SIGNAL PROCESSING OF POWER QUALITY DISTURBANCES

MATH H. J. BOLLEN

IRENE YU-HUA GU

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To my father and in memory of my mother (from Irene)

CONTENTS

PREFACE

This book originated from a few occasional discussions several years ago between the authors on finding specific signal-processing tools for analyzing voltage disturbances. These simple discussions have led to a number of joined publications, several Masters of Science projects, three Ph.D. projects, and eventually this book. Looking back at this process it seems obvious to us that much can be gained by combining the knowledge in power system and signal processing and bridging the gaps between these two areas.

This book covers two research areas: signal processing and power quality. The intended readers also include two classes: students and researchers with a power engineering background who wish to use signal-processing techniques for power system applications and students and researchers with a signal-processing background who wish to extend their research applications to power system disturbance analysis and diagnostics. This book may also serve as a general reference book for those who work in industry and are engaged in power quality monitoring and innovations. Especially, the more practical chapters (2, 5, 6, and 10) may appeal to many who are currently working in the power quality field.

The first draft of this book originated in 2001 with the current structure taking shape during the summer of 2002. Since then it took another three years for the book to reach the state in which you find it now. The outside world did not stand still during these years and many new things happened in power quality, both in research and in the development of standards. Consequently, we were several times forced to rewrite parts and to add new material. We still feel that the book can be much more enriched but decided to leave it in its current form, considering among others the already large number of pages. We hope that the readers will pick up a few open subjects from the book and continue the work. The conclusion sections in this book contain some suggestions on the remaining issues that need to be resolved in the authors' view.

Finally, we will be very happy to receive feedback from the readers on the contents of this book. Our emails are m.bollen@ieee.org and i.gu@ieee.org. If you find any mistake or unclarity or have any suggestion, please let us know. We cannot guarantee to answer everybody but you can be assured that your message will be read and it will mean a lot to us.

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May 2006

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The availability of data from real power system measurements has been an important condition for allowing us to write this book. Measurement data and other power system data and information were collected through the years. Even though not all of them were used for the material presented in this book, they all contributed to our further understanding of power quality monitoring and disturbance data analysis. Therefore we would like to thank all those that have contributed their measurement data through the years (in alphabetical order): Peter Axelberg (Unipower); Geert Borloo (Elia); Larry Conrad (Cinergy); Magnus Ericsson (Trinergi); Alistair Ferguson (Scottish Power); Zhengti Gu (Shanghai, China); Per Halvarsson (Trinergi and Dranetz BMI); Mats Häger (STRI); Daniel Karlsson (Sydkraft, currently at Gothia Power); Johan Lundquist (Chalmers, currently at Sycon); Mark McGranaghan (Electrotek, currently at EPRI Solutions); Larry Morgan (Duke Power); Robert Olofsson (Göteborg Energi, currently at Metrum, Sweden); Giovanna Postiglione (University of Naples, currently at FIAT Engineering); Christian Roxenius (Göteborg Energi); Dan Sabin (Electrotek); Ambra Sannino (Chalmers, currently at ABB); Helge Seljeseth (Sintef Energy Research);

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M. H. J. B
I. Y-H. G

CHAPTER 1

INTRODUCTION

This chapter introduces the subjects that will be discussed in more detail in the remainder of this book: power quality events and variations, signal processing of power quality measurements, and electromagnetic compatibility (EMC) standards. This chapter also provides a guide for reading the remaining chapters.

1.1 MODERN VIEW OF POWER SYSTEMS

The overall structure of the electric power system as treated in most textbooks on power systems is as shown in Figure 1.1: The electric power is generated in large power stations at a relatively small number of locations. This power is then transmitted and distributed to the end users, typically simply referred to as “loads.” Examples of books explicitly presenting this model are [193, 211, 322].

In all industrialized countries this remains the actual structure of the power system. A countrywide or even continentwide transmission system connects the large generator stations. The transmission system allows the sharing of the resources from the various generator stations over large areas. The transmission system not only has been an important contributing factor to the high reliability of the power supply but also has led to the low price of electricity in industrialized countries and enabled the deregulation of the market in electrical energy.

Distribution networks transport the electrical energy from the transmission substations to the various loads. Distribution networks are typically operated radially and power transport is from the transmission substation to the end users. This

Signal Processing of Power Quality Disturbances. By Math H. J. Bollen and Irene Yu-Hua Gu

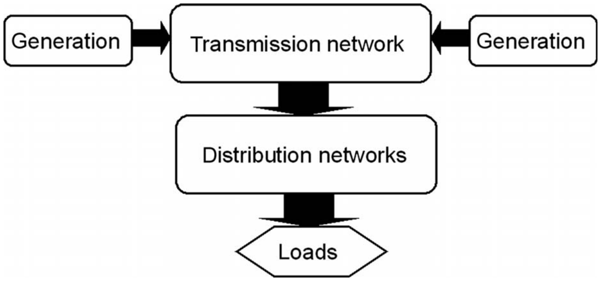

Figure 1.1 Classical structure of power system.

allows for easy methods of protection and operation. The disadvantage is that each component failure will lead to an interruption for some end users.

There are no absolute criteria to distinguish between distribution and transmission networks. Some countries use the term *subtransmission networks* or an equivalent term to refer to the networks around big cities that have a transmission system structure (heavily meshed) but with a power transport more or less in one direction. Discussion of this terminology is however far outside the scope of this book.

Due to several developments during the last several years, the model in Figure 1.1 no longer fully holds. Even though technically the changes are not yet very big, a new way of thinking has emerged which requires a new way of looking at the power system:

- The deregulation of the electricity industry means that the electric power system can no longer be treated as one entity. Generation is in most countries completely deregulated or intended to be deregulated. Also transmission and distribution are often split into separate companies. Each company is economically independent, even where it is electrically an integral part of a much larger system.
- The need for environmentally friendly energy has led to the introduction of smaller generator units. This so-called embedded generation or distributed generation is often connected no longer to the transmission system but to the distribution system. Also economic driving forces, especially with combined heat and power, may result in the building of smaller generation units.
- Higher demands on reliability and quality mean that the network operator has to listen much closer to the demands of individual customers.

A more modern way of looking at the power system resulting from these developments is shown in Figure 1.2. The electric power network no longer transports energy from generators to end users but instead enables the exchange of energy between customers. Note that these customers are the customers of the network (company), not only the end users of the electricity.

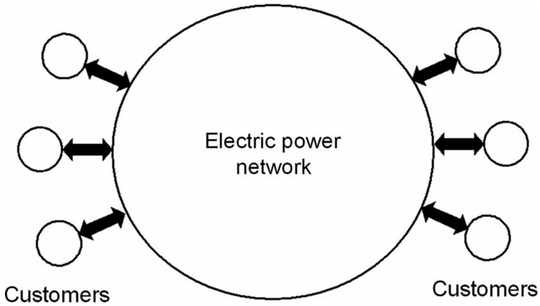

Figure 1.2 Modern view of power system.

The actual structure of the power system is still very much as in Figure 1.1, but many recent developments require thinking in the structure of Figure 1.2. The power network in Figure 1.2 could be a transmission network, a distribution network, an industrial network, or any other network owned by a single company. For a transmission network, the customers are, for example, generator stations, distribution networks, large industrial customers (who would be generating or consuming electricity at different times, based on, e.g., the price of electricity at that moment), and other transmission networks. For a distribution network, the customers are currently mainly end users that only consume electricity, but also the transmission network and smaller generator stations are customers. Note that all customers are equal, even though some may be producing energy while others are consuming it. The aim of the network is only to transport the electrical energy, or in economic terms, to enable transactions between customers. An example of a transmission and a distribution network with their customers is shown in Figure 1.3.

The technical aim of the electric power networks in Figures 1.2 and 1.3 becomes one of allowing the transport of electrical energy between the different customers,

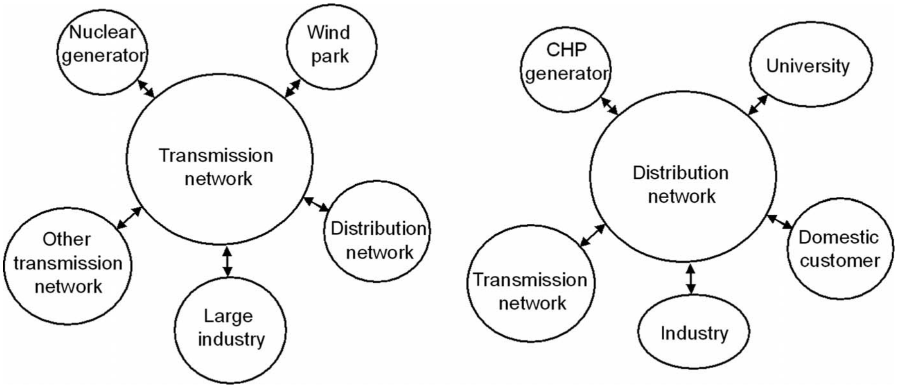

Figure 1.3 Customers of a transmission network (left) and a distribution network (right).

guaranteeing an acceptable voltage, and allowing the currents taken by the customers. As we will see in Section 1.2.2 power quality concerns the interaction between the network and its customers. This interaction takes place through voltages and currents. The various power quality disturbances, such as harmonic distortion, of course also appear at any other location in the power system. But disturbances only become an issue at the interface between a network and its customers or at the equipment terminals.

The model in Figure 1.2 should also be used when considering the integration of renewable or other environmentally friendly sources of energy into the power system. The power system is no longer the boundary condition that limits, for example, the amount of wind power that can be produced at a certain location. Instead the network's task becomes to enable the transport of the amount of wind power that is produced and to provide a voltage such that the wind park can operate properly. It will be clear to the reader that the final solution will be found in cooperation between the customer (the owner of the wind park) and the network operator considering various technical and economic constraints.

Concerning the electricity market, the model in Figure 1.2 is the obvious one: The customers (generators and consumers) trade electricity via the power network. The term *power pool* explains rather well how electricity traders look at the power network. The network places constraints on the free market. A much discussed one is the limited ability of the network to transport energy, for example, between the different European countries. Note that under this model lack of generation capacity is not a network problem but a deficiency of the market.

1.2 POWER QUALITY

1.2.1 Interest in Power Quality

The enormous increase in the amount of activity in the power quality area can be observed immediately from Figure 1.4. This figure gives the number of papers in the INSPEC database [174] that use the term *power quality* in the title, the abstract, or the list of keywords. Especially since 1995 interest in power quality appears to have increased enormously. This means not that there were no papers on power quality issues before 1990 but that since then the term power quality has become used much more often.

There are different reasons for this enormous increase in the interest in power quality. The main reasons are as follows:

- Equipment has become less tolerant of voltage quality disturbances, production processes have become less tolerant of incorrect operation of equipment, and companies have become less tolerant of production stoppages. Note that in many discussions only the first problem is mentioned, whereas the latter two may be at least equally important. All this leads to much higher costs than before being associated with even a very short duration disturbance. The

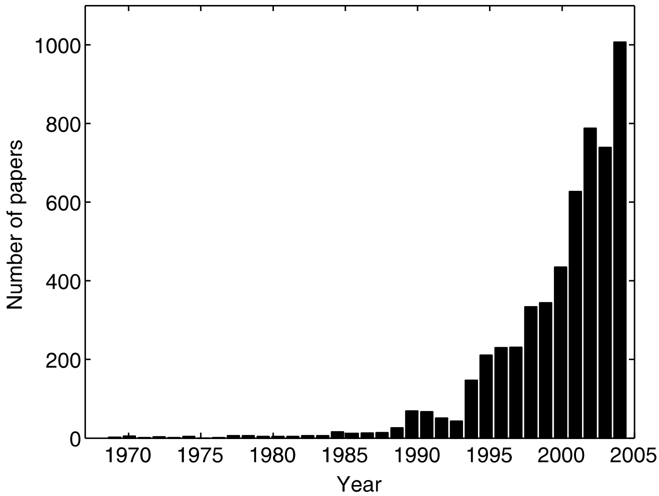

Figure 1.4 Use of term power quality, 1968–2004.

main perpetrators are (long and short) interruptions and voltage dips, with the emphasis in discussions and in the literature being on voltage dips and short interruptions. High-frequency transients do occasionally receive attention as causes of equipment malfunction but are generally not well exposed in the literature.

- Equipment produces more current disturbances than it used to do. Both low- and high-power equipment is more and more powered by simple power electronic converters which produce a broad spectrum of distortion. There are indications that the harmonic distortion in the power system is rising, but no conclusive results are available due to the lack of large-scale surveys.
- The deregulation (liberalization, privatization) of the electricity industry has led to an increased need for quality indicators. Customers are demanding, and getting, more information on the voltage quality they can expect. Some issues of the interaction between deregulation and power quality are discussed in [9, 25].
- Embedded generation and renewable sources of energy create new power quality problems, such as voltage variations, flicker, and waveform distortion [325]. Most interfaces with renewable sources of energy are sensitive to voltage disturbances, especially voltage dips. However, such interfaces may be used to mitigate some of the existing power quality disturbances [204]. The relation between power quality and embedded generation is discussed among others in [178, Chapter 5; 99, Chapter 9; 118, Chapter 11]. An important upcoming issue is the immunity of embedded generation and large wind parks to voltage dips and other wide-scale disturbances. The resulting loss of generation as a result of a fault in the transmission system becomes a system security (stability) issue with high penetration of embedded generation.

- Also energy-efficient equipment is an important source of power quality disturbances. Adjustable-speed drives and energy-saving lamps are both important sources of waveform distortion and are also sensitive to certain types of power quality disturbances. When these power quality problems become a barrier for the large-scale introduction of environmentally friendly sources and end-user equipment, power quality becomes an environmental issue with much wider consequences than the currently merely economic issues.

1.2.2 Definition of Power Quality

Various sources give different and sometimes conflicting definitions of power quality. The Institute of Electrical and Electronics Engineers (IEEE) dictionary [159, page 807] states that "power quality is the concept of powering and grounding sensitive equipment in a matter that is suitable to the operation of that equipment." One could, for example, infer from this definition that harmonic current distortion is only a power quality issue if it affects sensitive equipment. Another limitation of this definition is that the concept cannot be applied anywhere else than toward equipment performance.

The International Electrotechnical Commission (IEC) definition of power quality, as in IEC 61000-4-30 [158, page 15], is as follows: "Characteristics of the electricity at a given point on an electrical system, evaluated against a set of reference technical parameters." This definition of power quality is related not to the performance of equipment but to the possibility of measuring and quantifying the performance of the power system.

The definition used in this book is the same as in [33]: Power quality is the combination of voltage quality and current quality. *Voltage quality* is concerned with deviations of the actual voltage from the ideal voltage. *Current quality* is the equivalent definition for the current. A discussion on what is ideal voltage could take many pages, a similar discussion on the current even more. A simple and straightforward solution is to define the ideal voltage as a sinusoidal voltage waveform with constant amplitude and constant frequency, where both amplitude and frequency are equal to their nominal value. The ideal current is also of constant amplitude and frequency, but additionally the current frequency and phase are the same as the frequency and phase of the voltage. Any deviation of voltage or current from the ideal is a *power quality disturbance*. A disturbance can be a voltage disturbance or a current disturbance, but it is often not possible to distinguish between the two. Any change in current gives a change in voltage and the other way around. Where we use a distinction between voltage and current disturbances, we use the cause as a criterion to distinguish between them: Voltage disturbances originate in the power network and potentially affect the customers, whereas current disturbances originate with a customer and potentially affect the network. Again this classification is due to fail: Starting a large induction motor leads to an overcurrent. Seen from the network this is clearly a current disturbance. However, the resulting voltage dip is a voltage disturbance for a neighboring customer. For the network operator this is a current disturbance, whereas it is a voltage disturbance for the neighboring customer. The fact that one underlying event (the motor start in this case) leads to different disturbances for different customers or at different locations is very common for power quality issues. This still often leads to confusing discussions and confirms the need for a new view of power systems, as mentioned in Section 1.1.

This difficulty of distinguishing between voltage and current disturbances is one of the reasons the term power quality is generally used. The term voltage quality is reserved for cases where only the voltage at a certain location is considered. The term current quality is sometimes used to describe the performance of power-electronic converters connected to the power network.

Our definition of power quality includes more disturbances than those that are normally considered part of power quality: for example, frequency variations and non-unity power factor. The technical aspects of power quality and power quality disturbances are not new at all. From the earliest days of electricity supply, power system design involved maintaining the voltage at the load terminals and ensuring the resulting load currents would not endanger the operation of the system. The main difference with modern-day power quality issues is that customers, network operators, and equipment all have changed. The basic engineering issues remain the same, but the tools have changed enormously. Power-electronic-based (low-power and high-power) equipment is behind many of the timely power quality problems. Power-electronic-based equipment is also promoted as an important mitigation tool for various power quality problems. The introduction of cheap and fast computers enables the automatic measurement and processing of large amounts of measurement data, thus enabling an accurate quantification of the power quality. Those same computers are also an essential part in power-electronic-based mitigation equipment and in many devices sensitive to power quality disturbances.

A large number of alternative definitions of power quality are in use. Some of these are worth mentioning either because they express the opinion of an influential organization or because they present an interesting angle.

Our definition considers every disturbance as a power quality issue. A commonly used alternative is to distinguish between *continuity* (or *reliability*) and *quality*. Continuity includes interruptions; quality covers all other disturbances. Short interruptions are sometimes seen as part of continuity, sometimes as part of quality. Following this line of reasoning, one may even consider voltage dips as a reliability issue, which it is from a customer viewpoint. It is interesting to note that several important early papers on voltage dips were sponsored by the reliability subcommittee of the IEEE Industrial Applications Society [e.g., 30, 75, 73].

The Council of European Energy Regulators [77, page 3] uses the term *quality of service in electricity supply* which considers three dimensions:

- *Commercial quality* concerns the relationship between the network company and the customer.
- *Continuity of supply* concerns long and short interruptions.

- *Voltage quality* is defined through enumeration. It includes the following disturbances: "frequency, voltage magnitude and its variation, voltage dips, temporary and transient overvoltages, and harmonic distortion."

It is interesting that "current quality" is nowhere explicitly mentioned. Obviously current quality is implicitly considered where it affects the voltage quality. The point of view here is again that adverse current quality is only a concern where it affects the voltage quality.

A report by the Union of the Electricity Industry (Eurelectric) [226, page 2] states that the two primary components of supply quality are as follows:

- *Continuity*: freedom from interruptions.
- *Voltage quality*: the degree to which the voltage is maintained at all times within a specific range.

Voltage quality, according to [226], has to do with "several mostly short-term and/or frequency related ways in which the supply voltage can vary in such a way as to constitute a particular obstacle to the proper functioning of some utilization equipment." The concept of voltage quality, according to this definition, is especially related to the operation of end-use equipment. Disturbances that do not affect equipment would not be part of voltage quality. Since at the measurement stage it is often not possible to know if a disturbances will affect equipment, such a definition is not practical.

Another interesting distinction is between *system quality* and *service quality*. System quality addresses the performance of a whole system, for example, the average number of short-circuit faults per kilometer of circuit. This is not a value which directly affects the customer, but as faults lead to dips and interruptions, it can certainly be considered as a quality indicator. A regulator could decide to limit the average number of faults per kilometer per circuit as a way of reducing the dip frequency. Service quality addresses the voltage quality for one individual customer or for a group of customers. In this case the number of dips per year would be a service quality indicator. Like any definition in the power quality area, here there are also uncertainties. The average number of dips per year for all customers connected to the network could be seen as a service quality indicator even though it does not refer to any specific customer. The 95% value of the number of dips per year, on the other hand, could be referred to as a system quality indicator. We will come back to this distinction when discussing site indices and system indices in Chapters 5 and 10.

Reference [260] refers in this context to *aggregate system service quality* and *individual customer service quality*. Reference [77] refers to the quality-of-supply and the quality-of-system approach of regulation. Under the *quality-of-supply approach* the quality would be guaranteed for every individual customer, whereas under the *quality-of-system approach* only the performance of the whole system would be guaranteed. An example of the quality-of-supply approach is to pay compensation to customers when they experience an interruption longer than a predefined duration (24 h is a commonly used value). Under the quality-of-system approach a network operator would, for example, have to reduce the use-of-system charges for all customers when more than 5% of customers experience an interruption longer than this predefined duration.

A term that is very much related to power quality is the term *electromagnetic compatibility* as used within IEC standards. According to IEC 61000-1-1 [148], "Electromagnetic compatibility is the ability of an equipment or system to function satisfactorily in its electromagnetic environment without introducing intolerable electromagnetic disturbances to anything in that environment." The first part of the definition, "ability ··· to function ··· in its ··· environment" fits well with the aforementioned definition of voltage quality. The second part of the definition, "introducing ··· disturbances ···" is rather similar to our term current quality. The IEC has published a whole series of standards and technical reports on EMC, most of which are part of the IEC 61000 series. Most international standards on power quality are part of this series. The most important ones are listed in Appendix A. Some aspects of EMC that are important for power quality are discussed in Section 1.4.

Within the IEC standards on EMC, a distinction is made between an (electromagnetic) disturbance and (electromagnetic) interference: "A disturbance is a phenomenon which may degrade the performance of a device, equipment or system, or adversely affect living or inert matter" [148]. In power quality terms, any deviation from the ideal voltage or current can be labeled as a disturbance. *Interference* is much stricter defined: It is the actual *degradation of a device, equipment, or system caused by an electromagnetic disturbance* [148]. The term *power quality problem* could be used as a synonym. In this book we will mainly discuss (power quality) disturbances as the term *interference* can only be used with reference to a specific piece of equipment.

1.2.3 Events and Variations

An important division of power quality disturbances is between variations and events. Variations are steady-state or quasi-steady-state disturbances that require (or allow) continuous measurements. Events are sudden disturbances with a beginning and an ending. Such a distinction is made in almost all publications on power quality, but the terminology differs. With reference to more classical power engineering, the measurement of variations is similar to metering of the energy consumption (i.e., continuous), whereas the measurement of events is similar to the functioning of a protection relay (i.e., triggered).

A typical example of a power quality variation is the variation of the power system frequency. Its nominal value is 50 Hz but the actual value always differs from this by up to about 1 Hz in a normal system. At any moment in time the frequency can be measured and a value will be obtained. For example, one may decide to measure the power system frequency once a second from the number of voltage zero crossings of the voltage waveform. In this way the average frequency is obtained every second. After one week this measurement will have resulted in $7 \times 24 \times 60 \times 60 = 604{,}800$ frequency values. These values can next be used to obtain information on the probability distribution, like average, standard deviation, and 99% interval (the range not exceeded by 99% of the values).

The issues to be discussed when measuring power quality variations include

- extracting the characteristics, in this case the frequency, from the sampled voltage or current waveform;
- statistics to quantify the performance of the supply at one location; and
- statistics to quantify the performance of a whole system.

These issues will be discussed in detail in the forthcoming chapters. The origin of some power quality variations is discussed in Chapter 2. Signal-processing methods for extracting characteristics from measured voltage and current waveforms are discussed in Chapters 3 and 4. Statistical methods for further processing the characteristics obtained are discussed in Chapter 5.

A typical example of a power quality event is an interruption. During an interruption the voltage at the customer interface or at the measurement location is zero. To measure an interruption, one has to wait until an interruption occurs. This is done automatically in most power quality monitors by comparing the measured voltage magnitude with a threshold. When the measured voltage magnitude is less than the threshold for longer than a certain time, the monitor has detected the start of an interruption. The end of the interruption is detected when the voltage magnitude rises above a threshold again. The duration of the interruption is obtained as the time difference between the beginning and the end of the event. This description for a rather simple event already shows the complexity in the measurement of events:

- A method has to be defined to obtain the *voltage magnitude* from the sampled waveform.
- Threshold levels have to be set for the beginning threshold and for the ending threshold. These two thresholds could be the same or different. Also a value has to be chosen for the minimum duration of an interruption.
- Characteristics have to be defined for the event, in this case the duration of the interruption.

After a sufficiently long monitoring time at a sufficiently large number of locations, it is again possible to obtain statistics. But these statistics are of a completely different nature than for power quality variations. Instead of a distribution over time, a distribution of the duration of the interruption is obtained. One may be interested in the number of interruptions lasting longer than 1 min or longer than 3 h. The average duration of an interruption no longer has any direct meaning, however. It will depend on the minimum duration of an interruption to be recorded. If only interruptions longer than 1 min are recorded, the average duration may be 25 min. If, however, all interruptions longer than 1 s are recorded, a large number of very short duration events may show up, leading to an average duration of only 20 s. The choice of the thresholds will also affect the average values with some events.

The origins of some power quality events are discussed in Chapter 6, methods for detecting events in Chapter 7, characterization of events in Chapter 8, event classification in Chapter 9, and the presentation of event statistics in Chapter 10.

The distinction between variations and events is not always easy to make. If we, for instance, consider changes in the voltage magnitude as a power quality disturbance, one may consider a voltage dip as an extreme case of a voltage magnitude variation. A unique way of defining events is by the triggering that is required to start their recording. Variations do not need triggering, events do. The difference between a voltage dip and a voltage (magnitude) variation is in the triggering. A voltage dip has a specific starting and ending instant, albeit not always uniquely defined. Both voltage dips and voltage variations use the root-mean-square (rms) voltage as their basic measurement quantity. However, for the further processing of voltage variations all values are important, whereas for the further processing of voltage dips only the rms values below a certain threshold are considered.

1.2.4 Power Quality Monitoring

From a pure measurement viewpoint there is no difference between power quality measurements and the measurement of voltages and currents, for example for protection or control purposes. In fact, many signal-processing tools discussed in this book have a wider application that just power quality. The difference is in the further processing and application of the measured signals. The results of power quality monitoring are not used for any automatic intervention in the system. Exceptions are the measurements as part of power quality mitigation equipment, but such equipment is more appropriately classified as protection or control equipment.

Power quality measurements are performed for a number of reasons:

- Finding the cause of equipment malfunction and other power quality problems. Finding the cause of a power quality problem is in many cases the first step in solving and mitigating the problem. The term *power quality troubleshooting* is often used for this. With these kind of measurements it is important to extract as much information as possible from the recorded voltage and current waveforms. With most existing equipment the power quality engineer directly interprets the recorded waveform or some simple characteristics such as the rms voltage versus time or the spectrum of the voltage or current. In most cases hand-held or movable equipment is used and the measurements are performed during a relatively short period. This has been the main application of power quality measurements for a long time.
- Permanent and semipermanent monitoring to get statistical information on the performance of the supply or of the equipment. An increasing number of network companies are installing permanent monitors to be able to provide information to their customers on the performance of their system. In some

cases, a national regulator demands this kind of information as well. The latter is becoming common practice for long interruptions but only very slowly taking off for other power quality disturbances.

- Permanent and semipermanent monitoring can also be used to monitor the network instead of only the voltage and current quality at the interface with the customer. A number of network companies have used voltage-dip recordings and statistics to assess the performance of the distribution system protection. Long voltage dips are often due to overly slow settings of protection relays. The resetting of protection relays resulted in a significant reduction of the number of long voltage dips and thus in an improvement of the voltage quality. But also system events that do not lead directly to problems with customer equipment provide information on the performance of the network. Examples are prestrike and restrike transients with capacitor switching and self-clearing faults in high-impedance grounded systems. Taking the right action may prevent future dips and even interruptions. The term *power quality predictive maintenance* is used in this context in [217]. Permanent power quality monitors can play an important role in reliability-centered maintenance (RCM).
- Another important application of permanent power quality monitoring is that troubleshooting no longer requires additional measurements. The moment a problem is reported, past data can be used to find the cause. When a sufficiently long data period is available, it is even possible to compare the effectiveness of different mitigation methods.
- The results of wide-scale monitoring campaigns, such as the distribution power quality (DPQ) survey in the United States, can be used to define the electromagnetic environment to which end-user equipment is subjected.
- The data obtained from permanent monitors can be used to analyze the system events that led to an interruption or blackout. Even though transmission operators have installed disturbance recorders for this purpose, power quality monitors may give important additional information. This holds to an even higher degree for public and industrial distribution systems. Knowledge about the chain of events that led to an interruption or blackout is important for preventing future events. An analysis of power quality recordings during the August 2003 blackout in the United States and Canada was published within a few days [132].

A general scheme for carrying out power quality measurements is shown in Figure 1.5. Part of the measurements take place in dedicated devices, often referred to as power quality monitors, part take place in devices that have other functions as well. The postprocessing of the data often takes place on computers far away from the monitors. The actual measurement takes place in a measurement device, which often includes the standard instrument transformers. The whole chain from the analog voltages and currents in the power system to the statistical indices resulting from the postprocessing is referred to as *power quality monitoring*.

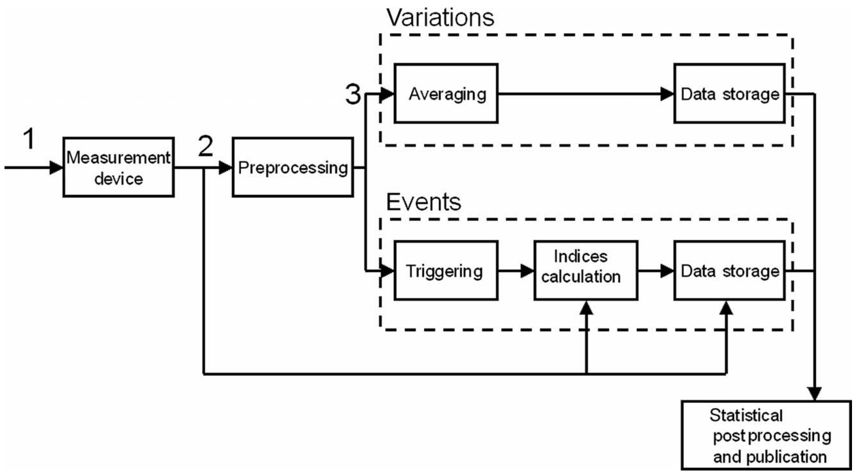

Figure 1.5 General scheme of power quality measurements: (1) voltage or current in system; (2) sampled and digitized voltage or current; (3) quantity for further processing.

The first step in power quality monitoring is the transformation from analog voltages and currents in the power system to sampled digital values that can be processed automatically. The measurement device block in Figure 1.5 includes

- instrument transformers,
- analog anti-aliasing filters,
- sampling and digitizing, and
- digital anti-aliasing and down sampling.

Anti-aliasing is needed to prevent frequency components above the Nyquist frequency (half the sampling frequency) from showing up at low-frequency components. This is a standard part of any digital measurement device. The use of special instrument transformers is a typical power system issue. Voltages and currents in the power system are in many cases far too high to be measured directly. Therefore they are transformed down to a value that can be handled, traditionally 110 V and 1 or 5 A. These so-called instrument transformers are designed and calibrated for 50 or 60 Hz. At this frequency they have a small error. However, some of the power quality disturbances of interest require the measurement of significantly higher frequencies. For those frequencies the accuracy of the instrument transformers can no longer be taken for granted. This is especially important when measuring harmonics and transients. For some measurements special equipment such as resistive voltage dividers and Rogowski coils is being used.

In this book we will assume that the sampled and digitized voltage or current waveforms (referred to as *waveform data*) are available for processing. From the waveform data a number of characteristics are calculated for further processing. The example mentioned a number of times before is the rms voltage. The voltage waveform cannot be directly used to detect events: It would lead to the detection of 100 voltage dips per second. It would also not be very suitable to describe variations in the magnitude of the voltage. For the detection of voltage dips, the one-cycle rms voltage shall be compared with a threshold every half cycle, according to IEC 61000-4-30 [158]. Once an event is detected, its indices are calculated and stored. Some monitors not only store calculated event data but also part of the complete voltage and/or current waveform data. These data can later be used for diagnostics, for calculating additional indices, or for educational purposes. In our research groups we learned a lot about power quality and about power systems in general from the study of waveforms obtained by power quality monitors.

Note that we will refer to the whole chain, including the instrument transformers and the postprocessing outside the actual monitors, as power quality monitoring. This book will not go into further detail on the transformation from voltages and currents in the system to digital waveform data. The main theme of this book is the further processing of these digital waveform data.

The further processing of the data is completely different for variations and events. For power quality variations the first step is again the calculation of appropriate characteristics. This may be the rms voltage, the frequency, or the spectrum. Typically average values over a certain interval are used, for example, the rms voltage obtained over a 10-cycle window. The standard document IEC 61000-4-30 prescribes the following intervals: 10 or 12 cycles, 150 or 180 cycles, 10 min, and 2 h. Some monitors use different window lengths. Some monitors also give maximum and minimum values obtained during each interval. Some monitors do not take the average of the characteristic over the whole interval but a sample of the characteristic at regular intervals, for example, the spectrum obtained from one cycle of the waveform once every 5 min. Further postprocessing consists of the calculation of representative statistical values (e.g., the average or the 95 percentile) over longer periods (e.g., one week) and over all monitor locations. The resulting values are referred to as site indices and system indices, respectively.

The processing of power quality events is different from the processing of power quality variations. In fact, the difference between events and variations is in the method of processing, not necessarily in the physical phenomenon. Considering again the rms voltage, the events considered are short and long interruptions, voltage dips and swells, and (long-duration) overvoltages and undervoltages. The standard first step in their processing is the calculation of the rms voltage, typically over a one-cycle window. But contrary to power quality variations, the resulting value is normally not stored or used. Only when the calculated rms voltage exceeds a certain threshold for a certain duration does further processing start. Some typical theshold and duration values are given in Figure 1.6. These events are referred to as *voltage magnitude events* in [33] and as *rms variations* by some authors. We will refrain from using the latter term because of the potential confusion with our term, (*power quality*) *variations*.

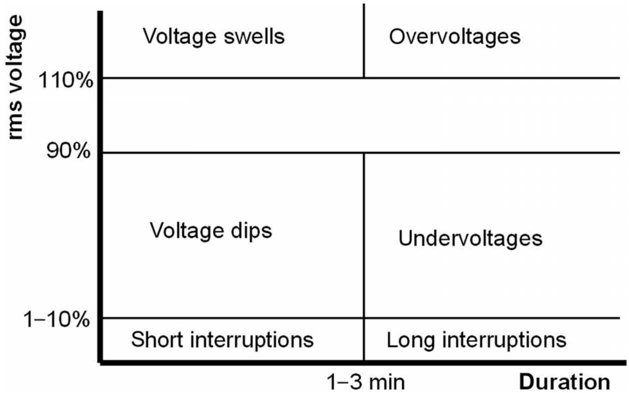

Figure 1.6 Examples of threshold values triggering further processing of events based on rms voltage.

The vertical axis of Figure 1.6 gives the threshold value as a percentage of a reference voltage. Typically the nominal voltage is used as a reference, but sometimes the average voltage over a shorter or longer period before the event is used as a reference. The horizontal axis gives the time during which the rms voltage should exceed the threshold before further processing of the event starts. Further processing of a voltage-dip event is triggered whenever the rms voltage drops below the voltage-dip threshold (typically 90%), whereas further processing of a long interruption is triggered when the rms voltage drops below the interruption threshold (typically 1 or 10%) for longer than 1 to 3 min. Different values are used for the border between dips and interruptions and for the border between short and long interruptions. A further discussion on triggering of power quality events can be found in Chapter 7.

The triggering levels in Figure 1.6 are often referred to as "definitions" for these events. This is, for example, the case in IEEE standard 1159[165]. The authors are of the opinion that this is strictly speaking not correct. The thresholds are aimed at deciding which voltage-dip events require further processing (e.g., to be included in voltage-dip statistics). Any temporary reduction in rms voltage, no matter how small, is a voltage dip, even if there is no reason to record the event.

The further processing of a power quality event consists of the calculation of various indices. The so-called single-event indices (also known as *single-event characteristics*) typically include a duration and some kind of magnitude. The actual processing differs for different types of events and may include use of the sampled waveform data. Statistical processing of power quality events consists of the calculation of site indices (typically number of events per year) and system events (typically number of events per site per year). The calculation of single-event indices will be discussed in further detail in Chapter 8, the calculation of site and system indices in Chapter 10.

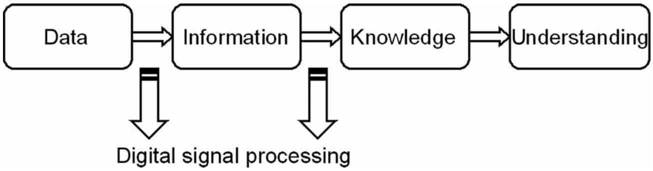

Figure 1.7 Role of signal processing in extraction of information from power quality data.

1.3 SIGNAL PROCESSING AND POWER QUALITY

Digital signal processing, or signal processing in short, concerns the extraction of features and information from measured digital signals. As a research area signal processing covers any type of signal, including electrocardiogram (ECG) and electroencephalogram (EEG) signals, infrared pictures taken from fields suspected of containing land mines, radio waves from distant galaxies, speech signals transmitted over telephone lines, and remote-sensing data. A wide variety of signal-processing methods have been developed through the years both from the theoretical point of view and from the application point of view for a wide range of signals. In this book, we will study the application of some of these methods on voltage and current waveforms. The processing of power quality monitoring data can be described by the block diagram in Figure 1.7. Data are available in the form of sampled voltage and/or current waveforms. From these waveforms, information is extracted, for example, the retained voltage and duration of a voltage dip (see Section 8.6). Signal-processing tools play an essential role in this step. To extract knowledge from the information (e.g., the type and location of the fault that caused the voltage dip), both signal-processing tools and power system knowledge are needed. Having enough knowledge will in the end lead to understanding, for example, that dips occur more during the summer because of lightning storms and to potential mitigation methods. See also the discussion on the reasons for power quality monitoring at the start of Section 1.2.4.

We will not discuss the details of the difference between data, information, knowledge, and understanding. In fact, there are no clear boundaries between them. Having lots of data and the ability to assess them may give the impression of understanding. What is important here is that each step in Figure 1.7 is a kind of refinement of the previous step. One may say that signal processing extracts and enhances the information that is hidden or not directly perceivable.

1.3.1 Monitoring Process

The main emphasis in the signal-processing parts of this book will be on the analysis and extraction of relevant features from sampled waveforms. The process of power quality monitoring involves a number of steps that require signal processing:

- Characterizing a variation is done by defining certain features. The choice of features is often very much related to the essence of the variation: What is actually varying? For example, voltage variations concern variations in the magnitude of the voltage waveform. But such a definition is not sufficient to quantify the severity of the voltage variation through measurements. There are a number of features that can be used to quantify this magnitude: the absolute value of the complex voltage, the rms voltage, and the peak voltage. Other choices have to be made as well: the sampling frequency, the length of the window over which the characteristic is extracted, the repetition frequency of the measurement, and the way of processing a series of values. The choice of measurement methods may impose influence on the resulting value, which in turn may be decisive for compliance with a standard.

An excellent example of the use of signal-processing tools to extract and analyze features is the flickermeter standard for characterization of voltage fluctuations. See Section 2.4 for a detailed discussion on the flickermeter algorithm.

- Distinguishing between a variation and an event, a triggering mechanism is needed. The most commonly used method compares a sliding-window rms value with a threshold value. This again requires the definition of a number of values, such as the size of the window, the overlap between successive windows, and the choice of the threshold. However, other triggering methods may be more appropriate. A discussion on triggering methods can be found in Chapter 7.
- Characterizing each event through a number of parameters once an event is detected (or captured). This again involves the extraction of one or more features. For voltage dips the event characterization is very much related to the characterization of voltage variations. There is a reasonable amount of agreement in the power quality field on how this should be done. But for voltage and current transients no standardized method is currently available. We will discuss the characterization of voltage dips and transients in more detail in Sections 8.6 and 8.10, respectively.
- Classifying each event according to its underlying causes from the extracted features. This can often be considered as the final aim of the analysis. One of the essential issues is to choose between the categories of classification methods, for example, linear or nonlinear classifier, depending on the signal characteristics. Next, in each category, a number of possible candidates can be selected. For example, a Newman–Pearson method is selected if one needs to maximize the classification rate while the false-alarm rate of classification should be below a certain threshold. Or, one may choose a support vector machine where the learning complexity of the machine is a practical issue of concern and the performance of the classifier to the testing data needs to be guaranteed.

Although the fundamental signal-processing techniques used in practical power quality monitoring have been the discrete Fourier transform (DFT) and the rms, many more have been proposed in the literature. This book will discuss recent developments in more detail.

1.3.2 Decomposition

Analyzing the sampled voltage or current waveforms offers quantitative descriptions of power quality, for example, the dominant harmonic components and their associated magnitudes, the points where disturbances start and end, and the block of data where different system faults led to the disturbances. Many signal-processing methods can be applied for such purposes. As we will describe later, a signal-processing method could be very good for one application but not very suitable for another application. For example, the wavelet transform may be very attractive for finding the transitions while it could be unattractive to harmonic analysis [129]. For each application, a set of methods can be chosen as candidates, and each may offer different performance and complexity; again it is a matter of trade-off. Below we try to roughly summarize the types of signal-processing methods that may be attractive to power quality analysis. It should be mentioned that the list of methods below is far from complete. They can be roughly categorized into two classes: transform or subband filter-based methods and model-based methods.

1. *Data Decomposition Based on Transforms or Subband Filters* These methods decompose the measurement into components. Depending on the stationarity of the measurement data (or data blocks), one may choose frequency- (or scale-) domain analysis or time–frequency- (or time–scale-) domain analysis.
   - *Frequency-Domain Analysis* If the measurement data (or block of the data) are stationary, frequency-domain decomposition of the data is often desirable. A standard and commonly preferred method is the DFT or its fast algorithm, the fast Fourier transform (FFT).

     Wavelet transform is another transform closely related to frequency-domain analysis. Wavelet transform decomposes data to scale-domain components where scales are related to frequencies in logarithmic scales.
   - *Time–Frequency- (or Time–Scale-) Domain Analysis* If the measurement data are nonstationary, it is desirable that they are decomposed into time-dependent frequency components. To obtain the time–frequency representation of data, a commonly used method is the short-time Fourier transform (STFT) or a set of sliding-window FFTs.

     The STFT can be explained equivalently by a set of bandpass filters with an equal bandwidth. The bandwidth is determined by the selected window and the size of the window.

     Another way to implement time–frequency representation of data is to use time–scale analysis by discrete wavelet filters. This is mostly done by successively applying wavelet transforms to decompose the low-pass-filtered data (or the original data) into low-pass and high-pass bands. This is equivalently described by a set of bandpass filters with octave bandwidth. The advantages are the possibility to trade off between time resolution and frequency resolution given a fixed joint time–frequency resolution value constrained under the uncertainty principle.

2. *Data Analysis Using Model-Based Methods* Another important set of signal-processing methods for power system data analysis are the model-based methods. Depending on the prior knowledge of systems, one may assume that the data sequences are generated from certain models, for example, sinusoidal models, autoregressive models, or state-space models. One of the advantages of model-based methods is that if the model is correctly chosen, it can achieve a high-frequency resolution as compared with filter-bank and transform-based methods. Conversely, if an incorrect model is applied, the performance is rather poor.
   - *Sinusoidal Models* The signal is modeled as the sum of a finite number of frequency components in white noise. The number of components is decided beforehand and the frequencies and (complex) magnitudes are estimated by fitting the measured waveform to the model. Three estimation methods—multiple signal classification (MUSIC), estimation of signal parameters via rotational invariance techniques (ESPRIT), and Kalman filters—are discussed in detail in Chapters 3 and 4.
   - *Other Stochastic Models* We limit ourselves to the autoregressive (AR), autoregressive moving-average (ARMA), and state-space models. In the models, the signal is modeled as the response of a linear time-invariant system with white noise as the input, where the system is modeled by a finite number of poles or poles and zeros. The AR and ARMA models are both discussed in detail in Chapters 3 and 4. For state-space modeling essential issues include predefining state variables and formulating a set of state and observation equations. Although Kalman filters are employed for estimating harmonics in the examples, their potential applications for power system disturbance analysis are much broader depending on how the state space is defined.

1.3.3 Stationary and Nonstationary Signals

As far as the signals are concerned, we can roughly classify them into two cases: stationary and nonstationary signals. The signal-processing methods introduced in Chapter 3 are for stationary signals. However, strictly stationary signals do not exist in real-life power systems: Both small and large statistical changes occur in the signal parameters. The presence of small and relatively slow statistical changes is addressed through so-called block-based methods. The signal is assumed stationary over a short duration of time (or window), a so-called block of data; the signal features (or characteristics or attributes) are estimated over this window. Next the window is shifted in time and the calculations are repeated for a new block of data. The resulting estimated features become a function of time depending on the location of the window. Apart from these block-based signal-processing methods, Kalman filters offer non-block-based processing which can be directly applied to nonstationary signal processing. The different aspects of block-based (batch processing) and non-block-based (iterative processing) signal-processing methods are discussed in detail in Chapter 4. A more sophisticated segmentation method which automatically uses an adaptive block size is described in Chapter 7.

1.3.4 Machine Learning and Automatic Classification

A logical next step after quantifying and characterizing the data is to classify, diagnose, and mitigate the disturbances. Appropriate tools to achieve this include machine learning and automatic classification and diagnostics. Classification methods use features (or attributes or characteristics) of data as the input and the designated class label of the data as the output. A classification process usually consists of steps such as feature extraction and optimization, classifier design that finds a mapping function between the feature space and decision space, supervised or nonsupervised machine learning, validation, and testing. In Chapter 9 we will describe some frequently used linear and nonlinear classification methods where static features are considered. Further, in Chapter 9 a simple rule-based expert system for data classification will be described through a number of examples. A number of statistical-based classification methods such as Bayesian learning, Newman–Pearson methods, support-vector machines, and artificial neural networks together with practical application examples will also be described in Chapter 9.

1.4 ELECTROMAGNETIC COMPATIBILITY STANDARDS

1.4.1 Basic Principles

All communication between electrical devices is in the form of electromagnetic waves ruled by Maxwell's equations. This holds for intentional as well as unintentional communication. Electromagnetic waves are responsible for the power supply to the equipment (note that for the power supply in most cases Kirchhoff's equations are used as a low-frequency approximation of Maxwell's equations) and for the exchange of information between equipment. They are also responsible for all kinds of disturbances that may endanger the correct operation of the equipment. These so-called electromagnetic disturbances may reach the equipment trough metallic wires (so-called conducted disturbances) or in the form of radiation (radiated disturbances). Note that there is no difference between intentional information exchange and a disturbance from an electromagnetic viewpoint.

The general approach is to achieve *electromagnetic compatibility* between equipment. Electromagnetic compatibility is defined as "the ability of a device, equipment or system to function satisfactorily in its electromagnetic compatibility without introducing intolerable electromagnetic disturbances to anything in that environment" [148]. The IEC has published several standard documents (mainly in the 61000 series) which define various aspects of EMC. These include a number of standards on power quality issues like harmonics and voltage dips. An overview of all relevant EMC standards is given in Appendix A.

The principle of the EMC standards can best be explained by considering two devices: one which produces an electromagnetic disturbance and another that may be adversely affected by this disturbance. In EMC terms, one device (the "emitter") emits an electromagnetic disturbance; the other (the "susceptor") is susceptible to this disturbance. Within the EMC standards there is a clear distinction in meaning between (electromagnetic) "disturbance" and (electromagnetic) "interference." An electromagnetic disturbance is any unwanted signal that may lead to a degradation of the performance of a device. This degradation is referred to as electromagnetic interference. Thus the disturbance is the cause, the interference the effect.

The most obvious approach would be to test the compatibility between these two devices. If the one would adversely affect the other, there is an EMC problem, and at least one of the two needs to be improved. However, this would require testing of each possible combination of two devices, and if a combination would fail the test, it would remain unclear which device would require improvement.

To provide a framework for testing and improving equipment, the concept of *compatibility level* is introduced. The compatibility level for an electromagnetic disturbance is a reference value used to compare equipment emission and immunity. From the compatibility level, an emission limit and an immunity limit are defined. The immunity limit is higher than or equal to the compatibility level. The emission limit, on the other hand, is lower than or equal to the compatibility level (see Fig. 1.8). Immunity limit, compatibility level, and emission limit are

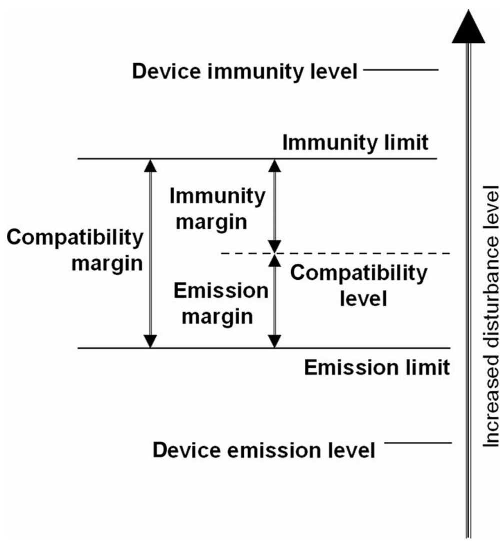

Figure 1.8 Various levels, limits, and margins used in EMC standards.

defined in IEC standards. The ratio between the immunity limit and the compatibility level is called the *immunity margin*; the ratio between the compatibility level and the emission level is referred to as the *emission margin*. The value of these margins is not important in itself, as the compatibility level is just a predefined level used to fix emission and immunity limits. Of more importance for achieving EMC is the *compatibility margin*: the ratio between the immunity limit and the emission limit. Note that the compatibility margin is equal to the product of the emission margin and the immunity margin. The larger the compatibility margin, the smaller the risk that a disturbance from an emitter will lead to interference with a susceptor.

The testing of equipment involves comparing the amount of electromagnetic disturbance produced by the equipment (the *emission level*) with the emission limit and the maximum amount of disturbance for which the equipment functions normally (the *immunity level*) with the immunity limit. To pass the test, the emission level should be less than the emission limit and the immunity level should be higher than the immunity limit. The result of this is obvious: When two devices both pass the test, they will not adversely affect each other.

In the next section we will discuss how to choose the ratio between compatibility level and maximum emission level. This, however, does not say where to start when deciding on emission and immunity levels.

In case both emission and immunity levels can be freely chosen, the compatibility level can be freely chosen. A too high compatibility level would lead to high costs for equipment immunity; a too low level would lead to high costs for limiting equipment emission. The compatibility level should be chosen such that the sum of both costs (for all devices, thus the total costs to society) is minimal. With conducted disturbances that can be attributed to equipment such a trade-off is in principle possible. However, in practice the existing disturbance levels are often used as a basis for determining the compatibility level.

For some disturbances the emission level cannot be affected. One may think of (variations in) Earths magnetic field or cosmic radiation as an example in which it is impossible to affect the source of the disturbance. But also disturbances due to events in the power system (faults, lightning strokes, switching actions) are treated like this in the EMC standards even though it is possible to affect the source of the disturbance. This way of treating the power system as something that cannot be affected is again related to the fact that EMC standards apply to equipment only. There is no technical argument for this. An often-used argument is that voltage dips cannot be prevented because lightning strokes (leading to faults, leading to dips) are part of nature. (The very inappropriate term "acts of God" is sometimes used.) Even though it is not possible to prevent lightning, it is technically very well possible to limit the number of faults due to lightning strokes to overhead lines. Shielding wires, higher insulation levels, and underground cables are possible options. The prohibiting costs associated with some of these improvements would be a more valid argument.

Finally there are disturbances for which it is not possible (or not practical) to affect the immunity of the equipment. With voltage fluctuation the "equipment" is the combination of our eye with our brain. The susceptibility of the eye–brain combination to light intensity fluctuations is not possible to affect. Therefore the compatibility level is determined by the immunity limit.

1.4.2 Stochastic Approach

From the previous section the reader could get the impression that a very small margin between immunity and emission limits would be sufficient to guarantee that no device is affected adversely by another device. This would be the case if the tests could reproduce all possible operating conditions for all possible devices. But that would require an almost infinite number of tests to be applied on all devices. In practice a limited number of tests under strictly defined laboratory conditions are applied to a small number of devices (the so-called type testing). If these devices pass the test, all other devices of the same type are supposed to have passed the test and will get the appropriate certification.

A number of phenomena contribute to the uncertainty in immunity and emission limits[148], all in some way related to the fact that it is not possible to test each device for each possible situation:

- *Relevance of Test Methods* Each device to be tested is subjected to a number of well-defined tests in a laboratory environment. The actual operating conditions of the device are likely to deviate from the laboratory environment. This could lead to a device emitting more disturbance than under test conditions or to a susceptor being more susceptible than under test conditions. For example, the harmonic current emission of a device is tested for a voltage waveform of a given magnitude with small distortion and for a well-defined source impedance. Any difference in voltage magnitude, voltage distortion, and/or source impedance will affect the current distortion (i.e., the emission). The emission or immunity of a device may also be affected by the outside temperature, by its loading, or by the state of the device in its duty cycle.

  The tests have to be done under well-defined conditions to guarantee that they are reproducible. A test performed by one testing laboratory should give the same results as the same test performed by another laboratory. The result of this is however that the variations in ambient conditions and state of the device cause a spread in immunity and emission levels when the device is used in the real world.
- *Normal Spread in Component Characteristics* As said before, only a small number of devices are subjected to the tests. The characteristics of different devices will show slightly different characteristics, even if they are from the same type. An example is the second-harmonic current taken by a power-electronic converter. Second-harmonic current is due to the difference in component parameters between the diodes or transistors within one pair. This level will likely vary a lot between different devices.
- *Superposition Effects and Multidimensional Characteristics* During the tests the device is subjected to one disturbance at a time. When a device is subjected

to different disturbances at the same time, its susceptibility may be significantly different than for the individual disturbances. A classical example is the combination of voltage dips and harmonic distortion. Most voltage distortion in low-voltage networks is such that the peak value of the voltage shows a reduction without affecting the rms voltage; the voltage waveform becomes more of a trapezoidal wave instead of a sine wave. This is due to single-phase rectifiers all together drawing current during the maximum voltage. The effect of this reduction in crest factor is that the voltage at the direct current (dc) bus inside the single-phase rectifiers gets smaller; the dc bus voltage is more or less proportional to the crest factor. This reduction in dc bus voltage makes the rectifiers more susceptible to voltage dips.

Another example concerns the susceptibility of rotating machines for voltage unbalance. The machine can tolerate a higher unbalance for a nondistorted voltage waveform than for a distorted waveform. In the same way, its susceptibility against harmonic distortion is affected by the voltage unbalance.

- *Multiple-Emitting Sources* The problem of multiple-emitting sources was mentioned already before as it is one of the contributing factors to the uncertainty in emission level. The discussion before on the choice of emission and immunity limits was based on the assumption of one emitter and one susceptor. In reality there are in most cases a number of emitters and a number of susceptors. The presence of multiple susceptors does not affect the earlier reasoning very much. The susceptibility of a device to an electromagnetic disturbance is not affected by the susceptibility of a neighboring device. The neighboring device may affect the disturbance level and in that way the operation of the device. But the susceptibility in itself is not affected nor is the susceptibility of the neighboring device of any influence. The effect of neighboring devices on the disturbance is included in the statistical uncertainty in emission and immunity levels.

  The presence of multiple emitters will of course also not affect the susceptibility of a device. But it will have such a large effect on the electromagnetic environment that it cannot be treated as just another statistical variation. The concept for setting the immunity limit, as shown in Figure 1.8, can still be applied when the total emission (the resulting disturbance level) is used instead of the emission level. A method similar to the hosting-capacity approach (Section 1.7.1) may be used when the number of emitters is not known.

In the IEC EMC standards and in most publications on EMC it is stated that emission and immunity limits should be chosen such that the probability of electromagnetic interference is sufficiently small. This assumes of course that the distributions are known, which is generally not the case. The various contributions given here are such that it is very hard to bring then into a probability distribution. The result is that a large amount of engineering judgment is needed when deciding about emission and immunity limits. With almost any of the phenomena adjustments to the limits and/or to the tests have been shown to be needed. The EMC standards are not as static as one would expect. With new types of equipment, new types of emission and new types of susceptibility will be introduced. This means that EMC will remain an interesting area for many years to come.

1.4.3 Events and Variations

A distinction was made before between *events* and *variations*. This distinction also appears in the EMC standards, or more precisely in the lack of standard documents on power quality events. For example, the European voltage characteristics documents EN 50160 [106] gives useful information for variations but nothing for events [33].

As we saw before, the EMC standards are developed around the concept of compatibility level. For variations, which are measured continuously, a probability distribution can be obtained for each location. The 95% values for time and location can be used to obtain the compatibility level. It will be rather difficult to perform measurements for each location, but even an estimated probability distribution function will do the job. For events the situation becomes completely different, as it is no longer possible to obtain a value that is not exceeded 95% of the time. This requires a reevaluation of the concept of compatibility level. One can no longer define the requirement (emission limits and immunity limits) by a probability that interference will occur. Instead the setting of limits should be ruled by the number of times per year that interference will occur. This part of the EMC standards is not very well defined yet. We will come back to the statistical processing of events in Chapter 10.

A place where the distinction between variations and events becomes very clear is with voltage magnitude (rms voltage). Small deviations from the nominal voltage are called *voltage variations* or *voltage fluctuations*; large deviations are called *voltage dips*, *overvoltages*, or *interruptions*. Without distinguishing between variations and events, the somewhat strange situation would arise that the small deviations are regulated and the large ones are not.

1.4.4 Three Phases

Most power systems consist of three phases. But neither the EMC standards nor the power quality literature make much mention of this. There are a number of reasons for the lack of attention for three-phase phenomena:

- In normal operation the system voltages are almost balanced. For a balanced system a single-phase approach (more exactly the positive sequence) is sufficient. Most variations concern normal operation so that this approach is also generally deemed sufficient here.
- The EMC standards apply to devices, most of which are single phase.
- Three-phase models increase the complexity of the approach, in some cases significantly. This makes it harder to get a standard document accepted.

The only phenomenon that is treated in a three-phase sense is *unbalance*, where the negative-sequence voltage is divided by the positive-sequence voltage to quantify the unbalance. For most other disturbances the individual phase voltages are treated independently, after which the worst phase is taken to characterize the disturbance level.

However, most disturbances are not balanced as they are deviations from the ideal (constant and balanced) situation. The fact that *three-phase unbalance* is addressed in the EMC standards further emphasizes that even for variations the voltages are not fully balanced. During events (e.g., voltage dips) the deviation from the balanced case can be very large. During a phase-to-phase fault the magnitudes of positive-sequence and negative-sequence voltages become equal at the fault location. For fundamental frequency disturbances such as voltage fluctuations and voltage dips, a symmetrical-component approach seems the most appropriate. Also for harmonic distortion symmetrical-component methods have been proposed. For transients a different approach may have to be developed. We will come back to this discussion at various places in the forthcoming chapters.

1.5 OVERVIEW OF POWER QUALITY STANDARDS

The main set of international standards on power quality is found in the IEC documents on EMC. The IEC EMC standards consist of six parts, each of which consists of one or more sections:

- *Part 1: General* This part contains for the time being only one section in which the basic definitions are introduced and explained.
- *Part 2: Environment* This part contains a number of sections in which the various disturbance levels are quantified. It also contains a description of the environment, classification of the environment, and methods for quantifying the environment.
- *Part 3: Limits* This is the basis of the EMC standards where the various emission and immunity limits for equipment are given. Standards IEC 61000-3-2 and IEC 61000-3-4 give emission limits for harmonic currents; IEC 61000-3-3 and IEC 61000-3-5 give emission limits for voltage fluctuations.
- *Part 4: Testing and Measurement Techniques* Definition of emission and immunity limits is not enough for a standard. The standard must also define standard ways of measuring the emission and of testing the immunity of equipment. This is taken care of in part 4 of the EMC standards.
- *Part 5: Installation and Mitigation Guidelines* This part gives background information on how to prevent electromagnetic interference at the design and installation stage.
- *Part 6: Generic Standards* Emission and immunity are defined for many types of equipment in specific product standards. For those devices that are not covered by any of the product standards, the generic standards apply.

The most noticeable non-IEC power quality standard is the voltage characteristics document EN 50160 published by Cenelec. This document will be discussed in Section 5.6.3. Several countries have written their own power quality documents, especially on harmonic distortion. The IEEE has published a significant number of standard documents on power quality, with the harmonics standard IEEE 519 (see Section 5.6.6) probably being the one most used outside of the United States. A more recent document that has become a de facto global standard is IEEE 1366 defining distribution reliability indices (see Section 10.1.2). Other IEEE power quality standard documents worth mentioning are IEEE 1346 (compatibility between the supply and sensitive equipment, see Section 10.2.4), IEEE 1100 (power and grounding of sensitive equipment), IEEE 1159 (monitoring electric power quality), and IEEE 1250 (service to sensitive equipment). The relevant IEC and IEEE standard documents on power quality are listed in Appendixes A and B, respectively. Also the as-yet not-officially-published work within task forces 1159 (power quality monitoring) and 1564 (voltage-sag indices) is already widely referenced.

1.6 COMPATIBILITY BETWEEN EQUIPMENT AND SUPPLY

The interest in power quality started from incompatibility issues between equipment and power supply. Therefore it is appropriate to spend a few lines on this issue, even though this is not the main subject of this book. The distinction between voltage and current quality originates from these compatibility issues. We will mainly discuss voltage quality here but will briefly address current quality later.

Voltage quality, from a compatibility viewpoint, concerns the performance of equipment during normal and abnormal operation of the system. What matters to the equipment are only the voltages. In Section 1.2.3 we introduced the distinction between variations and events. This distinction is also important for the compatibility between equipment and supply. Events will further be divided into "normal events" and "abnormal events." In the forthcoming paragraphs guidelines are given for the compatibility between equipment and supply. It is thereby very important to realize that ensuring compatibility is a joined responsibility of the network and the customer. This responsibility sharing plays an important part in the discussion below.

1.6.1 Normal Operation

The voltage as experienced by equipment during normal operation corresponds to what we refer to here as *voltage variations*. Voltage variations will lead to performance deterioration and/or accelerated aging of the equipment. We distinguish between three levels of voltage variations:

- voltage variations that have no noticeable impact on equipment,
- voltage variations that have a noticeable but acceptable impact on equipment, and
- voltage variations that have an unacceptable impact on equipment, which includes malfunction and damage of equipment.

The design of the system and the design of the equipment should be coordinated in such a way that the third level is never reached during normal operation and the time spent at the second level is limited. In practice this means that the design of equipment should be coordinated with the existing level of voltage variations. A good indication of the existing level of voltage variations can in part be obtained from such documents as EN 50160 and IEC 61000-2-2 (see Sections 5.6.3 and 5.6.4, respectively). The alternative, to perform local measurements, is not always feasible. Any further discussion on the appropriateness of these documents is beyond the scope of this chapter.

The responsibility of the network operator is to ensure that the voltage quality does not deteriorate beyond a mutually agreed-upon level. Again the limits as given in EN 50160 are an appropriate choice for this. Several countries have regulations in place or are developing such regulations, in many cases based on the EN 50160 limits.

1.6.2 Normal Events

For design purposes it is useful to divide power quality events into *normal events* and *abnormal events*. Normal events are switching events that are part of the normal operation of the system. Examples are tap changing, capacitor switching, and transformer energizing as well as load switching. If the resulting voltage events are too severe, this will lead to equipment damage or malfunction. If there are too many events, this will cause unacceptable aging of equipment. The same approach may be used as for normal operation: Equipment design should be coordinated with the existing voltage quality. There are, however, two important differences. The first difference is in the type of limits. For events limits are in the form of a maximum severity for individual events and in a maximum number of events. (In Chapter 10 we will refer to these two types of event limits as single-event indices and single-site indices, respectively.) The second difference with normal operation is that there is no document that gives the existing levels. Some normal events are discussed in EN 50160, but the indicated levels are too broad to be of use for equipment design. What is needed is a document describing the existing and acceptable voltage quality with relation to switching actions in the system (i.e., normal events).

Fortunately, normal events rarely lead to problems with equipment. The main recent exception are capacitor-energizing transients. These have caused erroneous trips for many adjustable-speed drives. The problem is solved by a combination of system improvement (synchronized switching) and improved immunity of equipment. In terms of responsibility sharing, the network operator should keep the severity and frequency of normal events below mutually agreed-upon limits; the customer should ensure that the equipment can cope with normal events within those limits.

1.6.3 Abnormal Events

Abnormal events are faults and other failures in the system. These are events that are not part of normal operation and in most cases are also unwanted by the network operator. Voltage dips and interruptions are examples of voltage disturbances due to abnormal events in the system. It is not possible to limit the severity of abnormal events and thus also not possible to ensure that equipment can tolerate any abnormal event. A different design approach is needed here.

When the performance of the supply is known, an economic optimization can be made to determine an appropriate immunity of the equipment. A higher immunity requirement leads to increased equipment costs but reduced costs associated with downtime of the production. The total costs can be minimized by choosing the appropriate immunity level. This approach is behind the *voltage-sag coordination chart* as defined in IEEE 1346 [74]. Such an optimization is, however, only possible when detailed information is available on system performance and is therefore difficult to apply for domestic and commercial customers.

An alternative approach is to define a *minimum equipment immunity*. The requirements placed by normal operation and normal events already place a lower limit on the equipment immunity. This lower limit is extended to include also *common abnormal events*. An example of such a curve is the Information Technology Industry Council (ITIC) curve for voltage dips and swells. Although the origins of these curves are different, they may all be used as a minimum immunity curve. (Note that the term *voltage tolerance curve* is more commonly used than *immunity curve*.) The practical use of such a curve only makes sense when the number of events exceeding the curve are limited. This is where the responsibility of network operators comes in. The responsibility sharing for abnormal events such as voltage dips is as follows: The network operator should ensure a limited number of events exceeding a predefined severity; the customer should ensure that all equipment will operate as intended for events not exceeding this predefined severity. In the current situation a large compatibility gap is present between immunity requirements placed on equipment and regulatory requirements placed on the network operator. This compatibility gap is shown in Figure 1.9. The immunity curve shown is according to the class 3 criteria in Edition 2 of IEC 61000-4-11. Regulatory requirements are available in some countries for long interruptions, typically starting at durations between 1 and 5 min (3 min duration and 10% residual voltage have been used for the figure). The range in dips between the two curves is regulated on neither the equipment side nor the network side.

A more desirable situation is shown in Figure 1.10: A mutually agreed-upon curve defines both the minimum equipment immunity and the range of events that occur only infrequently. A regulatory framework may be needed to ensure the latter. As part of the regulation, the frequency of occurrence of events below the curve should be known. This allows an economic optimization to be performed by those customers that require a higher reliability than the standard one.

The existing compatibility gap is even larger than would follow from Figure 1.9. The IEC immunity standard refers to equipment performance, not to the performance of a production process. If a piece of equipment safely shuts down during an event, this may classify as compliance with the standard (this is the case for the drive standard IEC 61800-3). The process immunity curve is thus located toward the left of the equipment immunity curve.

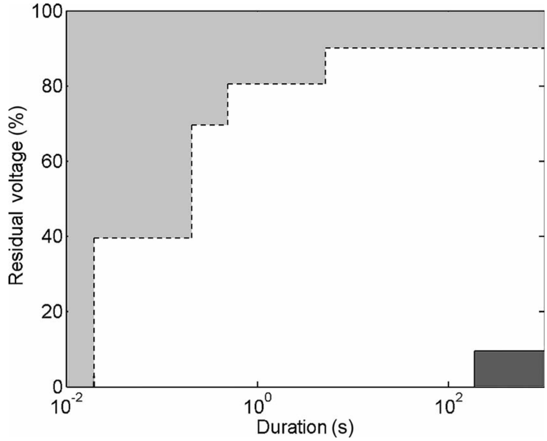

Figure 1.9 Compatibility gap with IEC 61000-4-11 class 3 criteria toward left and area to which regulation most commonly applies to right.

Power quality also has a current quality side, which requires design rules in the same way as voltage quality. There are two reasons for limiting the severity and frequency of current disturbances. Current disturbances should not lead to damage, malfunction, or accelerated aging of equipment in the power system. The design rules should be the same as for normal operation and normal events as discussed before. The only difference is that the network operator is now on the receiving end of the disturbance. The second reason for limiting current disturbances is that they cause voltage disturbances, which are in turn limited. The limits placed by

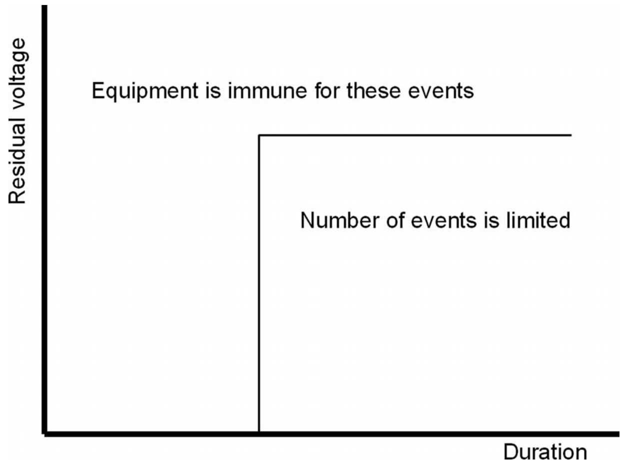

Figure 1.10 Responsibility sharing between equipment and network operator: Compatibility gap has disappeared.

the network operator on the current quality for customers and equipment should correspond with the responsibility of the network operator to limit voltage disturbances.

1.7 DISTRIBUTED GENERATION

In Section 1.2.2 power quality was defined as the electrical interaction between the electricity grid and its customers. These costumers may be consumers or generators of electrical energy. The interaction was further divided into *voltage quality* and *current quality*, referring to the way in which the network impacts the customer and the way in which the customer impacts the network, respectively. When considering systems with large amounts of distributed generation, power quality becomes an important issue that requires a closer look. Three different power quality aspects are considered in [40]:

- Distributed generation is affected by the voltage quality in the same way as all other equipment is affected. The same design rules hold as in Section 1.6. An important difference between distributed generation and most industrial installations is that the erroneous tripping of the generator may pose a safety risk: The energy flow is interrupted, potentially leading to overspeed of the machine and large overvoltages with electronic equipment. This should be taken into consideration when setting immunity requirements for the installations.
- Distributed generation affects the current quality and through the grid also the voltage quality as experienced by other customers. The special character of distributed generation and its possible wide-scale penetration require a detailed assessment of this aspect. We will discuss this in detail below.
- A third and more indirect aspect of the relation between distributed generation and power quality is that the tripping of a generator may have adverse consequences on the system. Especially when large numbers of generators trip simultaneously, this can have an adverse impact on the reliability and security of the system.

1.7.1 Impact of Distributed Generation on Current and Voltage Quality

The impact of distributed generation on power quality depends to a large extent on the criteria that are considered in the design of the unit. When the design is optimized for selling electricity only, massive deployment of distributed generation will probably adversely impact quality, reliability, and security. Several types of interfaces are however capable of improving the power quality. In a deregulated system this will require economic incentives, for example, in the form of a well-functioning ancillary services market.

To quantify the impact of increasing penetration of distributed generation on the power system, the hosting capacity approach is proposed in [40] and [272]. The basis of this approach is a clear understanding of the technical requirements that the customer places on the system (i.e., quality and reliability) and the requirements that the system operator may place on individual customers to guarantee a reliable and secure operation of the system. The hosting capacity is the maximum amount of distributed generation for which the power system operates satisfactorily. It is determined by comparing a performance index with its limit. The performance index is calculated as a function of the penetration level. The hosting capacity is the penetration level for which the performance index becomes less than the limit. A hypothetical example is shown in Figure 1.11.

The calculation of the hosting capacity should be repeated for each different phenomenon in power system operation and design: The hosting capacity for voltage variations is different from the hosting capacity for frequency variations. Even for one phenomenon the hosting capacity is not a fixed value: It will depend on many system parameters, such as the structure of the network, the type of distributed generation (e.g., with or without storage; voltage/power control capability), the kind of load, and even climate parameters (e.g., in case of wind or solar power). For studying the impact of distributed generation on power quality phenomena the indices introduced in Chapters 5 and 10 should be used. Note that the "ideal" value of many of those indices is zero, so that the hosting capacity is reached when the index value exceeds the limit.

By using the hosting capacity approach, the issue of power quality and distributed generation has now been reduced to a discussion of the acceptable performance of a power system. This may not always be an easy discussion, but it is at least one that leads to quantifiable results. Obviously what is acceptable to one customer may not be acceptable to another customer and here some decisions may have to be made.

Figure 1.12 gives an example of how to implement this method for the overvoltages due to the injection of active power by distributed generation units. This

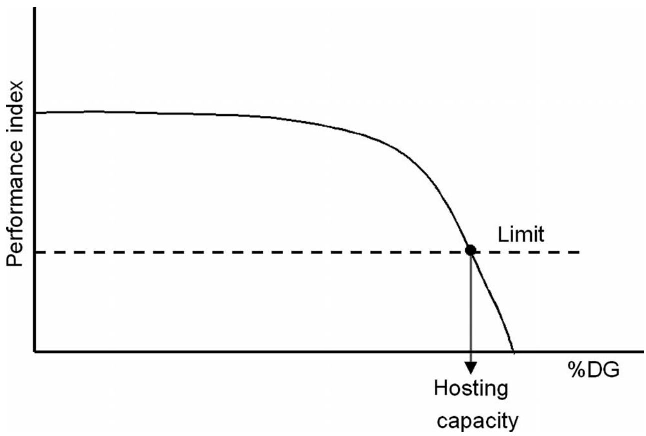

Figure 1.11 Definition of hosting capacity approach for distributed generation.

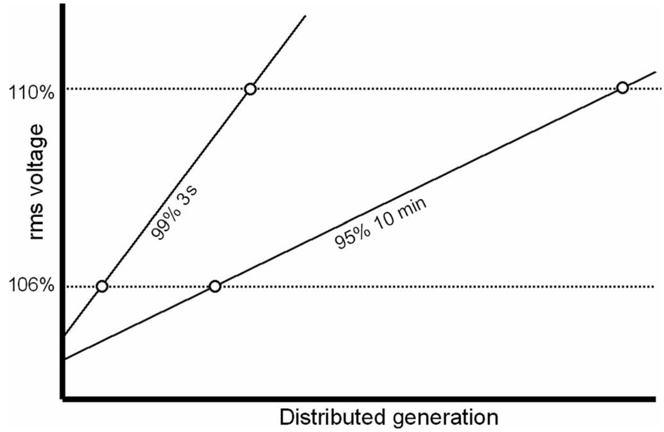

Figure 1.12 Example of hosting capacity approach as applied to voltage variations; two different limits and two different indices result in four different values for hosting capacity.

is a standard example in many studies. In the figure two different indices are used, both based on the rms voltage. One index uses the 95 percentile of the 10-min rms values, whereas the other one uses the 99 percentile of the 3-s rms values. The figure also shows two different limits: 106 and 110% of the nominal voltage. The choice of two limits and two indices results in four values for the hosting capacity. The hosting capacity depends strongly on the choice of index and the choice of limit. The amount of distributed generation that can be accepted by the system depends on the performance requirements placed on the system. Note that this is exactly the same discussion as the coordination between current quality and voltage quality in Section 1.6. By quantifying the responsibility of the network operator for voltage quality, the hosting capacity for distributed generation is also determined.

Distributed generation may have an adverse influence on several power quality variations. The most-discussed issue is the impact on voltage variations. The injection of active power may lead to overvoltages in the distribution system (see Section 2.2.3.3). Also, increased levels of harmonics and flicker are mentioned as potential adverse impacts of distributed generation. But distributed generation can also be used to mitigate power quality variations. This especially holds for power-electronic interfaces that can be used to compensate voltage variations, flicker, unbalance, and low-frequency harmonics. The use of power-electronic interfaces will however lead to high-frequency harmonics being injected into the system. These could pose a new power quality problem in the future.

1.7.2 Tripping of Generator Units

As we mentioned at the start of this section, there is a third power quality aspect related to distributed generation. With large penetration of distributed generation, their tripping is an issue not only for the generator owner but also for the system operator and other customers. The tripping of one individual unit should not be a concern to the system, but the simultaneous tripping of a large number of units is a serious concern. Seen from the network this is a sudden large increase in load. Simultaneous tripping occurs due to system events that exceed the immunity of the generator units. As discussed in the previous section, we assume that distributed generator units will not trip for normal events such as transformer or capacitor energizing. Their behavior for abnormal events such as faults (voltage dips) and loss of a large generator unit (frequency swings) is at first a matter of economic optimization of the unit.

A schematic diagram linking a fault at the transmission level with a large-scale blackout is shown in Figure 1.13. The occurrence of a fault will lead to a voltage dip at the terminals of distributed generation units. When the dip exceeds the immunity level of the units, they will disconnect, leading to a weakening of the system. For a fault at the transmission system, clearing the fault will also lead to a weakening of the system. The safety concerns and the loss of revenue are a matter for the unit operator; they will be taken care of in a local economic optimization. Of importance for the system is that the loss of generation potentially leads to instability and component overload. The voltage drop resulting from the increased system loading may lead to further tripping of distributed generation units.

The most threatening event for the security of a system with a large penetration of distributed generation is the sudden loss of a large (conventional) generation unit. This will lead to a frequency swing in the whole system. The problem is more severe in Scandinavia and in the United Kingdom than in continental Europe because of the size of the interconnected systems. The problem is most severe on small islands. Even with low penetration it is recommended that all generation units remain online with the tripping of a large power station, as such events may happen several times a week. Larger frequency swings occur only once every few

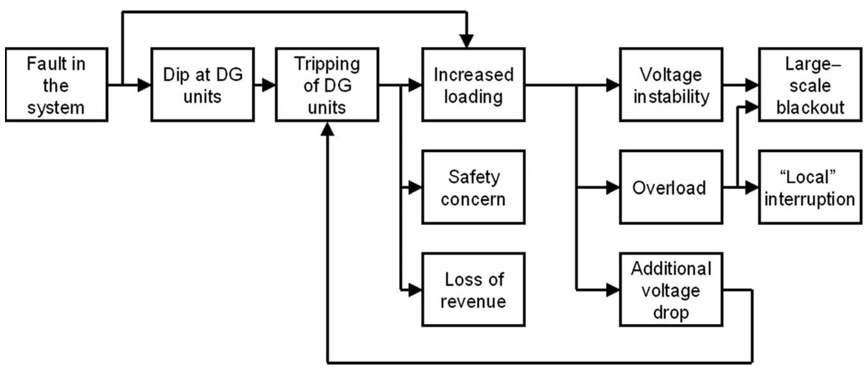

Figure 1.13 Potential consequences of fault or loss of generation in system with large penetration of distributed generation.

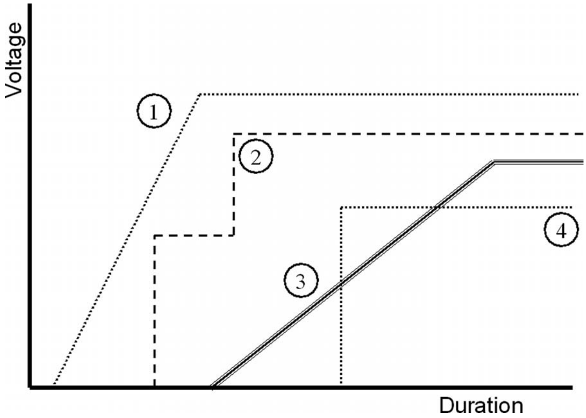

Figure 1.14 Voltage tolerance curves for distributed generation.

years, and there is no economical need for the generator operator to be immune against such a disturbance. However, with a large penetration of distributed generation tripping due to severe events will increase the risk of a blackout.

Several network operators place protection requirements on distributed generation for the maximum tripping time with a given undervoltage. Preventing islanding and the correct operation of the short-circuit protection are typically behind such requirements. Network operators may also prescribe immunity requirements based on system security and reliability concerns. The different types of voltage tolerance curves are plotted together in Figure 1.14:

1. A (future) immunity requirement set by the transmission system operator or by an independent system operator to guarantee that the generators remain connected to the system during a fault in the (transmission) system. This curve is a minimum requirement: The unit is not allowed to be disconnected for any disturbance above or toward the left of this curve.
2. The actual immunity of the generator determined by the setting of the protection. The operator of the unit is free to set this curve within the limitations posed by curves 1, 3, and 4.
3. The limits set by the physical properties of the generator components: thermal, dielectrical, mechanical, and chemical properties. This curve is determined by the design of the unit and the rating of its components. The operator of the generator can only affect this curve in the specification of the unit. Generally speaking, moving this curve to the right will make the unit more expensive.
4. The protection requirements dictated by the distribution system operator to ensure that the generator units will not interfere with the protection of the distribution system. This is a maximum requirement: The unit should trip for every disturbance below and to the right of this curve.

Three coordination requirements follow for these curves:

- Curve 2 should be to the right of curve 1.
- Curve 2 should be to the left of curve 3.
- Curve 2 should be to the left of curve 4.

The condition that curves 3 and 4 should be to the right of curve 1 follows from these requirements. There is no requirement on coordination between curves 3 and 4.

1.8 CONCLUSIONS

Power quality has been introduced as part of the modern, customer-based view on power systems. Power quality shares this view with deregulation and embedded generation. Deregulation and embedded generation are two important reasons for the recent interest in power quality. Other important reasons are the increased emission of disturbances by equipment and the increased susceptibility of equipment, production processes, and manufacturing industry to voltage disturbances.

Power quality has been defined as a combination of voltage and current quality. Voltage and current quality concern all deviations from the ideal voltage and current waveforms, respectively, the ideal waveform being a completely sinusoidal waveform of constant frequency and amplitude. A distinction is made between two types of power quality disturbances: (voltage and current) variations are (quasi-) steady-state disturbances that require or allow permanent measurements or measurements at predetermined instants; (voltage and current) events are disturbances with a beginning and an end, and a triggering mechanism is required to measure them. The difference in processing between variations and events is the basis for the structure of this book.

Signal processing forms an important part in power quality monitoring: the analysis of voltage and current measurements from sampled waveforms to system indices. Signal-processing techniques are needed for the characterization (feature extraction) of variations and events, for the triggering mechanism needed to detect events, and to extract additional information from the measurements.

The IEC EMC standards are based on the coordination of emission and immunity levels by defining a suitable compatibility level. In power system studies, the emission level and the compatibility level are determined by the existing level of disturbances.

A large number of papers have been written on power quality and related subjects. A database search resulted in several thousand hits (see Fig. 1.4). Also several books have been published on this subject. We will come across several papers and most of the books in the remaining chapters of this book. For an excellent overview of the various power quality phenomena and other issues, the reader is referred to the book by Dugan et al. [99]. Other overview books are the ones by Heydt [141], Sankaran [263], and Schlabbach et al. [271]. The latter one was originally published in German. The Swedish readers are referred to the overview book by Gustavsson [134]. Two books directed very much toward practical aspects of power quality monitoring are the *Handbook of Power Signatures* [95] and the *Field Handbook for Power Quality Analysis* [336]. Well-readable overview texts on power quality are also found in a number of IEEE standards—IEEE 1100 [164], IEEE 1159 [165], and IEEE 1250 [167]—and in some general power system books—*The Electric Power Engineering Handbook* [101, Chapter 15]—as well in some of the books from the IEEE Color Book Series.

1.9 ABOUT THIS BOOK

This book aims to introduce the various power quality disturbances and the way in which signal-processing tools can be used to analyze them. The various chapters and their relation are shown graphically in Figure 1.15. The figure shows horizontal as well as vertical lines that group the chapters into related ones. The vertical subdivision corresponds to the subdivision of power quality disturbances in variations and events. Chapters 2, 3, 4, and 5 discuss the most common power quality variations and their processing; Chapters 6, 7, 8, 9, and 10 discuss power quality events and their processing. The horizontal subdivision is based on the tools used and background needed. Chapters 2 and 6 are typical power system or power quality chapters in which the disturbances are described that will be subject to processing in the other chapters. Signal-processing tools and their application to power quality disturbances are described in detail in Chapters 3, 4, 7, 8, and 9. Chapter 5 and 10 use statistical methods for presenting the data resulting from the signal processing. These two

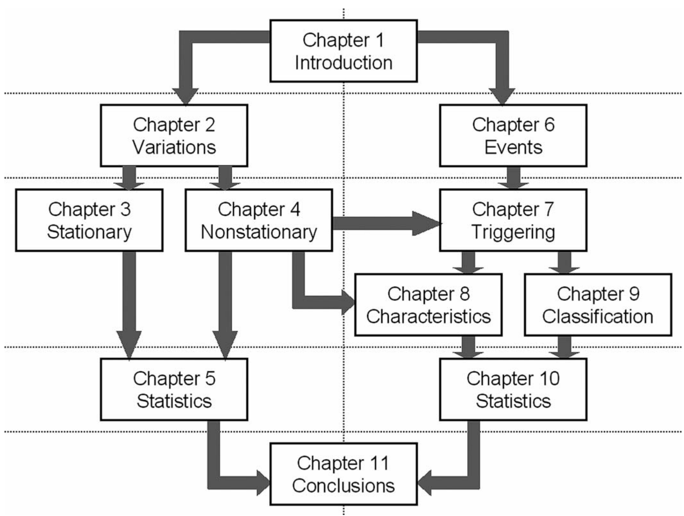

Figure 1.15 Relation between different chapters in this book.

chapters are based on standard methods for statistical processing, extended with some methods under development and proposed in the literature.

Chapter 2 introduces the most common power quality variations: frequency variations, voltage variations, three-phase unbalance, voltage fluctuations leading to light flicker, and waveform distortion (harmonics). Chapter 3 introduces the basic features that are used to quantify the stationary signal waveforms and discusses signal-processing tools for extracting these features that are statistical time invariant. The two most commonly methods, rms and DFT, are discussed next along with some more advanced methods (such as MUSIC, ESPRIT, and Kalman filters) for estimating the spectral contents of a signal. Chapter 3 also introduces power quality indices: quantifiers that indicate the severity of a power quality disturbance. Both features, commonly referred to as characteristics in the power quality field, and indices will play an important part in several chapters. Chapter 4 discusses methods for processing signals that are not stationary, where the statistical characteristics or attributes of the signal are time varying, for example, the mean and variance of the signal are time dependent. The STFT, dyadic structured discrete wavelet transform, and a variety of Kalman filters will be discussed in detail. Block-based processing will be introduced where the signal is divided into blocks (time windows) during which it is assumed to be stationary. The term *quasi-stationary* is often used for this. Some signal-processing methods in Chapter 3 will be modified to form, for example, the sliding-window MUSIC/ESPRIT method and block-based AR modeling. Events are examples of signals that are nonstationary, so that the methods introduced in Chapter 4 will be used later when discussing the processing of power quality events, notably in Chapters 7 and 8. As we will see in Chapter 5 and in some of the examples in Chapters 3 and 4, the measurement of a power quality variation results in a large amount of data: features and indices as a function of time and at different locations. Chapter 5 will discuss methods for obtaining statistics from these data. Methods to be discussed include time aggregation (where the features obtained over a longer window of time are merged into one representative value for the whole window), site indices (quantifying the disturbance level at a certain location over several days, weeks, or even years), and system indices (quantifying the performance of a number of sites or even of a complete system). Chapter 5 will also discuss a number of relevant power quality standards, including IEC 61000-4-30 (power quality monitoring), EN 50160 (voltage characteristics), and IEEE 519 (harmonic limits).

Power quality events, sudden severe disturbances typically of short duration, are the subject of Chapters 6 through 10. The origin of the most common events (interruptions, dips, and transients) is discussed in Chapter 6. The three-phase character of voltage dips plays an important role in this chapter. Many event recordings will be shown to illustrate the various origins of the events. Some early triggering and characterization concepts, to be discussed in more detail in later chapters, will be used in Chapter 6. In Chapter 7 event triggering and segmentation are discussed. Both triggering and segmentation are methods that detect a sudden change in waveform characteristics. The term *triggering* is used to distinguish between events and variations or just to detect the beginning and ending points of events. The term *segmentation* refers to the further subdivision of event recordings. But, as we will see in Chapter 7, both are methods to detect instants at which the signal is nonstationary. The chapter starts with an overview of existing methods followed by a discussion of advanced methods for triggering and segmentations. Among others, wavelet filters and Kalman filters will be treated. Chapters 8 and 9 treat the further processing of event recordings resulting in parameters that quantify individual events. These parameters are generally referred to as *event characteristics* or *single-event indices*. Chapter 8 concentrates on methods to quantify the severity of an event, with magnitude and duration being the most commonly used characteristics for dips, interruptions, and transients. Reference is made to methods prescribed by IEC 61000-4-30 and to methods discussed in IEEE task forces P1159.2 and P1564 and in the International Council on Large Electric Systems (CIGRE) working group C4.07. Chapter 8 further contains a discussion on extracting three-phase characteristics for dips and on methods to characterize voltage and current transients. Chapter 9 treats a special type of event characterization: directed toward finding additional information about the origin of the event. The term *event classification* is used and the chapter concentrates on automatic methods for event classification, including the simplest linear discriminants, to somewhat more sophisticated Bayesian classifiers, Neyman–Pearson approaches, artificial neutral networks, support vector machines, and expert systems. Support vector machines are a relatively new method for power engineering which is based on the statistical learning theory and can be considered as the solution of a constrained optimization problem. Support vector machines provide a great potential for event classification in terms of both their generalization performance (i.e., classification performance on the test set) and their affordable complexity in machine implementation. Chapter 9 also contains an overview of machine learning and pattern classification techniques. Chapter 10 is equivalent to Chapter 5; it discusses methods of presenting the results from monitoring surveys by means of statistical indices. The differences in processing between events and variations make it appropriate to have separate chapters, where Chapter 10 concerns the statistical processing of events. The IEEE standard 1366 is discussed in detail as a method for presenting statistics on supply interruptions, better known as *reliability indices*. The statistical processing of voltage dips is presented as a three-step process: time aggregation, site indices, and system indices. Each chapter contains the main conclusions belonging to the subjects discussed in that chapter. Heavy emphasis is placed in the conclusion sections on gaps in the knowledge that may be filled by further research and development. Chapter 11 presents general conclusions on signal processing of power quality events.

CHAPTER 2

ORIGIN OF POWER QUALITY VARIATIONS

This chapter describes the origin and some of the basic analysis tools of power quality variations. The consecutive sections of the chapter discuss (voltage) frequency variations, voltage (magnitude) variations, voltage unbalance, voltage fluctuations (and the resulting light flicker), and waveform distortion. A summary and conclusions for each of the sections will be given at the end of this chapter.

2.1 VOLTAGE FREQUENCY VARIATIONS

Variations in the frequency of the voltage are the first power quality disturbance to be discussed here. After a discussion on the origin of frequency variations (the power balance) the method for limiting the frequency variations (power–frequency control) is discussed. The section closes with an overview of consequences of frequency variations and measurements of frequency variations in a number of interconnected systems.

2.1.1 Power Balance

Storage of electrical energy in large amounts for long periods of time is not possible, therefore the generation and consumption of electrical energy should be in balance. Any unbalance in generation and production results in a change in the amount of energy present in the system. The energy in the system is dominated by the rotating

Signal Processing of Power Quality Disturbances. By Math H. J. Bollen and Irene Yu-Hua Gu

energy E_{rot} of all generators and motors:

$$E_{\text{rot}} = \tfrac{1}{2} J \omega^2 \tag{2.1}$$

with J the total moment of inertia of all rotating machines and ω the angular velocity at which these machines are rotating. An unbalance between generated power P_g and the total consumption and losses P_c causes a change in the amount of rotational energy and thus in angular velocity:

$$\frac{d\omega}{dt} = \frac{P_g - P_c}{J\omega} \tag{2.2}$$

The amount of inertia is normally quantified through the *inertia constant* H, which is defined as the ratio of the rotational energy at nominal speed ω_0 and a base power S_b:

$$H = \frac{\frac{1}{2} J \omega_0^2}{S_b} \tag{2.3}$$

The base power is normally taken as the sum of the (apparent) rated powers of all generators connected to the system, but the mathematics that will follow is independent of the choice of base power. Typical values for the inertia constant of large systems are between 4 and 6 s.

Inserting (2.3) in (2.2), assuming that the frequency remains close to the nominal frequency, and replacing angular velocity by frequency give the following expression:

$$\frac{df}{dt} = \frac{f_0}{2H}(P_g - P_c) \tag{2.4}$$

where P_g and P_c are per-unit (pu) values on the same base as the inertia constant H.

Consider a 0.01-pu unbalance between generation and production in a system with an inertia constant of 5 s. This leads to a change in frequency equal to 0.05 Hz/s. If there would be a 0.01-pu surplus of generation, the frequency would rise to 51 Hz in 20 s; for a 0.01-pu deficit in generation the frequency would drop to 49 Hz in 20 s. It is very difficult to predict the load with a 1% accuracy. To keep the frequency constant some kind of control is needed.

The sudden loss of a large power station of 0.15 pu will result in a frequency drop of 1 Hz/s. In 1 s the frequency has dropped to 49 Hz. As the sudden unexpected loss of a large generator unit cannot be ruled out, there is obviously the need for an automatic control of the frequency and of the balance between generation and consumption.

For comparison we calculate the amount of electrical and magnetic energy present in 500 km of a 400-kV three-phase overhead line when transporting 1000 MW of active power at unity power factor. Assuming 1 mH/km and

12 nF/km as inductance and capacitance, respectively, gives for the electrical energy $\frac{1}{2}Cu^2 = 320\,\text{kJ}$ and for the magnetic energy $\frac{1}{2}Li^2 = 1040\,\text{kJ}$. For unity power factor the peaks in magnetic and electrical energy (current and voltage) occur at the same time, so that the maximum total electromagnetic energy equals 1360 kJ. As before we can express this as a time constant by dividing with the rated power. For a 1000-MVA base, we find a time constant of 1.4 ms. This is significantly less than the 4- to 6-s time constant for the rotational energy. This example confirms the statement at the start of this section that the energy present in a power system is dominated by the rotational energy of generators and motors.

2.1.2 Power–Frequency Control

To maintain the balance between generation and consumption of electrical energy most large generator units are equipped with power–frequency control. Maintaining the frequency close to its nominal value is a natural consequence of maintaining the balance between generation and consumption. The principle of power–frequency control is rather simple. The measured frequency is compared with a frequency setting (the nominal frequency, 50 or 60 Hz, in almost all cases). When the measured frequency is higher than the nominal frequency, this indicates a surplus of rotational energy in the system. To mitigate this, the generator reduces its active power output. More correctly, the mechanical input to the turbine generator is reduced. This leads after a transient to a new steady state with a lower amount of electrical energy supplied to the system.

The principle of power–frequency control is shown in Figure 2.1. The input to the speed governor is a corrected power setting (corrected for the deviation of the frequency from its setting). We will come back to the choice of the power setting below. The speed governor is a control system that delivers a signal to the steam valves with a thermal power station to regulate the amount of steam that reaches the turbine. The turbine reacts to this, with a certain delay, by changing the amount of mechanical power. Much more detailed models can be found in the literature [e.g, 6, Chapter 10; 26, Chapter 3]. For the purpose of this chapter, it is sufficient to know that there is a time delay of several seconds (10 s and more for large units) between a change in the power signal at the input of the governor and an increase in the mechanical power produced by the turbine. Also note that the speed governor is a

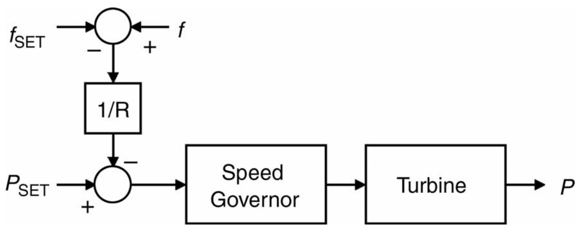

Figure 2.1 Power–frequency control.

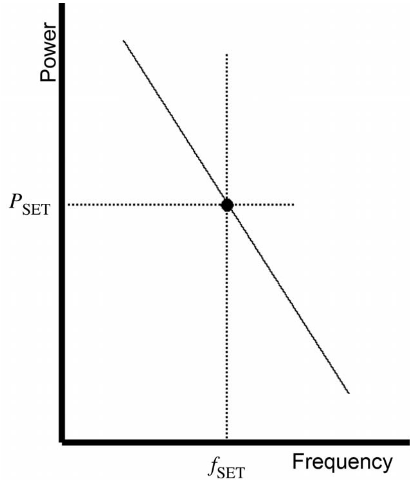

Figure 2.2 Relation between system frequency and amount of power generated by one unit.

controller (its parameters are chosen during the design of the control system) whereas the turbine is a physical system (its parameters cannot be affected).

If we consider the system in steady state, where the production of the generator equals the input signal to the speed governor, the mechanical power is as follows:

$$P = P_{\mathrm{SET}} - \frac{1}{R}(f - f_{\mathrm{SET}}) \tag{2.5}$$

where R is referred to as the *droop setting*. This relation is shown in Figure 2.2. When the system frequency drops, the power production increases. This compensates for the cause of the frequency drop (a deficit of generation). The frequency setting is equal to the nominal frequency of the system and the same for all generators connected to the system. In the Nordic system the frequency should not only be within a certain band but also on average be equal to 50 Hz to ensure that clocks indicate a correct time. When the integrated frequency error (the time difference for a clock) exceeds a certain value, the frequency setting of the generators is slightly changed. But the setting remains the same for all generators.

2.1.2.1 Spinning Reserve To allow for an increase in generated power when there is a deficit of generation, for example, because a large unit has been disconnected from the system, the power produced by a generator should be less than its maximum capacity. The amount of extra power which can be produced in a matter of seconds is called *spinning reserve*. The total spinning reserve in an

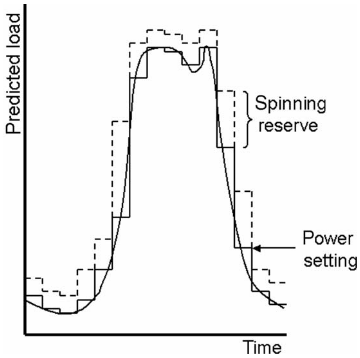

Figure 2.3 Daily load curve (thick solid curve) for a power system, with the sum of generator power settings (thin solid lines) and the spinning reserve (dashed lines).

interconnected system should at least be equal to the largest unit connected to the system. For smaller systems during low load, the spinning reserve should be relatively high. However, in large interconnected systems like the Nordic system or the European interconnected system, a spinning reserve of a few percent is acceptable.

2.1.2.2 Choice of Power Set Point Figure 2.3 shows a hypothetical daily load curve for a system. Such a curve is used to schedule the amount of generation capacity needed. The day is divided into a number of time intervals, typically of 15 to 30 min duration. For each interval the expected load is determined. This required generation is then spread over a number of generator stations. For each time interval the sum of the power settings is chosen equal to the expected load. The actual scheduling is in most countries done by a free-market principle where each generator can place bids. When such a bid is accepted for a certain time block, it will become the power setting of the generator for that block. Even the load is in principle market based, but the distribution companies typically place bids based on the expected consumption of their customers. For example, see [25] for a description of the various market principles.

Also for each time interval a spinning reserve can be decided, but this is typically kept at a fixed percentage of the total power. Even for the spinning reserve and the droop setting market principles can be applied (as discussed, e.g., in [335]).

2.1.2.3 Sharing of Load A change in load, or a change in generation setting, results in a change in generated power for all generator units equipped with power–frequency control. Consider a system with n generators with power setting $P_{\mathrm{i,SET}}$, $i = 1, \ldots, n$; droop setting R_i; and frequency setting f_{SET}. Note that the power setting and the droop setting are different for each unit whereas the frequency setting is the same. The produced power for each generator at a system frequency f is

$$P_i = P_{i,\mathrm{SET}} - \frac{1}{R_i}(f - f_{\mathrm{SET}}) \tag{2.6}$$

The sum of all power settings is equal to the total predicted load:

$$\sum_{i=1}^{n} P_{i,\mathrm{SET}} = P_C \tag{2.7}$$

Assume that the actual load deviates from the predicted load by an amount ΔP_c, so that in steady state

$$P_g = P_c + \Delta P_c \tag{2.8}$$

Combining (2.6), (2.7), and (2.8) gives

$$P_g = \sum_{i=1}^{n} P_i = \sum_{i=1}^{n} P_{i,\mathrm{SET}} + \Delta P_c \tag{2.9}$$

which gives for the steady-state frequency

$$f = f_{\mathrm{SET}} - \frac{\Delta P_c}{\sum_{i=1}^{n}(1/R_i)} \tag{2.10}$$

The increase in consumption causes the system frequency to drop by an amount determined by the power–frequency control settings of all the generators that contribute. Each generator contributes to the increase in consumption by ratio of the inverse of its droop setting:

$$P_k = P_{k,\mathrm{SET}} + \frac{1/R_k}{\sum_{i=1}^{n}(1/R_i)}\Delta P_c \tag{2.11}$$

The droop setting is normally a constant value in per unit with the generator rating as a base. For a generator of rated power S and per-unit droop setting R_{pu}, the droop setting in hertz per megawatt is

$$R_k = R_{\mathrm{pu}}\frac{f_{\mathrm{SET}}}{S} \tag{2.12}$$

with typically $f_{\mathrm{SET}} = f_0$, the nominal frequency. The new steady-state frequency is obtained from inserting (2.12) in (2.10) under the assumption that the per-unit droop setting is the same for all units:

$$f = f_{\mathrm{SET}} - \frac{\Delta P_c}{\sum_{i=1}^{n} S_k} R_{\mathrm{pu}} f_{\mathrm{SET}} \tag{2.13}$$

The relative drop in frequency is equal to the relative deficit in generation times the per-unit droop setting:

$$\frac{\Delta f}{f_{\mathrm{SET}}} = -\frac{\Delta P_c}{\sum_{i=1}^{n} S_i} R_{\mathrm{pu}} \tag{2.14}$$

Each generator contributes by the ratio of its rated power to any deficit in generation:

$$P_k = P_{k,\mathrm{SET}} + \frac{S_k}{\sum_{i=1}^{n} S_i} \Delta P_c \tag{2.15}$$

Thus large generators contribute more than small generators. This calls for a spinning reserve which is a fixed percentage of the rated power of the generator unit.

2.1.3 Consequences of Frequency Variations

As far as the authors are aware, no equipment problems are being reported due to frequency variations. Still some of the consequences and potential problems are mentioned below.

2.1.3.1 Time Deviation of Clocks Clocks still often synchronize to the voltage frequency (typically by counting zero crossings). A consequence of frequency variations is therefore that clocks will show an erroneous time. The size of the error depends on the deviation of the frequency from the nominal frequency.

Consider a system with nominal frequency f_0 and actual frequency $f(t)$. The number of zero crossings in a small time Δt is

$$\Delta n_{\mathrm{zc}} = 2f(t)\,\Delta t \tag{2.16}$$

Note that there are two zero crossings per cycle. In a long period T (e.g., one day), the number of zero crossings is

$$N_{\mathrm{zc}} = \int_0^T 2f(t)\,dt \tag{2.17}$$

Because the clock assumes a frequency f_0, the apparent elapsed time is

$$T + \Delta T = \frac{N_{\mathrm{zc}}}{2f_0} \tag{2.18}$$

From (2.17) and (2.18) the time error ΔT is obtained as

$$\Delta T = \int_0^T \frac{f(t) - f_0}{f_0} \, dt \qquad (2.19)$$

A frequency of 50.05 Hz instead of 50 Hz will cause clocks to run 0.1% faster. This may not appear much, but after one day the deviation in clocks is $0.001 \times 3600 \times 24 = 86.4$ s. Thus 0.05 Hz frequency deviation causes clocks to have an error of over 1 min per day. A frequency equal to 50.5 Hz (1% deviation) would cause clocks to be 15 min ahead after one day.

2.1.3.2 Variations in Motor Speed Also the speed of induction motors and synchronous motors is affected when the voltage frequency changes. But as the frequency does not vary more than a few percent, these speed variations are hardly ever a problem. Very fast fluctuations in frequency could cause mechanical problems, but in large interconnected systems the rate of change of frequency remains moderate even for large disturbances. Variations in voltage magnitude will have a bigger influence.

2.1.3.3 Variations in Flux Lower frequency implies a higher flux for rotating machines and transformers. This leads to higher magnetizing currents. The design of rotating machines and transformers is such that the transition from the linear to the nonlinear behavior (the "knee" in the magnetic flux-field, B-H, curve) is near the maximum normal operating flux. An increase of a few percent in flux may lead to 10% or more increase in magnetizing current. But the frequency variation is very rarely more than 1%, whereas several percent variations in voltage magnitude occur daily at almost any location in the system. One percent drop in frequency will give the same increase in flux as 1% rise in voltage magnitude. Where saturation due to flux increase is a concern, voltage variations are more likely to be the limiting factor than frequency variations.

2.1.3.4 Risk of Underfrequency Tripping Larger frequency deviations increase the risk of load or generator tripping on overfrequency or on underfrequency. Overfrequency and underfrequency relays are set at a fixed frequency to save the power system during very severe disturbances like the loss of a number of large generating units. The most sensitive settings are normally for the underfrequency relays. In some systems the first level of underfrequency load shedding occurs already for 49.5 Hz, although 49 Hz is a more common setting. The loss of a large generator unit causes a fast drop in frequency due to the sudden deficit in generation followed by a recovery when the power–frequency control increases the production of the remaining units. The maximum frequency deviation during such an event is rather independent of the preevent frequency. Thus when the preevent frequency is lower, the risk of an unnecessary underfrequency trip increases.

Generally speaking large frequency variations point to unbalance between generation and (predicted) consumption. As long as this unbalance is equally spread over the system, it is of limited concern for the operation of the system. As shown in Section 2.1.2 the daily load variations are spread equally between all generator units that contribute to power–frequency control. However, fast fluctuations in frequency (time scales below 1 min) point to a shorter term unbalance that is associated with large power flows through the system. These fluctuating power flows cause a higher risk of a large-scale blackout.

Distributed generation has also become a concern with frequency variations. Most units are equipped with underfrequency and overfrequency protection. The underfrequency protection is the main concern as this is due to lack of generation. Tripping of distributed generation units will aggravate the situation even more.

2.1.3.5 Rate of Change of Frequency Some equipment may be affected more by the rate of change in frequency than by the actual deviation from the nominal frequency. Any equipment using a phase-locked loop (PLL) to synchronize to the power system frequency will observe a phase shift in the voltage during a fast change in frequency. The design of a PLL is a tradeoff between speed (maximum rate of change of frequency) and accuracy (frequency deviation in the steady state).

Distributed generation is often equipped with a ROCOF (rate-of-chance-of-frequency) relay to detect islanding. These relays are reportedly also sensitive to the frequency drop caused by the tripping of a large generator unit.

No statistical measurement data are available on the rate of change of frequency, but it is possible to estimate expected values based on a knowledge of the underlying phenomenon. A large rate of change of frequency occurs during the loss of a large generator unit. The resulting unbalance between generation and consumption causes a drop in frequency in accordance with (2.4):

$$\frac{df}{dt} = 0.05p \qquad \text{Hz/s} \tag{2.20}$$

with p the size of the largest unit as a fraction of the system size during low load. This does not mean that larger values of the rate of change of frequency are not possible, but they will only occur during the loss of more than one large unit at the same time. Such a situation has a much lower probability than the loss of one large unit. Also such a situation will severely endanger the survival of the system so that power quality disturbances become of minor importance. Some examples of fast changes in frequency will be shown in Section 5.3.2.

2.1.4 Measurement Examples

Examples of measured frequency variations are shown in Figures 2.4 and 2.5. As was explained in the earlier parts of this section, frequency variations are the same throughout an interconnected system and are related to the relative unbalance between generation and load and to power–frequency control. Generally speaking,

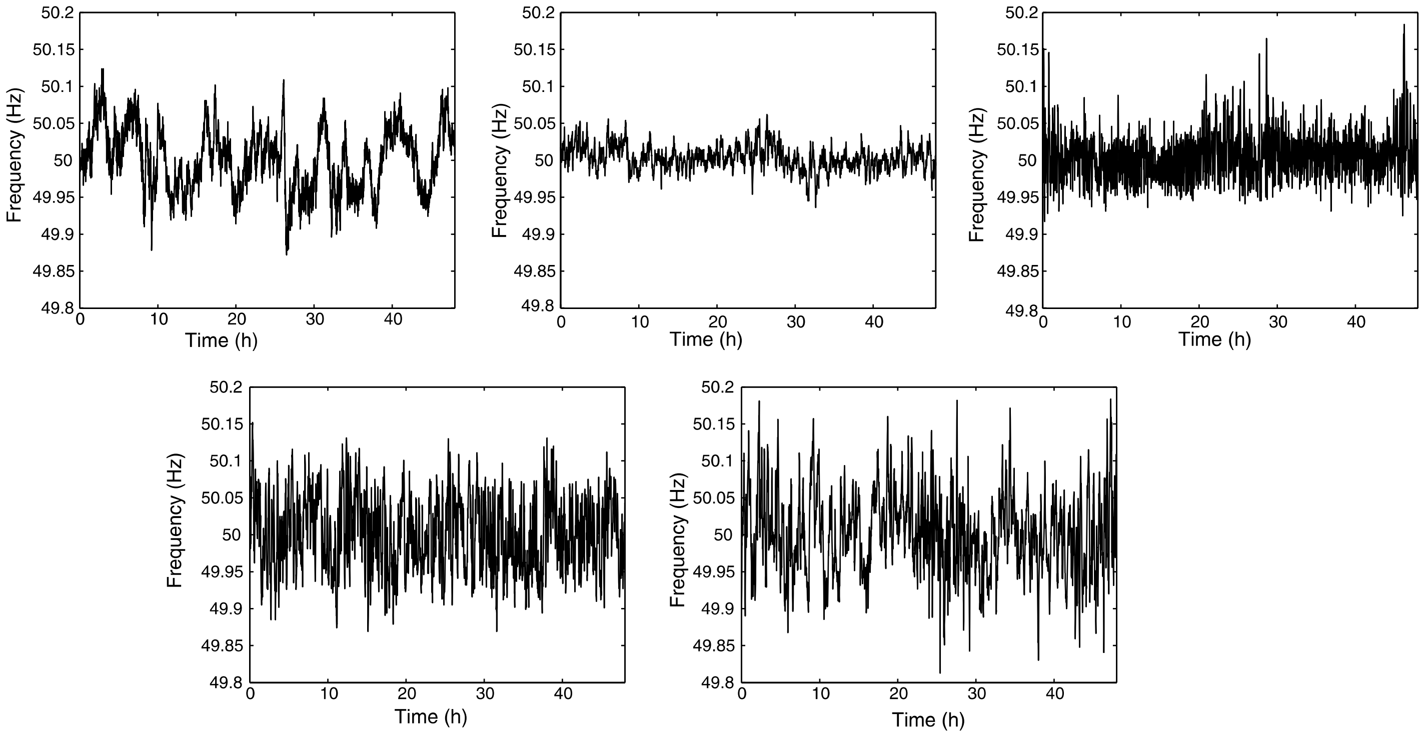

Figure 2.4 Frequency variations measured in Sweden (top left), in Spain (top center), on the Chinese east coast (top right), in Singapore (bottom left), and in Great Britain (bottom right).

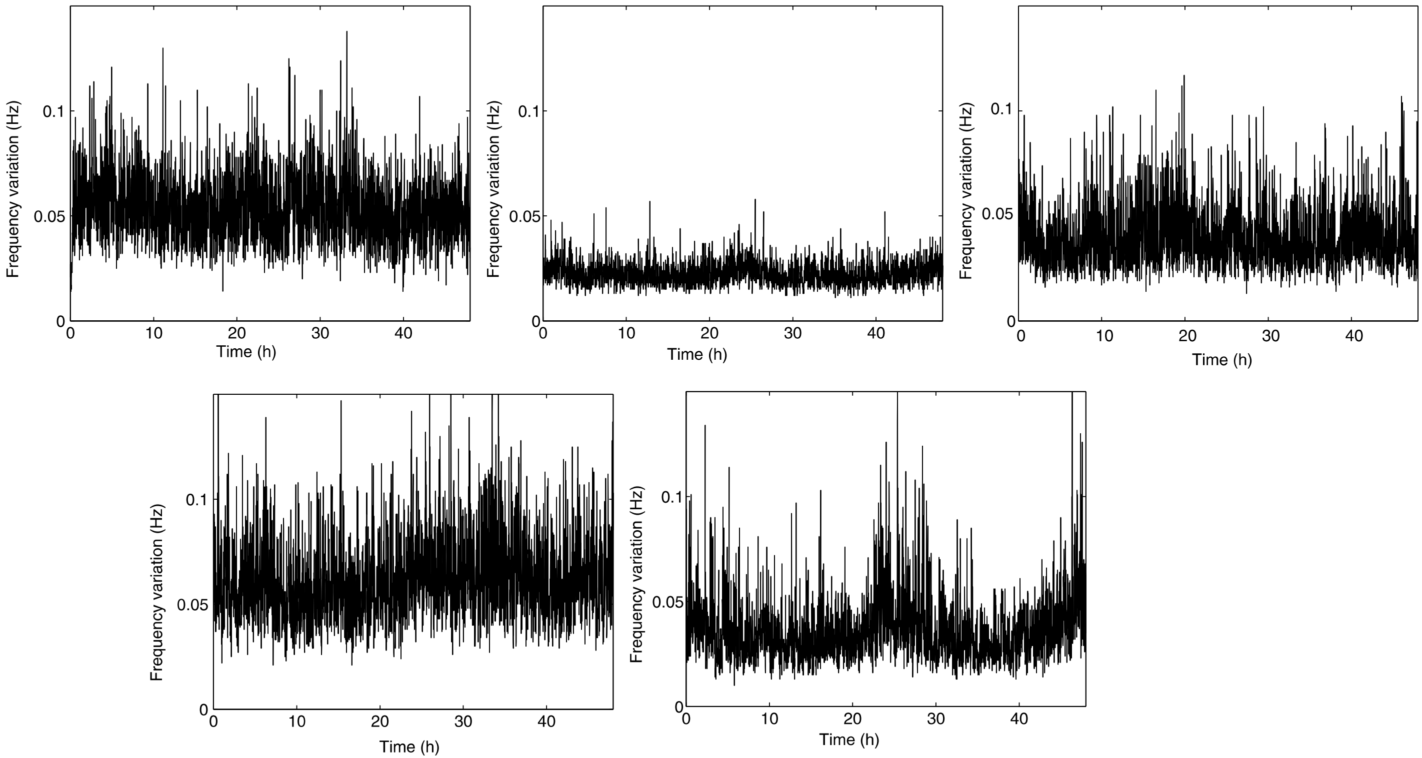

Figure 2.5 Range in frequency during 1 min measured in Sweden (top left), in Spain (top center), on the Chinese east coast (top right), in Singapore (bottom left), and in Great Britain (bottom right).

the larger the system, the less the frequency variations. The data presented here were collected at five different locations in five different interconnected systems. Figure 2.4 gives the 1-min average frequency during a two-day (48-h) period, whereas Figure 2.5 gives the spread in frequency during each 1-min period. One may say that the first figure shows slow variations in frequency and the second figure the fast variations. Spain is part of the European interconnected system, one of the largest in the world. As expected, the range in frequency is small in this system and so are the fast variations. The Chinese system is smaller but still larger than the Nordic system (consisting of Norway, Sweden, Finland, and part of Denmark). Singapore and Great Britain are relatively small systems, which is visible from the relatively large variations in frequency.

The different systems show different patterns in variations, both at longer and at shorter time scales. These differences are related to the size of the system and to the control methods used. It should be noted, however, that in none of the systems presented here are the frequency variations of any concern.

2.2 VOLTAGE MAGNITUDE VARIATIONS

This section will discuss slow variations in the magnitude of the voltage. The section will start with an overview of the impact of voltage variations on end-user equipment followed by a discussion of several expressions to estimate voltage drops in the system. Expressions will be derived for a concentrated load and for load distributed along a feeder. The impact of distributed generation on voltage variations will also be discussed. The section concludes with an overview of voltage control methods, with transformer tap changers and capacitor banks being discussed in more detail.

2.2.1 Effect of Voltage Variations on Equipment

Voltage variations can effect the performance and the lifetime of the equipment. Some examples are as follows:

1. Any overvoltage will increase the risk of insulation failure. This holds for system components such as transformers and cables as well as for end-user equipment such as motors. This is obviously a long-term effect and in most cases not significant. Note, however, that a higher voltage during normal operation increases the base from which transient overvoltages start. This increases the peak voltage and thus the risk of insulation failure. Again this is probably an insignificant effect.
2. Induction motors:
   - Undervoltages will lead to reduced starting torque and increased full-load temperature rise. The reduced starting torque may significantly increase the time needed to accelerate the motor. In some cases the motor may not accelerate at all: It will “stall.” The stalled motor will take a high current

but will not rotate (it becomes a short-circuited transformer). If a stalled motor is not removed by the protection, it will overheat very quickly. The further reduced voltage due to the high current taken by the stalled motor may lead to stalling of neighboring motors. Stalling normally does not occur until the voltage has dropped to about 70% of nominal.

- Overvoltages will lead to increased torque, increased starting current, and decreased power factor. The increased starting torque will increase the accelerating forces on couplings and driven equipment. Increased starting current also causes greater voltage drop in the supply system and increases the voltage dip seen by the loads close to the motor. Although the motor will start quicker, its effect on other load may be more severe.

3. Incandescent lamps: The light output and life of such lamps are critically affected by the voltage. The expected life length of an incandescent lamp is significantly reduced by only a few percent increase in the voltage magnitude. The lifetime somewhat increases for lower-than-nominal voltages, but this cannot compensate for the decrease in lifetime due to higher-than-nominal voltage. The result is that a large variation in voltage leads to a reduction in lifetime compared to a constant voltage.
4. Fluorescent lamps: The light output varies approximately in direct proportion to the applied voltage. The lifetime of fluorescent lamps is affected less by voltage variation than that of incandescent lamps.
5. Resistance heating devices: The energy input and therefore the heat output of resistance heaters vary approximately as the square of the voltage. Thus a 10% drop in voltage will cause a drop of approximately 20% in heat output.
6. An undervoltage will lead to an increased duty cycle for any equipment that uses a thermostat (heating, refrigerating, air conditioning). The result is that the total current for a group of such devices will increase. Even though individual heaters behave as a constant-resistance load, a group of them behave as constant-power loads. This phenomenon is one of the contributing factors to voltage collapse.
7. Electronic equipment may perform less efficient due to an undervoltage. The equipment will also be more sensitive to voltage dips. A higher-than-nominal voltage will make the equipment more sensitive to overvoltages. As the internal voltage control maintains the application voltage at a constant level (typically much lower than the 110 through 230 V mains voltage), a reduction in terminal voltage will lead to an increase in current which gives higher losses and reduced lifetime.
8. Transformers: A higher-than-nominal voltage over the transformer terminals will increase the magnetizing current of a transformer. As the magnetizing current is heavily distorted, an increase in voltage magnitude will increase the waveform distortion.

2.2.2 Calculation of Voltage Magnitude

The voltage as considered in this section is the rms value of a sinusoidal voltage waveform. We will neglect all distortion, so that the voltage waveform is described as

$$u(t) = \sqrt{2}u \cos(2\pi f_0 t) \tag{2.21}$$

where u is the rms voltage and f_0 the voltage frequency. The time axis is chosen such that the phase angle of the voltage is zero. In any system it is possible to set the phase angle to zero for one of the voltages or currents without loss of generality. Voltage magnitude variations, or simply *voltage variations*, are variations in the value of U.

Note that in (2.21) the phase angle of the voltage is defined relative to the voltage maximum. More typically in power engineering, the phase angle is defined relative to the upward zero crossing. The zero crossing is easier to detect than the maximum. The *power system definition* would imply a sine function instead of cosine. The cosine function however fits better with the complex notation used for the calculations. The choice of reference does not affect the calculations as only phase *differences* have any physical meaning.

For calculations of the voltage magnitude, the complex notation is most often used. The voltage is written as the real part of a complex function of time:

$$u(t) = \mathrm{Re}\{\underline{U}\, e^{j2\pi f_0 t}\} \tag{2.22}$$

where $\underline{U} = Ue^{j\theta}$ is referred to as the *complex voltage* or simply the voltage where confusion is unlikely. In the same way a complex current can be calculated. A complex impedance is defined as the ratio between complex voltage and complex current. Complex power is defined as the product of complex voltage and the complex conjugate of the current. See any textbook on electric circuit theory for more details.

2.2.2.1 Thevenin Source Model To model the effect of a certain load on the voltage, the power system is represented through a Thevenin source: an ideal voltage source behind a constant impedance, as shown in Figure 2.6, with $\underline{E}$ the no-load voltage and $\underline{Z}$ the source impedance.

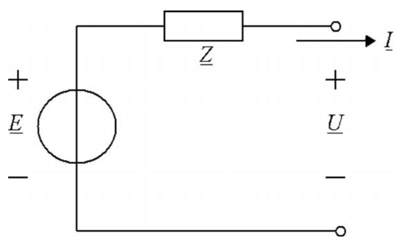

Figure 2.6 Power system with load.

Thevenin's theorem states that any linear circuit, at its terminals, can be modeled as a voltage source behind an impedance. This holds for any location in the power system. The term *no-load voltage* does not imply that the load of the power system is neglected. It only refers to the loading of the Thevenin equivalent at the location under consideration. All other load is incorporated in the source model, that is, in the source voltage and the source impedance. Note also that the model in Figure 2.6 is a mathematical model. The source impedance $\underline{Z}$ and the source voltage $\underline{E}$ are not physical quantities. However, the values can often be approximated by physical quantities, for example, the impedance of a transformer and the voltage on primary side of the transformer.

2.2.2.2 Changes in Voltage Due to Load Consider the Thevenin model in Figure 2.6 for the source at the load terminals. The following relation holds between the load voltage and the no-load voltage:

$$\underline{U} = \underline{E} - \underline{ZI} \tag{2.23}$$

The complex power delivered to the load is

$$\underline{S} = \underline{UI}^* = P + jQ \tag{2.24}$$

with P the active power and Q the reactive power. Taking the load voltage along the positive real axis (so that $\underline{U} = U$) gives the following expression for the current as a function of the active and reactive power:

$$\underline{I} = \frac{P - jQ}{U} \tag{2.25}$$

This results in the following expression for the *complex voltage drop*, $\underline{U}_\Delta = \underline{E} - \underline{U}$:

$$U\underline{U}_\Delta = RP + XQ + j(XP - RQ) \tag{2.26}$$

The *scalar voltage drop* or simply the voltage drop is defined as the difference in absolute value between the no-load and the load voltage:

$$\Delta U = |\underline{E}| - |\underline{U}| = |U + \underline{U}_\Delta| - U \tag{2.27}$$

Inserting (2.26) for the complex voltage drop gives the following expression for the (scalar) voltage drop due to active and reactive power:

$$\frac{\Delta U}{U} = \sqrt{\left(1 + \frac{RP + XQ}{U^2}\right)^2 + \left(\frac{XP - RQ}{U^2}\right)^2} - 1 \tag{2.28}$$

Note that this expression cannot be used to calculate the voltage U, as this variable appears on both sides of the equal sign. It is possible to derive a closed expression for U, but this is outside of the scope of this book. Expression (2.28) can however be used to calculate the magnitude of the no-load voltage E in case the voltage at the load terminals U is known. The expression can thus be used to calculate the rise in voltage due to a reduction in load. If we linearize the relation between power and voltage, the voltage drop due to a load increase will be the same as the voltage rise due to a load decrease. The expression (2.28) could be used as an approximation for calculating the voltage drop due to a load increase. We will however obtain more practical approximated expressions for this in the next section.

2.2.2.3 Approximated Expressions In the previous section an exact expression has been derived for the voltage drop due to a load $P + jQ$. Such an exact expression will however not be used often. This is partly due to the complexity of the expression, even for such a simple case. Additionally, there are rarely any situations where active and reactive power are exactly known. Both active and reactive power are typically a function of the applied voltage, so that the "exact expression" remains an approximation after all. Therefore simplified but practical expressions are used to estimate the voltage drop.

The first-order approximation of (2.28) is obtained by replacing the square and the square root as their first-order approximations:

$$(1 + x)^2 \approx 1 + 2x \tag{2.29}$$

$$\sqrt{1 + x} \approx 1 + \tfrac{1}{2}x \tag{2.30}$$

The result is the following simple expression for the voltage drop due to active and reactive power flow:

$$\Delta U = \frac{RP + XQ}{U} \tag{2.31}$$

With θ the angle between voltage and current, we get

$$\Delta U = RI \cos\theta + XI \sin\theta \tag{2.32}$$

Expressions (2.31) and (2.32) are commonly used expressions for the voltage drop due to a load. As in most cases the voltage drop is limited to a few percent, this approximation is acceptable. Note that the same expression can be obtained by neglecting the imaginary part in (2.26), which is the normal derivation [193, p. 39].

Including second-order terms, we can make the following approximations:

$$(1 + x)^2 = 1 + 2x + x^2 \tag{2.33}$$

and

$$\sqrt{1+x} \approx 1 + \tfrac{1}{2}x - \tfrac{1}{8}x^2 \tag{2.34}$$

This results in the following second-order approximation for the voltage drop due to a load:

$$\Delta U = \frac{RP + XQ}{U} + \frac{3}{8}\frac{(RP + XQ)^2}{U^3} + \frac{1}{2}\frac{(XP - RQ)^2}{U^3} \tag{2.35}$$

For a small voltage drop we can also find an approximated expression for the change in phase angle. From (2.26) we find for the change in phase angle

$$\Delta\phi = \arctan\left(\frac{\mathrm{Im}(\underline{U}_\Delta)}{U + \mathrm{Re}(\underline{U}_\Delta)}\right) = \arctan\left(\frac{XP - RQ}{U^2 + RP + XQ}\right) \tag{2.36}$$

Using $\arctan x \approx x$, $U \approx 1\,\mathrm{pu}$, and $RP + XQ \ll 1$, we get the following approximation:

$$\Delta\phi \approx XP - RQ \tag{2.37}$$

Note that these expressions only give the change in voltage at a certain location due to the current at this location. Two possible applications are the daily voltage variation due to the daily load variation and the step in voltage due to a step in load current.

2.2.2.4 Three Phases; Per Unit

The calculations before were done for a single-phase system. For a three-phase system we will consider balanced operation: Voltages and currents form a three-phase balanced set of phasors. Unbalanced voltages will be discussed in Section 2.3. For balanced operation the three-phase voltages can be written as follows in the time domain:

$$\begin{aligned} u_a(t) &= \sqrt{2}\,U\cos(2\pi f_0 t) \\ u_b(t) &= \sqrt{2}U\cos\left(2\pi f_0 t - \frac{2\pi}{3}\right) \\ u_c(t) &= \sqrt{2}U\cos\left(2\pi f_0 t + \frac{2\pi}{3}\right) \end{aligned} \tag{2.38}$$

where the voltage in phase a has been used as a reference, resulting in a zero phase angle. The earlier expressions give the drop in phase voltage. The drop in line voltage is obtained by multiplying with $\sqrt{3}$. One should note, however, that P and Q in the earlier expressions are active and reactive power per phase. Let P_3

and Q_3 be the total active and reactive power, respectively. This results in the following approximated expression for the drop in line voltage:

$$\Delta U_{\text{line}} = \frac{RP_3 + XQ_3}{U_{\text{line}}} \tag{2.39}$$

Expressing all quantities in per-unit with a base equal to the nominal voltage results in the following well-known expression for the voltage drop in a three-phase system:

$$\Delta U = RP + XQ \tag{2.40}$$

where it has been assumed that the voltage is close to the nominal voltage.

2.2.2.5 Voltage Drop Along a Feeder Consider a low-voltage feeder with distributed load, as shown in Figure 2.7. The active and reactive load density at any location s along the feeder is denoted by $p(s)$ and $q(s)$, respectively. The total active and reactive power downstream of location s is denoted by $P(s)$ and $Q(s)$, respectively. These latter powers determine the current and thus the voltage drop. From Figure 2.7 the following difference equations are obtained:

$$P(s + \Delta s) = P(s) + p(s)\,\Delta s \tag{2.41}$$

$$Q(s + \Delta s) = Q(s) + q(s)\,\Delta s \tag{2.42}$$

$$U(s + \Delta s) = U(s) + r\frac{P(s)}{U_0}\Delta s + x\frac{Q(s)}{U_0}\Delta s \tag{2.43}$$

where $r + jx$ is the feeder impedance per unit length and all quantities are given in per unit. The approximation in (2.43) holds for small variations in voltage around U_0. If $U(s)$ is used instead of U_0, a nonlinear differential equation results, which

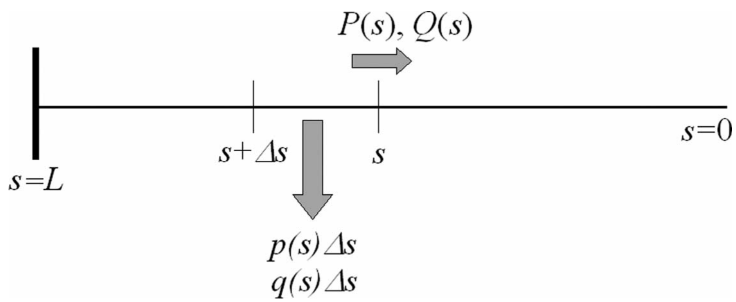

Figure 2.7 Feeder with distributed load or generation.

is difficult to solve analytically. Alternatively, (2.43) can be obtained by considering constant-current load instead of constant-power load.

Taking the limit transition $\Delta s \to 0$ in (2.41) through (2.43) gives a set of three differential equations:

$$\frac{dP}{ds} = p(s) \tag{2.44}$$

$$\frac{dQ}{ds} = q(s) \tag{2.45}$$

$$\frac{dU}{ds} = \frac{1}{U_0}[rP(s) + xQ(s)] \tag{2.46}$$

Differentiation (2.46) and inserting (2.44) and (2.45) result in a second-order differential equation (if $r + jx$ is constant along the distance s):

$$\frac{d^2U}{ds^2} = \frac{1}{U_0}[rp(s) + xq(s)] \tag{2.47}$$

with boundary conditions

$$\frac{dU(0)}{ds} = 0 \tag{2.48}$$

$$U(L) = U_0 \tag{2.49}$$

The first boundary condition results from the fact that there is no load beyond the end of the feeder; the second one states that the voltage at the start of the feeder is known.

For a given load distribution $p(s)$, $q(s)$ the voltage profile along the feeder can be obtained. The case commonly studied in power system textbooks is uniformly distributed load along the feeder [e.g., 322]:

$$p(s) = p_0 \tag{2.50}$$

$$q(s) = q_0 \tag{2.51}$$

Combining (2.50) and (2.51) with (2.47) through (2.49) results in an expression for the voltage profile along a uniformly loaded feeder:

$$U(s) = U_0 - \frac{rp_0 + xq_0}{2U_0}(L^2 - s^2) \tag{2.52}$$

The voltage at the end of the feeder (i.e., the lowest voltage in case p_0 and q_0 are both positive) is equal to

$$U(L) = U_0 - \frac{rp_0 + xq_0}{2U_0} L^2 \tag{2.53}$$

Note that s decreases from $s = L$ to $s = 0$ when going downstream along the feeder. From (2.53) an expression can be derived for the maximum feeder length under a minimum-voltage constraint:

$$L_{\max} = U_0 \sqrt{\frac{2}{rp_0 + xq_0} \times \frac{\Delta U_{\max}}{U_0}} \tag{2.54}$$

with $\Delta U_{\max}$ the maximum voltage drop along the feeder.

2.2.3 Voltage Control Methods

The voltage in the transmission network is controlled in a number of ways:

- The generator units control the voltage at their terminals through the field voltage.
- Shunt capacitor banks at strategic places in the transmission and subtransmission network compensate for the reactive power taken by the loads. In this way the reactive power in the transmission network is kept low. As the reactance of transmission lines dominates, the voltage drop is mainly due to the reactive power. Shunt capacitor banks will be discussed in Section 2.2.3.2.
- Series capacitor banks compensate for the reactance of long transmission lines. This limits the voltage drop due to the reactive power. Series capacitor banks also improve the stability of the system.
- Shunt reactors are used to compensate for the voltage rise due to long unloaded transmission lines or cables.

The voltage in the distribution network is controlled in a number of ways:

- By limiting the length of feeders (cables and lines). Note that the customer location cannot be affected by the design of the distribution network, so a given feeder length immediately implies a given amount of load. The relations between voltage drop limits and feeder length are discussed in Section 2.2.2.
- At a low voltage level the cross section of the feeder can be increased to limit the voltage drop.
- By installing transformer tap changers. Here one should distinguish between on-load tap changers and off-load tap changers. Both will be discussed in Section 2.2.3.1.

- Long distribution lines are sometimes equipped with series capacitor banks.
- Shunt capacitor banks are in use with large industrial customers, mainly to compensate for reactive power taken by the load. This also limits the voltage drop due to the load.
- For fast-fluctuating loads highly controllable sources of reactive power are used to keep the voltage constant. Examples are synchronous machines running at no load and static var compensators (SVCs).

2.2.3.1 Transformer Tap Changers The transformation steps from the transmission network to the load typically consist of an high-voltage/medium-voltage (HV/MV) transformer with a relatively large impedance (15 to 30%) and an MV/low-voltage (LV) transformer with a small impedance (4 to 5%). Without any countermeasures the load variation would cause voltage variations of 10% and more over the HV/MV transformer. Together with the voltage variations due to cables or lines, due to the MV/LV transformer, plus the voltage variations in the transmission network and on the premises of the customer, the final load variation would be unacceptable.

The most common way of limiting the voltage variations is by installing on-load tap changers on the HV/MV transformers. The transformation from HV to MV sometimes takes place in two or more steps. In that case typically all these steps are equipped with on-load tap changers. For varying primary voltage and varying load, the voltage on the secondary side can be controlled by changing the turns ratio of the transformer. This enables compensation of the voltage variations in the transmission system and the voltage drop over the transformer. A typical range is $\pm 16\%$ of the nominal voltage for a total of 2×16 stages of 1% each [1].

To understand the method for voltage control, consider the voltage profile along the distribution system, as shown in Figure 2.8 for low load (top) and high load

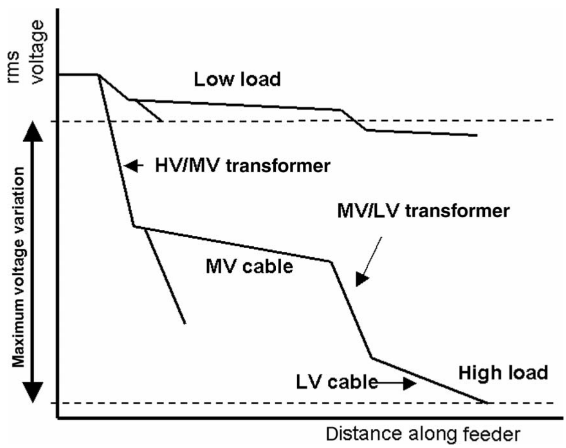

Figure 2.8 Voltage profile in distribution system without voltage control.

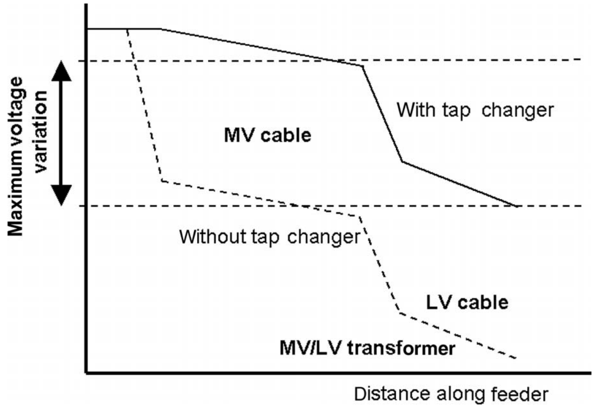

Figure 2.9 Effect of on-load tap changers on voltage profile in distribution system.

(bottom). This is based on the distribution network as described above. The upper horizontal dashed line indicates the highest voltage for a customer close to the main substation. The lower dashed line gives the lowest voltage for a customer far away from the main substation. The difference between the two lines should be less than the permissible voltage range.

Assume that the permissible voltage range during the design stage is from 215 to 245 V. The design and control of the system should be such that the highest voltage is less than 245 V for the customer nearest the main substation. Also the lowest voltage should be above 215 V for the most remote customer. This will be very difficult without seriously restricting the maximum feeder length and the loading of the transformers.

The result of using an on-load tap changer is a constant voltage on the secondary side of the transformer. The effect on the voltage profile is shown in Figure 2.9. The voltage variation has decreased significantly. It becomes easier to keep the voltage variation within the permissible range. Alternatively, cable length can be longer so that more customers can be supplied from the same transformer. This limits the number of transformers needed. Note that the number of transformers needed is inversely proportional to the square of the feeder length.

The transformer tap changers are equipped with a delay to prevent them from reacting too fast. This delay varies between a few seconds and several minutes depending on the application. The resulting voltage variation due to a step in load current is shown in Figure 2.10. Transformer tap changers are not able to mitigate fast changes in voltage. They do however result in a constant voltage at a time scale of minutes.

For large transformers it is worth using *on-load tap changers*. But for smaller transformers, the costs become too high, simply because there are too many of them. Distribution transformers (10 kV/400 V) are typically equipped with *off-load tap changers*. As the relative impedance is only a few percent, there is also

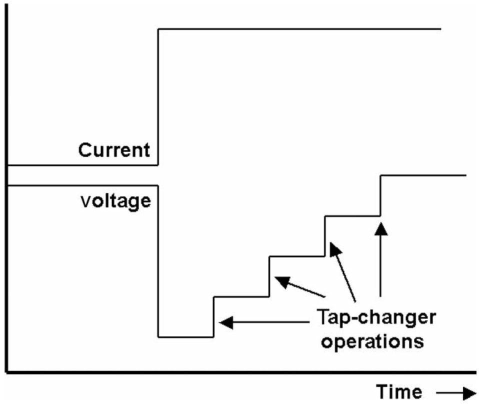

Figure 2.10 Voltage variation due to a load step.

less need for voltage control. With off-load tap changers the transformer has a number of settings for the turns ratio. But the setting can only be changed when the transformer is not energized. The tap changer typically covers a band of $\pm 5\%$ around the nominal voltage. The taps are changed off load (i.e., when the transformer is disconnected from the system) in 2×2 stages of 2.5% each [1]. For example, a 10-kV/400-V transformer has tap settings of 10.5, 10.25, 10, 9.75, and 9.5 kV on the primary side. The secondary side nominal voltage is 400 V in all cases.

A smaller turns ratio (larger secondary voltage, smaller primary voltage) can be used for transformers near the end of a long feeder. The resulting voltage profile is shown in Figure 2.11, where the dotted line indicates the voltage profile with off-load tap changers. The use of off-load tap changers leads to a further decrease

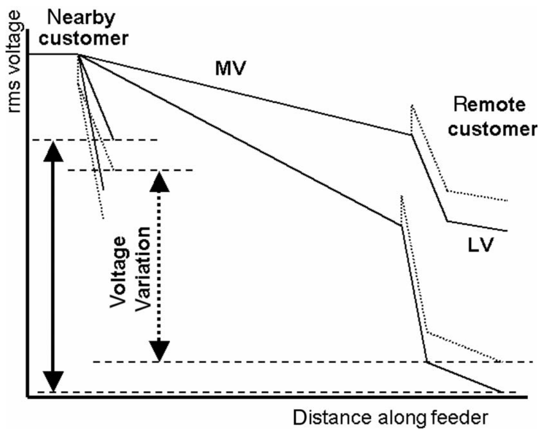

Figure 2.11 Effect of off-load tap changers on voltage profile in distribution system.

in the voltage variation. Alternatively, longer feeder lengths are possible without exceeding the voltage limits.

2.2.3.2 Shunt Capacitor Banks Another common way of controlling the voltage is by installing shunt capacitor banks. By reducing the reactive power, the voltage drop is reduced. Capacitor banks can be installed at different voltage levels. In industrial systems they are often installed at low voltage, close to the equipment to limit the voltage drops in the distribution system. Industrial customers are often given financial incentives to limit their reactive power consumption, for example, by charging for kilovar-hours next to kilowatt-hours. In public supply networks capacitor banks are used in distribution and subtransmission substations. Installing a capacitor bank at a distribution substation limits the voltage drop over the HV/MV transformer and improves the voltage profile of the transmission system. In Sweden capacitor banks in the distribution and subtransmission networks are used to prevent voltage collapse in the transmission system. The distribution networks on average export reactive power to the transmission network.

A disadvantage of shunt capacitor banks is the voltage steps that arise when switching them. Energizing the bank may also lead to a transient overvoltage and the bank may create a resonance for harmonic currents produced by the load. Harmonic resonance and energizing transients will be discussed in Sections 2.5 and 6.3, respectively.

The voltage step when the capacitor is connected to the system can be calculated from the capacitor size Q (in Mvar) and the fault level of the source S_k (in MVA). The reactive power consumption of the capacitor bank is $-Q$; thus the capacitor bank generates reactive power. The resulting per-unit voltage step is

$$\frac{\Delta U}{E} = -\frac{Q}{S_k} \tag{2.55}$$

Note that a negative voltage drop indicates a rise in voltage. When the capacitor is removed from the system, the voltage shows a sudden decrease in rms value. The voltage steps should not exceed certain limits to prevent problems with end-user equipment. Typical steps in voltage magnitude due to switching of capacitor banks are between 1 and 3% of the nominal voltage.

In distribution systems the capacitor bank is typically connected to the secondary side of a transformer with on-load tap changers. The voltage step due to capacitor bank switching will be detected by the tap-changer control, which will bring back the voltage to within the normal range. The result is a (large) step followed by one or more (smaller) steps in the opposite direction, as in Figure 2.10.

2.2.3.3 Distributed Generation and Voltage Variations An increased penetration of distributed generation will impact the voltage in the distribution system. A single unit of relatively large size, 1 to 10 MW, will change the power flow and thus the voltage drop in the system. The generated power in many cases is not related to the consumed power so that the total load may become negative, leading to a voltage rise in the distribution system. The impact of distributed generation on the voltage control in transmission systems will occur for higher penetration levels and is more complex as it is also related to the closing of large generator stations as the generation is taken over by small units.

Power production by a distributed generator will in most cases lead to an increase in the voltage for all customers connected to the same feeder. During periods of high load, and thus low voltage, this improves the voltage quality. Generator units connected close to the load may be used as a way of controlling the voltage. This assumes, however, that the generator will be available during periods of high load. The operation of a distributed generator depends often on circumstances unrelated to the total load on the feeder. With combined heat and power the generated power is related to the heat demand, which has some relation to the electricity demand. The production of wind or solar power is completely independent of the electricity demand. The voltage rise due to distributed generation is discussed in several publications [e.g., 80, 99, 111, 178, 298].

The practical situation is that power production is steered by other factors than the need for voltage support. The extreme situations are high load without power production and low load with power production. The latter case may result in a voltage rise along the feeder, with the highest voltage occurring for the most remote customer. This will put completely new requirements on the design of the distribution system. Note that the off-line tap changers employed for distribution transformers may make the situation worse (see Figs. 2.9 and 2.11). For generation sources with a rather constant output (e.g., combined heat and power), the main impact is the voltage rise at low load, which simply calls for a change in distribution system design. Once the appropriate mitigation measures are in place in the system, the customer will have the same voltage quality as before. For generation with fluctuating sources (sun and wind) a statistical approach may be used. Standard requirements often allow voltage to be outside the normal range for a certain percentage of time. The introduction of such types of distributed generation may not lead to standard requirements being exceeded and thus does not require any mitigation measures in the system. The customer may however experience a deterioration of the voltage quality.

When a distributed generation unit is connected to a grid with line drop compensation on the transformer tap changers, the voltage along a distribution feeder may be lower or higher than without the generator. Connection of the unit close to the transformer will give a reduced voltage, whereas connection far away will lead to an increase in voltage [21, 188]. The impact also depends on the control mode of the line drop compensation relay [188]. In [143, 199] a method is proposed to determine the optimal setting of the tap changer (the so-called target voltage) from the voltages measured at several locations in the distribution network.

The use of distributed generation units with voltage source converter-based interfaces for controlling the voltage (and for providing other "ancillary services") is proposed in several publications. This remains a sensitive issue, however, as network operators often do not allow active power control by distributed generation units.

But according to [186] some utilities have somewhat loosened their requirement that distributed generation units should operate in a constant-power-factor mode and allow constant-voltage-mode operation. This statement however seems to refer to rather large units (of several megawatt), not to small units. A method for controlling the voltage is proposed in [42]. Under the proposed method the voltage source converter injects an amount of reactive power proportional to the difference between the actual voltage and the nominal voltage:

$$Q = \alpha(U - U_{\mathrm{nom}}) \tag{2.56}$$

It is shown that this significantly reduces the voltage variations along a distribution feeder. By using proportional control only (as with power frequency control of generators), the risk of controller fighting is much reduced. The choice of the control parameter remains a point of discussion. A microgrid with converter-interfaced generation is discussed in [234]. A droop line in used for the voltage control as in (2.56). The droop setting is chosen as 4% of rated power. The method has however only been applied to one of the converters.

In [307] a control strategy is proposed for the connection of distributed generation units to weak distribution networks in South Africa. The unit operates at unity power factor for voltage below 105% of nominal. For higher terminal voltage the power factor may vary between unity and 0.95 inductive. Capacitive operation is blocked, as it would imply that the unit gives voltage support to the grid.

Some types of distributed generation show a strongly fluctuating power output (noticeably solar and wind power). If the unit significantly affects the voltage (in this case more than about 1%), it will pose an excessive duty on voltage-regulating equipment (tap changers and capacitor banks) resulting in premature failure of this equipment [99].

Regulations in distribution networks often require distributed generation (DG) units to disconnect during a fault and to come back after a fixed time (e.g., 5 min). In a system with a large penetration of distributed generation this would create a complex voltage variation: a voltage dip due to the fault followed by a sustained lower voltage corrected in one or more steps by the transformer tap changers. When the units reconnect, the voltage goes up, followed again by the operation of the tap changers [99]. The resulting voltage profiles along the feeder are shown in Figure 2.12, where the initiating event may be a fault at the distribution or transmission level but also the tripping of a large generator unit elsewhere in the system. Before the event the voltage along the feeder is higher than at the substation bus due to the power flow from the generator units back to the transformer (solid curve, normal operation). After the event, the generator units have tripped, leading to a drop in voltage for the loads connected to this feeder (dashed curve, tripping of DG). If other feeders are also equipped with distributed generation, the current through the transformer will also increase significantly, leading to a further drop in voltage at the terminals of the transformer. This drop will be more severe for generation connected to MV than for generation connected to LV.

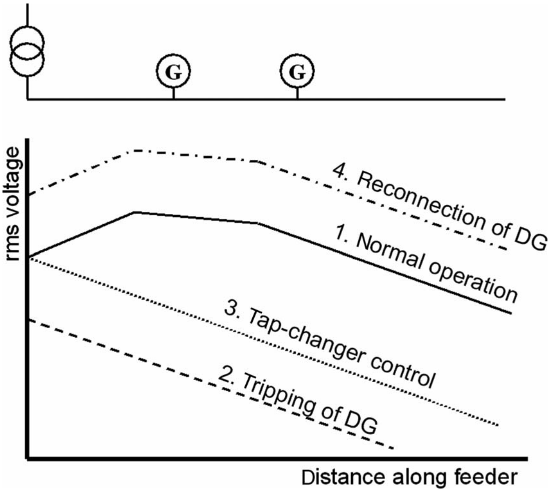

Figure 2.12 Impact of tripping of local DG units due to external event on voltage profile along a feeder.

The impedance of an HV/MV transformer is higher (20 to 30%) than that of an MV/LV transformer (4 to 5%). The transformer tap changer on the HV/MV transformer will bring back the voltage to its normal level within seconds to minutes (depending on the local practice), but only for the secondary side of the HV/MV, not for the whole feeder (dotted curve, tap-changer control). If the units come back automatically after several minutes, this will lead to an overvoltage (dash-dot curve, reconnection of DG). The tap changers will alleviate the overvoltage and return the voltage profile to its normal shape.

The voltage variations due to variations in power output may occur in a time scale between the flicker range (1 s and faster) and the 10-min average as in EN 50160 and other standard documents. In [325, 326] the fluctuations in solar power generation are studied on time scales of 1 s and longer. Passing clouds may cause fast changes in power output that are on the borderline of the flicker spectrum. Further studies are needed on the severity of the problem. It may also be necessary to propose regulations for the permissible voltage variations between the flicker spectrum (time scale of 1 s and faster) and the limits in EN 50160 (10-min averages). We will introduce such a method in Section 5.2.4.

2.3 VOLTAGE UNBALANCE

This section will discuss the difference in voltage between the three phases. The method of symmetrical components is introduced to analyze and quantify the voltage unbalance. The origin of unbalance and the consequences of unbalance are also discussed.