Chapter 2
Grid Security: Problem Statement

2.1 System Characteristics Affecting Reliability Analysis

2.1.1 A Meshed Grid Configuration

In a way, the meshed structure of the grid is a consequence of reliability requirements, as actually a meshed system can be seen as a specific application of the redundancy principle. Often the main transmission grid is meshed whilst the local distribution grid is radial. The consequence of a component failure in the radial system is straightforward: all customers downstream the faulted feeder will face an interruption. In a meshed system, a failed component usually does not lead to any interruptions on connecting customers, because the electricity flow always has parallel paths. This is a direct consequence of the common principle applied for transmission grids: the $N-1$ principle. This means that the system always has to withstand the loss of one component, in all operational situations including also planned maintenance outages. This redundancy is because it would be intolerable to have wide-area interruptions too frequently. Secondly, because electricity storage in a large scale does not yet exist, the power flow must continue in spite of single faults. The $N-1$ criterion is usually applied for primary components, for example transmission lines, generators and transformers. In addition to surviving the loss of a single component, the system should cope with the dynamic fault sequence caused by the fault and the consequential loss of the component. In practice, some of those faults may be drastic for the system. For example, short circuits with large currents can jeopardize the system stability. Hence, dynamic simulations help to identify the consequences of these faults.

Even though a meshed system offers several routes, it is not always self-evident that the system would survive the transition into a post-fault state and that continuous operation at this stage would be possible. A power system is a dynamic system where generators with big rotating masses have inertia. Transients, such as short circuits, start electromechanical oscillations between different generators or generator groups. The fault duration, location, and power flow define if the
transition to the post-fault state after a fault is stable. In addition, it is necessary to ensure if the transmission capacity of the post-fault system is adequate, since lines and other grid components have a limited transmission capacity.

In a system reliability analysis, it is, therefore, crucial to analyse the dynamic performance of the system immediately after faults, i.e. to perform a stability analysis. It is not enough just to check that the steady-state post-fault situation is acceptable. If the transition is unstable, the system may collapse due to transient instability or electromechanical oscillations and the system never reaches any post-fault steady-state power flow but ends up to a system breakdown.

In a radial system, it is usually enough to check the continuity of the transmission path, but no stability analyses are needed. In the short-term future, with distributed generators, the situation might change.

Grid topology changes can be made only at locations where circuit breakers exist. Most circuit breakers are located at substations, which are nodes of the network. In addition, some important functions for the reliable operation of the system, for example telecontrol terminal equipment and relay protection systems, are located at substations. The chosen substation scheme also defines the possible switching actions, topology changes, and the availability of a feeder.

Figure 2.1a and b presents two different substation arrangements whilst in Fig. 2.2 different breaker schemes are shown. In a double busbar substation with a two-breaker arrangement (Fig. 2.1a), each feeder has two circuit breakers. This ensures the high availability of a single feeder since one breaker is sufficient for the operation of the feeder. The two-breaker system offers flexible possibilities to connect the feeders into any of two main busbars. The two-breaker system is not vulnerable in the case of a busbar fault. Indeed, operation can continue through the other main busbar after the protection has tripped the faulted busbar. The main drawback of the two-breaker system is that it is more expensive in comparison with other alternatives.

The single busbar substation with a sectionalizing circuit breaker (Fig. 2.1b) can be a viable solution in a meshed sub-transmission network where all feeders are supplied from both directions and the transmission function is not so crucial.
The sectionalizing breaker gives some advantage in the case of a busbar fault and during the scheduled maintenance of the equipment directly connected to the main busbar. However, the grouping of feeders is fixed and the availability of radial feeders is relatively low. This solution is more at home at gas-insulated switchgear (GIS) where the reliability of single components is good and the number of gas-tight pressure vessels is reasonably low.

The one-and-a-half circuit breaker arrangement (Fig. 2.2a) falls somewhere between the two-breaker and one-breaker systems as regards the availability and the cost per feeder. The availability of a single feeder is close to that of the two-breaker system due to two-way infeed. The grouping of feeders is not as flexible as in the two-breaker system. The ring substation in Fig. 2.2b can be the first step towards the formation of a 1½-circuit breaker system. With six feeders, the 1½-circuit breaker configuration is actually a ring substation.

In reliability evaluation, it is important to distinguish the aspects linked to grid customers (generators and electricity consumers) and the operability of the grid, both described by performance indicators. What happens in the grid is not important as such if only the grid remains operational and the customers get the service they need. If there are outages of components in a meshed grid, but the customers get their service, the customer-related performance indicators remain good. For a meshed transmission grid, the relevant performance indicator expresses the occurrence of outages for a wide area. In practice, this can happen after a major disturbance, cascading outages or a system breakdown.

There is a difference between the reliability challenges for radial and meshed grids. In a radial system, an outage always leads to an interruption to some customers but not to all of them. In a meshed system, an outage does not lead to problems for a single customer, but the consequences of a system breakdown may affect a large number of customers spread across the control zones of transmission system operators. These differences mean that reliability analyses of meshed and radial systems are inherently different.

**Fig. 2.2** Two different circuit breaker arrangements, where black squares represent circuit breakers. (a) presents a 1½-breaker arrangement, which is a substation scheme, where all circuit breakers are usually closed in normal operation. Since each feeder is fed from two sides, all feeders are in operation also after a busbar fault. (b) presents a ring substation, which is a single busbar substation, where the busbar is a closed loop with circuit breakers in series. The ring busbar arrangement allows an uninterrupted operation of all feeders.
2.1.2 Generation and Grid Adequacy

In a power system, the generation and load must be equal or almost equal at any time. If the load is bigger than the generation, the rotating speed of synchronous machines will slow down, which leads to frequency decline. If generation exceeds the load, the opposite happens and the frequency increases.

The stable operation of a power system requires that the imbalance should be within given magnitude and duration at any time. In practice, this means that a sufficient balance shall be maintained at any moment. The rotating machines cannot endure the operation with a high over-speed because of the too large mechanical stresses they induce. Under-frequency is dangerous due to the risk of mechanical resonances. Therefore, the generation (and load) needs to be controlled.

Usually the generation and the consumption do not locate near each other since other issues define their optimal or possible location. In order to feed the consumption, enough transmission capacity is needed. Adequate transmission capacity involves especially sufficient thermal loading capability and high enough transmission voltages for the transmission distance and transmitted power.

Adequacy evaluation is twofold: both generation and transmission grid adequacy must be considered.

2.1.3 Impacts of System Dynamics

During over-frequency situations, the operators can always reduce the generated power or even trip generators. Under-frequency calls for reserve generation, else some load must be shed; otherwise the system may collapse. In a large synchronous system consisting of several interconnected parallel operating subsystems, regional surplus or deficit of power up to the transmission capacity of interconnections from other subsystems, however, is fully acceptable. If transmission is higher than predefined security limits, transmission needs to be reduced to an acceptable level. In addition to continuous load and generation variations, the transmission system is exposed to faults and disturbances that create dynamic transitions from one system state to another. The transitions are oscillatory by nature.

In order to keep the system stable, it is essential to disconnect the faults and restore the system into a state, where it can withstand a new fault (restore security). Ways to do this are for example connecting healthy components into operation rapidly, starting generation reserves or shedding load. Many line faults are temporary and high-speed automatic reclosing enables the system restoration into a secure state. The security and stability depend on the characteristics of the transmission system and generators, the magnitude of power flows, and the fault location, duration and type.

Often it is possible to get more transmission capacity if $N - 1$ security is planned in such a way that remedial operational actions (for example starting reserve power stations) are accepted after the fault and trip of the faulted component.
If this is the case, the secure operation needs three things: maintaining power flow at an acceptable level, tripping faulted components rapidly enough, and sufficient operation actions to recover the system in such a state that it can withstand a new fault. Figure 2.3 illustrates the possible chains of events that can occur if these remedial operational actions are inadequate or fail.

A delay in restoring the system after an interruption caused by a fault may lead to an overload on the remaining circuits (Fig. 2.3a) or to abnormal voltages (Fig. 2.3b). The constraint and the operational state together define the urgency of

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**Fig. 2.3** Two simple chains of events (called event trees), which present possible consequences after a power system fault with a correct trip. A typical proper operational action is to reduce power flow by starting reserve power plants. A thermal loading of lines defines the transmission capacity (typically short lines), and system stability defines the transmission capacity (typically long lines).
the remedial actions needed. If the constraint is the thermal overloading of lines, for example, the remedial actions are dictated by the thermal time constant, which can be in the range of 10–20 min. Otherwise, the lines start to sag too much due to heat and contact with vegetation is possible. With voltage stability, the time from the initial fault occurrence to voltage collapse varies from a few seconds to several hours [1, p. 19].

The variability of operational states and transmission patterns leads to a situation, where a comprehensive reliability analysis would be a very complex and laborious task. Therefore, it is important to focus on selecting prevailing and representative transmission patterns that represent also the most challenging situations to the grid security. The results of faults are different depending on power flow, as described before. Therefore, simulations reveal the consequences and the urgency of the possible remedial actions.

In order to make a proper reliability analysis of a given power system, it is important to select the analysis methods in such a way that they are capable of capturing the relevant phenomena for each specific case. In a meshed grid, it is not always sufficient to make a steady-state adequacy analysis to judge the system reliability. Even though the adequacy analyses would indicate an acceptable performance, the system still can fail in a dynamic transition from the initial to the post-fault state. For thermal limits, power flow simulations are sufficient, but if stability is the issue, dynamic simulations are usually needed.

### 2.2 Motivation of a Probabilistic Approach

No specific, comprehensive methodology for power system security analysis has thus been developed until now. It is therefore worth investigating how other industrial sectors have managed this issue. The safety of nuclear power plants (NPP) has been a major concern from the very start of their operation. Even though the consequences of an unmitigated transient in an NPP are different in nature from that of a blackout or a major service interruption, the heart of the problem rests on protection engineering [2]. By this, we mean how to optimally devise, dimension, and operate protection systems and procedures in order to satisfactorily mitigate credible transients likely to occur in the grid, at all realistic load levels.

The history of nuclear safety teaches us that safety studies were first deterministic, aiming at dimensioning safety devices and protection systems in order to successfully mitigate a set of postulated accidents, from the so-called “design basis”, for which conservative assumptions worsening the transients were taken. However, it was soon estimated (and later confirmed by the occurrence of Three Mile Island accident in 1979) that the design basis accidents could not thoroughly envelop all possible cases; transients outside the design basis were still likely to take place, and the corresponding residual risk had to be properly investigated in order to optimally reduce it. Probabilistic safety analyses (PSA) were then done [3] in order to complement the initial deterministic studies. Abandoning the conservative
assumptions underlying the deterministic approach, PSA studies were completed on a more realistic basis, with the purpose of systematically delineating and identifying accident scenarios challenging the NPP safety. Scenarios were built at the system level, the successful or unsuccessful solicitation of protection devices generating branch points in the transient development. Each of these branch events was in parallel analysed in a top-down approach to determine which combinations of basic component failures could cause them. Probabilities were then associated to the logical decomposition of events, eventually providing occurrence frequencies associated to these scenarios. These frequencies were then interpreted as an importance weight to build up a severity ranking amongst the scenarios challenging the NPP integrity, driving the efforts of improving the plant safety towards efficient risk reduction. The probabilistic character of the analysis hence appears as the measure according to which the level of completeness of the plant environment protection must be assessed, given regulatory and economic constraints.

An analogy with power system security can quite straightforwardly be drawn. Deterministic studies can be compared with the application of the \( N - 1 \) criterion, through which the grid has to be proven to be correctly dimensioned (in terms of mesh structure and line capacity), i.e. to be adequate, in order to successfully face the loss of any single element, in all operational circumstances. PSA studies then appear as a natural way to complement the \( N - 1 \) analysis, providing a deeper insight in the potential grid vulnerabilities.

The methodology presented in this book is strongly inspired by the one that has been extensively applied to NPP safety analysis. It is, however, adapted to the peculiarities of a geographically distributed and meshed, interconnected infrastructure as a transmission network. It provides the classical 3-uples of a risk analysis, i.e. scenario identification, occurrence frequency estimation and damage assessment.

### 2.3 State of the Art in the Field of Power System Reliability

#### 2.3.1 Concepts of Power System Reliability

The term *reliability*\(^1\) is used as a general concept in power systems and in relay protection and it relates to the probability of a satisfactory operation in the long run. The reliability of a bulk power system can be measured by the quality of service the customers receive. There are different measures or indexes for reliability evaluation, for example the frequency and duration of interruptions. [4]

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\(^1\) Maybe it is worth mentioning that often dependability is the general term describing reliability. IEC standard *Dependability and quality of service* uses dependability as a term of collective availability performance but points out that it is used only for general description in non-quantitative terms (IEC 60050-191).
Reliability of power systems has two aspects: adequacy and security. Power system security is the ability of the power system to withstand short circuits and other faults and sudden disturbances, for example the loss of generators or other system components. A secure power system survives after faults and disturbances (contingencies) without losing its stability or causing interruptions to customers. Thus, security relates to the robustness of the system in a context of contingencies and depends on the power system operating condition before the disturbance and the probability of disturbances. Security is a dynamic issue, it implies both the transition to the new operating point and the state of this new operating point and thus is a time varying attribute. A power system can be reliable even though it was not secure in every time instant. This is because the probability of faults is low if the system stayed insecure for short time instants [4].

Power system adequacy (discussed also in Sect. 2.1.2) is the ability of the system to supply the aggregate electric power and energy requirements of the customers at all times [4]. Adequacy deals both with generation and transmission capacity. Adequacy, being the steady-state issue, is measured by established probability-based indexes, such as the loss of load probability LOLP, the oldest index in use [5], defined the average number of days on which the peak load is expected to exceed the generation capacity [6]. Commonly used indexes are also system average interruption duration index SAIDI and system average interruption frequency index SAIFI [7]. Often these indexes are used for the performance evaluation of radial distribution systems, but they can be used for evaluating the performance of a connection point of a meshed transmission grid, too.

2.3.2 Static and Statistical Approaches

After a blackout has occurred, it can be analysed as a deterministic sequence of events, to better understand its causes and development. This does not imply that the opposite would be possible, i.e. identify via simulation all the possible events leading to a blackout before it happens. For the latter, there are too many possibilities to analyse power system states, initial events and failures. Therefore, security analyses that try to capture cascading events causing blackouts are often made with probabilistic methods. Most methods use static models, such as cascading overloads, protection failures and voltage collapse. A common simulation model includes static line overloads or voltage instability after contingencies. Although generator protection, controls and dynamic stability often play important roles in blackout evolution, dynamic analysis is seldom applied for reasons of modelling difficulties and complexities. Nevertheless, issues, such as uncontrollable system splitting, angle instability and generation tripping, require dynamic models and simulations [8].

Billinton and Allan made plenty of pioneering research on different aspects of power system reliability, where the focus was on steady-state issues [6, 9]. They pointed out the importance of probability-based reliability evaluation instead of commonly used deterministic criteria that do not take into account the stochastic
nature of faults and system behaviour. They also defined concepts, such as hierarchical levels of power system (adequacy) evaluation. The levels are generation alone (hierarchical level I), generation and transmission together (hierarchical level II), and all the parts: generation, transmission and distribution (hierarchical level III) [6, 10, 11].

Billinton and Khan [12] calculated probability indices (the probabilities and frequencies of power system operational states) for composite power systems using a flow chart in detecting the operational states. The states are a normal (secure) state, an alert state and an emergency state. In the normal (secure) state, a power system can withstand single contingencies. In an alert state, the loss of a component will result in a current or voltage violation. The alert state is similar to the normal state in that all constraints are satisfied, but there are no longer sufficient margins to withstand an outage due to a disturbance. In an emergency state, no load is curtailed, but operating constraints have been violated.

The concept of power system states in reliability evaluation is widely used but the definitions of states and sometimes the states are different to some extent. The concept of states represents a classification of complicated reality and this, naturally, can be made in different ways. An example of states different from Billinton’s is in Nordic Grid Code [13, p. 66]. In this collection of rules, the power system planning principles were deterministic but they were shifted in a probabilistic direction: more severe consequences are accepted after rare contingencies.

### 2.3.3 Uncertainty and Dynamics in Power System Analysis

The probabilistic assessments of transient stability were studied for example by Billinton and Kuruganty [14–17], Anderson and Bose [18] and Anders [19]. They considered the randomness of the events that may affect transient instability. These events are for example initial operation conditions, fault type and location, the inertia of synchronous generators, fault duration and critical clearing time. Treating the events probabilistically enables calculating the probabilistic distribution of transient instability.

There have also been security analysis studies made without considering the protection or other substation components. For example, Khan [20], Rei et al. [21] and Leite da Silva et al. [22] carried out analyses of power system security having a probability-based approach. The trips after disturbances occur; the interest is the power system state after those trips. This approach inherently assumes that the protection and circuit breakers act 100% reliably. This assumption is good for operation planning for example, but has limited use as part of an overall approach to the reliability analysis of transmission grids.

Some other approaches exist, too. Miki et al. [23] developed a hybrid model that includes power system dynamic simulations and event trees for protection system operation. The protection systems, but not circuit breakers, are included in the model because “the protection systems play an important role for preventing
fault cascading”. The protection system is modelled with a Markov model, and the method is applied to a small model grid (19 nodes, 11 lines and 5 generators).

### 2.3.4 Probabilistic Transitions into Combined Contingencies

Phadke et al. [24] introduced the concept of a hidden failure of protection as an important factor leading to cascading outages. A hidden failure is an unwanted and unselective trip by the protection system after the occurrence of another switching event. Since hidden failures are not spontaneous but occur after a switching event, they change an $N - 1$ disturbance into an $N - k$ event and, therefore, are connected to blackout analyses. The hidden failures can influence relay performance in limited areas, called the regions of vulnerability. If an abnormal power system state occurs inside a given region of vulnerability, a hidden failure could cause the relay to incorrectly trip its associated circuit breaker. In order to quantify the effect of hidden failures within a region of vulnerability, a vulnerability index is calculated. The hypothesis is that a probability model for hidden failures enables calculating the events leading to cascading. If given line $L$ and other lines are connected to a bus and any of the other lines trips, a hidden failure in line $L$ might appear: there is probability $p$ that line $L$ will trip (Phadke et al., p. 32).

Several studies have analysed the chains of events that lead to cascading outages and introduced additional concepts, such as critical loading, as a factor that has a remarkable impact on cascading failures. Some examples of the analyses are briefly presented.

Nedic et al. [25] presented a model to analyse the risk of a blackout. Their model estimates the risk of a blackout from a global perspective as a function of critical loading. The blackout is caused by cascading outages due to an initial failure connected with additional trips due to protection malfunctions (sympathetic trips) or generator instability. Sympathetic trips and generator instability were more probable to occur near the original fault. Generator instability was simulated with a heuristic model [26]. They use the concept of critical loading at which the blackout risk increases sharply. Their model, tested for a grid with 1000 buses and 1800 lines, found a critical loading, at which the energy not supplied and the blackout size increased drastically.

Dobson [27], too, has studied the system load increase in the transition from isolated failures to a system-wide collapse. At the critical system loading, the risk of cascading failures starts to increase. With a low system load, the failures can be assumed independent and the blackout probability and size are small. Whilst increasing the system loading, the possible blackout size increases and the probability of cascading outages increases. Dobson also discusses which aspects of cascading failures should be modelled, the tradeoffs between model detail and simulation speed, and what details are required. Possible influencing factors are operational policies, software and human errors. He concludes that there is a need for simple, high-level models to explain the phenomena observed in the simulations.
Kirschen and Jayaweera [28] compared risk-based and deterministic security assessments. According to them, risk-based methods bring considerably more information on which to base operational decisions. In their model, the effect of weather condition is included since, in the case of bad weather, outages occur more often. They estimate the outage costs for customers via Monte Carlo simulations. They apply different operation states, contingencies and possible unwanted unselective trips by relays (sympathetic trips) randomly. They use power flow simulation to determine the system state. If some lines or transformers are heavily overloaded, they are disconnected and the process is repeated, potentially leading to cascading outages. A non-convergence of the power flow computation then indicates voltage instability. In this way, they can evaluate the risk level variations in the same operating conditions during different weather conditions: fair, average and bad weather.

In the Nordic countries, there has been research on the vulnerability of the power system. The scope of one vulnerability analysis [29, 30] was to identify incidents, situations, and scenarios leading to critical or serious consequences to the power system and society as a whole. This study presented a comprehensive methodology for a systematic classification of the Nordic power system with respect to three aspects of vulnerability: energy shortage, capacity shortage and power system failures. The methodology made it possible to quantify the vulnerability of the power system in terms of risk exposures, given by the expected frequency of occurrence of events and their consequences.

### 2.3.5 Dynamic Event Cascading

Chen [31] and Chen and McCalley [32] estimated the contingency probabilities of power systems by fitting an existing probability model for the historical statistical data. They extend the traditional $N-1$ contingency to $N-k$ contingencies, where $k \geq 1$. They developed dynamic event trees for different contingencies. Dynamic event trees differ from normal event trees in three aspects:

1. they include decision nodes where it is possible to take actions for that avoiding or mitigating consequences,
2. they are automatically generated by running the dynamic model and grow according to a set of branching rules and
3. the tree structure, branch probabilities, consequence values, and decisions are updated to reflect changes in the physical network. This means that the evolution of electrical variables defines the possible branch points of the event tree, for example, when a setting value of protection is exceeded.

The dynamic event trees are meant for a decision support tool for control room operators for keeping the system secure. The contingencies and the actions after them change with the topology of the system. Therefore, real-time grid configuration information is required. This is usually possible with energy management
systems and state estimation. Possible operator actions are for example generation dispatch, load shedding and system islanding.

Levi et al. [33] did a reliability analysis, which included dynamics. They calculated post-fault states with a Monte Carlo method and doing so, added the calculation of the states with dynamic simulations into the reliability model of Khan and Billinton [34]. The steps in the simulation were follows:

1. transient stability analysis,
2. the evaluation of frequency dynamics during governor control,
3. activation of the emergency level of the thermal protection and the steady-state after the automatic generation control (AGC),
4. the minimization of the overall curtailed load,
5. overload rotation and
6. voltage restoration and economic dispatching.

They analysed the 39-node IEEE test system [35], and their results indicate that the conventional steady-state reliability analysis gives too optimistic results, since it ignores a number of unfavourable power system phenomena.

2.3.6 Conclusion

There exists no standard methodology for power system security analysis. There are different methods adapted to specific system characteristics but none of which can capture the system security problem as a whole. System dynamics is seldom included; usually a static post-fault steady-state analysis is selected. Developed methods rely on simplifications in modelling and definite scope is necessary.

For adequacy, several measures like the loss of load probability (LOLP), system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), etc. are available for distribution grids.

The power system reliability analyses are often made without a substation model or with a limited model. Sometimes the methods use probability values for switching actions, which occur at the substation and change the grid topology. Protection rather than circuit breaker actions are included.

For large complex systems, it may not even be worthwhile to try to include all aspects in one methodology.

2.4 Security and Electricity Markets

As already stated, large disturbances, e.g. partial or total system breakdowns, have effects on the critical functions of modern society. These events should be avoided and the desired level of security maintained in liberalized electricity markets, too.
Nowadays it seems to be a common thought that because of electricity markets, blackouts occur more often. The reason behind this thought may be that electricity markets lead to a more efficient use of the existing networks and increased mutual interdependency. The markets alone should not be blamed, but rather the grid operation not adapted for the new procedures. In Italy and the United States in 2003, the power flows were high before the blackouts. The overloading of remaining lines after several trips caused instability and the collapse. In these cases, high power flows were amongst the causes of the blackout. A report by the IEEE PES CAMS Task Force [8] reveals that blackouts do not always occur during peak load days in winter and summer, when the system is stressed but rather on “shoulder” periods (spring and autumn), and are caused by outages due to maintenance or other reasons. The combination of these outages changes the power flows and dynamic characteristics of the system. The result may be a much higher probability of a cascading outage due to the unexpected forced outage of other equipment or to operating mistakes.

Roles and responsibilities affecting security are defined in the legal framework. In electricity markets, the responsibility to ensure secure power system operation falls to those parties who develop, maintain and operate the power system. Usually, transmission system operators are responsible for the security of the power system as a whole within their region—typically a country or part of a country. Distribution system operators are responsible for ensuring security in their networks and for meeting the requirements set by the transmission system operator for security in order to avoid local faults spreading in other parts of the national power system.

The system operators also have powers to set requirements for the connection and operation to the parties connected to their grid—generators and loads—to ensure a secure operation of the power system. The legal framework may set performance requirements for system operators through obligations and/or incentives to maintain a predefined level of security and quality of electric supply. The system operator copes with these legal obligations by developing, maintaining and operating the grid.

Transmission system operators apply congestion management methods of limiting the power flows in the grid to ensure secure system operation. In Europe, the legal framework requires that these methods should be market-based and the transmission capacity should be given to those who value the capacity most. The core of congestion management methods is the calculation of transmission capacity taking into account probable power flows, faults and consequences of these faults to the system. The legal framework may require that the transmission capacity is firm when it is given to the market. Specific legal instructions may be applied to allow curtailments of the transmission capacity and/or reduced firmness of the transmission capacity.

The transmission capacity made available to the electricity market should be maximized without violating the system security. This requirement for a more efficient use of the grid calls for advanced methods and approaches to evaluate the security of the power system. Here the PSA approach may give added value to those planning, maintaining and operating the power system.
Integration of electricity markets implies that more transmission capacity will become available between national markets. This requires that either more interconnections should be built between national power systems or more transmission capacity should be released to the electricity market using the existing interconnections. The national power systems become thus more dependent on each other due to the tighter electric connection and due to the increased flows between power systems. Furthermore, the variable generation to meet the policy goals for sustainability will require more flexible power systems. It will increase the interdependence between systems due to the larger variations in the power interdependency of national power systems. This implies that a disturbance within a national power system may extend to neighbouring power systems and in the worst case cause a system breakdown extending several national power systems [36–38].

2.5 Scope of the Book

The PSA approach for transmission grid security presented in this book is one of the security analysis methods for specific purposes; it is a probabilistic approach to assessing the risk of a system breakdown after grid faults, and observing system dynamics, too [39, 40]. Based on systematic and analytical modelling of post-fault events rather than on random sampling, the PSA approach can reveal the vulnerable parts of the system. The main objective is to increase the understanding of the system and reveal those components, where the improvements most effectively support the security after grid faults.

The PSA approach enables the inclusion of dynamics in the analysis. The methods that rely on steady-state analyses after faults cannot capture the system level dynamic stability phenomena though this would be beneficial and necessary when dynamics and stability after contingencies are crucial. This is typically the case when power flows are high and transmission routes are long. In this case, the transmitted rather than consumed power is important for the system security.

The power system reliability analysis is a large and complex issue. There are different methods, none of which can capture the whole problem. Commonly used methods for steady-state adequacy analyses exist, but security methods are adjusted for specific properties of the system under study.

A common measure and the important matter for transmission system security is the system state (such as secure, alert, collapsed), rather than the states of the connection points of single customers. With the PSA method, it is possible to analyse different chains of events in such a way that their consequences are quantitatively comparable and their effect on the system state can be found. Central to the approach presented in this book is the system security including an analytical probability model for post-fault substation events (the protection system and circuit breaker operations), and the power system dynamics after the contingencies.
The method described in this book and presented in Fig. 2.4 is applicable to real-size transmission grids. The model for substation post-fault operations uses event and fault trees and, therefore, inherently introduces the possibility of calculating different grid level importance measures for substation components and for model parameters. With the component and parameter importance measures, the relatively effective ways of improving grid security can be found. They also help to find the contributing factors to a system breakdown. The method takes into account the effect of the following issues on reliability:

- the frequency of faults,
- fault locations on the line,
- different substation arrangements,
- the failure rates of substation components and
- the dynamic behaviour of the power system after different contingencies.

Resources (always limited) can be used in a more efficient way after the contributions of components to a possible blackout are known. Therefore, the method can be the basis for connecting reliability-centred maintenance and power

Fig. 2.4 A simplified block diagram of the PSA security analysis of transmission grids [40]
system security together. The results can be used in system planning and in the maintenance planning since they give the importance of components for the power system security after short circuits. The contributions of a component failure on the system breakdown are achieved even though the probability of a system breakdown is very low.

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