criterion.

The paper presents a case study, which demonstrates how one can choose between different grid reinforcement, by choosing the option resulting in the lowest EORC. Due to lack of data the case study presented does not consider the cost of not fulfilling the N-1 criterion.

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Another method capable of assessing the combined reliability and socio-economic impact is OPAL [14]. It gives as an output traditional probabilistic reliability indices as well as cost of energy not supplied (CENS):

- Expected annual interruptions
- Expected annual interruption duration
- Expected hours per interruption
- Expected interrupted power
- Expected annual interrupted energy
- Expected cost of energy not supplied (CENS).

The methodology uses a contingency enumeration approach and minimal cut-sets to determine for which contingencies the indices should be calculated. It has been implemented in a prototype tool, which can simulate the operating conditions using a MATLAB developed tool or the EMPS market model together with PSS/E. The tool can also possibly be extended for operational planning as investigated in [89].

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7 LESSONS LEARNED FROM OTHER SECTORS

In this chapter, reliability management is addressed for the air traffic and nuclear power sector. In addition, a summary is made of other sectors like gas supply, water and sewage, and railway. The description of lessons learned from this part is based on a limited literature survey.

7.1 Air Traffic Management (ATM)

7.1.1 Introduction

Air Traffic Management (ATM) at European level bears some analogy with the management of the pan European electricity system. Planes must flow in congested corridors. Air traffic controllers must make sure in real time that no plane collision occurs. Air Traffic Control (ATC) must also still continue working even if a critical piece of equipment is failing. Overall, can we borrow from the safety approaches used by ATM designers to transfer some of the knowledge gained in air traffic control into the future approaches addressed by the GARPUR project?

The present chapter analyses two issues (the construction of safety indicators and reliability management) to show that both value chains are addressing these issues with similar approaches, but that the underlying physics prevent from borrowing specific knowledge from one value chain to the other. Ironically enough, a recent paper [120] models the reliability of a local ATC system in Iceland. It describes the interactions between the ATM and the electricity systems which can be prone to blackouts due to adverse weather conditions. This paper shows how reliability modelling can shed light on ATM reliability management when the electric power is partially out.

7.1.2 Background

Like electricity demand, air flights and therefore air traffic are steadily growing worldwide: there are populated areas in the US and in Europe where the air traffic demand is now higher than the capacity which can be reached using well established operational procedures.

It is thus necessary to introduce new effective operations in Air Traffic Management (ATM) where high safety standards in civil aviation, combined with the complexity of ATM, makes it difficult to foresee the consequences of introducing new operations upon safety [121]. Moreover, the very nature of civil aviation makes ATM architectures highly distributed: there are human controllers in each aircraft, at each airport, and also in each node of the global network of ground based air traffic service centres. Statistical analysis of the past safety performances of ATM becomes less and less helpful. Indeed, aircraft pilots and air traffic controllers currently play a key role in meeting high safety standards in civil aviation: a special attention is to-day paid with the modelling of their cognitive performance [122] in ATM operations and the relation with safe operations. This is a first area of great concern for air transportation.

7.1.3 Safety [123] indicators in ATM

Safety has always been a key quality parameter onto which advanced air traffic management (ATM) concepts are designed, even though capacity and efficiency are amongst the prominent development drivers for such complex systems.

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Improved safety targets when designing new ATM systems are very often ranked as 'equal' or 'better' than the ones reached by existing practices [123], thus leaving a large freedom to express targets and to measure them. As a matter of fact, the development of innovative communication, navigation, surveillance and air traffic management (CNS/ATM) systems are managed without using any feedback from appropriate safety assessment. ATM concept design teams (e.g., Free Flight or “four dimensional” ATM) aim at enhancing capacity-efficiency performances by exploiting new technologies, changing human controller roles or/and introducing new procedures, while relying on established safety-related indicators in ATM such as conflict rates and types, workload of human operators and failure rates and effects of technical systems. Yet, reliable ATM systems result from complex interactions between multiple human operators, procedures and technical systems, all of them being distributed. Overall, providing safety is more than ensuring that each of the ATM elements function properly; it is the complex interactions between them that lead to safe systems.

Today, the assessment of isolated safety indicators falls short in covering the complex interactions between procedures, human operators and technical systems in safety-critical, non-nominal situations. Thus, it is to improve the present day situation that novel probabilistic assessment methodologies are developed to further optimize ATM systems. Recent work has started delivering risk assessment results.

7.1.4 Supporting Air Traffic Control reliability [124]

The way to prove a support system’s reliability consists of showing that Air Traffic Control systems, as a whole, can still provide full traffic control services when errors suddenly appear. Indeed, if the controllers are timely and adequately informed of the incidents, they can accordingly adjust their current control tasks and the resulting tasks. They can often manage without some of their tools being available, this kind of working mode being seen as a type of Degraded Mode of Operation, like in electricity systems. There exists then a need for a decision-aided system that helps the controllers in using their multiple software tools, particularly in situations where some tools are not available, or in other words when technical incidents happen. Suitable multi-agent technology can help in this respect [125].

7.1.5 Reliability models of ATM systems: a case study

The ability to provide safe and efficient air navigation services depends upon the ATM system of any given area. The recent work on the Reykjavik system see [120] is based on the development of a reliability model that can be used to ascertain the risk of technical failure in the ATM system of this area. The Failure Mode Effect and Criticality Analysis (FMECA) and Reliability Block Diagram (RBD) is implemented within a simulation package to propose a quantitative model used to study the impact of the ATC electrical power system failures on the reliability of the ATM system. Beyond providing Mean Time to Failure values, the use of the simulation software helps in redesigning the local electrical system. Last but not least, ATM systems are continuously upgraded and modified: reliability analysis should become a continuous activity, which simulation facilitates and makes less costly [126].

7.2 Nuclear safety

7.2.1 Using deterministic and probabilistic models

Nuclear power plants are planned in such a way that there are safety functions that prevent dangerous accidents such as the core melt. The nuclear safety includes ensuring that nuclear plants operate without excessive risks, preventing incidents and; limiting the consequences of any incidents that might occur.

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Probabilistic safety assessment (PSA) for nuclear power plants was introduced to commercial nuclear power industry in mid-1970-s [127]. PSA is commonly used for identifying and understanding the vulnerabilities at nuclear power stations. According to the International Atomic Energy Agency (IAEA), one of the most important applications for PSAs of operating nuclear power plants is to identify potential safety improvements and to support the selection, design, installation, and licensing of plant upgrades (e.g., owing to changes in licensing criteria) [128].

Also, deterministic methods are still used in nuclear power plants. The objective of deterministic safety analyses in nuclear power plants is to demonstrate that, in normal operational conditions and accident conditions, a sufficient number of barriers are retained [129]. Since deterministic methods continue to be very effective to ensure safe plant designs, PSA should be used to complement, enhance, and validate conclusions that are based on well-established deterministic design principles [128].

Compared to power system reliability methods, the nuclear industry has a longer history with probabilistic methods and these methods have an established position. One lesson that the power industry can learn from the nuclear industry is using deterministic and probabilistic methods in parallel in such a way that both have their specific role. IAEA states that a major part of the process of designing and licensing a nuclear power plant is the safety analysis. A deterministic safety analysis alone does not demonstrate the overall safety of the plant, and it should be complemented by a probabilistic safety analysis [129].

7.2.2 Understanding the limitations in the current probabilistic models

Advanced plant designs rely on increased use of software based systems for instrumentation and control, plant protection, and operator interfaces. There is currently very limited experience in the development and application of PSA methods to analyse complex software based logic. Therefore, current PSA methods have limited capability to estimate the actual reliability and risk contributions from these systems [128].

7.2.3 Data

The PSA analyses should be based on the best available data for the types of equipment and systems in the plant. In some cases, very limited data may be available for evolutionary designs or new equipment, especially in the case of passive systems. In these cases, data for similar components or documented expert judgment should be used to estimate failure rates, maintenance unavailability, common cause failure parameters, etc. The absence of documented component specific reliability data should not be used as a basis for postponement of a PSA evaluation or for omission of specific component failure modes from the PSA models. The models and analyses should be updated as more information, experience and data become available for the new equipment [128].

Considerable experience and engineering judgment are also required to determine which existing data are most applicable to the new systems or which generic databases or models provide the best information for a new design. Sensitivity analyses of the results will show the importance of such judgments for the assessed safety of the plant [128].

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7.2.4 Common cause failures

The reliability tools used in PSA, such as event and fault trees that are constructed with basic events are in general powerful in identifying common cause failures [129]. Since common cause failures can significantly impact the reliability of the safety systems, they should be identified also for power systems.

7.2.5 Lessons learnt

Briefly, the lessons that can be learned from the nuclear industry are the following:

1) Finding the best way to use both deterministic and probabilistic methods
2) Data: find the best data and estimate the data for cases where no proper data is available
3) Recognizing the limitations of the current probabilistic methods in use, regarding modelling of passive components, common cause failures and software in complex software based systems
4) Identification of (and modelling correctly) common cause failures.

7.3 Other sectors

In the COST[2] action C19 Proactive crisis management of urban infrastructure [130] conducted in the period 2004 - 2008, risk analysis and risk management was studied in various sectors such as railway, water supply, gas supply and road transport. In addition, the work covered planning and handling of acute crisis. A questionnaire on the use and potential of risk analysis showed that consequences were mostly predicted using deterministic models which are extended in some applications with Monte Carlo simulations. Reliability data were mostly derived from expert judgment. Probabilistic assessment was so far not very common, but an increasing potential was seen. It was concluded that the current use of risk based methods was regarded insufficient and the methods needed further development [130]. The knowledge gaps were also studied. The current progress in risk assessment was found to be limited by the lack of knowledge of existing risk analysis methods, lack of forecasting models as well as coordinated data bases. These limitations appeared however, to a varying degree among the sectors. It was concluded that formal methodologies and demonstration projects applied to practice had to be developed. Some lessons learned were, amongst others [130]:

- There are needs for better understanding of risk within society and increased awareness of possible critical events and the following consequences.
- Traditionally, engineers and practitioners are better trained for solving deterministic problems. There are needs for better training including uncertainty in problem solving.
- Appropriate data are crucial for making decisions in the context of risk management. Systematic data collection should be part of daily operations.

In [131], a study was performed to possibly reveal indicators relevant for describing risk and vulnerability in other sectors. Information was mainly found for the oil and gas sector and the railway sector. For instance, the oil and gas sector in Norway focuses to a large extent on health, safety and environment (HSE) issues and a set of risk indicators are developed and being reported to the Petroleum Safety Authority. The indicators cover issues like major accidents and selected related barriers, serious injuries, chemical and physical environment.

[2] COST = European COoperation in the field of Scientific and Technical Research

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As regards the railway sector, the condition of the railway infrastructure is being monitored in Norway [131]. Various methods are used for the purpose. The Norwegian National Rail Administration collects data about disturbances in the railway sector that have consequences for the punctuality of trains. Both causes and extent of consequences are recorded. In addition, safety indicators are in use. Like the oil and gas sector, the railway sector focuses especially on the potential for large accidents.

7.4 Critical infrastructures and common approaches

Electric power systems are critical infrastructures like water supply, transportation and information and communication technologies. Critical infrastructures are complex physical and logical systems essential for social welfare, see e.g., [132]. Various approaches for analysing risk and vulnerability in complex systems like critical infrastructures and their increasing interdependencies are described in [132]. Examples are also given for different sectors, including power systems. A framework for analysing risk and interdependencies in critical infrastructures is also described in [11]. This framework covers identification of hazards that are threatening infrastructures and various approaches for analysing how these threats can propagate throughout the system and affect other infrastructures. In addition, state of the art methods for risk based (probabilistic) methods are described for water supply systems, information and communication technology and maritime transport systems (in addition to electricity supply).

References like [11] and [132] describe other approaches than those involved in the probabilistic reliability methodologies described in Chapter 4, which are designed for electric power systems. Methods for analysing risk and vulnerability such as outlined in [11] and [132], provide important supplements to the traditional power system oriented approaches. For example, there are useful approaches for analysing human threats, high impact low probability events and not the least interdependencies with other infrastructures. For power systems, the interdependencies with information and communication technologies are the most obvious and increasingly important to take into consideration also in reliability assessment. A lesson to be learned in this regard, is that there are generic techniques available for critical infrastructures that can be utilized and adapted to probabilistic reliability assessment in the power sector.

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8 SUMMARY AND CONCLUSION

This report has described state of the art in theory and practice of reliability assessment methodologies and socio-economic impact assessment. Some lessons learned from other sectors are also included. The report provides a common basis for the development of new reliability criteria.

The results are based on literature surveys covering a total of about 130 publications from the electricity sector and the research community. In addition, a questionnaire survey was performed among TSOs to provide information about the status of reliability management in practice. The responses cover 9 TSOs in total from the Nordic countries and the Continental Europe. These represent different system sizes, characteristics and control zones. Despite the limited number, the responses are regarded sufficiently representative for Europe due to the variety revealed through the answers.

Power system reliability means having the ability to supply adequate electric service on a nearly continuous basis with only few interruptions over an extended period of time. Reliability is divided in power system security and power system adequacy. Reliability can be explained by the combination of the power system's vulnerability to external threats that may lead to failures, and the implied loss of electricity supply for the end-users. Threats can be related to nature, humans or the operational conditions. The criticality of the consequences is directly dependent on factors like affected area, duration, type of customers, economic and social consequences. There are numerous factors (technical, work force related and organizational) that have an influence on the power system vulnerability and, as such, on the power system reliability.

Assessing power system reliability is a complex and comprehensive task involving a multitude of factors, dimensions and uncertainties. Due to the complexity and different needs in different decision contexts and time horizons, it is necessary to decompose the problem into sub problems. Various methodologies for reliability assessment have been developed over decades, each solving a specific part of the overall problem and there are different indicators in use to describe the reliability. There is no single methodology suitable for an all-encompassing reliability analysis. Nevertheless, the main principles remain the same. The report describes a framework for reliability analysis which serves as a background for structuring the methodologies:

In analogy to risk analysis, reliability analysis of power systems traditionally attempts to answer three fundamental questions:
1. What can go wrong?
2. How likely is it to happen?
3. What are the consequences?

The results of the literature survey on reliability are presented for two main areas: reliability indicators and reliability methods. Reliability indicators are separated in deterministic and probabilistic indicators for security and adequacy, respectively, and component reliability indicators. In the area of reliability analysis, a distinction is made between the two main approaches to probabilistic reliability assessment, namely analytical approaches and Monte Carlo simulations. It is considered how to model different aspects of the power system, such as weather and other specific issues, contingency selection methods, and how to analyse high impact low probability events (blackouts). There is an extensive literature on probabilistic methods for reliability assessment. Both online and offline tools found in the literature are also presented.

While most research papers argue for a probabilistic assessment of the power system, the most used approach in the European industry is deterministic. The responses (from nine TSOs) to the questionnaire

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show that most of the TSOs use probabilistic reliability analysis for long-term planning purposes, a few in mid-term planning and asset management but hardly any for short-term operation. Although the literature survey identified a lot of research regarding probabilistic reliability indicators, both for security and adequacy, the questionnaire survey revealed that these are generally not in use. It seems that the current industry practice is closer to what is required by ENTSO-E's network codes, than what is presented in the literature. The methods and modelling issues identified as the most relevant seem, however, to be the same in both literature and practice. There is a variety of tools in use for the different time horizons, the dominating are PSS/E and in-house tools. All respondents reported that they collect reliability data for most primary equipment, regarding number of faults, outage times and failure causes.

The literature survey on socio-economic impact assessment mainly deals with value of lost load (VOLL) or customer interruption costs, and how to estimate such costs. A lot of different methods exist. The most common approach is based on stated preference, i.e., how the customers value their consequences of being interrupted, using surveys or interviews. Examples of applications of VOLL estimates are given in the report, such as, cost-benefit studies of probabilistic reliability criteria compared to the N-1 criterion and the use in quality of supply regulation of the network companies. There are also methods and tools available where the socio-economic impact assessment is incorporated in the probabilistic reliability assessment using VOLL estimates.

In practice, reliability management is decomposed in three types of time horizons and activities, namely long-term system development, mid-term planning including asset management, and short- term system operation. Reliability management follows some principles known as reliability criteria in the different time horizons. The overall objective of reliability management is to ensure an adequate level of reliability while minimizing total socio-economic costs. This can only be achieved with a probabilistic criterion that considers both the severity and the probability of potential interruptions. The current N-1 criterion is a simplified deterministic reliability criterion, where the level of reliability is not actually assessed, and hence neither is the reliability part of the socio-economic benefits of investments.

Most of the TSOs in the questionnaire survey reported that they use the N-1 criterion strictly. Only a few of them have estimated the costs of applying this criterion compared to other reliability criteria. However, the majority also reports that they sometimes apply the N-0 criterion meaning that they accept more severe consequences in cases when the probability is regarded small due to the cost of keeping N-1. All the respondents consider socio-economic impacts at the planning stage of grid developments, but there is less emphasis on this aspect on shorter time-horizons. While reduced loss of load probability is considered an important benefit of grid investments, only half the participating TSOs use value of lost load or cost of energy not supplied as a metric in their reliability studies. Costs of maintaining reliability, such as cost of reserves, congestion, and redispatching, are easier to measure, and widely used among TSOs in their assessment of socio-economic impacts. TSOs use different software tools for their analysis in this area – ranging from Excel to market models.

The literature surveys have revealed that a lot of probabilistic methods and reliability (security and adequacy) indicators and methods are developed, covering all time frames. Both commercial and research grade tools exist for reliability assessment, some even including socio-economic impact assessment in terms of interruption costs. Methods for estimating the VOLL cost rates are well developed, though they reveal different cost estimates. The TSOs are already collecting reliability data for the primary components. The synthesis of the literature survey and responses to the questionnaire indicates that there is a gap between the existing research literature and what is practiced by TSOs. Probabilistic methods, including socio-economic impact assessment, seems to be used to some extent in long-term planning and in mid-term planning and asset management, while almost absent in the short-term operation of the power system. Current reliability practices and drivers and barriers for introducing

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probabilistic reliability criteria will be discussed in the next deliverable from this work package in the GARPUR project.

The review of reliability management in other sectors comprises foremost air traffic and nuclear power, and there is a brief summary provided of sectors such as gas supply, water supply, and railway. Lessons to be learned are amongst other:

- Finding the best way to use both deterministic and probabilistic methods
- Be aware of the limitations in current probabilistic methods in use, regarding specific modelling issues
- Appropriate data are crucial for making decisions in the context of risk management. Find the best data and estimate them for cases where no proper data is available. Systematic data collection should be part of daily operations.
- Traditionally, engineers and practitioners are better trained for solving deterministic problems. There are needs for better training including uncertainty in problem solving.
- Reliable infrastructures result from complex interactions between multiple human operators, procedures and technical systems. The existing safety indicators used in ATM for instance, as well as the traditional reliability indicators in power systems falls short in covering these complex interactions. Thus, there is a need for novel probabilistic assessment methodologies.
- Generic techniques for critical infrastructures are available that can be utilized and adapted to supplement the probabilistic reliability assessment methods developed for the power sector.

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APPENDIX 1 N-1 CRITERION – DEFINITIONS

To show the variety of definitions of the N-1 criterion, a few definitions are included in this appendix from Europe (UCTE, ENTSO-E, Nordel), U.S. (NERC) and IEEE/CIGRE.

UCTE operational handbook [available at: https://www.entsoe.eu/publications/system-operations-reports/operation-handbook/]
The N-1 CRITERION is a rule according to which elements remaining in operation after failure of a single network element (such as transmission line / transformer or generating unit, or in certain instances a bus-bar) must be capable of accommodating the change of flows in the network caused by that single failure.

> Contingency
> Contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A CONTINGENCY also may include multiple components, which are related by situations leading to simultaneous component outages.

ENTSO-E Network code for operational security (2013)
(N-1)-Criterion means the rule according to which elements remaining in operation within TSO's Responsibility Area after a Contingency from the Contingency List must be capable of accommodating the new operational situation without violating Operational Security Limits;
(N-1)-Situation means the situation in the Transmission System in which a Contingency from the Contingency List has happened;

> Contingency:
> Contingency means the identified and possible or already occurred Fault of an element within or outside a TSO's Responsibility Area, including not only the Transmission System elements, but also Significant Grid Users and Distribution Network elements if relevant for the Transmission System Operational Security. Internal Contingency is a Contingency within the TSO's Responsibility Area. External Contingency is a Contingency outside the TSO's Responsibility Area, with an Influence Factor higher than the Contingency Influence Threshold;
>
> Ordinary Contingency means the loss of a Transmission System element such as, but not limited to: a single line, a single transformer, a single phase-shifting transformer, a voltage compensation installation connected directly to the Transmission System; it also means the loss of a single Power Generating Module connected directly to the Transmission System, the loss of a single Demand Facility connected directly to the Transmission System, or the loss of a single DC line;

Nordic Grid Code 2007
N-1 criteria are a way of expressing a level of system security entailing that a power system can withstand the loss of an individual principal component (production unit, line, transformer, bus bar, consumption etc.). Correspondingly, n-2 entails two individual principal components being lost.

The criteria for system security shall be based on the n-1 criterion. This is an expression of a level of system security entailing that a power system is assumed to be intact apart from the loss of individual principal components (production units, lines, transformers, bus bars, consumption etc.). For faults having the largest impact on the power system, the term dimensioning faults is used.

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NERC [25]
Definition of "Adequate Level of Reliability"
The Bulk-Power System ("System") will achieve an adequate level of reliability when it possesses following characteristics:

1. The System is controlled to stay within acceptable limits during normal conditions;
2. The System performs acceptably after credible Contingencies;
3. The System limits the impact and scope of instability and cascading outages when they occur;
4. The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings;
5. The System's integrity can be restored promptly if it is lost; and
6. The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

Definition and classification of power system stability, IEEE/CIGRE joint task force on stability terms and definitions [3]
N-1 definition:
"The power system is designed and operated to withstand a set of contingencies referred to as "normal contingencies" selected on the basis that they have a significant likelihood of occurrence. In practice, they are usually defined as the loss of any single element in a power system either spontaneously or preceded by a single-, double-, or three-phase fault. This is usually referred to as the criterion because it examines the behavior of an N-component grid following the loss of any one of its major components."

Haarla, L., Koskinen, M., Hirvonen, R., Labeau, P-E.: Transmission Grid Security – a PSA Approach. Springer 2011
"In transmission system planning, a common criterion is the so-called N – 1 criterion. Shortly put, this means that a system having N components can continue its operation even though whichever single component at a time is taken out of operation. However, there is variation how the actual process leading to an outage of a single component can develop and which components are observed. These differences can be mainly explained with different system characteristics and environment conditions. The selection of contingencies for the N – 1 criterion is usually based on the probabilistic evaluation of the fault frequencies of the diverse power system components and possible consequences of those faults. In general, larger consequences can be allowed for rare contingencies, but the most common contingencies should be imperceptible for grid clients."

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APPENDIX 2 QUESTIONNAIRE: RELIABILITY MANAGEMENT IN PRACTICE

Part I Current reliability management

Please comment on differences in planning, operation and asset management in questions where relevant. Multiple choices are allowed.

Q1. How do you define the N-1 criterion?	Please define/specify (for each of the three time horizons planning, operation and asset management):
a) for the intact grid?	
b) for a planned outage?	
c) for an unplanned outage (such as a permanent line fault)?	
Comments/remarks:	

Q2. How do you define the N-2 criterion?	Please define/specify (for each of the three time horizons planning, operation and asset management):
a) for the intact grid?	
b) for a planned outage?	
c) for an unplanned outage (such as a permanent line fault)?	
Comments/remarks:	

Q3. Do you follow the N – 1 criterion strictly?	☐ Yes ☐ No
Comments/remarks:	

Q4. Do you sometimes use weaker/stronger criteria?	☐ Yes ☐ No If yes, please describe.
Comments/remarks:	

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Q5. How do you take into account planned outages if you use the N – 1 criterion for the intact grid?	1 ☐ The grid is operated with N – 0 principle 2 ☐ The grid is planned in such a way that during a planned outage, the N – 1 criterion can be used in the operation in a similar way as when the grid is intact 3 ☐ Varies according to the case, such as location, duration of the outage, timing of the outage, load type, severity of the consequences (please specify) 4 ☐ Other (please specify)
Comments/remarks:	

Q6. Do you have different reliability requirements for different areas, for example for a major city vs. a rural area?	☐ Yes ☐ No If yes, please answer the following alternatives
	1 ☐ Important cities have higher reliability requirements 2 ☐ Important industry has higher reliability requirements 3 ☐ Critical societal functions or infrastructures have higher reliability requirements 4 ☐ Other (please specify)
Comments/remarks:	

Q7. What kind of faults are included in the N-1 criterion as N – 1 faults?	1 ☐ Single line faults 2 ☐ Double line faults 3 ☐ Busbar faults without generators connected 4 ☐ Busbar faults with generators connected 5 ☐ HVDC connection faults 6 ☐ Generator faults 7 ☐ Transformer faults 8 ☐ Other (please specify)
Comments/remarks:	

Q8. If you have double lines in your grid (two lines on the same towers, or two cables in the same ditch) and apply the N – 1 principle: Which is the N – 1 fault here?	1 ☐ Fault and trip of one line/cable 2 ☐ Fault (on one or two lines/cables) and the trip of two lines/cables 3 ☐ Varies according to the case (please specify) 4 ☐ Other (please specify)
Comments/remarks:	

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In answering the following question, please have the intact grid situation in mind. If there are big differences between intact grid and outage situations, please comment. Multiple choices are allowed.

Q9. Which limiting factors after N – 1 faults in the intact grid set the limits for the transmission capacity?	1 ☐ Thermal overloading of lines 2 ☐ Thermal overloading of other components (than lines) 3 ☐ Slow voltage instability (Several minutes or more) 4 ☐ Fast voltage instability (from seconds to some minutes) 5 ☐ Transient voltage instability (instantaneous cascading due to voltage instability) 6 ☐ Transient angle instability 7 ☐ Frequency instability 8 ☐ Damping of electromechanical oscillations 9 ☐ Short circuit currents 10 ☐ Other (please specify)
Comments/remarks:	

Q10. In which cases is the N – 1 criterion not fulfilled in your system? (The list is taken directly from ENTSO-E operational security code as it was 17th Oct 2013)	1 ☐ During switching sequences, 2 ☐ as long as the consequences are local, 3 ☐ during the time period required to activate the Remedial Actions. 4 ☐ Other (please specify)
Comments/remarks:	

Q11. a) Have you experienced or do you foresee cases when the N – 1 criterion is *not* sufficient to secure the electricity supply?	☐ Yes ☐ No If yes, please answer the following questions.
b) In what kind of circumstances do you consider the N – 1 criterion is insufficient?	1 ☐ During severe weather conditions 2 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 3 ☐ Where there are long repair times, example for sea cables (not interconnectors) 4 ☐ Other (please specify)
c) If you find the N – 1 criterion is insufficient what do you do?	Please describe
Comments/remarks:	

Q12. Have you estimated the costs and benefits of applying the N – 1 criterion compared to other reliability criteria?	☐ Yes ☐ No If yes, please describe.
Comments/remarks:	

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For the following question, please remember to consider the highest voltage levels (220 kV and above) and concentrate on power transmission components such as lines and cables. A rough estimate is adequate.

Q13. For how long periods (in %) of the year is your grid not intact, i.e., one of the following components are on outage (planned or unplanned), on average per year	1 ☐ Overhead line ..... % 2 ☐ Underground cable ..... % 3 ☐ HVDC link ..... % 4 ☐ Other (please specify) ..... %
Comments/remarks:	

Q14. How large a share of your grid do the following types of lines/cables amount to?	1 ☐ Overhead single lines ..... % 2 ☐ overhead double lines ..... % 3 ☐ underground cables ..... % 4 ☐ submarine cables ..... % 5 ☐ Others (please specify) ..... %
Comments/remarks:	

Q15. Do you include varying repair times of different components in your N − 1 interpretation (related to how detailed do you perform the consequence evaluation)?	☐ Yes ☐ No If yes, please answer the following question (Q16).
Comments/remarks:	

Q16. How do you include varying repair times of different components in your N − 1 interpretation?	1 ☐ Depends on the importance of the component 2 ☐ Depends on the duration of the repair time 3 ☐ Depends on the type and characteristic of the component 4 ☐ Depends on the costs of the outage (please specify) 5 ☐ Other (please specify)
Comments/remarks:	

Q17. Do you include probabilities in your interpretations of the N − 1 criterion, such as, ignoring some very rare faults.	☐ Yes ☐ No If yes, please answer the following question (Q18).
Comments/remarks:	

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Q18. What kind of probability considerations do you take in the N – 1 criterion?	1 ☐ After very rare faults, the consequences can be different than after normal and frequent faults 2 ☐ Grid fault frequency is taken into account 3 ☐ What else? 4 ☐ Other (please specify)
Comments/remarks:	

By using the N-1 criterion, the consequences after a single fault are regarded acceptable. In the following question we investigate cases where this is too restrictive. Please interpret "using the N-0 criterion" as accepting more severe consequences after certain faults.

Q19. Do you sometimes apply the N – 0 criterion, as defined above?	☐ Yes ☐ No If yes, please answer the following questions.
a. When do you apply the N – 0 criterion?	1 ☐ During a certain period 2 ☐ During a fixed duration (e.g. a certain percentage of time) 3 ☐ During planned outages 4 ☐ In some areas (please specify) 5 ☐ Other (please specify)
b. When applying the N – 0 criterion, do you take into account the ambient situation (temperate, wind, other weather or something else).	☐ Yes ☐ No If yes, please define the criteria.
c. Why do you apply the N – 0 criterion?	1 ☐ The probability of a fault is small, i.e., you accept the risk 2 ☐ To use the grid more efficiently 3 ☐ The transmission capacity given to the market would be too small 4 ☐ It is too expensive to apply the N – 1 criterion (for example when connecting wind power to the grid it would be too expensive to build an additional connection for the rated power of the wind power plant). 5 ☐ Other (please specify)
d. Which are the acceptable situations when you apply the N – 0 criterion?	1 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 2 ☐ Low load situation (For instance in summer time or night time) 3 ☐ The duration of the N – 0 situation is short 4 ☐ No risks for personal safety 5 ☐ After a fault there is overload that is acceptable for a short duration, e.g. 20 minutes, during which the necessary remedial actions can be done. 6 ☐ The alternative would be to shed load 7 ☐ Other (please specify)

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e. When applying the N – 0 criterion, how do you evaluate the probability of a fault?	1 ☐ We use the same statistics as always 2 ☐ We have different probabilities (if yes, please specify) 3 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 4 ☐ Other (please specify)
f. Which are the acceptable consequences when you apply the N – 0 criterion and there is a fault?	1 ☐ Load shedding for some loads regardless of the duration 2 ☐ Load shedding for some loads for a short duration 3 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 4 ☐ A blackout 5 ☐ The consequences of a fault are limited to a small number of customers or a local area, i.e. you accept the risk 6 ☐ The consequences are local and limited and can be handled (e.g. overloading of a line, which has overloading capacity for a fixed duration). Please define the criteria (e.g. the maximum permitted overloading) 7 ☐ No cascading trips as a consequence 8 ☐ Other (please specify)
Comments/remarks:	

Q20. When planning the grid, do you…	1 ☐ Take into account the repair time of components (or time to restore electricity to customers that are (partly) interrupted)? 2 ☐ Take into account the type of load, for example do you interpret the N - X criterion differently for industrial load and domestic load? 3 ☐ Use system protection schemes for mitigating the consequences? 4 ☐ Plan re-dispatching for mitigating the consequences of a fault? 5 ☐ Other (please specify)
Comments/remarks:	

Q21. When operating the grid, do you…	1 ☐ Take into account the repair time of components (or time to restore electricity to customers that are (partly) interrupted)? 2 ☐ Take into account the type of load, for example do you interpret the N - X criterion differently for industrial load and domestic load? 3 ☐ Use system protection schemes for mitigating the consequences? 4 ☐ Use system protection schemes for increasing the transmission capacity? 5 ☐ Plan re-dispatching for mitigating the consequences of a fault? 6 ☐ Other (please specify)
Comments/remarks:	
Q22.	1 ☐ Take into account the repair time of components (or

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When operating the grid during maintenance work, do you…	time to restore electricity to customers that are (partly) interrupted)? 2 ☐ Take into account the type of load, for example do you interpret the N - X criterion differently for industrial load and domestic load? 3 ☐ Use system protection schemes for mitigating the consequences? 4 ☐ Plan re-dispatching for mitigating the consequences of a fault? 5 ☐ Other (please specify)
Comments/remarks:	

The following question is important to see how you evaluate grid investments and operations today. Multiple choices are allowed.

Q23. How do you include socio-economic benefits and costs in the transmission system today? (Please comment on differences in planning and operation)	Benefits: 1 ☐ Increased transmission capacity 2 ☐ Reduced expected loss of load (expected interruption costs) 3 ☐ Increased security margins 4 ☐ Other (please specify) Costs: 5 ☐ Congestion costs 6 ☐ Expected interruption costs 7 ☐ Costs of reserves 8 ☐ Re-dispatch costs 9 ☐ Outages that lead to high electricity market prices in some areas 10 ☐ Other (please specify)
Comments/remarks:	

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Part II Reliability methods, tools and data in use

II.1 Reliability methods in use (incl. socio-economic impact assessment)

Multiple choices are allowed.

Q24. Which methods are used to assess the reliability of planned grid developments?	1 ☐ Power flow analysis 2 ☐ Dynamic analysis 3 ☐ Reliability analysis including probabilities (or frequencies) of failures and consequences (please specify) 4 ☐ Short circuit analysis 5 ☐ Other (please specify)
Comments/remarks:	

Q25. Which methods are used to assess the operational reliability?	1 ☐ Power flow analysis 2 ☐ Dynamic analysis 3 ☐ Reliability analysis including probabilities (or frequencies) of failures and consequences (please specify) 4 ☐ Short circuit analysis 5 ☐ Other (please specify)
Comments/remarks:	

Q26. Which methods are used for mid-term planning (asset management?	1 ☐ Reliability-centred maintenance (RCM) 2 ☐ Failure mode and effect analysis (FMEA) 3 ☐ Reliability analysis including probabilities (or frequencies) of failures and consequences (please specify) 4 ☐ Other (please specify)
Comments/remarks:	

Q27. Do you also assess the socio-economic impacts for the above mentioned time horizons?	1 ☐ In planning of grid developments 2 ☐ In operational planning 3 ☐ In online operation 4 ☐ In asset management If yes, please specify the methodology in use time for each time horizon.
Comments/remarks:	

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Please comment on differences in planning, operation and asset management in questions where relevant.

Q28. How do you model or take into consideration the probabilities of external threats (e.g. weather, human errors etc.) and the actual consequences of interruptions to the loads (customers)	Please describe:
Comments/remarks:	

Q29. How do you model or take into consideration corrective control (remedial actions) and its probability of failure?	Please describe:
Comments/remarks:	

Q30. How do you model or take into consideration demand side management and energy storage?	Please describe:
Comments/remarks:	

Q31. How do you model or take into consideration low-probability high-impact events?	Please describe:
Comments/remarks:	

Q32. Are there any areas you feel the existing methodologies fail to cover?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

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II.2 Software tools in use

Multiple choices are allowed.

Q33. Which software tools are used to assess the reliability of planned grid developments? Please provide name of tools.	1 ☐ In-house developed software (one or more, in Matlab, Excel or other) 2 ☐ Commercial or external software (one or more, please specify) 3 ☐ Other (please specify)
Comments/remarks:	

Q34. Which software tools are used to assess operational reliability? Please provide name of tools.	1 ☐ In-house developed software (one or more, in Matlab, Excel or other) 2 ☐ Commercial or external software (one or more, please specify) 3 ☐ Other (please specify)
Comments/remarks:	

Q35. Which software tools are used for mid-term planning (asset management)? Please provide name of tools.	1 ☐ In-house developed software (one or more, in Matlab, Excel or other) 2 ☐ Commercial or external software (one or more, please specify) 3 ☐ Other (please specify)
Comments/remarks:	

Q36. Which software tools are used for socio-economic impact assessment? Please provide name of tools.	1 ☐ Same tool as for reliability assessment (please specify 2 ☐ In-house developed software (one or more, in Matlab, Excel or other) 3 ☐ Commercial or external software (one or more, please specify) 4 ☐ Other (please specify)
Comments/remarks:	

Q37. Are there any areas you feel the software tools fail to cover?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

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II.3 Reliability metrics/indicators in use

Multiple choices are allowed.

Q38. Which metrics/indicators are used to assess the effect of planned grid developments on the system reliability?	1 ☐ Load point indices 2 ☐ Bulk power system indices 3 ☐ Annual number of interruptions 4 ☐ Annual interruption duration 5 ☐ Average interruption duration 6 ☐ Annual interrupted power 7 ☐ Annual energy not supplied 8 ☐ Annual interruption cost (cost of energy not supplied) 9 ☐ Value of lost load 10 ☐ System minutes 11 ☐ Electricity market prices in the system (with or without a certain investment) 12 ☐ Other (please specify) Metrics: .....
Comments/remarks:	

Q39. Which metrics/indicators are used to assess operational reliability?	1 ☐ Load point indices (please specify 2 ☐ Severity indices: 3 ☐ Overload (or risk of overload) 4 ☐ Voltage deviations (or risk of voltage deviations) 5 ☐ Frequency deviations (or risk of frequency deviations) 6 ☐ Margin to instability (please specify) 7 ☐ Duration of the system being in alert state 8 ☐ Critical fault clearing time 9 ☐ Probability of load curtailment 10 ☐ Other (please specify) Metrics: .....
Comments/remarks:	

Q40. Are there any aspects you feel the metrics/indicators fail to measure?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

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II.4 Reliability data and interruption cost data

In this section we investigate collection of reliability data in the TSOs. By this, we mean outage statistics on lines and components, typically registering fault, failure causes and repair times.
Multiple choices are allowed.

Q41. Do you collect the following type of data about faults on components?	1 ☐ Faults 2 ☐ Outage times 3 ☐ Failure causes 4 ☐ Other (please specify)
Comments/remarks:	

Q42. How do you use these data?	1 ☐ System development, grid investment planning 2 ☐ Asset management in general (please specify) 3 ☐ Maintenance planning 4 ☐ Grid performance statistics 5 ☐ Other (please specify)
Comments/remarks:	

Q43. Do you process the data, like calculating…?	1 ☐ Failure frequency 2 ☐ Repair time 3 ☐ Long-term unavailability 4 ☐ Other (please specify)
Comments/remarks:	

Q44. For which components do you collect and process reliability data (number of faults, fault causes, repair time)?	1 ☐ Overhead lines 2 ☐ Cables 3 ☐ Busbars 4 ☐ Generators 5 ☐ Transformers 6 ☐ HVDC lines 7 ☐ Circuit breakers 8 ☐ Protection system 9 ☐ System failures such as under-frequency situations, islanding 10 ☐ Other (please specify)
Comments/remarks:	

Q45. What kind of data do you use when you perform socio-economic impact assessment in planning or operation (in relation to the reliability assessment, i.e. estimate VOLL, CENS or other)?	1 ☐ Cost rates for different customer groups (please specify) 2 ☐ One fixed average cost rate (please specify) 3 ☐ Cost rates as a function of interruption duration 4 ☐ Cost rates as a function of time of day, day of week, season 5 ☐ Other (please specify)
Comments/remarks:	

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Q46. Are you willing to share data with other TSOs?	☐ Yes ☐ No
Comments/remarks:	

Q47. Do you collect data about human errors (e.g. when somebody is working at a substation or at a line)?	☐ Yes ☐ No If yes, please specify
Comments/remarks:	

Q48. Do you collect data of faults on corrective control measures (remedial actions)?	☐ Yes ☐ No If yes, please specify
Comments/remarks:	

Q49. Do you collect real time information (from PMUs and other) for reliability assessment?	☐ Yes ☐ No If yes, please answer the following questions
a. Is PMU applied in detecting unstable voltage situations?	☐ Yes ☐ No
b. At which voltage levels is PMU applied?	1 ☐ 220 kV and above 2 ☐ 132 - 150 kV 3 ☐ 50 - 60 kV 4 ☐ Other (please specify)
c. Are the PMU measurements aggregated in one or more data concentrators?	☐ Yes ☐ No
d. For how long time is the PMU measurements archived in full resolution?	1 ☐ one month 2 ☐ two months 3 ☐ three months 4 ☐ Other (please specify)
e. Which time normal is applied for the PMU in your grid system?	Please specify:
Comments/remarks:	

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IV. Drivers and barriers

In this section we are asking for your opinion. Multiple choices are allowed.

Q50. If the reliability criterion is changed from N-1 to one that in some way considers the probability and consequences of contingencies would you achieve one or more of the following benefits?	1 ..... More efficient grid use 2 ..... More transmission capacity given to the market 3 ..... Less capacity given to the reserves and more capacity to power transmission 4 ..... Probabilistic methods would enable an estimate of the reliability 5 ..... Increase in wind or other variable production 6 ..... Other (please specify) Please rank the alternatives you have chosen:
Comments/remarks:	

Q51. Which factors will prevent or act as barriers to introducing a reliability criterion that in some way considers the probability and consequences of contingencies instead of the strict N-1?	1 ☐ Applying the method/tools would be too laborious 2 ☐ Applying the method/tools would take too much time 3 ☐ There would not be sufficient and reliable statistical or other data available for the evaluation 4 ☐ It would be difficult to understand and justify to society 5 ☐ Regulation requirements 6 ☐ The uncertainty of the acceptable and non-acceptable consequences would increase 7 ☐ Other (please specify)
Comments/remarks:	

Q52. Do you think that it would be useful or important to assess the reliability level taking the probability and consequences of contingencies into account?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

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