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Renewable Energy Systems

Robert Lis, Marian Sobierajski

INTEGRATION OF DISTRIBUTED RESOURCES IN POWER SYSTEMS

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Foreword

As one of today's electrical power engineers, energy managers or students, you may be seeking ways to solve problems such as high energy costs or low electric power reliability at your facility. If so, distributed energy resources (DER) could be the solution you're looking for. Distributed energy resources are small, modular, energy generation and storage technologies that provide electric capacity or energy where you need it. Typically producing less than 10 megawatts (MW) of power, DER systems can usually be sized to meet your particular needs and installed on site. DER systems may be either connected to the local electric power grid or isolated from the grid in stand-alone applications. DER technologies include wind turbines, photovoltaics (PV), fuel cells, microturbines, reciprocating engines, combustion turbines, cogeneration, and energy storage systems. DER systems can be used in several ways. They can help you manage energy bills and ensure reliable power by augmenting your current energy services. DER systems also enable a facility to operate independently of the electric power grid, whether by choice or out of necessity. Certain DER systems can even lower emissions and improve fuel utilization on site. Utilities can use DER technologies to delay, reduce, or even eliminate the need to obtain additional power generation, transmission, and distribution equipment and infrastructure. At the same time, DER systems can provide voltage support and enhance local reliability.

Today, several economic and environmental factors make it worthwhile to consider DER. These factors include the high prices associated with both electric energy and fuel in recent years. Uncertain fuel supplies and the increasing potential for disruptions in electricity service are prompting electric energy managers to look for alternatives to traditional energy providers and for new ways to supplement current supplies. Particularly where a facility's energy-producing infrastructure is aging, it may be time to review current operating costs and maintenance requirements. The performance, cost, and availability of DER technologies have all been improving steadily over the past several years. New technologies are much more efficient than old ones, so a replacement or upgrade may pay for itself sooner than expected. Also, energy security is a primary concern at many national facilities. In those cases, DER systems can power mission-critical loads, reduce hazardous or costly power outages, and diversify the local energy supply.

This book deals with the basic concept, generation technologies, impacts, operation, control and management aspects, and economic viability and market participation issues of active distribution networks with DER in a broad perspective.

Chapter 1 and 2 discusses the basic concepts of distributed energy resources and active distribution networks, their needs, technical advantages and challenges, socioeconomic impacts and several management and operational issues.

Chapter 3 discusses the basic principles of operation and diagrams of connection of dispersed generators into electric power system.

Chapter 4 discusses the technical impacts of DER concepts. DER has enormous impact on main grid operation and its customers. This chapter covers aspects of electricity generation and utilization, process optimization, and electricity market reforms to accommodates DER for their potential economical benefits. Major issues like impacts on distribution system, emission reduction, communication infrastructure needs, ancillary services, protection co-ordination, etc., have also been discussed in detail.

Chapter 5 discusses the technical features of DER and modeling of active distribution.

network and their applicability in integrated operation of the DER with the main power utility. It also details how and to what extent the operational needs may be taken care of by the DER technologies.

Chapters 6 and 7 deal with the voltage impacts and short-circuit current impacts of DER, respectively.

Chapters 8 and 9 discus the dispersed generator contribution to voltage regulation and frequency regulation in electrical power system, respectively.

Chapter 10 concentrates on stability analysis. There is a limit of active and reactive power generation, which must not be violated without loss of synchronism of DG. If any generator does not remain in synchronism with the rest of the power system, large circulating currents occur and the following action of relays and circuit breakers removes the generator from the system.

Chapter 11 discusses in detail the protection systems in DER, which have quite different protection requirements as compared to conventional distribution systems.

Chapter 12 discusses power quality and reliability issues of DER and active distribution networks.

Chapter 13 discusses and the technical features of DER and stand-alone DER installations.

Chapter 14 discusses the basic concepts of Microgrids and active distribution networks, their needs, technical advantages and challenges, socioeconomic impacts and several management and operational issues.

In Chapter 15 there are many sample calculations and design examples, which help to illustrate the techniques and facilitate their application.

1. Definitions and classification of distributed energy resources

1.1 Introduction

Distributed generation (DG) is related to the use of small generating units installed at strategic points of the electric power system or locations of load centers [2]. DG can be used in an isolated way, supplying the consumer's local demand, or integrated into the grid supplying energy to the remainder of the electric power system. DG technologies can run on renewable energy resources, fossil fuels or waste heat. Equipment ranges in size from less than a kilowatt (kW) to tens of megawatts (MW). DG can meet all or part of a customer's power needs. If connected to a distribution or transmission system, power can be sold to the utility or a third party. DG and renewable energy sources (RES) have attracted a lot of attention worldwide [3]. Both are considered to be important in improving the security of energy supplies by decreasing the dependency on imported fossil fuels and in reducing the emissions of greenhouse gases (GHGs). The viability of DG and RES depends largely on regulations and stimulation measures which are a matter of political decisions.

1.2 Reasons for distributed generation

DG can be applied in many ways and some examples are listed below:

- It may be more economic than running a power line to remote locations.
- It provides primary power, with the utility providing backup and supplemental power.
- For reactive supply and voltage control of generation by injecting and absorbing reactive power to control grid voltage.
- It can provide backup power during utility system outages, for

facilities requiring uninterrupted service. For cogeneration, where excess heat can be used for heating, cooling or steam production.

- Traditional uses include large industrial facilities with high steam and power demands, such as universities and hospitals.
- For network stability control by use of fast-response equipment to maintain a secure transmission system security.

DG can provide benefits for consumers as well as for utilities. Some examples are listed below:

- Transmission costs are reduced because the generators are closer to the load and smaller plants reduce construction time and investment cost.
- Technologies such as micro turbines, fuel cells and photovoltaic can serve in several capacities including backup or emergency power, peak shaving or base load power.
- Given the uncertainties of power utility restructuring and volatility of natural gas prices, power from a DG unit may be less expensive than conventional electric plant. The enhanced efficiency of combined heat and power (CHP) also contributes to cost savings [4].
- DG is less capital intensive and can be up and running in a fraction of the time necessary for the construction of large central generating stations.
- Certain types of DG, such as those run on renewable resources or clearer energy systems, can dramatically reduce emissions as compared with conventional centralized large power plants.
- DG reduces the exposure of critical energy infrastructure to the threat of terrorism.
- DG is well suited to providing the ancillary services necessary for the stability of the electrical system.
- DG is most economical in applications where it covers the base load electricity and uses utility electricity to cover peak consumption and the load during DG equipment outages, i.e. as a standby service.
- DG can offset or delay the need for building more central power plants or increasing transmission and distribution infrastructure, and can also reduce grid congestion, translating into lower electricity rates for all utility customers.
- Smaller, more modular units require less project capital and less lead-time than large power plants. This reduces a variety of risks to utilities, including forecasting of load/resource balance and fuel prices, technological obsolescence and regulatory risk.

- DG can provide the very high reliability and power quality that some businesses need, particularly when combined with energy storage and power quality technologies.
- Small generating equipment can more readily be resold or moved to a better location.
- DG maximizes energy efficiency by enabling tailored solutions for specific customer needs such as combined heat and power systems.
- By generating power at or very near the point of consumption where there is congestion, DG can increase the effective transmission and distribution network capacity for other customers.
- DG can reduce customer demands from the grid during high demand periods.
- DG can provide very high-quality power that reduces or eliminates grid voltage variation and harmonics that negatively affect a customer's sensitive loads.
- DG may allow customers to sell excess power or ancillary services to power markets, thus increasing the number of suppliers selling energy and increasing competition and reducing market power.
- DG can reduce reactive power consumption and improve voltage stability of the distribution system at lower cost than voltage-regulating equipment.
- DG eliminates the need for cost1y installation of new transmission lines, which frequent1y have an environmental issue.
- DG reduces energy delivery losses resulting in the conservation of vital energy resources.
- DG expands the use of renewable resources, such as biomass cogeneration in the paper industry, rooftop solar photovoltaic systems on homes, and windmills further to improve energy resource conservation.
- DG offers grid benefits like reduced line loss and increased reliability [5]. From a grid security standpoint, many small generators are collectively more reliable than a few big ones. They can be repaired more quickly and the consequences of a small unit's failure are less catastrophic. DG eliminates potential blackouts caused by utilities' reduced margin of generation reserve capacity.

1.2.1 Why integration of distributed generation?

In spite of several advantages provided by conventional power systems, the following technical, economic and environmental benefits have led to gradual development and integration of DG systems:

- Due to rapid load growth, the need for augmentation of conventional generation brings about a continuous depletion of fossil fuel reserve. Therefore, most of the countries are looking for non-conventional/renewable energy resources as an alternative.
- Reduction of environmental pollution and global warming acts as a key factor in preferring renewable resources over fossil fuels. As part of the Kyoto Protocol, the EU, Poland and many other countries are planning to cut down greenhouse gas (carbon and nitrogenous by-products) emissions in order to counter climate change and global warming. Therefore, they are working on new energy generation and utilization policies to support proper utilization of these energy sources. It is expected that exploitation of DERs would help to generate ecofriendly clean power with much lesser environmental impact.
- (3) DG provides better scope for setting up co-generation, trigeneration or CHP plants for utilizing the waste heat for industrial/domestic/commercial applications. This increases the overall energy efficiency of the plant and also reduces thermal pollution of the environment.
- Due to lower energy density and dependence on geographical conditions of a region, DERs are generally modular units of small capacity. These are geographically widespread and usually located close to loads. This is required for technical and economic viability of the plants. For example, CHP plants must be placed very close to their heat loads, as transporting waste heat over long distances is not economical. This makes it easier to find sites for them and helps to lower construction time and capital investment. Physical proximity of load and source also reduces the transmission and distribution (T&D) losses. Since power is generated at low voltage (LV), it is possible to connect a DER separately to the utility distribution network or they may be interconnected in the form of Microgrids. The Microgrid can again be connected to the utility as a separate semi-autonomous entity.
- Stand-alone and grid-connected operations of DERs help in generation augmentation, thereby improving overall power quality and reliability. Moreover, a deregulated environment and open access to the distribution network also provide greater opportunities for DG integration. In some countries, the fuel diversity offered by DG is considered valuable, while in some developing countries, the shortage of power is so acute that any form of generation is encouraged to meet the load demand.

1.3 Technical impacts of distributed generation

DG technologies include engines, small wind turbines, fuel cells and photovoltaic systems. Despite their small size, DG technologies are having a stronger impact in electricity markets. In some markets, DG is actually replacing the more costly grid electricity. However, there are technical issues that deserve attention.

1.3.1 DG Technologies

No single DG technology can accurately represent the full range of capabilities and applications or the scope of benefits and costs associated with DG. Some of these technologies have been used for many years, especially reciprocating engines and gas turbines. Others, such as fuel cells and micro turbines, are relative new developments. Several DG technologies are now commercially available, and some are expected to be introduced or substantially improved within the next few years [6].

Reciprocating engines. Diesel and gas reciprocating engines are well-established commercial DG technologies. Industrial-sized diesel engines can achieve fuel efficiencies exceeding 40 % and are relatively low cost per kilowatt. While nearly half of the capacity was ordered for standby use, the demand for units capable of being used continuously or in peak periods is increasing gradually.

Gas turbines. Originally developed for jet engines, gas turbines are now widely used in the power industry. Small industrial gas turbines of 1-20 MW are commonly used in combined heat and power applications. They are particularly useful when higher temperature steam is required than can be produced by a reciprocating engine. The maintenance cost is slightly lower than for reciprocating engines, but so is the electrical conversion efficiency. Gas turbines can be noisy. Emissions are somewhat lower than for engines, and cost-effective NO_x emission control technology is commercially available.

Micro turbines. Micro turbines extend gas turbine technology to units of small size. The technology originally developed for mobile applications, is now applied to power generation. One of the most striking technical characteristics of micro turbines is their extremely high rotational speed. The turbine rotates up to 120000 r/min and the generator up to 40000 r/min. Individual units range from 30 to 200 kW but can be combined into systems of multiple units. Low combustion temperatures can assure very low NO_x emission levels. These turbines make much less noise than an engine of comparable size. Natural gas is expected to be the most common fuel but flare gas, landfill gas or biogas can also be used. The main disadvantages of micro turbines are their short track record and high costs compared with gas engines.

Fuel cells. Fuel cells are compact, quiet power generators that use hydrogen and oxygen to make electricity. The transportation sector is the major potential market for fuel cells, and car manufacturers are making substantial investments in research and development. Power generation, however, is seen as a market in which fuel cells could be commercialized much more quickly. Fuel cells can convert fuels to electricity at very high efficiencies (35-60 %) as compared with conventional technologies [7]. As there is no combustion, other noxious emissions are low. Fuel cells can operate with very high reliability and so could supplement or replace grid-based electricity. Only one fuel cell technology for power plants, a phosphoric acid fuel cell plant (PAFC), is currently commercially available. Three other types of fuel cells, namely molten carbonate (MCFC), proton exchange membrane (PEMFC) and solid oxide (SOFC), are in intensive research and development.

Photovoltaic systems. Photovoltaic systems are a capital-intensive, renewable technology with very low operating costs. They generate no heat and are inherently small scale. These characteristics suggest that photovoltaic systems are best suited to household or small commercial applications, where power prices on the grid are highest. Operating costs are very low, as there are no fuelling costs.

Wind. Wind generation is rapidly gaining a share in electricity supply worldwide. Wind power is sometimes considered to be DG, because the size and location of some wind farms make it suitable for connection at distribution voltages.

1.3.2 Thermal Issues

When DG is connected to the distribution network, it alters the load pattern. The amount of feeder load demand will eventually results in the feeder becoming fully loaded. It is most likely that increased levels of DG will cause an increase in the overall current flowing in the network, bringing the components in the network c1oser to their thermal limits. If the thermal limits of the circuit components are likely to be exceeded by the connection of DG then the potentially affected circuits will need to be replaced with circuits of a higher thermal rating. This would usually take the form of replacement with conductors of a larger cross-sectional area.

1.3.3 Voltage Profile Issues

Voltage profiles along a loaded distribution network feeder are typically such that the voltage level is at maximum c1ose to the distribution network transformer busbar, and the voltage drops along the length of the feeder as a result of the load connected to the feeder. Voltage drop is generally larger on rural networks, which are commonly radial networks with feeders covering long distances with relatively low-current-capacity conductors, especially at the remote ends of the feeders. The distribution transformer, feeding the distribution network, with a tap-changer, which controls the setting of the busbar voltage. The tap-changer will be set to ensure that, under maximum feeder loads, the voltage drop along a feeder does not result in voltage levels falling below the lower of the statutory voltage limits.

DG along a distribution feeder will usually have the effect of reducing the voltage drop along the feeder, and may lead to a voltage rise at some points, which could push the feeder voltage above the statutory voltage limit. Voltage rise is generally more of a problem on rural radial networks than on interconnected or ring networks The excessive voltage rise can be initiated by relatively small amounts of DG due to the high impedance of the conductors since these feeders are often operated c1ose to the statutory upper voltage limit to counter the relatively large voltage drop over the length of such feeders. Voltage rise may be reduced by:

- Constraining the size of DG plant: the leve1 of voltage rise will depend upon the generation level compared with the minimum load demand.
- Reinforcing the network (initially using larger conductors with a lower impedance).
- Operating the generator at a leading power factor (i.e. importing VArs from the network), which will reduce overall power flow and hence reduce voltage drop. However, distribution network operators (DNOs) generally require DG plant to operate as c1ose to unity power factor as possible (i.e. negligible import or export of reactive power).
- Installing shunt reactor banks to draw additional reactive power from the network. DG could also contribute to voltage flicker through sudden variations in the DG output (e.g. variable wind speeds on turbines), start-up of large DG units or interactions between DG and voltage control equipment on the network. Wind turbines with induction generators will cause voltage disturbances when starting, due to the inrush of reactive current required to energize the rotor. The voltage step that will occur when a wind turbine

shuts down from full output, perhaps due to high wind speeds, must also be considered. A short-term reduction in the network voltage means that there is not enough energy to supply the connected load. There are two major causes of these voltage dips: namely, sudden connections of large loads or faults on adjacent branches of the network. When DG is connected to a network and is energized, a voltage step may result from the inrush current flowing into the generator or transformer. Step voltages also occur when a generator (or group of generators) is suddenly disconnected from the network, most likely due to a fault.

When large motor loads are suddenly connected to the network, they draw a current, which can be many times larger than the nominal operating current. The supply conductors for the load are designed for nominal operation; therefore this high current can cause an excessive voltage drop in the supply network. Voltage dips caused by large motor loads can be overcome by installing a starter, which limits the starting current but increases the starting time. Another option is to negotiate with the DNO for a low-impedance connection, though this could be an expensive option depending on the local network configuration. Depending on the reaction time of control systems, there are several options to reduce the severity of voltage dips: that is, to increase DG output, to reduce network loads, to utilize energy from storage devices or energize capacitor banks.

1.3.4 Fault-Level Contributions

A fault can occur in many ways on a network due to a downed overhead line or a damaged underground cable. The current that flows into a fault can come from three sources on a distribution network: namely, infeeds from the transmission system, infeeds from distributed generators or infeeds from loads (with induction motors).

The connection of DG causes fault level c1ose to the point of connection. This increase is caused by an additional fault level from the generator, and can cause the overall fault level to exceed the designed fault level of the distribution equipment. Increased fault 1evels can be accommodated, or reduced, by either upgrading equipment or reconfiguring distribution networks.

Induction generators contribute very little to root mean square (RMS) break fault levels, as the fault current from the induction generator quickly collapses as the generator loses magnetic excitation due to the loss of grid supply. However, they contribute more to peak fault 1evels. Synchronous generators contribute less to the initial peak current compared with induction generators but do have a larger steady-state RMS fault contribution. Generators which are connected to the distribution network via power electronics interfaces, it will be quickly disconnected under network fault conditions when a current is 20 % higher than the rated current. As a doubly fed induction generator (DFIG) is only partially connected via power electronics, the RMS break fault current contribution is low. However, the peak current contribution can be up to six times the rated current.

1.3.5 Harmonics and Interactions with Loads

In ideal electricity network the voltage would have a perfectly sinusoidal waveform oscillating, for example, at 50 cyc1es per second. However, any capacitive or inductive effects, due to switching of devices such as large cables, network reactors, rectified DG power supplies, variable speed motor drives and inverter-coupled generators, will introduce or amplify harmonic components into the voltage sine wave, thereby distorting the voltage waveform. It is expected that small-scale micro wind and solar generation will be inverter connected. Inverter connections incorporate the use of a high proportion of switching components that have the potential to increase harmonic contributions.

1.3.6 Interactions Between Generating Units

Increasing levels of intermittent renewable generation and fluctuating inputs from CHP units will ultimately make it more difficult to manage the balance between supply and demand of the power system. Unless the DG can offer the same control functions as the large generators on the system, the amount of generation reserve required when there is a significant contribution to the system from DG will need to be increased.

1.3.7 Protection Issues

Distribution networks were designed to conduct current from high to low voltages and protection devices are designed to reflect this concept. Under conditions of current flow in the opposite direction, protection mal-operation or failure may occur with consequent increased risk of widespread failure of supply. Due to opposite current flow, the reach of a relay is shortened, leaving high impedance faults undetected. When a utility breaker is opened, a portion of the utility system remains energized while isolated from the remainder of the utility system, resulting in injuries to the public and utility personnel.

1.4 Renewable Sources of Energy

These are the natural energy resources that are inexhaustible: for example, wind, solar, geothermal, biomass and small-hydro generation.

Small-hydro energy. Although the potential for small hydroelectric systems depends on the availability of suitable water flow where the resource exists, it can provide cheap, dean, reliable electricity. Hydroelectric plants convert the kinetic energy of a waterfall into electric energy. The power available in a flow of water depends on the vertical distance the water falls and the volume of the flow of water. The water drives a turbine, and its rotation movement is transferred through a shaft to an electric generator. A hydroelectric installation alters its natural environment. The impact on the environment must therefore be evaluated during planning of the project to avoid problems such as noise or damage to ecosystems.

Wind energy. Wind turbines produce electricity for homes, businesses and utilities. Wind power will continue to prosper as new turbine designs currently under development reduce its costs and make wind turbines economically viable in more and more places. Wind speed varies naturally with the time of day, the season and the height of the turbine above the ground. The energy available from wind is proportional to the cube of its speed. A wind generator is used to convert the power of wind into electricity. Wind generators can be divided into two categories, those with a horizontal axis and those with a vertical ones [8]. The Electric Power Research Institute, USA, has stated that wind power offers utilities pollution-free electricity that is nearly cost-competitive with today's conventional sources. However, one environmental concern about wind power is land use. Modem wind turbine technology has made significant advances over the last 10 years. Today, small wind machines of 5 to 40 kW capacities can supply the normal electrical needs of homes and small industries. Medium-size turbines rated from 100 to 500 kW produce most of the commercial generated electricity.

Biomass. The term biomass refers to the Earth's vegetation and many products that come from it. Some of the commonest biomass fuels are wood, agricultural residues and crops grown for energy. Utilities and commercial and industrial facilities use biomass to produce electricity. According to the World Bank, 50 to 60 % of the energy in the developing countries of Asia, and 70 to 90 % of the energy in the developing countries of Africa, come from biomass, and half the world's population cook with wood. In the USA, Japan and Europe, municipal and agricultural waste is being burned to produce electricity.

Solar energy. Solar thermal electric power plants use various concentrating devices to focus sunlight and achieve the high temperatures necessary to produce steam for power. Flat-plate collectors transfer the heat of the Sun to water either directly or through the use of another fluid and a heat exchanger. The market for photovoltaic is rapidly expanding. Homes can use photovoltaic systems to replace or supplement electric power from the utility. A stand-alone residential system consists of solar panels, a battery to store power for use at night, and an inverter to allow conventional appliances to be powered by solar electricity.

Geothermal. Geothermal energy is heat from the Earth that is used directly as hot water or steam, or used to produce electricity. While high-temperature geothermal sites suitable for electricity production are not widespread, low-temperature sites are found almost everywhere in the world and they can provide heating and cooling for buildings. Geothermal systems are located in areas where the Earth's crust is relatively thin. Drilling into the ground and inserting pipes enable hot water or steam to be brought to the surface. In some applications, this is used to providing direct heating to homes. In other areas, the steam is used for driving a turbine to generate electricity. According to the US Energy Information Agency, geothermal energy has the potential to provide the USA with 12000 megawatts of electricity by the year 2010, and 49 000 megawatts by 2030. It has the potential to provide up to 80000 megawatts. Geothermal energy resources are found around the world. As a local and renewable energy resource, geothermal energy can help reduce a nation's dependence on oil and other imported fuels. Geothermal heat pumps (GHPs) are an efficient way to heat and cool buildings. GHPs use the normal temperature of the Earth to heat buildings in winter and cool them in summer. GHPs take advantage of the fact that the temperature of the ground does not vary as much from season to season as the temperature of the air.

1.5 Barriers to distributed generation development

Cooperation, property ownership, personal consumption and security will change attitudes towards DG technologies and make people we1come them to their homes. There is now evidence of strong interest from a small community willing to pay the premium to enjoy green energy. There is significant regional variation in the use of DG systems. This is largely due to the fact that the potential benefits DG are greater in some areas than in others. In some areas, for example, relatively high e1ectricity rates, reliability concerns and DG-friendly regulatory programs have encouraged comparatively fast DG development. But in many areas, even where DG could offer benefits, projects are often blocked by market and other barriers. The most commonly cited barrier to DG development is the process of interconnecting to distribution and transmission systems. Other barriers inc1ude high capital costs, non-uniform regulatory requirements, lack of experience with DG, and tariff structures [9].

The lack of experience with competitive markets often increases risk about the use of unconventional power sources. Producers cannot easily sell power from on-site generation to the utility through a competitive bidding process, to a marketer or to other customers directly. For customers, there is a risk of DG being uneconomical, capital investments under market uncertainty and price volatility for the DG system fuel. There is a concern about the reliability and risks that arise from using unconventional technologies/applications with DG.

Utilities have a considerable economic disincentive to embrace distributed resources. Distribution company profits are directly linked to sales. Utilities' revenues are based on how much power they sell and move over their wires, and they lose sales when customers develop generation on site. Interconnecting with customer-owned DG is not in line with a utility's profit motive. Other barriers to the deployment of DG exist on the customer side. A utility has no obligation to connect DG to its system unless the unit is a qualifying facility. If a utility does choose to interconnect, lengthy case-by-case impact studies and redundant safety equipment can easily spoil the economics of DG. If a customer wants the utility to supply only a portion of the customer's load or provide backup power in case of unit failure, the cost of 'standby' and 'backup' rates can be prohibitive. Exit fees and competitive transition charges associated with switching providers or leaving the grid entirely can be burdensome. And obtaining all the necessary permits can be quite difficult.

1.6 Interconnection

A customer who wants to interconnect DG to the distribution system must undergo a utility's case-by-case interconnection review process [10]. Such a process can be time consuming and expensive. Installers thus face higher costs by having to meet interconnection requirements that vary from utility to utility. Additionally, manufacturers are not able to capture the economies of scale in producing package systems with standard safety and power quality protection. The interconnection process would benefit from the pre-certification of specific DG technologies. Recognized, independent or government testing labs (e.g. Underwriters Laboratories) would conduct initial testing and characterization of the safety, power quality and system reliability impacts of DG. They would recommend technical parameters that state legislatures, regulatory agencies or individual utilities could adopt.

1.6.1 Rate Design

The restructuring of electricity markets and an increased reliance on wholesale power purchases have brought distribution into the spotlight. As utilities have divested themselves of generation assets, they have become aware of the importance of distribution services in generating revenue. Usage-based rates help ensure that customers pay the actual costs they impose on the system so that their consumption neither subsidizes nor is subsidized by the consumption of others.

Rates should reflect the grid benefits of DG, like peak shaving, reduced need for system upgrades, capital cost reductions and increased reliability. Standby or backup charges are rates that a customer pays to receive power from the grid at times when its own DG is unavailable. Standby rates are typically based on serving a customer's maximum load at peak demand periods - a worst case scenario which, some argue, should not serve as the basis for rate making. Buyback rates are the prices a utility pays for excess generation from a customer's own DG unit. Buyback rates or credits would be higher for energy derived from DG located in constrained areas of the distribution system. Finally, DG owners sometimes face the implications of 'stranded costs' of utility investments in restructured markets. Competitive transition charges and exit fees can apply when a DG customer-owner seeks to switch providers or disconnect from the grid entirely.

In the future, one key area of concern is the technical details of interconnecting DG with the electric power systems (EPSs). RES will contribute to meet the targets of the Kyoto Protocol and support the security of supply with respect to limited energy resources. The interconnection must allow DG sources to be connected with the EPS in a manner that provides value to the end user without compromising reliability or performance.

The situation in Europe differs from country to country. Circumstances may also differ between synchronous interconnected systems and island systems. The capacity targets and the future portfolio of RES depend on the national situation. Nevertheless the biggest growth potential is for wind energy. The expectations of the European Wind Energy Association show an increase from 28.5 GW in 2003 to 180 GW in 2020. Due to different support schemes for RES restrictions in licensing and a limited number of suitable locations, this capacity tends to focus on very few regions in Europe. However, new wind farms will normally be built far away from the main load centers. New overhead lines will therefore be necessary to transport the electricity to where it is consumed. These investments are exc1usively or at least mainly driven by the new RES generation sites. The intermittent contributions from wind power must be balanced with other backup generation capacity located elsewhere. This adds to the requirements for grid reinforcements.

The licensing procedures for new lines are lasting several years, some even more than 10 years. A delay in grid extension will result in a delay of RES investments because wind farms cannot earn an adequate return on investment without an adequate grid connection. New lines are therefore critical for the success of new RES. Moreover, this new infrastructure could be a significant investment. There is not yet a European-wide harmonized rule about who should pay for it. The legal framework and administrative procedures have to be set properly to speed up the licensing of grid infrastructure.

As countermeasures, suitable European-wide harmonized grid codes for new wind farms and other RES defining their electrical behavior in critical grid situations are needed in all countries expanding their share of RES. Existing wind farms not fulfilling the actual grid code requirements must be upgraded or replaced (i.e. the electrical behavior of wind turbines in case of grid faults). Finally, a sufficient capacity from conventional generation has to be in the system at any one time to keep it stable.

1.7 Recommendations and Guidelines for DG Planning

Liberalization and economic efficiency. Liberalization of the electricity market has increased the complexity and transaction costs for all market players and particularly affected smaller producers. In certain markets where they can avoid charges on transmission, distributed generators may have an advantage over central generators. Elsewhere, in wholesale markets that are designed with large central generation in mind, smaller distributed generators may be at a disadvantage because of the additional costs and complexities of dealing with the market. Difficulties in the New Electricity Trading Arrangements (NETA)/British Electricity Trading and Transmission Arrangements (BETTA) market in the UK suggest that further market measures are needed to make the system fair to smaller generators [11]. Furthermore, treatment of connection charges for DG needs to be consistent with treatment of larger generators. In fact, liberalization of the e1ectricity market is not broad enough to take advantage of the flexibility of many types of DG. Retail pricing should encourage the development of DG in locations where it can reduce network congestion and operate at times when system prices are high.

Environmental protection. DG embraces a wide range of technologies with a wide range of both NO_x and GHG emissions. Emissions per kWh of NO_x from DG (excepting diesel generators) tend to be lower than emissions from a coal-burning power plant. At the same time, the emissions rate from existing DG (excepting fuel cells and photovoltaic) tends to be higher than the best available central generation, such as a combined cyc1e gas turbine with advanced emissions control. This puts a serious limitation on DG in areas where NO_x emissions are rigorously controlled. If, however, DG is used in a CHP mode, there can be significant emissions savings, even compared with combined cyc1e power plants. Measures should be designed that encourage distributed generators to reduce their emissions. The use of economic instruments (such as carbon emissions trading) would encourage DG operators to design and operate their facilities in ways that minimize emissions of GHGs.

Regulatory issues and interest in DG. The profits of distribution companies are directly linked to sales. The more kilowatt hours of e1ectricity that move over their lines, the more money they make. Interconnecting with customer-owned DG is plainly not in line with a utility's profit motive. Permission to connect to the grid should be restricted only for safety and grid protection. Guidelines should ensure that there are no restrictions, other than for safety or grid protection reasons.

The following issues need to be addressed [12]:

- Adoption of uniform technical standards for connecting DG to the grid.
- Adoption of testing and certification procedures for interconnection equipment.
- Accelerate development of control technology and systems. While policy in creases interest in DG, regulatory and institutional barriers surrounding the effective deployment of DG remain.
- Adoption of standard commercial practices for any required utility review of interconnection.
- Establish standard business terms for interconnection agreements.
- Development of tools for utilities to assess the value and impact of distributed power at any point on the grid.
- Development of new regulatory principles compatible with the

distributed power choices in competitive and utility markets.

- Adoption of regulatory tariffs and utility incentives to fit the new distributed power model. Design tariffs and rates to provide better price transparency to DG.
- Definition of the condition necessary for a right to interconnect.
- Development of a well-designed policy framework that will reward efficiency and environmental benefits in DG technologies the same way as it does for conventional large-scale generators.
- Inclusion of critical strategies for consumer education and cost evaluation tools to deploy DG effectively.

Distributed generators must be allowed to be connected to the utility grid. The owners of DG must recognize the legitimate safety and reliability concerns associated with interconnection. Regulators must recognize that the requirements for utility studies and additional isolation equipment will be minimal in the case of smaller DG units.

1.8 Economic Impact of distributed generation

DG has some economic advantages compared with power from the grid, particularly for on-site power production [13]. The possibility of generating and using both heat and power generated in a CHP plant can create additional economic opportunities. DG may also be better positioned to use low-cost fuels such as landfill gas.

The relative prices of retail electricity and fuel costs are critical to the competitiveness of any DG option. This ratio varies greatly from country to country. In Japan, for example, where electricity and natural gas prices are high, DG is attractive only for oil-fired generation. In other countries, where gas is inexpensive as compared with electricity, DG can become economically attractive. Many DG technologies can be very flexible in their operation. A DG plant can operate during periods of high electricity prices (peak periods) and then be switched off during low-price periods. The ease of installation of DG also allows the system capacity to be expanded readily to take advantage of anticipated high prices. Some DG assets are portable. In addition to this technological flexibility, DG may add value to some power systems by delaying the need to upgrade a congested transmission or distribution network, by reducing distribution losses and by providing support or ancillary services to the local distribution network. CHP is economically attractive for DG because of its higher fuel efficiency and low incremental capital costs for heat-recovery equipment. Domestic-level CHP, so-called 'micro-CHP', is attracting much interest, particularly where it uses external combustion engines and in some cases fuel cells. However, despite the potential for short payback periods, high capital costs for the domestic consumer are a significant barrier to the penetration of these technologies. The provision of reliable power represents the most important market for DG. Emergency diesel generating capacity in buildings, generally not built to export power to the grid, represents several percent of total peak demand for electricity. Growing consumer demand for higher quality electricity (e.g. 'five nines' or 99.999 % reliability) requires on-site power production.

Many of these technologies can be more energy efficient and c1eaner than central station power plants. Modularity is beneficial when load growth is slow or uncertain. The smaller size of these technologies can better match gradual increases in utility loads. DG also can reduce demand during peak hours, when power costs are highest and the grid is most congested. If located in constrained areas, DG can reduce the need for distribution and transmission system upgrades. Customers can install DG to cap their electricity costs, sell power, participate in demand response programs, provide backup power for critical loads and supply premium power to sensitive loads. The biggest potential market for DG is to supplement power supplied through the transmission and distribution grid. On-site power production reduces transmission and distribution costs for the delivery of electricity. These costs average about 30 % of the total cost of electricity. This share, however, varies according to customer size. For very large customers taking power directly at transmission voltage, the total cost and percentage are much smaller; for a small household consumer, network charges may constitute over 40 % of the price. Small-scale generation has a few direct cost disadvantages over central generation. Firstly, there is a more limited se1ection of fuels and technologies to generate electricity - oil, natural gas, wind or photovoltaic systems, and, in certain cases, biomass or waste fuels. Secondly, the smaller generators used in DG cost more per kilowatt to build than larger plants used in central generation. Thirdly, the costs of fuel delivery are normally higher. Finally, unless run in CHP mode, the smaller plants used in DG operate usually at lower fuel conversion efficiencies than those of larger plants of the same type used in central generation. DG uses a more limited selection of fuels. For photovoltaic systems, operating costs are very low, but high capital costs prevent them from competitive with grid electricity.

Generating electricity from the wind makes economic as well as environmental sense: wind is a free, clean and renewable resource which will never run out. The wind energy industry - designing and making turbines, erecting and running sustainable ways to generate electricity. Wind turbines are becoming cheaper and more powerful, with larger blade lengths, which can utilize more wind and therefore produce more electricity, bringing down the cost of renewable generation.

Making and selling electricity from the wind is not different from any other business. To be economically viable the cost of making electricity has to be less than its selling price. In every country the price of electricity depends not only on the cost of generating it, but also on the many different factors that affect the market, such as energy subsidies and taxes. The cost of generating electricity comprises capital costs (the cost of building the power plant and connecting it to the grid), running costs (such as buying fuel and operation and maintenance) and the cost of financing (how the capital cost is repaid).

With wind energy, and many other renewable, the fuel is free. Therefore once the project has been paid for, the only costs are operation and maintenance and fixed costs, such as land rental. The capital cost is high, between 70 and 90 % of the total for onshore projects. The more electricity the turbines produce, the lower the cost of the electricity. This depends on the power available from the wind. Roughly, the power derived is a function of the cube of the wind speed. Therefore if the wind speed is doubled, its energy content will increase eight fold. Turbines in wind farms must be arranged so that they do not shadow each other.

The cost of electricity generated from the wind, and therefore its final price, is influenced by two main factors, namely technical factors and financial perspective. Technical factors are about wind speed and the nature of the turbines, while financial perspective is related to the rate of return on the capital, and the period of time over which the capital is repaid. Naturally, how quickly investors want their loans repaid and what rate of return they require can affect the feasibility of a wind project; a short repayment period and a high rate of return push up the price of electricity generated. Public authorities and energy planners require the capital to be paid off over the technical lifetime of the wind turbine, e.g. 20 years, whereas the private investor would have to recover the cost of the turbines during the length of the bank loan. The interest rates used by public authorities and energy planners would typically be lower than those used by private investors.

Although the cost varies from country to country, the trend is everywhere the same: that is, wind energy is getting cheaper. The cost is coming down for various reasons. The turbines themselves are getting cheaper as technology improves and the components can be made more economically. The productivity of these newer designs is also better, so more electricity is produced from more cost effective turbines. The cost of financing is also falling as lenders gain confidence in the technology. Wind power should

become even more competitive as the cost of using conventional energy technologies rises.
However, renewable energy technologies will introduce new conflicts. For example, a basic parameter controlling renewable energy supplies is the availability of land. At present world food supply mainly comes from land. There is relatively little land available for other uses, such as biomass production and solar technologies. Population growth demands land. Therefore, future land conflicts will be intensified. Although renewable energy technologies often cause fewer environmental problems than fossil energy systems, they require large amounts of land and therefore compete with agriculture, forestry and other essential land-use systems. Reservoirs constructed for hydroelectric plants have the potential to cause major environmental problems. This water cover represents a major loss of productive agricultural land. Dams may fail, resulting in loss of life and destruction of property. Further, dams alter the existing plant and animal species in an ecosystem, e.g. by blocking fish migration. Generation, transmission and distribution utilities generally plan their systems to meet all of the power needs of all of their customers. They do not encourage their customers to develop on-site generation. In some cases, utilities have actively opposed DG projects.

2. Technical requirements for wind generation

2.1 The Resource

Winds result from the large scale movements of air masses in the atmosphere. These movements of air are created on a global scale primarily by differential solar heating of the earth's atmosphere. Therefore, wind energy, like hydro, is also an indirect form of solar energy. Air in the equatorial regions is heated more strongly than at other latitudes, causing it to become lighter and less dense. This warm air rises to high altitudes and then flows northward and southward towards the poles where the air near the surface is cooler. This movement ceases at about 30° N and 30° S, where the air begins to cool and sink and a return flow of this cooler air takes place in the lowest layers of the atmosphere.

The areas of the globe where air is descending are zones of high pressure. Conversely where air is ascending, low pressure zones are formed. This horizontal pressure gradient drives the flow of air from high to low pressure, which determines the speed and initial direction of wind motion. The greater the pressure gradient, the greater is the force on the air and the higher is the wind speed. Since the direction of the force is from higher to lower pressure, the initial tendency of the wind is to flow perpendicular to the isobars (lines of equal pressure). However, as soon as wind motion is established, a deflective force is produced due to the rotation of the earth, which alters the direction of motion. This force is known as the *Coriolis force*. It is important in many of the world ' s windy areas, but plays little role near to the equator.

In addition to the main global wind systems there is also a variety of local effects. Differential heating of the sea and land also causes changes to the general flow. The nature of the terrain, ranging from mountains and valleys to more local obstacles such as buildings and trees, also has an important effect.

The boundary layer refers to the lower region of the atmosphere where the wind speed is retarded by frictional forces on the earth's surface. As a result wind speed increases with height; this is true up to the height of the boundary layer, which is at approximately 1000 m, but depends on atmospheric conditions. The change of wind speed with height is known as the wind shear.

It is clear from this that the available resource depends on the hub height of the turbine. This has increased over recent years, reflecting the scaling – up

of wind turbine technology, with the hub heights of the multi-megawatt machines now being over 100 m.
The European accessible onshore wind resource has been estimated at 4800 TW h/year taking into account typical wind turbine conversion efficiencies, with the European offshore resource in the region of 3000 TW h/year although this is highly dependent on the assumed allowable distance from shore. A recent report suggests that by 2030 the EU could be generating 965 TW h from onshore and offshore wind, amounting to 22.6% of electricity requirements [10]. The world onshore resource is approximately 53 000 TW·h/year. To see these figures in context note that the UK annual electricity demand is in the region of 350 TW·h and the USA demand is 3500 TW·h. No figure is currently available for the world offshore resource, and this itself will be highly dependent on the allowable distance from shore.
Of the new renewable wind power is the most developed. On very windy sites wind farms can produce energy at costs comparable to those of the most economic traditional generators. Due to advances in technology, the economies of scale, mass production and accumulated experience, over the next decade wind power is the renewable energy form likely to make the greatest contribution to electricity production. As a consequence, more work has been carried out on the integration of this resource than any of the other renewable and, naturally, this is reflected in the amount of attention given to wind power integration in this book.

2.2 Wind Variability

The wind speed at a given location is continuously varying. There are changes in the annual mean wind speed from year to year (*annual*) changes with season (*seasonal*), with passing weather systems (*synoptic*), on a daily basis (*diurnal*) and from second to second (*turbulence*). All these changes, on their different timescales, can cause problems in predicting the overall energy capture from a site (annual and seasonal), and in ensuring that the variability of energy production does not adversely affect the local electricity network to which the wind turbine is connected.

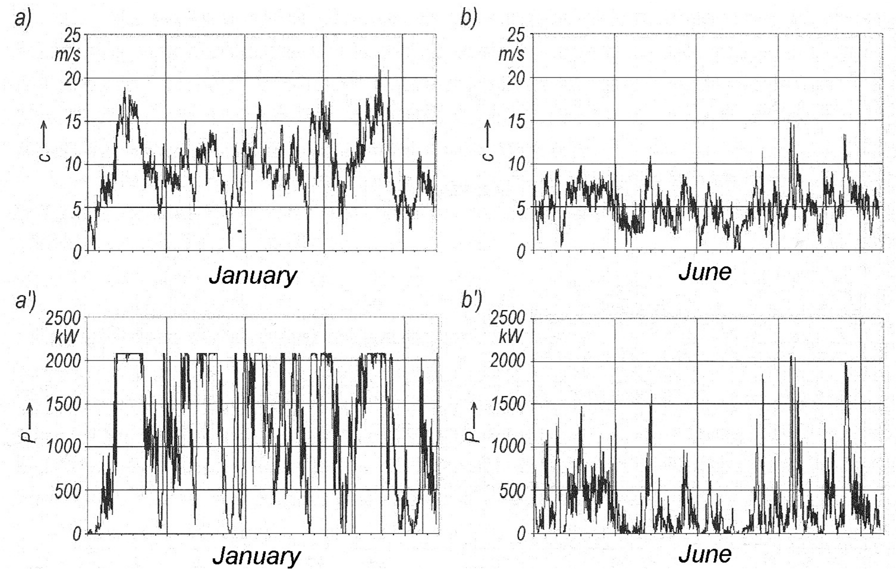


Figure 2.1 Wind speed diagram: vertical axis is wind speed c, 0-25 ms^{-1} and power output P, 0-2.5 MW for WP in Kamieńsk PL

In Figure 2.1 each graph shows the wind speed over the time periods indicated. Wind speed measured continuously over 100 days is shown on the first graph followed by graphs, which in sequence zoom in on smaller and smaller windows of the series. It is easy to see the much larger relative variability in the longer time series (synoptic) as compared with the time series covering hours or less (diurnal, turbulence). This information is summarized in the spectral density presentation in Figure 2.2. In a spectral density function the height indicates the contribution to variation (strictly the variance) for the frequency indicated. A logarithmic scale as used here is the norm, and allows a very wide range of frequencies/timescales to be represented easily. The y axis is scaled by n to preserve the connection between areas under any part of the curve and the variance. The area under the entire curve is the total variance. It can be seen that the largest contribution to variation is the synoptic variation, confirming the interpretation of Figure 2.1. Fortunately these variations, characterized by durations of typically 3 to 5 days, are slow in the context of the operation of large power systems.

Apparently more difficult to deal with is the impact of short term variations due to wind turbulence, which are clear on the right hand side of Figure 2.2. However, as will be shown later, the aggregation effects will reduce this problem considerably.

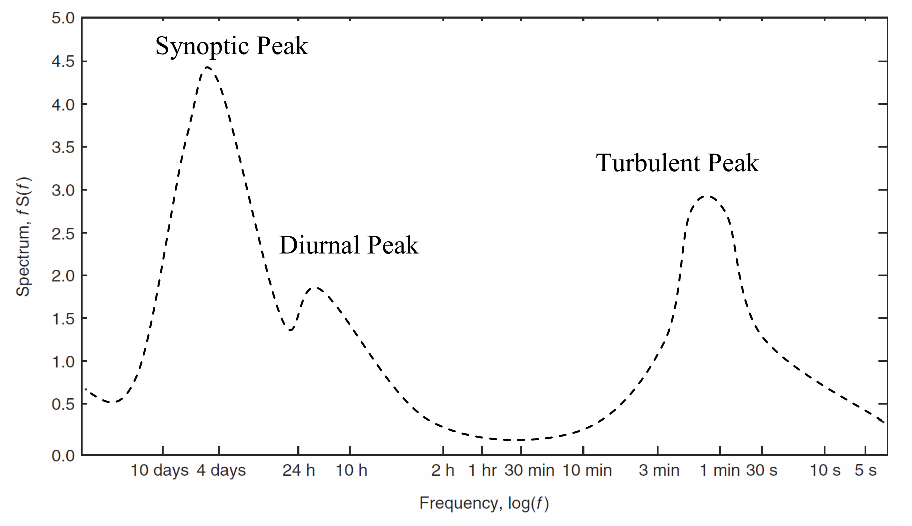


Figure 2.2 Power spectrum of wind speed variation

Fortuitously it is the timescales at which there is least variation, the so called spectral gap between 10 minutes and an hour or two, that pose the greatest challenge to power system operation.

The essential characteristics of the long term variations of wind speed can also be usefully described by a frequency or probability distribution. Figure 2.3 shows the frequency distribution for a year of 10 minute means recorded at Rutherford Appleton Laboratory, Oxfordshire UK [14, 15]. Its shape is typical of wind speeds across most of the world's windier regions, with the modal value (the peak) located below the mean wind speed and a long tail reflecting the fact that most sites experience occasional very high winds associated with passing storms. A convenient mathematical distribution function that has been found to fit well with data, is the *Weibull* probability density function. This is expressed in terms of two parameters, k, a shape factor, and C, a scale factor that is closely related to the long term mean. These parameters are determined on the basis of a best fit to the wind speed data. A number of mathematical approaches of differing complexity are available to perform this fitting [16].

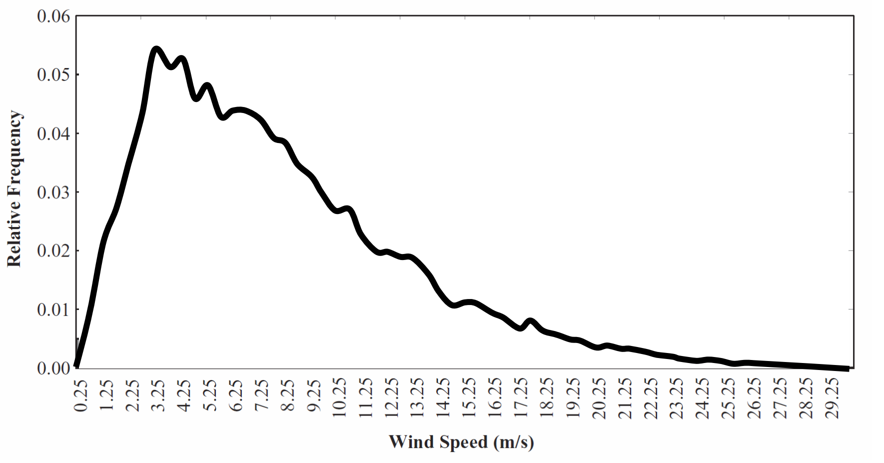


Figure 2.3 Frequency distribution of wind speed

2.3 Wind Turbines

The power of an air mass that flows at speed V through an area A can be calculated as follows:

$$\text{Power in wind} \qquad P = \frac{1}{2}\rho A V^3 \ \text{(watts)} \tag{2.1}$$

where

ρ - air density (kg m^{-3});

V - wind speed (m s^{-1}).

The power in the wind is proportional to the air density ρ, the intercepting area A (e.g. the area of the wind turbine rotor) and the velocity V to the third power. The air density is a function of air pressure and air temperature, which both are functions of the height above see level:

$$\rho(z) = \frac{P_0}{RT}\exp\left(\frac{-gz}{RT}\right) \tag{2.2}$$

where

$\rho(z)$ - air density as a function of altitude (kg m^{-3});

P_0 - standard sea level atmospheric density (1.225 kg m^{-3});

R - specific gas constant for air (287.05 J kg^{-1}K^{-1});

g - gravity constant (9.81m s^{-2});

T - temperature (K);

z - altitude above sea level (m).

The power in the wind is the total available energy per unit of time. The power in the wind is converted into the mechanical–rotational energy of the wind turbine rotor, which results in a reduced speed in the air mass. The power in the wind cannot be extracted completely by a wind turbine, as the air mass would be stopped completely in the intercepting rotor area. This would cause a ‘congestion’ of the cross-sectional area for the following air masses.
The theoretical optimum for utilizing the power in the wind by reducing its velocity was first discovered by Betz, in 1926. According to Betz, the theoretical maximum power P_{Betz} that can be extracted from the wind is

$$P_{Betz} = \frac{1}{2}\rho A V^3 C_{pBetz} = \frac{1}{2}\rho A V^3 \cdot 0.59 \qquad (2.3)$$

Hence, even if power extraction without any losses were possible, only 59% of the wind power could be utilized by a wind turbine.

2.3.1 Power curve

As explained by Equation (2.1), the available energy in the wind varies with the cube of the wind speed. Hence a 10% increase in wind speed will result in a 30% increase in available energy.
The power curve of a wind turbine follows this relationship between cut-in wind speed (the speed at which the wind turbine starts to operate) and the rated capacity, approximately (see Figure 2.4). The wind turbine usually reaches rated capacity at a wind speed of between 12-16ms^{-1}, depending on the design of the individual wind turbine. At wind speeds higher than the rated wind speed, the maximum power production will be limited, or, in other words, some parts of the available energy in the wind will be ‘spilled’. The power output regulation can be achieved with pitch-control (i.e. by feathering the blades in order to control the power) or with stall control (i.e. the aerodynamic design of the rotor blade will regulate the power of the wind turbine). Hence, a wind turbine produces maximum power within a certain wind interval that has its upper limit at the cut-out wind speed. The cut-out wind speed is the wind speed where the wind turbine stops production and turns out of the main wind direction. Typically, the cutout wind speed is in the range of 20 to 25 ms^{-1}. The power curve depends on the air pressure (i.e. the power curve varies depending on the height above sea level as well as on changes in the aerodynamic shape of the rotor blades, which can be caused by dirt or ice). The power curve of fixed-speed, stall-regulated wind turbines can also be influenced by the power system frequency.

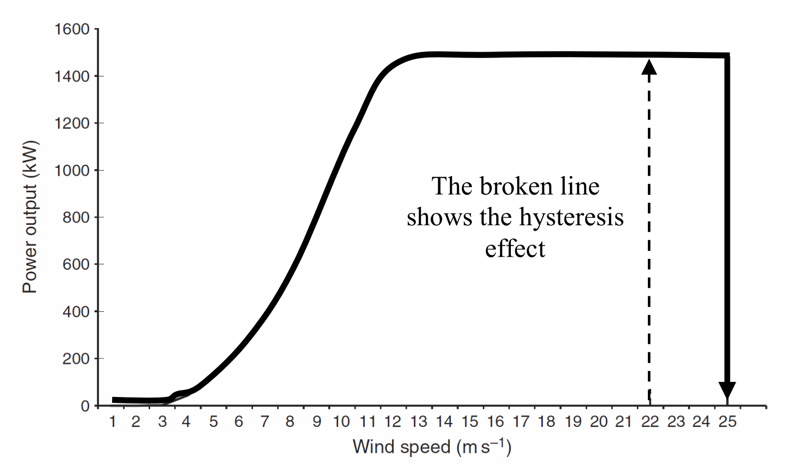


Figure 2.4 Power curve for a 1500 kW pitch regulated wind turbine with cut-out speed of 25 m s^{-1}.

Finally, the power curve of a wind farm is not automatically made up of the scaled-up power curve of the turbines of this wind farm, owing to the shadowing or wake effect between the turbines. For instance, if wind turbines in the first row of turbines that directly face the main wind direction experience wind speeds of 15 ms^{-1}, the last row may ‘get’ only 10 ms^{-1}. Hence, the wind turbines in the first row will operate at rated capacity, 1500 kW for the turbine in Figure 2.4, whereas the last row will operate at less than rated capacity (e.g. 1100 kW for the same turbines).

2.3.2. Hysteresis and cut-out effect

If the wind speed exceeds the cut-out wind speed (i.e. 25 ms^{-1} for the wind turbine in Figure 2.4) the turbine shuts down and stops producing energy. This may happen during a storm, for instance. When the wind drops below cut-out wind speed, the turbines will not immediately start operating again. In fact, there may be a substantial delay, depending on the individual wind turbine technology (pitch, stall and variable speed) and the wind regime in which the turbine operates. The restart of a wind turbine, also referred to as the hysteresis loop (see the broken line in Figure 2.4), usually requires a drop in wind speed of 3 to 4 ms^{-1}.

For the power system, the production stop of a significant amount of wind power arising from wind speeds that exceed the cut-out wind speed may result in a comparatively sudden loss of significant amounts of wind power. In European power systems, where wind power is installed in small clusters distributed over a significant geographic area, this shut down of a significant

amount of wind power as a result of the movement of a storm front usually is distributed over several hours. However, for power systems with large wind farms installed in a small geographic area, a storm front may lead to the loss of a significant amount of wind power in a shorter period of time (less than 1 hour). The hysteresis loop then determines when the wind turbines will switch on again after the storm has passed the wind farm.
To reduce the impact of a sudden shutdown of a large amount of wind power and to solve the issues related to the hysteresis effect, some wind turbine manufacturers offer wind turbines with power curves that, instead of an sudden cut out, reduce power production step by step with increasing wind speeds (see Figure 2.5). This certainly reduces the possible negative impacts that very high wind speeds can have on power system operation.

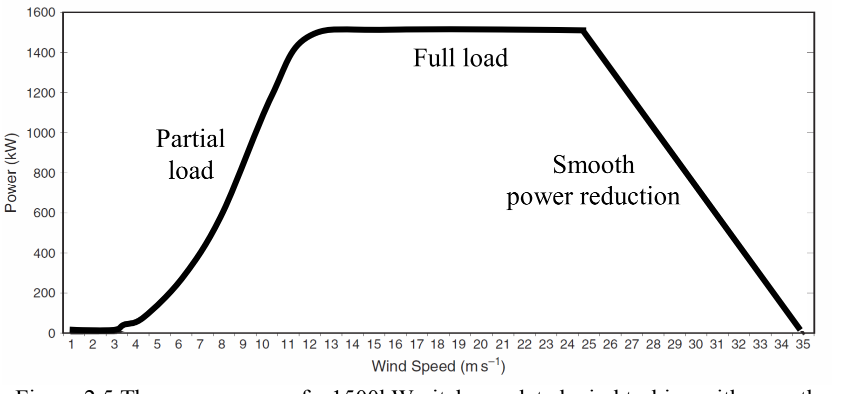


Figure 2.5 The power curve of a 1500kW pitch-regulated wind turbine with smooth power reduction during very high wind speeds

2.3.3 Impact of aggregation of wind power production

The aggregation of wind power provides an important positive effect on power system
operation and power quality. The positive effect of wind power aggregation on power system operation has two aspects:

- an increased number of wind turbines within a wind farm;
- the distribution of wind farms over a wider geographical area.

Increased number of wind turbines within a wind farm
An increased number of wind turbines reduces the impact of the turbulent peak (Figure 2.1) as gusts do not hit all the wind turbines at the same time. Under ideal conditions, the percentage variation of power output will drop as $n^{-1/2}$, where n is the number of wind generators. Hence, to achieve a

significant smoothing effect, the number of wind turbines within a wind farm does not need to be very large.

Distribution of wind farms over a wider geographical area
A wider geographical distribution reduces the impact of the diurnal and synoptic peak significantly as changing weather patterns do not affect all wind turbines at the same time. If changing weather patterns move over a larger terrain, maximum up and down ramp rates are much smaller for aggregated power output from geographically dispersed wind farms than from a very large single wind farm. The maximum ramp rate of the aggregated power output from geographically dispersed wind farm clusters in the range of 10 to 20 MW with a total aggregated capacity of 1000 MW, for instance, can be as low as 6.6 MW per minute, and single wind farms with an installed capacity of 200 MW have shown ramp rates of 20 MW per minute or more. The precise smoothing effect of the geographical distribution depends very much on local weather effects and on the total size of the geographical area. It must be emphasised that a distribution of wind farms over a larger geographical area usually has a positive impact on power system operation.

2.3.4 Probability density function

As explained in Section 2.1, the power production of a wind power plant is related to the wind speed [see Equation (2.1)]. Since wind speed varies, power production varies, too. There are two exceptions, though. If the wind speed is below the cut-in wind speed or is higher than the cut-out wind speed then power production will be zero. Figure 2.6 shows the structure of the probability density function (*pdf*), $f_P(x)$, of the total wind power from several wind power units during a specific period (e.g. one year). The total installed capacity (IC) is assumed to be C_{IC}. There is one discrete probability of zero production, p_0, when the wind speed is below the cut-in wind speed for all wind turbines or when the wind turbines are shut down because of too high winds. There is also one discrete probability of installed capacity, p_{IC}, when the wind speed at all pitch-controlled units lies between the rated wind speed and cut-out wind speed, and when for all stall-controlled turbines the wind speed lies in the interval that corresponds to installed capacity. Between these two levels there is a continuous curve where for each possible production level there is a probability. There is a structural difference between wind power production and conventional power plants, such as thermal power or hydropower. The difference is that these power plants have a much higher probability, p_{IC}, that the installed capacity is available and a much lower probability, p_0, of zero power production. For conventional power plants, there are normally only these two probabilities, which means that the continuous part of the (*pdf*) in Figure 2.6 will be equal to zero.

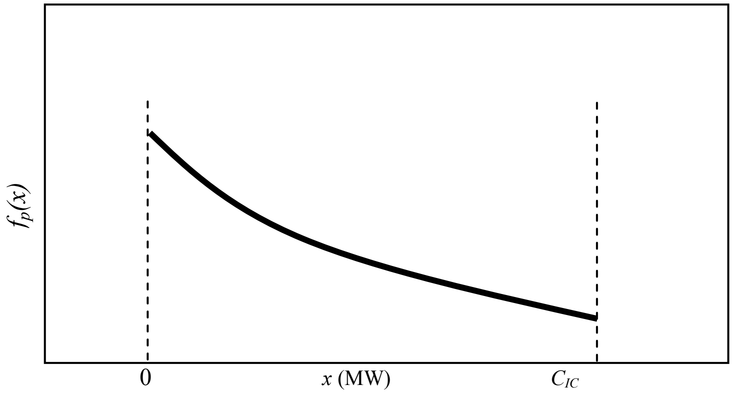


Figure 2.6 Probability density function for the available power production from several wind power units

The values of *p0* and p_{IC} decrease with an increasing total amount of wind power. This is owing to the fact that if there is a larger amount of wind power, the turbines have to be spread out over a wider area. This implies that the probability of zero wind speed at all sites at the same time decreases. The probability of high (but not too high) wind speeds at all sites at the same time will also decrease.

The mean power production of all units can be calculated as

$$P_m = \int_0^{C_{IC}} x f_p(x) dx \tag{2.4}$$

2.3.5 Capacity factor

The ratio P_m/C_{IC} is called the capacity factor (*CF*) and can be calculated for individual units or for the total production of several units. The capacity factor depends on the wind resources at the location and the type of wind turbine, but lies often in the range of about 0.25 (low wind speed locations) to 0.4 (high wind speed locations). The utilization time in hours per year is defined as 8760 P_m/C_{IC}. This value lies, then, in the range of 2200–3500 hours per year. In general, if the utilization time is high, the unit is most likely to be operating at rated capacity comparatively often.

The yearly energy production, *W*, can be calculated as

$$W = P_m \cdot 8760 = C_{IC} \cdot 8760 \cdot CF = C_{IC} \cdot t_{util} \tag{2.5}$$

where

CF - capacity factor;

t_{util} - utilization time.

Occasionally, the utilization time is interpreted as ‘equivalent full load hours’, and this is correct from an energy production perspective, but it is sometimes even misunderstood and assumed to be the operating time of a wind power plant.

Compared with base-load power plants, such as coal or nuclear power plants, the utilization time of wind power plants is lower. This implies that in order to obtain the same energy production from a base-load power plant and a wind farm, the installed wind farm capacity must be significantly larger than the capacity of the base-load power plant.

3. Diagrams of connection of dispersed generators into electric power system

3.1 Point of Common Coupling

The term *dispersed generation* or *embedded generation* refers to smaller generators that are usually connected to the distribution network. Distributed generation includes: generators powered from renewable energy sources (except large scale hydro and the largest wind farms); combined heat and power (CHP) systems, also known a co-generation (co-gen); standby generators operating grid connected, particularly when centralized generation is inadequate or expensive.

Smaller generators are not connected to the transmission system because of the cost of high voltage transformers and switchgear. Also, the transmission system is likely to be too far away since the geographical location of the generator is usually predetermined by the availability of the renewable energy resource. Such generators are *embedded* in the distribution network. An example of an embedded generator in a distribution network is shown in Figure 3.1. Distributed generation alters the power flows in distribution networks and breaks the traditional one - way power flow from the high to the low voltage layers of the power system. In some circumstances, a distributed generator can be accommodated into a distribution network without difficulty, but occasionally it can cause a variety of problems.

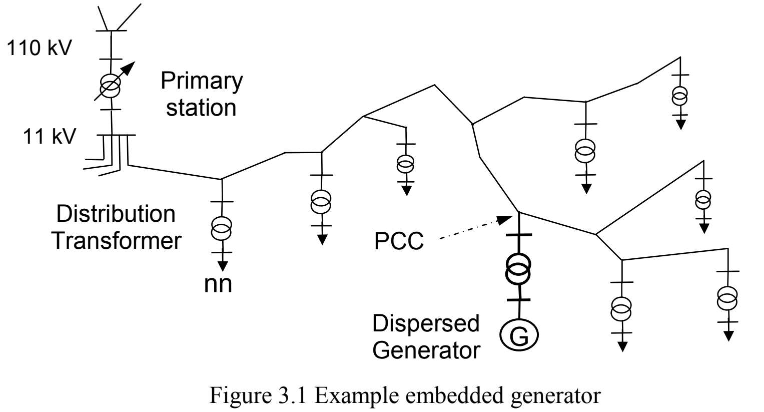


Figure 3.1 Example embedded generator

A basic requirement in connecting any generator to a power system is that it must not adversely affect the quality of electricity supplied to other customers on the network. With this in mind, it is useful to identify again the *point of common coupling* (PCC). Official definitions vary, but in simple terms the PCC is the point where the generator is connected to the public network as shown in Figure 3.1 . In other words, the PCC is the point on the network, nearest to the generator, at which other customers are, or could be, connected. Thus, the exact location of the PCC can depend on who owns the line between the generator and the rest of the network. The importance of the PCC is that it is the point on the public network at which the generator will cause most disturbance.

The impact of a renewable energy generator on the network is therefore very dependent on the fault level at the point of connection as well as on the size of the proposed generator. The appropriate voltage for connection of a distributed generator is largely dependent on its rated capacity. There are many other factors, as will be seen, and so a range of indicative figures are used as guidelines. Of course, whether a network is weak or not is entirely in relation to the size of the generator being considered. It is therefore common to express a proposed renewable energy source capacity (in MW) as a percentage of the fault level (in MVA) that can be labelled as 'short circuit ratio'. This can provide a rough guide to acceptability. Typical figures for wind farms range from 2 to 24%. These rules should ensure that the influence of the generator on the voltage at the point of connection is acceptable. Connecting at a higher voltage is usually more expensive because of the increased costs of transformers and switchgear and, most likely, because of the longer line required to make connection with the existing network. Connecting at too low voltage may not be allowed if the generator were to result in an excessive impact on the local network. This can lead to a situation where the developer of the renewable energy system wishes to connect at one voltage level for economic reasons, while the network operator suggests connection at the next level up.

3.2 Smaller, dispersed generators

There are two traditional types of smaller dispersed generators which operate interconnected with the utility system [83]. They are induction and synchronous generators. Induction machines are typically small-less than 500 kVA. These machines are restricted in size because their excitation is provided by an external source of VArs as shown in Figure 3.2. Induction generators are similar to induction motors and are started like a motor (no synchronizing equipment needed). Induction generators are less costly than synchronous generators because they have no field windings. Induction machines can supply real power (watts) to the utility but require a source of reactive power (VArs) which in some cases is provided by the utility system.

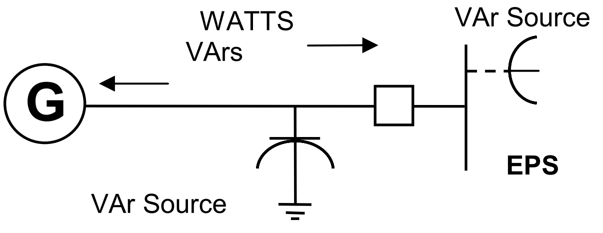


Figure 3.2 Induction Generator: excitation provided externally, start up like a motor (e.g. no synch. equipment needed), less costly than synchronous machines

Synchronous generators have a dc field winding to provide a source of machine excitation. They can be a source of both watts and VArs to the utility system as shown in Figure 3.2 and require synchronizing equipment to be paralleled with the utility.

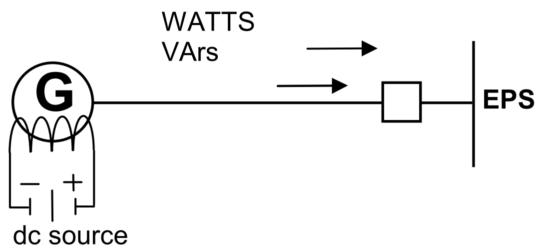


Figure 3.3 Synchronous Generator: dc field provides excitation, need to synchronize to utility system

Both types of machines require interconnection protection. Interconnection protection associated with induction generators typically requires only over/under voltage and frequency relaying. Non-traditional small dispersed generators, especially the new microturbine technologies, are being talked about more frequently as an energy source for the next years. Most of these machines are asynchronously connected to the power system through Static Power Converters (SPCs). These SPCs are solid-state microprocessor-controlled thyristor devices that convert AC voltage at one frequency to 50 Hz system voltage [17]. Digital electronic control of the SPC regulates the generator's power output and shuts down the machine when the utility system is unavailable. The need for independent protection to avoid system islanding has not yet been determined and is being addressed through Standards Coordinating Committee. Figure 3.4 shows a typical one-line diagram for these types of generators. As mentioned in the previous section, smaller independent power producers (IPPs) are generally connected to the utility system at the distribution level. In the European distribution systems are multi-grounded 4-wire systems. The use of this type of system allows single-phase, pole-top transformers, which typically make up the bulk of the feeder load, to be rated at line-to-neutral voltage.

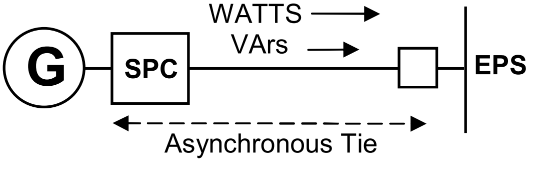


Figure 3.4 Asynchronous Generator: static power converter (SPC) converts generator frequency to system frequency, generator asynchronously connected to power system

Five transformer connections are widely used to interconnect dispersed generators to the utility system. Each of these transformer connections has advantages and disadvantages. Figure 3.5 shows a number of possible choices and some of the advantages/problems associated with each connection.

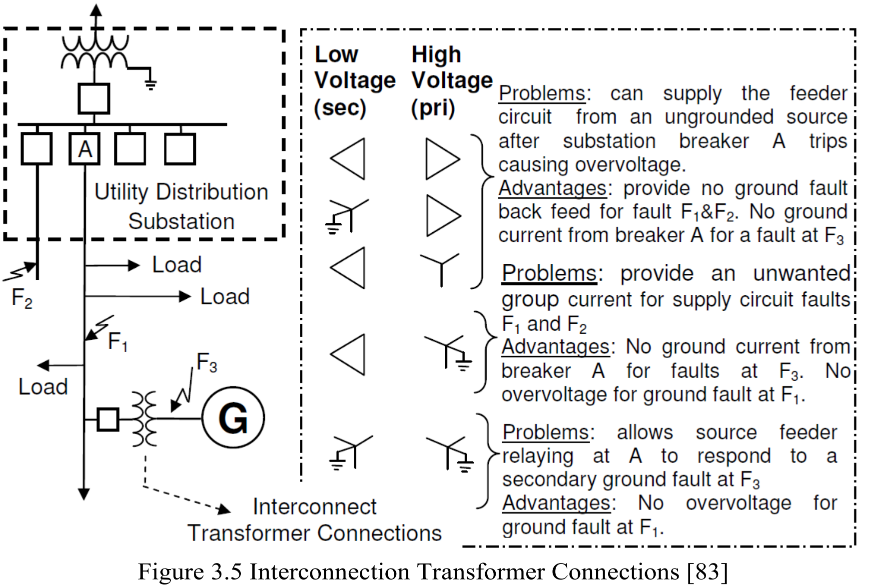


Figure 3.5 Interconnection Transformer Connections [83]

Delta (pri)/Delta (sec), Delta (pri)/Wye-Grounded (sec) and Wye-Ungrounded (pri)/Delta (sec) Interconnect Transformer Connections

The major concern with an interconnection transformer with an ungrounded primary winding is that after substation breaker A is tripped for a ground fault at location F1, the multi-grounded system is ungrounded subjecting the L-N (line-to-neutral) rated pole-top transformer on the unfaulted phases to an overvoltage that will approach L-L voltage. This occurs if the dispersed generator is near the capacity of the load on the feeder when breaker A trips. The resulting overvoltages will saturate the pole-top transformer which normally operates at the knee of the saturation curve as shown in Figure 3.6. Many utilities use ungrounded interconnection transformers only if a 200% or more overload on the generator occurs when breaker A trips. During ground faults, this overload level will not allow the voltage on the healthy phases to rise higher than the normal L-N voltage, avoiding pole-top transformer saturation. For this reason, ungrounded primary windings should be generally reserved for smaller dispersed generators where overloads of at least 200% are expected on islanding.

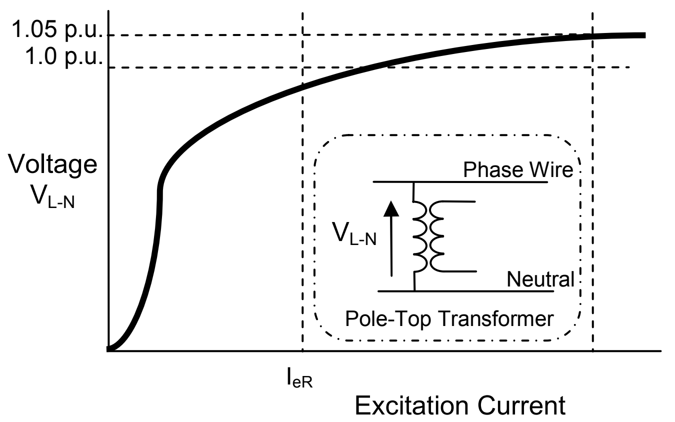


Figure 3.6 Saturation Curve of Pole-Top Transformer

Wye-Grounded (pri)/Delta (sec) Interconnect Transformer Connections

The major disadvantage with this connection is that it provides an unwanted ground fault current for supply circuit faults at F_l. Figure 3.7 illustrates this point for a typical distribution circuit. Analysis of the symmetrical component circuit shows that even when the dispersed generator is offline (the generator breaker is open), the ground fault current will still be provided to the utility system if the dispersed generator (DG) interconnect transformer remains connected. This would be the usual case since interconnect protection typically trips the generator breaker. The transformer at the dispersed generator site acts as a grounding transformer with zero sequence current circulating in the delta secondary windings. In addition to these problems, the unbalanced load current on the system, which prior to the addition of the dispersed generator transformer had returned to ground through the main substation transformer neutral, now splits between the substation and the dispersed generator transformer neutrals. This can reduce the load-carrying capabilities of the dispersed generator transformer and create problems when the feeder current is unbalanced due to operation of single-phase protection devices such as fuse and line reclosers. Even though the Wye-Grounded/ Delta transformer connection is universally used for large generators connected to the utility transmission system, it presents some major problems when used on 4-wire distribution systems. The utility should evaluate the above points when considering its use.

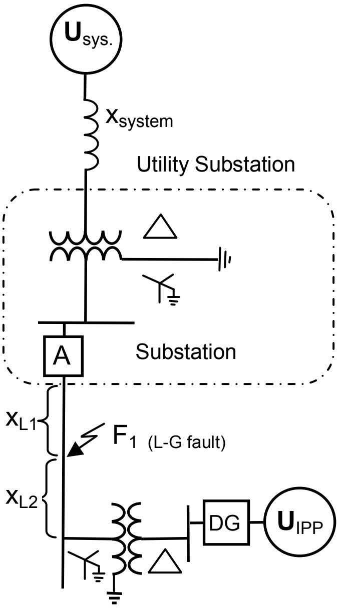


Figure 3.7 Single Line Diagram for *Wye-Grounded/Delta* Interconnection Transformer

Wye-Grounded (pri)/ Wye-Grounded (sec) Interconnect Transformer Connections.

The major concern with an interconnection transformer with grounded primary and secondary windings is that it also provides a source of unwanted ground current for utility feeder faults similar to that described in the previous section. It also allows sensitively-set ground feeder relays at the substation to respond to ground fault on the secondary of the dispersed generator transformer.

3.3 Large-scale Wind Power Plants

This subsection deals with the integration of large-scale Wind Power Plants (WPPs) connected to the transmission network rather than issues related to small distributed wind projects. There may be confusion among stakeholders about the differences and requirements between small dispersed generators projects connected to distribution system and large scale wind power plants connected to the transmission networks. Stakeholders should cooperate to set the boundaries and requirements for these projects. Such boundaries can be identified, taking into consideration the factors given in Table 3.1.

Table 3.1: Boundaries between distributed projects and large scale wind power plants

Boundary	**Distributed Wind Projects**	**Large Scale Wind Power Plants**
Connection to the Grid in Poland	Connected to distribution systems only ≤110 kV	Connected to high voltage transmission lines >110 kV
Installed Capacity	Stakeholders should set a threshold capacity (<20 MW in USA)	Stakeholders should set a threshold capacity For example this threshold is ≥20 MW in USA
Interconnection requirements	Stakeholders should work together to establish a set of technical requirements for interconnection. These requirements should be based on international standards for distributed generation such as IEC standards, IEEE standards 1549.	Stakeholders should work together to set the technical requirements that the new WPP needs to meet to be allowed to be connected. Such requirements should include: - Power Factor range - Voltage ride through - SCADA systems connected to system operators.
Interconnection request submittal	Developers of distributed wind projects should submit interconnection requests to local utilities queue of interconnection requests	Developers of large WPP should submit interconnection requests to transmission operator queue of interconnection requests
Impact studies	Utilities should perform impact studies to make sure this new installation will not affect the power quality of other customers on the same substation/feeder.	System operator needs to perform studies such as load flow, stability analysis and short circuit calculations to make sure this new WPP will not result in reliability risk for transmission network

Building large scale WPPs is better than building small wind farms for both the developers and the system operator for the following reasons:

- Small WPP has more production cost than larger ones;
- The existence of many small WPP (e.g. Germany experience) can

pose greater operational challenges for system operator in comparison with large plants with the same capacity. It will result in more effort/cost in:

- Interconnection studies;
- Interference with loads;
- Forecasting and dispatching.

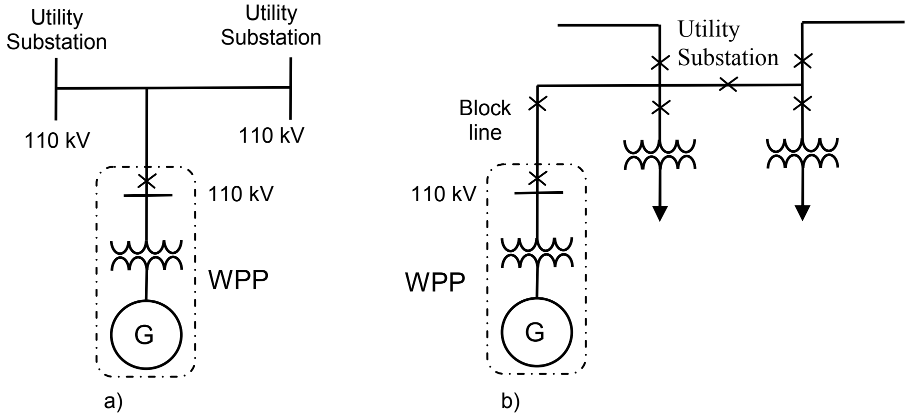


Figure 3.8 Methods for connecting Wind Power Plants to the National Power System: a) tap and b) radial connections

A typical WPP contains dozens to hundreds of megawatt-class turbines interconnected by a medium voltage network as shown in Figure 3.8 and Figure 3.9. New WPP projects around the world have a name plate from capacity from 20 MW to a capacity of up to 750 MW. The WPP is connected to the transmission network (>110 kV lines in case of the Poland grid) through one or more step up power transformers (Figure 3.10).

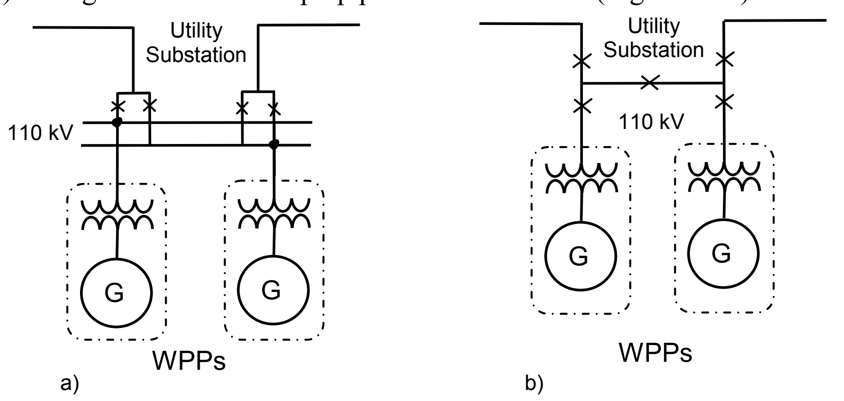


Figure 3.9 Methods for connecting Wind Power Plants to the National Power System: a) new station – 2W layout and b) New station – H layout

There may be reactive power compensation installed, usually at the MV of the WPP main substation. That depends on the wind turbine type and the voltage schedule/power factor requirements the WPP needs to meet.

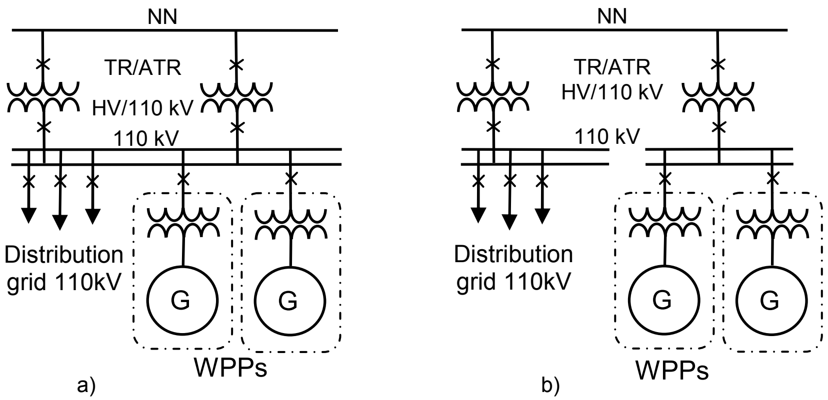


Figure 3.10 Methods for connecting Wind Power Plants to the National Power System: Connection to Highest Voltage/110 kV system stations: a) existing 110 kV switching station, b) detached TR (ATR)

4. Technical requirements for dispersed generators connection to the public electric power grids

This chapter provides a brief discussion and analysis of the current status of interconnection regulations for wind power in Europe. The chapter starts with a short overview of the relevant technical regulation issues, which includes a brief description of the relevant interconnection regulations considered in this chapter. This is followed by a detailed comparison of the different interconnection regulations. The discussion also includes the capabilities of wind turbines to comply with these requirements. In addition, a new wind farm control systems is briefly explained, which was developed particularly to comply with network interconnection requirements. Finally, issues related to international interconnection practice are briefly discussed.

4.1 Overview of Technical Regulations

Technical standards that are adopted by the industry often originate from standards developed by the Institute of Electrical and Electronic Engineers (IEEE) or from the International Electro-technical Commission (IEC). These standards are, however, voluntary unless a specific organization or legislative ruling requires the adoption of these standards. Hence, there is a large number of additional national or regional standards, requirements, guidelines, recommendations or instructions for the interconnection for wind turbines or wind farms worldwide. At the end of the 1980s, distribution network companies in Europe had to deal with small wind turbines and wind farms that wanted to be connected to the distribution network. At this time, the IEEE Standard 1001 (IEEE, 1988) IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems was the only IEEE guide in place that partly covered the connection of generation facilities to distribution networks. The standard included the basic issues of power quality, equipment protection and safety. The standard expired and, therefore, in 1998, the IEEE Working Group SCC21 P1547 started to work on a general recommendation for the interconnection of distributed generation, the IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE, 2003). Four years later, in September 2002, the working group finally agreed on a new standard. Back in the late

1980s, however, distribution network companies in Europe started to develop their own interconnection rules or standards. In the beginning, each network company that faced an increasing amount of interconnection requests for wind farms developed its own rules. During the 1990s, these interconnection rules where harmonized on a national level (e.g. in Germany or Denmark). This harmonization process often involved national network associations as well as national wind energy associations, which represented the interests of IPPs. In Europe, government organizations are hardly involved in the definition of interconnection guidelines. In other regions of the world, this can be different. In Texas and California, for instance, electricity regulation authorities were involved in defining the interconnection guidelines for distributed generation (DG) [see for instance the Interconnection Guidelines for Distributed Generation in Texas (PUCT, 1999) and the Distributed Generation Interconnection Rules (California Energy Commission, 2000) in California). In Europe, the harmonization of national interconnection rules was not the end of the development of such rules. National interconnection rules were continuously reformulated because of the increasing wind power penetration and the rapid development of wind turbine technology (i.e. wind turbine ratings increased rapidly, from around 200kW in the early 1990s to 3–4 MW turbines in early 2004). In addition, DG technology introduced new technologies such as doubly fed induction generators (DFIGs). Until then, generation technologies that used DFIGs with a rating of up to 3MW and combined a large number of these within one power station (i.e. wind farms) were unheard of in the power industry. Not only was the increased size of the wind turbines new but too was the increasing size of the DG, which resulted in interconnection requests at the transmission level. Hence, interconnection rules for wind farms to be connected to the transmission level were required. Unfortunately, the continuously changing network rules and the re-regulation of the power market make a comparison or evaluation of the already very complex interconnection rules very difficult and there is only very limited literature in this area.

4.2 Slow Voltage Variations

In the case of overhead distribution networks, the steady state voltage variations at the Point of Common Coupling (PCC) to the grid are usually the critical factor when examining the connection of new DG sources. Traditionally, utilities have imposed limiting values to the acceptable steady state voltage deviations from the nominal value, both at the MV and LV levels, which should not be exceeded in normal operation of the system. During the last decade, the statistical nature of the voltage variations has been recognized and relevant norms have been issued, such as the European Norm EN 50160, [18], which imposes statistical limits, in the sense that a small probability of exceeding them is acceptable. Checking the conformity with these limits at the planning stage calls for elaborate procedures, such as probabilistic load flow techniques (e.g. [19]), which are relatively difficult to apply and require data often unavailable in practice. For this reason, utility directives for the connection of DG adopt simpler and more straightforward procedures. The evaluation procedure of [20] is outlined in the following. It uses 10-min. average voltage values.

At a first stage, the maximum steady-state voltage change ε(%) at the PCC is evaluated and compared to the limit, using the following relation

$$\varepsilon(\%) \cong 100\frac{S_n}{S_k}\cos(\psi_k + \phi) = \frac{100}{R}\cos(\psi_k + \phi) \leq 3\% \tag{4.1}$$

where

S_n – is the DG rated apparent power,
S_k - is the network short circuit capacity at the PCC,
ψ_k - the phase angle of the network impedance,
φ - the phase angle of the DG output current,
$R=S/Sn$ - is the short circuit ratio at the PCC.

The 3% limit imposed (the German Guide [21] and other European national regulations impose an even more stringent 2% limit) is strict for two reasons:

- the grid voltage levels are determined by the aggregate effect of all connected consumers and generators and hence no single connection could be allocated the full variation limit;
- in order to achieve a (±10%) variation limit at the LV level, the MV grid voltage should be more narrowly bounded.

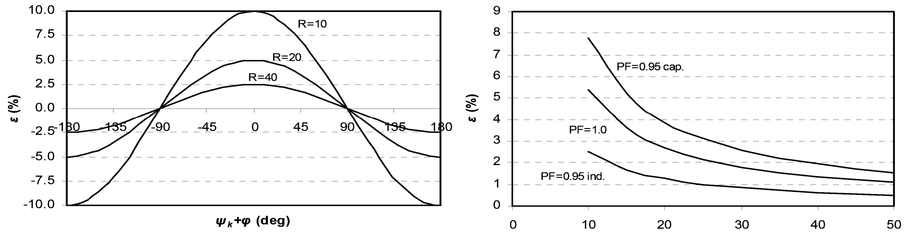


Figure 4.1 Voltage change ε(%) as a function of angle ($\psi_k+\varphi$), for three values of the short circuit ratio R (left diagram) and ε(%) as a function of R, for three power factor values of the DG (right diagram) [21].

Equation (4.1) is accurate enough for most practical purposes (its error being less than 0.5% for $R\geq15$). Depending on the grid angle ψ_k and the power factor angle φ of the installation, short-circuit ratios down to 15 or even lower may be acceptable, as illustrated in the left diagram of Figure 4.1. The effect of the DG power factor on the voltage variations is also important, as it is evident in the right diagram of Figure 4.1, drawn for ψ_k=~55° and DG power factor varying from 0.95 inductive to 0.95 capacitive.

The above procedure is generally unsuitable for cases of high DG penetration, multiple DG installations on the same feeder or when generators are connected to long feeders serving significant consumer load. In such cases, the resulting voltage variations are caused by the aggregate effect of all generating facilities and the existing (or planned) network loads. Therefore, load flow calculations are required, taking into account the actual network configuration and loads. Four basic load-generation combinations should be examined:

A. Minimum load-Minimum generation;
B. Minimum load-Maximum generation;
C. Maximum load-Minimum generation;
D. Maximum load- Maximum generation.

In typical rural overhead grids, case B yields the maximum and case C the minimum voltage levels. The maximum and minimum voltages, U_{max} and U_{min} of each node must be appropriately bounded. In [22] the following requirements are set for the steady state voltage of all nodes:

- The median voltage U_{med} of each node should not deviate more than ±5% from the nominal voltage U_n, so that it can be compensated by the fixed tap settings of the MV/LV distribution transformers (-5% to +5%, in steps of 2.5%):

$$0.95 \cdot U_n \leq U_{med} = \frac{U_{min} + U_{max}}{2} \leq 1.05 \cdot U_n \tag{4.2}$$

- The variation of the voltage around its median value should not exceed ±3% of the nominal voltage, so that the voltage level at the LV network remains within the ±10% limit, after the median deviation has been corrected:

$$2 \cdot \Delta U = U_{max} - U_{min} \leq 0.06 \cdot U_n \tag{4.3}$$

It should be noted that each of the four load flow scenarios has a certain probability of occurrence, which is difficult to evaluate in real-world situations. Hence, common sense and application of some engineering judgement are necessary, in order to exclude improbable situations. Proper account must also be taken of the voltage regulating means of the network (ULTCs of HV/MV transformers, line voltage regulators, switchable capacitors etc.), which normally operate on time scales of 30 s-1 min and therefore affect the steady-state (10- min average) voltage.

4.3 Rapid Voltage Changes - Flicker

According to the EN 50160 definition, rapid changes of the voltage are fast variations of its *rms* value between two consecutive levels, which are sustained for a certain (unspecified) duration. For consistency with the slow voltage changes definition, it is assumed that the rapid changes are much faster than the l0-min averaging interval.
Rapid voltage changes are induced either by switching operations within the premises of the DG installation (usually start/stop operations of equipment), or by the variability of the output power during normal operation. The magnitude of the change and the resulting flicker emissions should be limited, to avoid disturbing other nearby installations. Measures of the flicker emissions are the short term, *Pst,* and long term, *Pit,* flicker severity indices ([23,24]). Regarding switching operations, the limits imposed depend on the voltage level (LV or MV) where the customer is connected, the size of the equipment and the frequency of the operations. Taking into account the requirements of the relevant IEC documents, [23-26], the following limits are set in [27] for the relative (%) voltage change (Table 4.1):

Table 4.1: Rapid Voltage Magnitude Limits

	Rapid Voltage Magnitude Limits	Frequency of switching operations r h-hour, d-day		
LV		r>1 h^{-1}	2 d^{-1}< r <1 h^{-1}	r <2 d^{-1}
	Steady-state change, d_c	< 3,4%		
	Maximum change, d_{max}	< 4.4%	< 5,7 %	< 6.9%
MV		r>10 h^{-1}	2 d^{-1}< r <10 h^{-1}	r <1 h^{-1}
	Steady-state change, d_c	---------		
	Maximum change, d_{max}	< 2.1%	< 3,2 %	< 4.2%

A simplified evaluation of the voltage change at the PCC during the starting (cut-in) of the DG equipment can be made using the following relation:

$$d_{\max}(\%) = 100 \cdot k \cdot \frac{S_n}{S_k} = \frac{100}{R} k \tag{4.4}$$

For an accurate evaluation of $d_{max}(\%)$, k should be the voltage change factor k_u (ψ_k), which is defined for WTs in IEC 61400-21 CDV, [28], and is given as a function of the grid angle ψ_k. For simplified calculations, k can be set equal to the ratio of the equipment starting current to its rated current, ranging from less than 1 to higher than 8, depending on the type of equipment and the starting method used. Summation rules for simultaneous switchings of equipment need not be applied, due to the very low probability of coincident events.

Flicker emissions resulting from switching operations can be calculated as [28]:

$$P_{st} = \frac{18}{S_k}\left[\sum_{i=1}^{N} N_{10,i}\left(k_{f,i}(\psi_k)\cdot S_{n,i}\right)^{3.2}\right]^{1/3.2}$$
$$P_{lt} = \frac{8}{S_k}\left[\sum_{i=1}^{N} N_{120,i}\left(k_{f,i}(\psi_k)\cdot S_{n,i}\right)^{3.2}\right]^{1/3.2} \tag{4.5}$$

where

N - is the number of generators in the customer facilities operating in parallel;

$S_{n,i}$ - the rated capacity;

$K_{f,I}$ (ψ_k) - the flicker step factor of unit i (defined in [28]);

$N_{10,i}$ and $N_{120,i}$ - are the maximum number of switching operations that can take place in a l0-min and a 120-min interval for unit i.

If the flicker factor is unavailable, the flicker has to be evaluated either by the shape characteristics and the frequency of the disturbance (lEC 61000-3-

3, [26], provides useful guidance), or by simulation using a software implementation of the flickermeter algorithm of IEC 61000-4-15, [25].
At the LV level, limits for the calculated flicker indices, *Pst* and *Pit,* are:

$$P_{st} \leq 1.00 \; and \; P_{it} \leq 0.65 \tag{4.6}$$

At the MV level, the determination of exact limits is left to the utilities. In broad terms, depending on the compatibility levels (i.e. the existing disturbance level in the grid, [29]) and the internal quality objectives of the utility, the planning levels are set, which are the overall disturbance limits allowed at the planning stage (generally lower than the compatibility levels). Indicative values for the planning levels in MV systems, according to IEC 61000-3-7, are:

$$P_{st} \leq 0.90 \; and \; P_{it} \leq 0.70 \tag{4.7}$$

The allocation of the above limits to individual producers is made according to the principles presented in the next section for harmonics (equations similar to (10) and (12) are applied) and takes account of the following:

- Voltage flicker at the MV network is the combined result of emissions from loads connected at this voltage level and flicker transferred from the HV grid.
- The flicker emissions from individual installations are superimposed to determine the overall voltage flicker level in the network.

The following rule is commonly applied for the summation of flicker (used for P_{it} as well):

$$P_{st} = \sqrt[3]{\sum_i P_{st,i}^3} \tag{4.8}$$

During normal operation, voltage changes resulting from fluctuations of the DG output power may create flicker problems, which is a well-known concern for WTs, [33, 34]. According to the IEC 61400-21 CDV, the expected flicker indices of WTs can be assessed using the flicker coefficient, $c(\psi_k,\ v_a)$, dependent on the average annual wind speed (v_a), of the WT installation site and the grid short circuit impedance angle, ψ_k:

$$P_{st} = P_{lt} = c(\psi_k, v_a)\frac{S}{S_k} \tag{4.9}$$

For the total flicker emission of a wind farm comprising N WTs, the following relation is applied:

$$P_{st\sum} = P_{lt\sum} = \frac{1}{S_k}\sqrt{\left(c(\psi_k, v_a)\cdot S_i\right)^2} \tag{4.10}$$

Limits for flicker emissions during normal operation and their allocation to individual users of the system are the same as for switching operations.

4.4 Harmonics

The use of advanced power converters at the front end of many DG types (photovoltaics, fuel-cells, variable speed WTs and even small gas and hydro turbines) is constantly increasing, posing harmonic control requirements for their connection to the grid. During the last decade several national and interuational standards and recommendations have been developed (e.g. [30]), permitting the elaboration of appropriate evaluation procedures. In this section, the requirements of the Greek guide are outlined. The adopted approach is based on the IEC set of standards, comprising three basic steps: First, the definition of acceptable voltage distortion limits (planning levels), second, the allocation of global harmonic voltage limits to individual producers (or consumers) and third, the determination of the corresponding current distortion limits for a specific connection.

For LV systems specific compatibility levels are given in IEC 61000-2-2, [31], and IEC 61000-3-6, [32], which also serve as planning levels, and are included in Table 4.2.

Table 4.2 Planning levels for LV, MV and HV networks (IEC 61000-3-6)

Odd harmonics ≠ 3k				Odd harmonics = 3k				Even harmonics			
Order *h*	Harmonics voltage (%)			Order *h*	Harmonics voltage (%)			Order *h*	Harmonics voltage (%)		
	LV	MV	HV		LV	MV	HV		LV	MV	HV
5	6.1	5.1	2.2	**3**	5.2	4.3	2.1	**2**	2.1	1.7	1.6
7	5.2	4.2	2.1	**9**	1.6	1.3	1.3	**4**	1.3	1.1	1.1
11	3.5	3.0	1.6	**15**	0.4	0.4	0.4	**6**	0.6	0.6	0.6
13	3.2	2.2	1.4	**21**	0.2	0.2	0.2	**8**	0.5	0.4	0.4
17	2.3	1.3	1.0	**>21**	0.1	0.2	0.1	**10**	0.5	0.3	0.4
19	1.5	1.5	1.0					**12**	0.3	0.2	0.3
23	1.5	1.5	0.8					**>12**	0.2	0.2	0.2
25	1.5	1.5	0.6								
>25	0.3	0.3	0.3								
THD: 8.0% at LV, 6.5% at MV, 3.0% at HV											

At higher voltage levels (MV and HV), however, it is the responsibility of the utility to determine the compatibility levels in its network and then define appropriate planning levels. For reference purposes, Table 4.2 summarizes indicative planning

levels suggested in IEC 61000-3-6, which can be applied in the absence of more specific data.
The coordination of harmonic emission control at the different voltage levels (LV, MV and HV) of the system, requires to take account of distortion transmitted from one voltage level to the other. Hence, the distortion limit G_{hMV}, available to all installations connected to the MV system, can be found as

$$G_{hMV} = \sqrt[a]{L_{hMV}^{a} - \left(T_{hHV} \cdot L_{hHV}\right)^{a}} \tag{4.11}$$

where
L_{hMV} and L_{hHV} - are the MV and HV planning levels for the harmonic order h (from Table 4.2);
T_{hHM} - the harmonic transfer coefficient from HV to MV level (ranging from below 1.0 to more than 3);
a - is the exponent of the harmonic summation rule:

$$U_h = \sqrt[a]{\sum_i U_{hi}^{a}} \quad or \quad I_h = \sqrt[a]{\sum_i I_{hi}^{a}} \tag{4.12}$$

IEC 61000-3-6, [32], suggests: a=1 for h<5, a=1.4 for 5≤h≤10 and a=2 for h>10, since harmonics of higher order tend to have random phase angles.
From G_{hMV}, the voltage distortion limit E_{Uhi} for an individual installation can then be determined, in proportion to its rated power, $S_{n,i}$:

$$E_{Uhi} = G_{hMV}\sqrt[a]{\frac{S_{n,i}}{S_t}} = G_{hMV}\sqrt[a]{s_i} \tag{4.13}$$

where
S_t - is the total feeding capacity of the network (e.g. equal to the rated MV·A of the feeding transformer). The ratio s_i, can also be interpreted as the ratio of the connected equipment rated power to the total capacity of the *distorting* equipment in the network.
It is common practice in harmonic studies to regard the connected equipment as harmonic current sources (although this may not be correct in certain cases), whereas the limits discussed previously refer to the harmonic distortion of the system voltage. In order to relate these quantities, the system harmonic impedance Z_h at the PCC is needed. Then

$$U_{hi} = Z_h \cdot I_{hi} \leq E_{Uhi} \Rightarrow I_{hi} \leq E_{Ihi} = \frac{E_{Uhi}}{Z_h} \tag{4.13}$$

where
U_{hi} and I_{hi} - are the h-order harmonic voltage and current due to connection i;
E_{Uhi}, E_{Ihi} - the respective limits allocated to this connection.
For LV systems IEC 725, establishes a reference system impedance, permitting thus the direct determination of harmonic current limits, as defined in IEC 61000-3-2 and 61000-3-4. For MV systems, however, no standardized reference impedance is available and the evaluation of the system harmonic impedance Z_h is the most

difficult part of the whole procedure. A simplified approach can be established, with reference to the simplified network situation of Figure 4.2, where all network capacitance is aggregated at the MV busbars and any possible resonance in the HV system is ignored.

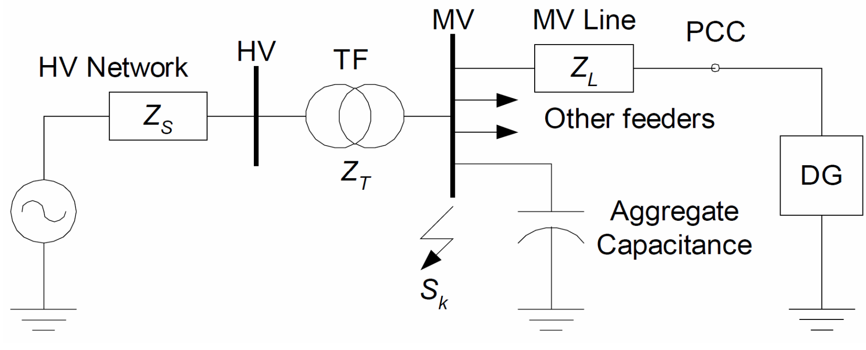


Figure 4.2 MV network equivalent for simplified harmonic emission evaluation

For systems without significant capacitance and no PFC correction capacitors or filters in the DG installations:

$$Z_h \approx h \cdot X_k \tag{4.14}$$

where

X_k - is the fundamental frequency inductive component of the short circuit impedance at the PCC.

The aggregate capacitance in Figure 4.2 accounts for the single parallel resonance with the upstream system (but not for other possible higher order resonances). If all resistances and system loads in Figure 4.2 are ignored, the resonant frequency f_r and the respective harmonic order h_r (not necessarily integer) are given by

$$f_r = f_1 \sqrt{\frac{S_{kS}}{Q_c}} \Rightarrow h_r = \frac{f_r}{f_1} = \sqrt{\frac{S_{kS}}{Q_c}} \tag{4.14}$$

where

S_{kS} - is the short circuit capacity at the MV busbars of the HV/MV substation;

Q_c - is the total capacitive reactive power of the MV network.

A rough and conservative estimation of Z_h (usually providing results on the safe side) is then given by the "envelope impedance curve" of IEC 61000- 3-

6, shown in Figure 4.3. The resonant amplification factor, *kr*, of the system impedance at the PCC typically varies between 2 and 5 in public distribution networks, depending mainly on the damping effect of the system loads. For installations with filters or significant PFC capacitance, in more complex networks or when there are resonances in the HV network, the approach presented above may not be suitable. Manual computation of Z_h is possible in certain cases (lEC 61000-3-6 provides relevant examples) but the application of harmonic load flow software is recommended, since the harmonic distortion of the voltage may be maximum at points other than the equipment PCC.

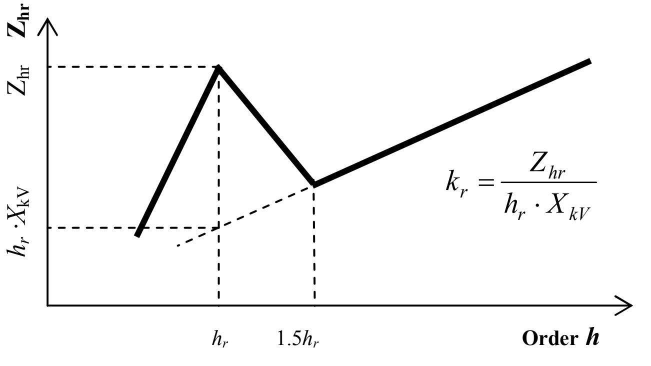


Figure 4.3 System harmonic impedance approximation, using the envelope impedance curve (IEC 61000-3-6)

5. Modeling of dispersed generators in power system analysis

5.1. Swing equation

The behavior of a synchronous generator during transients is described by the swing equation. It is convenient to measure the angular position of the machine rotor with respect to a reference axis, which is rotating at synchronous speed. For a two-pole machine one complete mechanical revolution corresponds to one electrical cycle what means that one electrical radian equals to one mechanical radian. If generator has p-pairs of poles then one mechanical revolution corresponds to p electrical cycles

$$\delta \text{ [electrical radian]} = \delta_r \text{ [mechanical radian]} \cdot p \tag{5.1}$$

The synchronous speed in electrical radians is represented by symbol as $\omega_s = 2\pi f_N$, where f_N means the nominal frequency (f_N = 50 Hz in Europe, f_N = 60 Hz in USA).

The rotor speed ω expressed in electrical radians per second can be related to the rotor speed in mechanical radians per seconds ω_m

$$\omega = \omega_m p = 2\pi f_m p \tag{5.2}$$

The mechanical frequency f_m is often expressed in revolutions per minute n *(rpm)*

$$f_m = \frac{np}{60} \tag{5.3}$$

For simplicity the swing equation will be developed for the two-pole synchronous generator. Let θ be the angular position of the rotor at any time t

$$\theta = \delta + \omega_s t \tag{5.4}$$

or

$$\delta = \theta - \omega_s t \tag{5.5}$$

Differentiating the above equation we have

$$\dot{\delta} = \frac{d\delta}{dt} = \frac{d(\theta - \omega_s t)}{dt} = \frac{d\theta}{dt} - \omega_s = \omega - \omega_s = \Delta\omega \tag{5.6}$$

Hence, the generator speed is the sum of the synchronous speed ω_s and the speed deviation $\Delta\omega$. The angular acceleration of a rotor can be determined by the second-order differential equation:

$$\ddot{\delta} = \frac{d^2\delta}{dt^2} = \frac{d^2\theta}{dt^2} = \frac{d\Delta\omega}{dt} = \Delta\dot{\omega} = \frac{d(\omega - \omega_s)}{dt} = \frac{d\omega}{dt} = \dot{\omega} \tag{5.7}$$

Any unbalanced torque applied to the rotor will result in the acceleration or deceleration of the rotor according to Newton's second law

$$J\frac{d\omega}{dt} = M_m - M_e - M_D \tag{5.8}$$

where

J – is the total inertia of the turbine and generator rotor,
M_m – is the input mechanical torque,
M_e – is the output electromagnetic torque,
M_D –is the damping torque.

The value of inertia varies over a wide range. It is a common practice to use a normalized inertia constant H instead of the total inertia. The inertia constant is defined as the stored kinetic energy at nominal rotor speed ω_{rN} divided by the generator rated power S_N

$$H = \frac{1}{2}\frac{\omega_{rN}^2}{S_N}J \tag{5.8}$$

where

S_N – is the generator rated power in $MV{\cdot}A$,
ω_{rN} – is the nominal rotor speed.

The inertia value of H is fairly constant for a given type of a generation unit. For cylindrical-rotor machines we have H=(2-15)s and for salient-pole machines
H=(1-4)s.

Example 5.1

Calculate the inertia constant H of the unit comprising hydro-turbine and synchronous generator.

Hydro-turbine

Turbine rated power	P_T= 4.7 MW,
Nominal turbine speed	n_T = 125 rev/min,
Turbine inertia moment	J_T=3800 kgm$^{2.}$

Synchronous generator

Generator rated power	S_N=6 MVA ,
Nominal generator speed	n_G=600 rev/min,
Generator inertia moment	J_G= 4100 kgm^2.

Solution

The nominal turbine speed

$$\omega_{TN} = 2\pi \frac{n_T}{60} = 2\pi \frac{125}{60} = 13.09 \ \ rad/s$$

The nominal rotor speed

$$\omega_{rN} = 2\pi \frac{n_G}{60} = 2\pi \frac{600}{60} = 6.28 \ \ rad/s$$

The total kinetic energy is the sum of the kinetic energy of both the turbine and the generator

$$\frac{J\omega_{rN}^2}{2} = \frac{J_G\omega_{rN}^2}{2} + \frac{J_T\omega_T^2}{2}$$

The total moment of inertia is simply the sum of the individual inertias

$$J = J_G + J_T\left(\frac{\omega_T}{\omega_{rN}}\right)^2 = J_G + J_T\left(\frac{n_T}{n_G}\right)^2$$

Substituting relevant values we have

$$J = 4100 + 3800\left(\frac{125}{600}\right)^2 = 4265kgm^2$$

The inertia constant H has the following value

$$H = \frac{1}{2}\frac{\omega_{rN}^2 J}{S_N} = \frac{1}{2}\frac{62.8^2 4265}{6\cdot 10^6} = 1.4\,s$$

It is common in Europe to use the mechanical time constant T_m instead of the inertia constant H

$$T_m = 2H \tag{5.9}$$

The mechanical time constant can be physically interpreted as the time range needed to accelerate the rotor from the position at rest to reach synchronous speed ω_{rN} using the mechanical torque

$$M_m = \frac{S_N}{\omega_{rN}} \tag{5.10}$$

The total moment of inertia can be expressed as follows

$$J = 2H \frac{S_N}{\omega_{rN}^2} = T_m \frac{S_N}{\omega_{rN}^2} \tag{5.11}$$

So we have

$$\frac{T_m S_N}{\omega_{rN}^2} \Delta\dot{\omega}_r = M_m - M_D - M_e \tag{5.12}$$

Multiplying torque by angular speed we obtain power $P = \omega M$. Dividing power by angular speed we obtain torque $M = P/\omega$.

Using the above substitution we have

$$\frac{T_m S_N}{\omega_{rN}^2} \Delta\dot{\omega}_r = \frac{P_m}{\omega_r} - M_D - \frac{P_e}{\omega_r} \tag{5.13}$$

where

$P_m = \omega_r M_m$ – is the input mechanical power,
$P_e = \omega_r M_e$ – is the output electrical power,
ω_r – is the actual rotor speed.

Multiplying equation by the rotor nominal speed ω_{rN} we obtain

$$\frac{T_m S_N}{\omega_{rN}} \Delta\dot{\omega}_r = \frac{\omega_{rN}}{\omega_r} P_m - \omega_{rN} M_D - \frac{\omega_{rN}}{\omega_r} P_e \tag{5.14}$$

During a disturbance, the rotor speed ω_r is close to the synchronous speed ω_s thus that

$$\frac{\omega_{rN}}{\omega_r} \cong 1 \tag{5.15}$$

As a result the swing equation can be rewritten as follows:

$$\frac{T_m S_N}{\omega_{rN}} \Delta\dot{\omega}_r = P_m - \omega_{rN} M_D - P_e \tag{5.16}$$

The rotor speed deviation depends on the number p of pairs

$$\Delta\omega_r = \omega_r - \omega_{rN} = \frac{\omega}{p} - \frac{\omega_N}{p} = \frac{\omega}{p} - \frac{\omega_s}{p} \tag{5.17}$$

Substituting the above relation we get

$$T_m S_N \frac{d(\omega / p - \omega_s / p)}{\omega_s / p \quad dt} = P_m - \frac{\omega_s}{p} M_D - P_e \tag{5.18}$$

$$T_m S_N \frac{d(\omega - \omega_s)}{\omega_s dt} = P_m - \frac{\omega_s}{p} M_D - P_e \tag{5.19}$$

$$\frac{T_m S_N}{\omega_s} \frac{d\Delta\omega}{dt} = P_m - \frac{\omega_s}{p} M_D - P_e \tag{5.20}$$

The damping torque is proportional to the damping-torque coefficient D

$$\frac{\omega_s}{p} M_D = D\Delta\omega \tag{5.21}$$

Finally, the swing equation can be expressed in the form of a differential equation which is the fundamental equation governing the rotor dynamics during transients

$$\frac{T_m S_N}{\omega_s} \Delta\dot{\omega} + D\Delta\omega = P_m - P_e \tag{5.22}$$

Sometimes the inertia coefficient is introduced

$$M = \frac{T_m S_N}{\omega_s} \left[\frac{s^2 MW}{rad} \right] \tag{5.23}$$

and then the differential equation takes the most common form

$$M\Delta\dot{\omega} + D\Delta\omega = P_m - P_e \tag{5.25}$$

Per unit calculations *(pu)* are often conducted in case of a multiple-machine system. Steady-state is determined using computer load flow program. Usually the base power is $S_b = 100\ MVA$ and the base voltage equals the nominal network voltage $U_b = U_{Nsi}$, where i means the bus index. To obtain the swing equation for the generation unit connected to the *i-th* bus we need to divide both sides of equation (5.22) by S_b

$$\frac{T_{mi} S_{Ni}}{\omega_s S_b} \Delta\dot{\omega}_i + \frac{\omega_s D_i}{\omega_s S_b} \Delta\omega_i = \frac{P_{mi}}{S_b} - \frac{P_{ei}}{S_b} \tag{5.26}$$

$$T_{mi}\frac{S_{Ni}}{S_b}\frac{\Delta\dot{\omega}_i}{\omega_s}+\frac{\omega_s D_i}{S_b}\frac{\Delta\omega_i}{\omega_s}=\frac{P_{mi}}{S_b}-\frac{P_{ei}}{S_b} \tag{5.27}$$

$$M_{ipu}\Delta\dot{\omega}_{ipu}+D_{ipu}\Delta\omega_{ipu}=P_{mipu}-P_{eipu} \tag{5.28}$$

where

$M_{ipu}=T_{mi}\frac{S_{Ni}}{S_b}$ - is the inertia coefficient of the *i-th* generator in *pu*,

$D_{ipu}=\frac{\omega_s D_i}{S_b}$ - is the damping coefficient of the *i-th* generator in *pu*,

$\Delta\omega_{ipu}=\frac{\Delta\omega_i}{\omega_s}$ - is the speed deviation od the *i-th* generator in *pu*.

From the numerical integration point of view it is more convenient to use two first-order equations instead of one second-order equation

$$\dot{\delta}_i=\Delta\omega_i=\omega_s\Delta\omega_{ipu} \tag{5.29}$$

$$\Delta\dot{\omega}_{ipu}=(P_{mi\,pu}-P_{e\,ipu}-D_{ipu}\Delta\omega_{ipu})/M_{ipu} \tag{5.30}$$

Note that the rotor angle is given in electrical radians and the rest of variables are in *pu*.

When only one generator is considered then the base power can be the same as the generator rated power $S_b = S_N$. Thus for one generator we have $M_{pu} = T_m$ and the swing equation has the following form in *pu*

$$\dot{\delta}=\omega_s\Delta\omega_{pu} \tag{5.31}$$

$$\Delta\dot{\omega}_{pu}=(P_{m\,pu}-P_{e\,pu}-D_{pu}\Delta\omega_{pu})/T_m \tag{5.32}$$

5.2. Classical model of the synchronous generator in transient states

The main simplification made in a classical model of the generator in transient state ignores the transient saliency, thus assuming $X_d^{'}=X_q^{'}$, (Figure 5.1.).

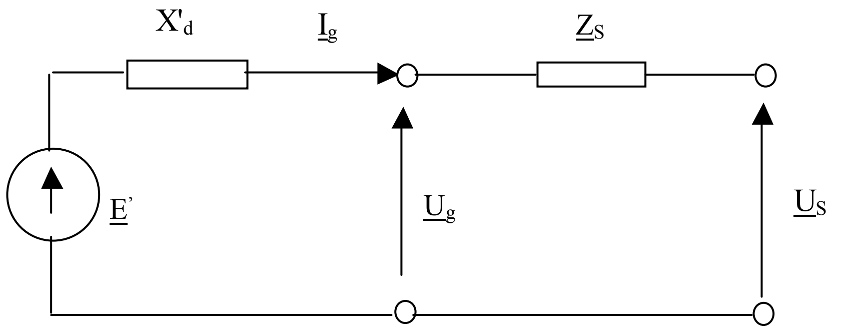


Figure 5.1. Equivalent scheme of generator in classical modeling.

If generator is connected to the power system through impedance Z_S then the generator voltage is

$$\underline{U}_g = U_S + \underline{Z}_S \underline{I}_g \tag{5.33}$$

The transient emf E' of a generator can be calculated using the known generator voltage $\underline{U}_g$ and current $\underline{I}_g$

$$\underline{E}' = \underline{U}_g + jX'_d \underline{I}_g \tag{5.34}$$

It is important to note that the angle of the transient emf δ' is the angle between the voltage at slack bus $\underline{U}_S$ = U_S+j0 and $\underline{E}'$, so the rotor angle becomes the following sum of angles

$$\delta = \delta' + \alpha \tag{5.35}$$

The value of α is small in comparison to δ' and may be neglected in simplified calculations (see Figure 5.2.). Hence, we get

$$E' \approx E'_q \text{ and } \delta \approx \delta' \tag{5.36}$$

$$\frac{d\delta}{dt} = \frac{d(\delta'+\alpha)}{dt} \approx \frac{d\delta'}{dt} \tag{5.37}$$

In simplified calculations the transient angle δ' can be considered equal to the rotor angle δ. The main advantage of the classic model is that the generator transient reactance is treated in calculations in the same way as the reactance of lines, transformers and other network elements. Therefore, we can use the real and imaginary parts of currents, voltages and *emf*.

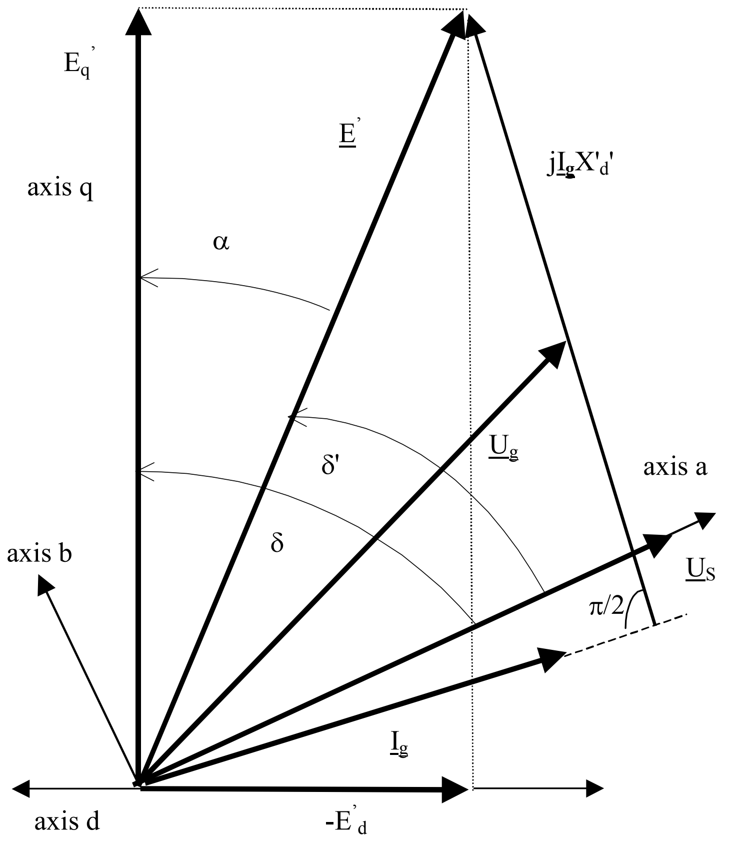


Figure 5.2. Phasor diagram of a generator in classical modeling.

5.3. Classic model of network in transient state

In simplified calculations the load $\underline{S}_i = P_{Li} + jQ_{Li}$ at any network node i may be modeled as constant shunt admittance.

$$\underline{y}_{pi} = \frac{\underline{S}_i^*}{U_i^2} \tag{5.38}$$

The active P_{Gi} and reactive Q_{Gi} at buses with a generator are treated as negative loads. So we have

$$\underline{S}_i = (P_{Li} - P_{Gi}) + j(Q_{Li} - Q_{Gi}) \tag{5.39}$$

Generator at any network node i is modeled as transient emf $\underline{E}_i = \underline{E}_i^{'}$ through transient reactance $X_{di}^{'}$ or complex generator admittance

$$\underline{y}_{Gi} = \frac{1}{jX_{di}^{'}} \tag{5.39}$$

Internal nodes with transient emf are connected to the network through transient reactances. All calculation should be done using the same base power and nominal network voltages.
Matrix equations of the enlarged network can be written as follows

$$\mathbf{I} = \mathbf{Y_{GG}}\,\mathbf{E} + \mathbf{Y}_{\mathrm{GL}}\,\mathbf{U}_{\mathrm{L}} \tag{5.40}$$

$$\mathbf{0} = \mathbf{Y}_{\mathrm{LG}}\,\mathbf{E} + \mathbf{Y}_{\mathrm{LL}}\,\mathbf{U}_{\mathrm{L}} \tag{5.41}$$

where

- $\mathbf{I}$ – is the vector of complex generator currents,
- $\mathbf{E}$ – is the vector of complex transient emfs,
- $\mathbf{U}_{\mathrm{L}}$ – is the vector of complex voltage at load nodes,
- $\mathbf{Y_{GG}}$ – is the submatrix of generator node admittances,
- $\mathbf{Y}_{\mathrm{LL}}$ – is the submatrix of load node admittances,
- $\mathbf{Y}_{\mathrm{GL}}$, $\mathbf{Y}_{\mathrm{LG}}$ – are other submatrices.

The complex voltage at load nodes are eliminated and then we have

$$\mathbf{I} = (\mathbf{Y_{GG}} - \mathbf{Y_{GL}}\mathbf{Y_{LL}^{-1}}\mathbf{Y_{LG}})\mathbf{E} = \mathbf{YE} \tag{5.42}$$

where

$\mathbf{Y} = \mathbf{Y_{GG}} - \mathbf{Y_{GL}}\mathbf{Y_{LL}^{-1}}\mathbf{Y_{LG}}$ - is the admittance transfer matrix.

The equivalent transfer network directly links all the generator nodes. Therefore the active power of a generator at a given node i can be calculated using the following node equations

$$P_{ei} = E_i^2 G_{ii} + E_i \sum_{j \neq i} E_j \left(G_{ij}\, cos(\delta_i - \delta_j) + B_{ij}\, sin(\delta_i - \delta_j) \right) \tag{5.43}$$

5.4. Small disturbance stability

For small disturbances the differential equations that describe the dynamics of the power system are mostly linear. Therefore it is considered small signal stability is considered small signal stability.

In simplified calculations the generator voltage regulation may be treated as proportional. It means that the value of transient *emf* is constant, thus

$$\Delta E_i = 0 \tag{5.44}$$

A loss of a synchronism is determined by the relative angles calculated with respect to a reference generator at slack bus. Usually, it is assumed that the first node of network acts as the reference generator. For this reason the power change at the i-*th* node can be expressed as follows [5]

$$\Delta P_{ei} = H_{i1}\,\Delta\delta_1 + H_{i2}\,\Delta\delta_2 + ... + H_{in}\,\Delta\delta_n \tag{5.45}$$

$$\Delta P_{ei} = H_{i1}\,\Delta\delta_1 + H_{i2}\Delta\delta_2 - H_{i2}\Delta\delta_1 + H_{i2}\Delta\delta_1 +.... + H_{in}\,\Delta\delta_n - H_{in}\,\Delta\delta_1 + H_{in}\,\Delta\delta_1 \tag{5.46}$$

$$\Delta P_{ei} = (H_{i1} + H_{i2} + ... + H_{in})\Delta\delta_1 + H_{i2}\Delta\delta_{21} +.... + H_{in}\,\Delta\delta_{n1} \tag{5.47}$$

$$\Delta P_{ei} = (H_{i1} + H_{i2} + ... + H_{in})\Delta\delta_1 + H_{i2}\Delta\delta_{21} + ... + H_{in}\,\Delta\delta_{n1} \tag{5.48}$$

However

$$H_{i1} + H_{i2} + ... + H_{in} = 0 \tag{5.49}$$

Finally, we obtain the following linear equation for the power change at the *i-th* node

$$\Delta P_{ei} = H_{i2}\Delta\delta_{21} + ... + H_{in}\,\Delta\delta_{n1} \tag{5.50}$$

To find the partial derivatives of a generator power one should take into considerations the exact formulas of load flow equations

$$P_{ei} = E_i^2 G_{ii} + E_i \sum E_j \left(G_{ij}\,cos(\delta_i - \delta_j) + B_{ij}\,sin(\delta_i - \delta_j) \right) \tag{5.51}$$

$$Q_{ei} = E_i^2 B_{ii} + E_i \sum E_j \left(- B_{ij}\,cos(\delta_i - \delta_j) + G_{ij}\,sin(\delta_i - \delta_j) \right) \tag{5.52}$$

The partial derivatives using the above load flow equations are as follows

$$H_{ii} = \frac{\partial P_{ei}}{\partial \delta_i} = E_i \sum_{j \neq i} E_j \left(G_{ij}\,sin(\delta_i - \delta_j) - B_{ij}\,cos(\delta_i - \delta_j) \right) \tag{5.53}$$

$$H_{ij} = \frac{\partial P_{ei}}{\partial \delta_j} = E_i E_j \left(G_{ij}\,sin(\delta_i - \delta_j) - B_{ij}\,cos(\delta_i - \delta_j) \right) \tag{5.54}$$

Generally, the linearized node equations can be written in the following matrix form

$$\mathbf{\Delta P} = \mathbf{H}\ \mathbf{\Delta \delta} \tag{5.55}$$

where

H – is the Jacobian matrix,

$\mathbf{\Delta P} = [\Delta P_{ei}]$ – is the vector of generator active power deviations,

$\mathbf{\Delta \delta} = [\Delta \delta_{i1}]$ – is the vector of rotor angle deviations relative to the reference generator.

The swing equations at the *i-th* node for small deviations have now the following form

$$\Delta\dot{\delta}_{i1} = \omega_s(\Delta\omega_i - \Delta\omega_1) \tag{5.56}$$

$$\Delta\dot{\omega}_i = (\Delta P_{mi} - \Delta P_{ei} - D_i\Delta\omega_i)/M_i \tag{5.57}$$

The deviation of input mechanical power may be neglected $\Delta P_{Ti} = 0$, then after substituting the formula of a power change we get

$$\Delta\dot{\delta}_{i1} = \omega_s(\Delta\omega_i - \Delta\omega_1) \tag{5.58}$$

$$\Delta\dot{\omega}_i = -H_{i2}\Delta\delta_{21}/M_i - H_{i3}\Delta\delta_{31}/M_i - \ldots - H_{in}\Delta\delta_{n1}/M_i - D_i\Delta\omega_i/M_i \tag{5.59}$$

For the reference generator we have only one differential equation [10]

$$\Delta\dot{\omega}_1 = -H_{12}\Delta\delta_{21}/M_1 - H_{13}\Delta\delta_{31}/M_1 - \ldots - H_{1n}\Delta\delta_{n1}/M_1 - D_1\Delta\omega_1/M_1 \tag{5.60}$$

For all generators we can write the following linear differential equation

$$\begin{bmatrix} \mathbf{\Delta\dot{\delta}} \\ \mathbf{\Delta\dot{\omega}} \end{bmatrix} = \begin{bmatrix} \mathbf{0} & \mathbf{W_s} \\ \mathbf{H_M} & \mathbf{D_M} \end{bmatrix} \begin{bmatrix} \mathbf{\Delta\delta} \\ \mathbf{\Delta\omega} \end{bmatrix} = \mathbf{A}\begin{bmatrix} \mathbf{\Delta\delta} \\ \mathbf{\Delta\omega} \end{bmatrix} \tag{5.61}$$

where

$$\mathbf{\Delta\delta} = [\Delta\delta_{21} \quad \Delta\delta_{31} \quad . \quad \Delta\delta_{i1} \quad . \quad \Delta\delta_{n1}]^T \tag{5.62}$$

$$\mathbf{\Delta}\omega = [\Delta\omega_1 \quad \Delta\omega_2 \quad \Delta\omega_3 \quad . \quad \Delta\omega_i \quad . \quad \Delta\omega_n]^T \tag{5.63}$$

$$\mathbf{A} = \begin{bmatrix} \mathbf{0} & \mathbf{W_s} \\ \mathbf{H_M} & \mathbf{D_M} \end{bmatrix} \tag{5.64}$$

$$\mathbf{W_s} = \begin{bmatrix} -\omega_s & \omega_s & & & & \\ -\omega_s & & \omega_s & & & \\ . & & . & . & & \\ -\omega_s & & & \omega_s & & \\ . & & & . & & \\ -\omega_s & & & & & \omega_s \end{bmatrix} \tag{5.65}$$

$$\mathbf{H_M} = \begin{bmatrix} -H_{12}/M_1 & -H_{13}/M_1 & . & -H_{1i}/M_1 & . & -H_{1n}/M_1 \\ -H_{22}/M_2 & -H_{23}/M_2 & . & -H_{2i}/M_2 & . & -H_{2n}/M_2 \\ . & . & . & . & . & . \\ -H_{i2}/M_i & -H_{i3}/M_i & . & -H_{ii}/M_i & . & -H_{in}/M_i \\ . & . & . & . & . & . \\ -H_{n2}/M_n & -H_{n3}/M_n & . & -H_{ni}/M_n & . & -H_{nn}/M_n \end{bmatrix} \tag{5.66}$$

$$\mathbf{D_M} = \begin{bmatrix} -D_1/M_1 & & & & & & \\ & -D_2/M_2 & & & & & \\ & & -D_3/M_3 & & & & \\ & & & . & & & \\ & & & & -D_i/M_i & & \\ & & & & & . & \\ & & & & & & -D_n/M_n \end{bmatrix} \tag{5.67}$$

Matrix **A** is known as the state matrix. The stability of a linear system is determined by the eigenvalues of the state matrix. The solution for each state variable is given by a linear combination of the dynamic modes

$$\Delta x_i(t) = \sum_{j=1}^{m} w_{ij}\, exp(\lambda_j t) z_{j0} \tag{5.68}$$

where

w_{ij} – is the element of the matrix W whose columns are the eigenvectors of matrix **A**,

λ_j – is the eigenvalue of matrix **A**,

z_{j0} – is the initial condition of mode z_j.

From the relation (5.68) it is clearly seen that, if any of the eigenvalues λ_j has a positive real part, then $\Delta x_i(t)$ tends to infinity. It means that the linear system described by such a state matrix **A** is unstable.

Concluding, we can say that a power system is stable for small deviations when all the eigenvalues of the state matrix **A** have negative real parts of the complex number.

Generally, the eigenvalue is a complex number

$$\lambda_i = a_i + jb_i = -\xi_i \omega_{mi} + j\omega_{mi}\sqrt{1-\xi_i^2} \tag{5.69}$$

where

ω_{mi} - is the undamped natural frequency of the *i-th* rotor small oscillations,

ξ_i - is the damping ratio of small oscillations,

$\omega_{di} = \omega_{mi}\sqrt{1-\xi_i^2}$ - is the natural damped frequency of small oscillations.

Knowing the complex value of a given eigenvalue we can calculate the undamped natural frequency

$$\omega_{mi} = \sqrt{a_i^2 + b_i^2} \tag{5.70}$$

and the damping ratio

$$\xi_i = -\frac{a_i}{\omega_{mi}} \tag{5.71}$$

5.5. Eigenvalue analysis of the state matrix

The linearized differential equations can be written in a matrix form

$$\dot{\mathbf{x}} = \mathbf{A}\mathbf{x} \tag{5.72}$$

The stability of small disturbance can be analyzed by evaluating the eigenvalues of the state matrix **A**. This matrix can be transformed into multiplication of three matrices

$$\mathbf{A} = \mathbf{M}\,\mathbf{\Lambda}\,\mathbf{N} \tag{5.73}$$

where

M = [$\mathbf{m_i}$] – is the matrix of right-hand eigenvectors $\mathbf{m_i}$,
N=$\mathbf{M^{-1}}$ – is the matrix of left-hand eigenvectors $\mathbf{n_i}$,
Λ = diag($\boldsymbol{\lambda_i}$) – is the diagonal matrix of eigenvalues $\boldsymbol{\lambda_i}$.

Multiplying the state variables by the left-hand eigenvector matrix gives the vector of modes **z**

$$\mathbf{z} = \mathbf{N}\,\mathbf{x} \tag{5.74}$$

Initial conditions of the mode can be found as

$$\mathbf{z_0} = \mathbf{N}\,\mathbf{x_0} \tag{5.75}$$

The state matrix equations get the following form

$$\dot{\mathbf{z}} = \mathbf{\Lambda z} \tag{5.76}$$

The solution for a given mode is as follows

$$z_j(t) = z_{j0} e^{\lambda t} \tag{5.77}$$

When all the modes are found then the state variable vector is a linear combination of all the modes

$$\mathbf{x} = \mathbf{M}\,\mathbf{z} \tag{5.78}$$

The solution for a given state variable $x_i(t)$ is determined by the linear combination of the modes

$$x_i(t) = \sum_{j=1}^{n} z_{j0} m_{ij} e^{\lambda_j t} \tag{5.79}$$

where

$$z_{j0} = n_{j1}x_{10} + n_{j2}x_{20} + ... + ... + n_{ji}x_{i0} + ... + n_{jn}x_{n0} \tag{5.80}$$

The components m_{ij} determine the relative contribution of the state variable $x_i(t)$ to the mode $z_j(t)$ is excited

$$x_i(t) = m_{i1}z_1(t) + ... + m_{ij}z_j(t) + ... + m_{in}z_n(t) \tag{5.81}$$

The components n_{ij} determine the relative contribution of a particular state variable $x_j(t)$, to a particular mode $z_i(t)$

$$z_i(t) = n_{i1}x_1(t) + ... + n_{ij}x_j(t) + ... + n_{in}x_n(t) \tag{5.82}$$

To determine a particular eigenvalue we may use the relevant eigenvectors

$$\mathbf{n_i^T A m_i} = \lambda_i \mathbf{n_i^T m_i} \qquad (5.83)$$

or

$$\lambda_i = \frac{\mathbf{n_i^T A m_i}}{\mathbf{n_i^T m_i}} \qquad (5.84)$$

The derivative of the eigenvalue λ_i relative the element a_{jj} of the state matrix **A** gives the contribution of state variable *j* in the mode *i*. It allows to find which state variable is the most associated with the eigenvalue λ_i .

$$\frac{\partial \lambda_i}{\partial a_{jj}} = \mathbf{n_i}^T \frac{\partial \mathbf{A}}{\partial a_{jj}} \mathbf{m_i} = n_{ij} m_{ji} = c_{ij} \qquad (5.85)$$

The coefficient c_{ij} depicts the contribution of the state variable x_j to the eigenvalue λ_i . Note that the sum of all the coefficients for a given eigenvalue should be equal to zero. For example for 3 dimensions we have

$$\mathbf{n_i^T m_i} = [n_{i1} \quad n_{i2} \quad n_{i3}] \begin{bmatrix} m_{1i} \\ m_{2i} \\ m_{3i} \end{bmatrix} = n_{i1}m_{1i} + n_{i2}m_{2i} + n_{i3}m_3 = c_{i1} + c_{i2} + c_{i3} = 1 \qquad (5.86)$$

5.6. Generator parameters in subtransient-, transient- and steady-state

It is important to use adequate model of synchronous generator when it is subject to an abrupt change in operating conditions. The detailed mathematical model of a generator is simplified for various states and results in different models for different states [35].

The following approximations are made:

- The rotor speed is near the synchronous speed, i.e. near 1 *pu*.
- The capacitance of all windings can be neglected.
- Distributed windings may be represented as concentrated windings.
- The magnetic circuits are linear and the inductance values are independent on the current.
- Leakage reactance exists only in a stator.
- The machine may be represented by a voltage source behind an impedance.

Using these approximations, classical theory leads to three models of a synchronous machine: in sub-transient state, in transient state and in steady-state. The following reactance's can be distinguished:

- X_{ld} , X_{lq} – are the armature leakage reactance's, which correspond to the path the armature leakage flux takes around the stator windings in *d*-axis or *q*-axis,
- X_{ad} , X_{aq} – are the armature reaction reactance's, which correspond to the flux path across the air-gap in *d*-axis or *q*-axis,
- X_D , X_D – are the damper winding reactance's, which correspond to flux path around damper winding in *d*-axis or *q*-axis,
- X_f – is the field winding reactance's, which correspond to the flux path around the field winding.

The armature reactance's are combined to give the equivalent reactance's in the sub transient, transient and steady-state.

Subtransient state

The *d*-axis subtransient reactance

$$X_d^{"} = X_l + \frac{1}{\frac{1}{X_{ad}} + \frac{1}{X_D} + \frac{1}{X_f}} \tag{5.87}$$

The *q*-axis subtransient reactance

$$X_q^{"} = X_{lq} + \frac{1}{\frac{1}{X_Q} + \frac{1}{X_{aq}}} \tag{5.88}$$

If a generator has only a *d*-axis damper winding, then the *q*-axis screening effect is much weaker than for the *d*-axis, and the corresponding *q*- axis subtransient reactance is greater then the *d*-axis subtransient reactance $X_q^{"} > X_d^{"}$.

If a generator has a damper winding in the *d*-axis and *q*-axis then the screening effect in both axis is similar $X_q^{"} \approx X_d^{"}$

Transient state

The *d*-axis transient reactance

$$X'_d = X_{ld} + \frac{1}{\frac{1}{X_{ad}} + \frac{1}{X_f}} \tag{5.89}$$

The q-axis transient reactance

$$X'_q = X_{lq} + \frac{1}{\frac{1}{X_{aq}}} = X_{lq} + X_{aq} \tag{5.90}$$

In a transient state screening is provided by the field winding, which is only in the d-axis. In a round-rotor generator some q-axis screening will be produced by eddy currents in the rotor iron and therefore $X'_q > X'_d$.

There is no screening in the q-axis in a salient-pole generator with laminated rotor construction and $X'_q = X_q$.

Steady-state

The d-axis synchronous reactance

$$X_d = X_{ld} + X_{ad} \tag{5.91}$$

The q-axis synchronous reactance

$$X_q = X_{lq} + X_{aq} \tag{5.92}$$

There is a symmetrical air-gap in both axes in a round-rotor generator, therefore $X_q \approx X_d$. In a salient-pole generator the air-gap is larger on the q-axis and therefore $X_q < X_d$.

Effect of winding resistance

A winding dissipates energy in its resistance at a rate proportional to the current squared and the stored magnetic energy decays with time determined by the circuit time constant.

The armature phase current decays with the armature time constant T_a determined by the equivalent inductance and resistance of the phase winding.

The damper winding current decays with the subtransient time constants. The field current decays with the transient time constants.

The following time constants are distinguished:

- T''_d, T''_q - are the subtransient short-circuit time constants in d-axis and q-axis,

- $T_{do}^{''}, T_{qo}^{''}$ - are the subtransient open-circuit time constants in *d*-axis and *q*-axis,
- $T_{d}^{'}, T_{q}^{'}$ - are the transient short-circuit time constants in *d*-axis and *q*-axis,
- $T_{do}^{'}, T_{qo}^{'}$ - are the transient open-circuit time constants in *d*-axis and *q*-axis.

There are following relations between the generator time constants:

$$T_{d}^{''} = T_{do}^{''} \frac{X_{d}^{''}}{X_{d}^{'}} \text{ and } T_{q}^{''} = T_{qo}^{''} \frac{X_{q}^{''}}{X_{q}^{'}} \tag{5.93}$$

$$T_{d}^{'} = T_{do}^{'} \frac{X_{d}^{''}}{X_{d}} \text{ and } T_{q}^{''} = T_{qo}^{'} \frac{X_{q}^{'}}{X_{q}} \tag{5.94}$$

These time constants depend on whether the *d*-axis armature coil is an open-circuit or a short-circuit.

6. Impact of dispersed generators on power load flow and voltage changes in electrical power network

An embedded generator is connected, by definition, to an electrical distribution network. This network is the conduit through which it exports the electrical energy that it produces. Since these exports can have a significant effect on the pattern of flows in the network, it is important to check that they will not degrade the quality of supply for the other users of the network. In most cases, this network was not designed for the sole use of the generator. It may indeed have been delivering power to consumers for many years before the embedded generator was commissioned. If the rating of this generator is a significant fraction of the capacity of the network, it will have a marked effect on the performance of this network. Reciprocally, this network can severely restrict the generator's ability to export power. An embedded generator must therefore be analyzed as a component of a system. Its proponents and the owners
of the distribution network must perform system studies to ascertain whether the network will need to be reinforced to accommodate the embedded generator. In some cases, these system studies may show that, rather than reinforcing the network, it may be more cost-effective to place limits or restrictions on the operation of the generator.
This chapter will review the per unit system, line and transformer parameters, bus admittance matrix and the purposes of power flow computations,

6.1. Power System Analysis

Practically all computations for a real power system having two or more voltage levels become very cumbersome. It becomes necessary to convert currents to a different voltage level wherever they flow through a transformer. In an alternative and simpler approach, a set of base values, or base quantities, is defined for each voltage level. Then all parameters and variables are expressed as a decimal fraction of the respective base. For instance, suppose a base voltage of 220 kV has been chosen, and under certain operating conditions the actual system voltage is 214 kV then the ratio of actual to base voltage is 0.97. The actual voltage may be then expressed as 0.97 per unit (*p.u.* or *pu*). The numerical per unit value of any quantity is defined as the ratio of its actual value to to the base value of the same dimension:

$$pu\_value = \frac{actual\_value}{base\_value} \tag{6.1}$$

Let us note that any per unit value is dimensionless. Four base quantities are required to completely define a per-unit system

- the base 3-phase power S_b in MVA,
- the base current I_b in kA,
- the base phase-to-phase voltage U_b in kV,
- the base impedance Z_b in ohms or base admittance Y_b in *S*.

Two base values are chosen arbitrary, i.e. S_b and U_b and two other are calculated using the following formulas:

$$Z_b = \frac{U_b}{\sqrt{3} I_b}; \quad S_b = \sqrt{3} U_b I_b; \quad Z_b = \frac{U_b^2}{S_b}; \quad Y_b = \frac{1}{Z_b} \tag{6.2}$$

where

Z_b - the base impedance in Ω,
Y_b - the base admittance in S,
I_b - the base current in kA.

Usually, the base power is chosen as S_b = 100 MV·A. The base voltage is chosen as the network nominal voltage at a given node $U_b=U_N$, kV. As a result we have the base impedance Z_b which is different for various voltage level

$$Z_b = \frac{U_b^2}{S_b} = \frac{U_N^2}{S_b}, \Omega \tag{6.3}$$

Now we can write using *pu* index

$$U_{pu} = \frac{U}{U_b} \tag{6.4}$$

$$S_{pu} = \frac{S}{S_b} \tag{6.5}$$

$$Z_{pu} = \frac{Z}{Z_b} \quad or \quad Y_{pu} = \frac{Y}{Y_b} \tag{6.6}$$

The same we can write for the complex values

$$\underline{S}_{pu} = \frac{\underline{S}}{S_b} = \frac{P + jQ}{S_b} = \frac{P}{S_b} + j\frac{Q}{S_b} = P_{pu} + jQ_{pu} = \frac{S}{S_b} e^{j\varphi} = S_{pu} e^{j\varphi} \tag{6.7}$$

$$\underline{Y}_{pu} = \frac{\underline{Y}}{Y_b} = \frac{G+jB}{Y_b} = \frac{G}{Y_b} + j\frac{B}{Y_b} = G_{pu} + jB_{pu} = \frac{Y}{Y_b}e^{-j\varphi} = Y_{pu}e^{-j\varphi} \tag{6.8}$$

$$\underline{Z}_{pu} = \frac{\underline{Z}}{Z_b} = \frac{R+jX}{Z_b} = \frac{R}{Z_b} + j\frac{X}{Z_b} = R_{pu} + jX_{pu} = \frac{Z}{Z_b}e^{j\varphi} = Z_{pu}e^{j\varphi} \tag{6.9}$$

Note that in *pu* representation $\sqrt{3}$ disappear in the complex power formula

$$\underline{S}_{pu} = \frac{\underline{S}_{MVA}}{S_b} = \frac{\sqrt{3}\underline{U}\underline{I}^*}{\sqrt{3}U_b I_b} = \frac{\underline{U}}{U_b}\frac{\underline{I}^*}{I_b} = \underline{U}_{pu}\underline{I}^*_{pu} \tag{6.10}$$

Obviously, all calculations performed in per unit representation give the same results as calculations conducted in MVA, kV, Ω and kA

$$U = U_{pu}U_b \tag{6.11}$$

$$S = S_{pu}S_b \tag{6.12}$$

$$Z = Z_{pu}Z_b \tag{6.13}$$

Parameters of transmission line in per unit representation

The base voltage for a line is the same as the nominal network voltage $U_b = U_N$. Hence the base impedance for a transmission line equals:

$$Z_b = \frac{U_N^2}{S_b} \tag{6.14}$$

Dividing the series parameters by the base impedance we obtain

$$R_{Lpu} = \frac{R_L}{Z_b} = \frac{R'l}{U_N^2/S_b} = R'l\frac{S_b}{U_N^2} \tag{6.15}$$

$$X_{Lpu} = \frac{X_L}{Z_b} = \frac{X'l}{U_N^2/S_b} = X'l\frac{S_b}{U_N^2} \tag{6.16}$$

For shunt parameters we have

$$B_{Lpu} = \frac{B_L}{Y_b} = B_L Z_b = B'l\frac{U_N^2}{S_b} \tag{6.17}$$

Transformer without tap regulation in per unit representation

The transformer without tap regulation are represented in load flow study by a Π-circuit. Usually, the transformer parameters are related to the high voltage side U_{NH} , so the nominal network voltage of upper voltage side U_N should be chosen as the base voltage. We need to point out that usually the rated transformer voltages are greater about 5% than the network nominal voltages.

Then we have

$$R_T = \frac{u_R}{100}\frac{U_{NH}^2}{S_N}, \Omega \;\; and \;\; R_{Tpu} = \frac{R_T}{Z_b} = \frac{u_R}{100}\frac{U_{NH}^2}{U_N^2}\frac{S_b}{S_N} \tag{6.18}$$

$$X_T = \frac{u_X}{100}\frac{U_{NH}^2}{S_N}, \Omega \;\; and \;\; X_{Tpu} = \frac{X_T}{Z_b} = \frac{u_X}{100}\frac{U_{NH}^2}{U_N^2}\frac{S_b}{S_N} \tag{6.19}$$

$$G_T = \frac{P_{Fe}}{U_{NH}^2}, S \;\; and \;\; G_{Tpu} = G_T Z_b = \frac{P_{Fe}}{S_b}\frac{U_N^2}{U_{NH}^2} \tag{6.20}$$

$$B_T = \frac{I_o}{100}\frac{S_N}{U_{NH}^2}, S \;\; and \;\; B_{Tpu} = B_T Z_b = \frac{I_o}{100}\frac{U_N^2}{U_{NH}^2}\frac{S_N}{S_b} \tag{6.21}$$

Transformer with on-load tap regulation in per unit representation

A convenient way to account for off-nominal turns ratio is to replace the actual turns ratio by some factious reactive shunt elements in such a way that these elements change the voltage up or down, as required. Fig. 6.1 presents the circuit of a transformer with tap regulation. The series impedance Z_T is replaced by its reciprocal Y_T in order to use the node voltage analysis

$$\underline{y} = \frac{1}{R_{Tpu} + jX_{Tpu}} \tag{6.22}$$

The shunt parameters are defined for the sending p and receiving end k of transformer

$$\underline{y}_p = \underline{y}_k = \frac{G_{Tpu} + jB_{Tpu}}{2} \tag{6.23}$$

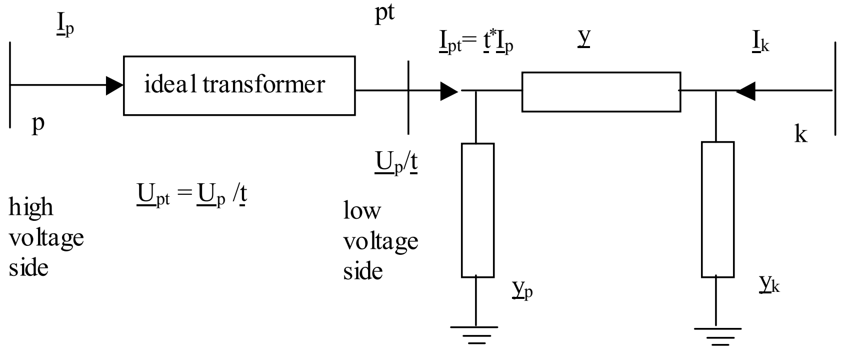


Figure 6.1. Scheme of transformer with on-load regulation

The nominal transformer ratio is defined as the quotient of the rated high and low voltages

$$t_N = \frac{U_{NH}}{U_{NL}} \tag{6.24}$$

The per unit transformer ratio is related to the nominal transformer ratio

$$t = \frac{t_{actual}}{t_N} = \frac{U_{high\,actual}}{U_{low\,actual}} \frac{U_{NL}}{U_{NH}} = \frac{U_{high\,pu} U_{Np}}{U_{low\,pu} U_{Nk}} \frac{U_{NL}}{U_{NH}} \tag{6.24}$$

where

U_{Np} - the nominal network voltage on the high voltage side of transformer,

U_{Nk} - the nominal network voltage on the low voltage side of transformer.

In general considerations the per unit transformer ratio is defined as a complex number. As a result phase-shifting transformer can be considered in a form:

$$\underline{t} = te^{j\theta} \tag{6.25}$$

To determine the equivalent Π-circuit for the transformer with tap regulation one can use the following admittance equations

$$\underline{I}_{pt} = \underline{Y}_{ptpt}\, \underline{U}_{pt} + \underline{Y}_{ptk}\, \underline{U}_k \tag{6.26}$$

$$\underline{I}_k = \underline{Y}_{kpt}\, \underline{U}_{pt} + \underline{Y}_{kk}\, \underline{U}_k \tag{6.27}$$

where

$\underline{Y}_{ptpt} = \underline{y} + \underline{y}_p$ – the self admittance of the pt node,

$\underline{Y}_{ptk} = -\underline{y}$ – the mutual admittance between the pt and k nodes,

$\underline{Y}_{kpt} = -\underline{y}$ – the mutual admittance between the k and pt nodes,

$\underline{Y}_{kk} = \underline{y} + \underline{y}_k$ – the self admittance of the k node.

For the ideal part of the transformer shown in Fig. 6.1 the complex power on both sides is the same and the current in the primary is equal to the secondary current multiplied by the conjugate of the ratio $\underline{t}^*$

$$\underline{S}_p = \underline{U}_p\, \underline{I}_p^* \tag{6.28}$$

$$\underline{S}_{pt} = \underline{U}_{pt}\, \underline{I}_{kp}^* = (\underline{U}_p/\underline{t})(\underline{t}^*\, \underline{I}_p)^* = (\underline{U}_p/\underline{t})(\underline{t}\, \underline{I}_p^*) = \underline{S}_p \tag{6.29}$$

$$\underline{U}_{pt} = \underline{U}_p \,/\, \underline{t} \tag{6.30}$$

$$\underline{I}_{pt} = \underline{t}^*\, \underline{I}_p \tag{6.31}$$

Substituting proper variables to equation (6.26) and (6.27) we obtain

$$\underline{I}_p = \underline{Y}_{pp}\, \underline{U}_p + \underline{Y}_{pk}\, \underline{U}_k \tag{6.32}$$

$$\underline{I}_k = \underline{Y}_{kp}\, \underline{U}_p + \underline{Y}_{kk}\, \underline{U}_k \tag{6.33}$$

The self admittance $\underline{Y}_{pp}$ can be described as follows

$$\underline{Y}_{pp} = \underline{Y}_{ptpt} / (\underline{t}^* \underline{t}) \tag{6.34}$$

$$\underline{Y}_{pp} = (\underline{y} + \underline{y}_p) / (\underline{t}^* \underline{t}) \tag{6.35}$$

$$\underline{Y}_{pp} = \underline{y} / \underline{t}^* + (1/\underline{t} - 1) / \underline{t}^* + \underline{y}_p / t^2 \tag{6.36}$$

The mutual admittance $\underline{Y}_{pk}$ equals

$$\underline{Y}_{pk} = \underline{Y}_{ptk} / \underline{t}^* = -\underline{y} / \underline{t}^* \tag{6.37}$$

The self admittance $\underline{Y}_{kk}$

$$\underline{Y}_{kk} = \underline{y} + \underline{y}_k \tag{6.38}$$

The mutual admittance $\underline{Y}_{kp}$ equals

$$\underline{Y}_{pk} = \underline{Y}_{kpt} / \underline{t} = -\underline{y} / \underline{t} \tag{6.39}$$

The above equations can be used to create the equivalent Π-circuit as shown in Figure 6.2. It is important to note that the series branch has a different admittance value depending on which side the transformer is viewed from. The shunt admittances on the p node side embrace $\underline{t}^2\ \underline{y}_p$, and the fictitious admittance $\underline{y}/\underline{t}^*$ + $(1/\underline{t} - 1)\underline{y}/\underline{t}^*$. The shunt admittances on the k node side embrace $\underline{y}_k$, and the fictitious admittance $(1\text{-}1/\underline{t})\ \underline{y}$. The fictitious shunt elements cause the change in the voltages in a series that corresponds to the voltage transformation in a real transformer.

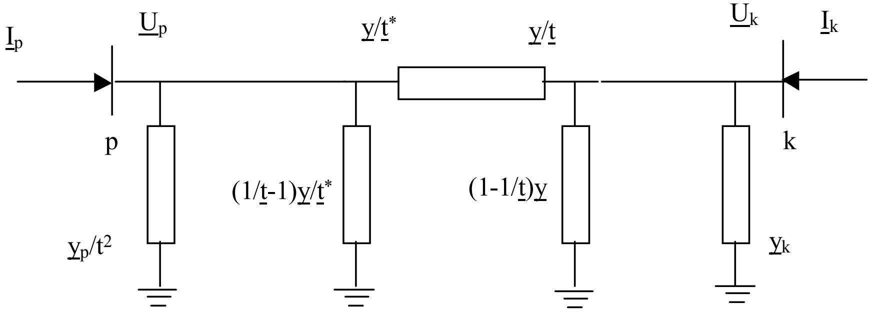


Figure 6.2 Equivalent circuit using factious shunt elements

6.2. Bus admittance matrix

In networks where there is no mutual coupling, simple rules may be used to form the bus admittance matrix $\mathbf{Y}_{\mathbf{bus}}$. The diagonal element $\underline{Y}_{ii}$ which is the self admittance of node i can be obtained as the algebraic sum of all admittances incident to node i of m:

$$\underline{Y}_{ii} = \sum_{j=0}^{m} \underline{y}_{ij} \tag{6.40}$$

The off diagonal element $\underline{Y}_{ij}$ = $\underline{Y}_{ji}$ which is the mutual admittance between the node *i* and *j* equals the negative value of the admittance connecting nodes *i* and *j*

$$\underline{Y}_{ij} = \underline{Y}_{ji} = -\underline{y}_{ij} \tag{6.41}$$

The bus admittance matrix properties are as follows

- square of order $m \cdot m$,
- symmetrical, since $\underline{Y}_{ij} = \underline{Y}_{ji}$,
- complex,
- highly sparse because of very few nonzero mutual admittances.

6.3. Load flow equations

Section 6.1 looked at the maths describing an individual overhead line or underground cable. Vast power systems are likely to have thousands of such lines, all interconnected. The same basic maths applies to each and every line, but now the equations must be solved simultaneously. Structured procedures for such calculations are known as *load flow*. A basic load flow calculation provides information about the voltages and currents and complex power flows throughout a network, at a particular point in time, with a given set of load and generation conditions. Additional information, such as losses or line loadings, can then be easily calculated. Load flow analysis is an essential tool that provides the following vital information for the

design as well as the operation and control of power systems:

- checking whether equipment run within their rated capacity;
- checking that voltages throughout the network are kept within acceptable limits;
- ensuring that the power system is run as efficiently as possible;
- ensuring that the protection system will act appropriately under fault conditions and that
- under likely contingencies the system will remain secure and operational;
- assisting in the planning of the expansion of conventional and renewable generation and the necessary strengthening of the transmission and distribution system to meet future increases in power demand.

In small networks, it is often possible to obtain valid and useful results by direct application of the mathematical analysis presented earlier. Also, larger networks can often be reduced to equivalent circuits that can be solved in the same way. However, load flow analysis of any system beyond a few nodes is carried out by a computer.
Each bus of a power network is characterized by a number of variables. For a network
with predominantly reactive transmission line impedances all these variables are linked by the complex Equation (6.42):

$$\mathbf{I}_{\mathbf{bus}} = \mathbf{Y}_{\mathbf{bus}} \cdot \mathbf{U}_{\mathbf{bus}} \tag{6.42}$$

However, in practice node powers are used instead of node currents. For a given node i we have

$$\underline{S}_i = P_i + jQ_i = \underline{U}_i \underline{I}_i^*, \quad i = 1,2,..,m \tag{6.43}$$

where

$\underline{S}_i$ - the complex node power,

$\underline{U}_i$ - the complex node voltage,

$\underline{I}_i$ - the complex node current,

P_i - the active node power,

Q_i - the reactive node power,

m - the number of power system nodes.

The complex node current can be calculated using the following formula [36]:

$$\underline{I}_i = \frac{\underline{S}_i^*}{\underline{U}_i^*} = \frac{P_i - jQ_i}{\underline{U}_i^*} \tag{6.44}$$

Generally, the positive sign (+) means injection, and negative (-) - drain. Consequently, (+) means to a node, and (-) from a node. Generation is to a node P_g (+), Q_g (+). Load is from node P_{odb} (-), Q_{odb} (-).

The Kirchhoff's current law in term of node voltages may be written as

$$\underline{I}_i = \sum_{j=0}^{m} \underline{I}_{ij} = \sum_{j=0}^{m} \underline{U}_{ij} \underline{y}_{ij} = \sum_{j=0}^{m} \left(\underline{U}_i - \underline{U}_j\right) \underline{y}_{ij} \tag{6.45}$$

where

m – the total node number, where 0 means ground,
$\underline{y}_{ij}$ – the branch admittance between nodes i and j,
$\underline{y}_{i0} = \underline{y}_{i1p} + \underline{y}_{i1p} + \underline{y}_{i2p} + ... + \underline{y}_{inp}$ – the shunt admittance at the node i equal the sum of all shunt admittances connected to the node i,
$\underline{U}_i$, $\underline{U}_j$ – the complex voltage at the nodes i and j respectively.

Substituting (2.45) to (2.43) we can determine the complex node power equation

$$\underline{S}_i = \underline{U}_i \underline{I}_i^* = \underline{U}_i \sum_{j=0}^{m} \underline{I}_{ij}^* = \underline{U}_i \sum_{j=0}^{m} \left(\underline{U}_i^* - \underline{U}_j^*\right) \underline{y}_{ij}^* = \sum_{j=0}^{m} \left(\underline{U}_i \underline{U}_i^* - \underline{U}_i \underline{U}_j^*\right) \underline{y}_{ij}^* \quad (6.46)$$

$$\underline{S}_i = \sum_{j=0}^{m} \left(U_i^2 \underline{y}_{ij}^* + \underline{U}_i \underline{U}_j^* (-\underline{y}_{ij}^*)\right) = \sum_{j=0}^{m} \left(U_i^2 \underline{y}_{ij}^*\right) + \sum_{j=0}^{m} \left(\underline{U}_i \underline{U}_j^* (-\underline{y}_{ij}^*)\right) \quad (6.47)$$

$$\underline{S}_i = \sum_{j=0}^{m} \left(U_i^2 \underline{y}_{ij}^* + \underline{U}_i \underline{U}_j^* (-\underline{y}_{ij}^*)\right) = \sum_{j=0}^{m} \left(U_i^2 \underline{y}_{ij}^*\right) + \sum_{j=0, j\neq i}^{m} \left(\underline{U}_i \underline{U}_j^* (-\underline{y}_{ij}^*)\right) \quad (6.48)$$

$$\underline{S}_i = U_i^2 \sum_{j=0}^{m} \left(\underline{y}_{ij}^*\right) + \sum_{j=0, j\neq i}^{m} \left(\underline{U}_i \underline{U}_j^* (-\underline{y}_{ij}^*)\right) \quad (6.49)$$

Taking into account that the self admittance of node *i* equals

$$\underline{Y}_{ii} = \sum_{j=0}^{m} \underline{y}_{ij} \quad (6.50)$$

and the mutual admittance between nodes *i* and *j* is

$$\underline{Y}_{ij} = -\underline{y}_{ij} \quad (6.51)$$

we get the load flow equation in the complex form

$$\underline{S}_i = \underline{Y}_{ii}^* U_i^2 + \sum_{j=0, j\# i}^{m} \left(\underline{U}_i \underline{U}_j^* \underline{Y}_{ij}^*\right) \quad (6.52)$$

Load flow equations in rectangular coordinates

A node voltage can be written in rectangular coordinates, Figure 6.3.

$$\underline{U}_i = e_i + jf_i \quad (6.53)$$

where

e_i – the real part of node voltage,

f_i – the imaginary part of node voltage.

Using rectangular coordinates we obtain

$$U_i^2 Y_{ii}^* = U_i^2 (G_{ii} - jB_{ii}) = U_i^2 G_{ii} - jU_i^2 B_{ii} \quad (6.54)$$

$$\underline{U}_i \underline{U}_j^* = (e_i + jf_i)(e_j - jf_j) = e_i e_j + f_i f_j + j(-e_i f_j + f_i e_j) = K_{ij} + jL_{ij} \quad (6.55)$$

$$\underline{U}_i \underline{U}_j^* Y_{ij}^* = (K_{ij} + jL_{ij})(G_{ij} - jB_{ij}) = K_{ij} G_{ij} + L_{ij} B_{ij} + j(-K_{ij} B_{ij} + L_{ij} G_{ij}) \quad (6.56)$$

where

$K_{ij} = e_i e_j + f_i f_j$,

$L_{ij} = -e_i f_j + f_i e_j$.

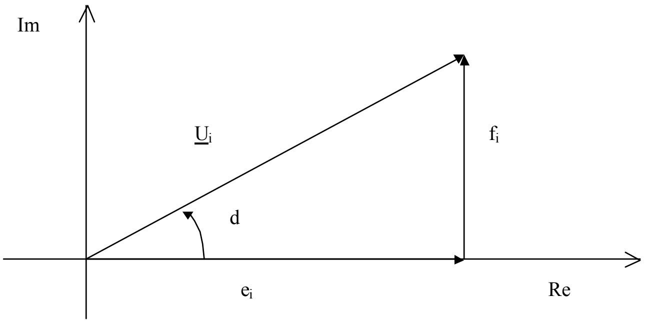


Figure. 6.3. Node voltage phasor as the complex number

Distinguishing between the active and reactive node powers we have

$$\underline{S}_i = P_i + jQ_i = U_i^2 G_{ii} - jU_i^2 B_{ii} + \sum_{j=0, j\# i}^{m} \left(K_{ij} G_{ij} + L_{ij} B_{ij} \right) + j \sum_{j=0, j\# i}^{m} \left(-K_{ij} B_{ij} + L_{ij} G_{ij} \right) \qquad (6.57)$$

After separating the active and reactive node powers:

$$P_i = U_i^2 G_{ii} + \sum_{j=0, j\# i}^{m} \left((e_i e_j + f_i f_j) G_{ij} + (-e_i f_j + f_i e_j) B_{ij} \right) \qquad (6.58)$$

$$Q_i = -U_i^2 B_{ii} + \sum_{j=0, j\# i}^{m} \left(-(e_i e_j + f_i f_j) B_{ij} + (-e_i f_j + f_i e_j) G_{ij} \right) \qquad (6.59)$$

Load flow equations in polar coordinates

Node voltage can be rewritten using the trigonometric form

$$\underline{U}_i = e_i + jf_i = U_i \cos\delta_i + jU_i \sin\delta_i \qquad (6.60)$$

where

U_i – the magnitude of a node voltage,
δ_i – the angle of a node voltage,
$e_i = U_i \cos\delta_i$,
$f_i = U_i \sin\delta_i$.

So we have

$$K_{ij} = e_i e_j + f_i f_j = U_i U_j \cos\delta_i \cos\delta_j + U_i U_j \sin\delta_i \sin\delta_j \qquad (6.61)$$

$$K_{ij} = U_i U_j \cos(\delta_i - \delta_j) \qquad (6.62)$$

$$L_{ij} = -e_i f_j + f_i e_j = -U_i U_j \cos\delta_i \sin\delta_j + U_i U_j \sin\delta_i \cos\delta_j \tag{6.63}$$

$$L_{ij} = U_i U_j \sin(\delta_i - \delta_j) \tag{6.64}$$

Finally we obtain the new formula for the active node power

$$P_i = U_i^2 G_{ii} + U_i \sum U_j \left(G_{ij} \cos(\delta_i - \delta_j) + B_{ij} \sin(\delta_i - \delta_j) \right) \tag{6.65}$$

and reactive node power

$$Q_i = -U_i^2 B_{ii} + U_i \sum U_j \left(-B_{ij} \cos(\delta_i - \delta_j) + G_{ij} \sin(\delta_i - \delta_j) \right) \tag{6.66}$$

These last equations relate the active and reactive power injection at a bus to the voltage magnitude and angle at this bus and at its neighbours. Since similar equations can be written for each of the *n* buses in the system, we have *2n* equations. These equations relate *4n* variables:

- *n* active power injections P_k;
- *n* reactive power injections Q_k;
- *n* voltage magnitudes V_k;
- *n* voltage angles θ_k.

Two of these variables must therefore be given at each node to ensure a balance between the number of equations and the number of unknowns. Three combinations of known and unknown variables are used in practice. These combinations are related to the physical characteristics of the buses, as follows.

Node types in power system analysis

The complete definition of power flow analysis requires determination of four variables at each bus in the system, i.e. (P_i, Q_i, U_i, δ_i). However only two of variables are given for each node, while the other two need to be calculated. The aim of the load flow computation is to find the value the remaining two variables at each node. A network node in power system analysis is called a bus. There are three different bus conditions based on the steady-state assumptions of constant system power and constant voltages, where these are controlled.

Slack (reference, swing) bus - type Uδ

The known variables at slack node:

- U_s – the voltage magnitude,
- $\delta_s = 0$ – the voltage phase angle.

The unknown variables at slack bus:

- P_s – the active power dependent on the active power balance in power system,
- Q_s – the reactive power dependent on the reactive power balance in power system.

This bus has to be defined because the transmission losses in the system are not known before the solution is arrived at! This conundrum is resolved by allowing one bus that has a generator connected to it to be specified in terms of the magnitude V and angle δ of its voltage. Such a bus is known as a *slack, swing or reference bus* . The voltage at this bus acts as the reference with respect to which all other bus voltages are expressed. At the end of the load flow the calculated P and Q at this bus take up all the slack associated with the losses in the transmission.

Generation node - type PU – voltage controlled bus

The known variables:

- U_g – the voltage magnitude,
- P_g – the active power.

The unknown variables:

- δ_g – the voltage angle;
- Q_g – the reactive power.

For large synchronous generators, the Q is often not specified, and instead it is the voltage U that is known. This is because such generators are fitted with AVR (Automatic Voltage Regulator) that hold the U constant. To accommodate this, in load flow analysis nodes where such generators are connected are referred to as *PU* buses and are dealt with a little differently in the maths. Unfortunately, *PU* buses are sometimes described as generator buses, which makes sense so long as all the generators are large synchronous generators with AVRs. As renewable energy generators increase in size, utilities have been developing regulations requiring that such generators behave in a traditional manner. Multimegawatt wind turbines connected to the network through PWM inverters may therefore be required to regulate the local bus voltage. In such cases the node has to be treated as a *PU* bus.

PQ Buses - are typically load buses

Small renewable energy generators also fall in the *PQ* bus category. Distributed generators are infrequently called upon to control the network voltage. Instead, they are often configured to operate at near - unity power factor ($Q = 0$); in this case, it may be appropriate to label the node to which they are connected as a *PQ node* . In the case of fixed speed wind turbines, however, the reactive power consumed by the induction generator will be dependent on voltage, as will the reactive power generated by the power factor correction capacitors. Many load flow software packages include facilities to model induction machines and related equipment appropriately. The situation is similar with small hydro systems interfaced to the grid through induction generators. Energy from photovoltaic, wave and tidal schemes and MW sized wind turbines is fed to the grid through a power electronic converter. This provides the facility of reactive power injection/extraction at the point of connection.

To summarize, for relatively small embedded RE generators the P injection depends solely on the RE source (wind, sun, water) level at the time and the Q injection either on the bus voltage or on the setting of the power electronic converter. In the latter case the converter could be regulated to inject active power at a chosen power factor.

6.4 Solving the power flow equations

The power flow equations, eqns. (6.58&6.59 or 6.65&6.66), are non-linear and cannot be solved manually except for trivial systems. Sophisticated iterative methods have been developed for solving them quickly and accurately. Detailed descriptions of these methods can be found in References [37–38]. The Newton-Raphson technique converges equally fast (as measured in number of iterations) for large as well as small systems, usually in less than 4 to 5 iterations. Therefore it has become very popular for large system studies. Running power flow studies with the help of a commercial package involve the following steps:

- *Gathering data:* This is often the most time-consuming task. The impedances of the lines and cables must be calculated based on the data provided by the manufacturer and the layout of the network. The parameters of the generators and transformers must be extracted from the relevant data sheets. Data pertaining to the distribution network to which the embedded generation plant will be connected must be obtained from the operator of this network. All quantities must then be converted to a consistent per unit system.
- *Creating a model:* The data gathered at the previous step are then used to create a model of the system to be studied. Older power flow programs require the user to enter these data in a file according to a precisely defined format. With modern programs, the user draws a

diagram of the network before entering the parameters through forms.

- *Setting up cases:* The user must then decide the load and generation conditions for which a power flow must be calculated. These data, as well as the position of the transformer taps and the settings of other control devices, must also be provided for the program.
- *Running the program:* This is the easy part, unless the iterative method does not converge! Divergence is usually caused by errors in the model. There is unfortunately no easy way to determine which parameters are faulty. Errors in the network topology are easily made when this information is not entered through a graphical user interface. The value of all the components of the model must be checked. Excessive loading can also be a cause of divergence. This form of non-convergence is an indication that voltages in the system would be unacceptably low for loads in that range.
- *Analysing the results:* Once a solution has been obtained, it must be checked for reasonableness. Slightly surprising results should be investigated carefully as they can be an indication of a minor error in the model. Once the user is satisfied that the model is correct, the program can be used to study other load and generation conditions as well as other network configurations.

Iteration process is used for load flow solution; the consecutive iteration solution is used as the starting point for the new iteration:

$$\begin{bmatrix} \mathbf{e_{it+1}} \\ \mathbf{f_{it+1}} \end{bmatrix} = \begin{bmatrix} \mathbf{e_{it}} \\ \mathbf{f_{it}} \end{bmatrix} + \begin{bmatrix} \mathbf{\Delta e_{it}} \\ \mathbf{\Delta f_{it}} \end{bmatrix} \tag{6.67}$$

Iterations are continued until the node power unbalances (mismatches) can be treated as neglectable. The acceptable mismatches are typically of magnitude 10^{-4} pu. The unbalance of node active power is determined as follows

$$\Delta P_{i\,it} = P_i - \left\{ G_{ii}(e_i^2 + f_i^2) + \sum_{i \neq j} [\, G_{ij}(e_i e_j + f_i f_j) + B_{ij}(-e_i f_j + f_i e_j)] \right\}_{it}$$

(3.17)

The unbalance of voltage magnitude at PU bus

$$\Delta U_{i\,it}^2 = U_i^2 - \left\{ e_i^2 + f_i^2 \right\}_{it} \tag{6.68}$$

The unbalance of reactive power at PQ bus

$$\Delta Q_{i\,it} = Q_i - \{\ B_{ii}(e_i^2 + f_i^2) + \sum_{i \neq j}[-B_{ij}(e_i e_j + f_i f_j) + G_{ij}(-e_i f_j + f_i e_j)]\ \}_{it}$$

(6.69)

Generally, iterative solution of the nonlinear equations set **f(x)** with **y** - the vector of given variables and **x** - the vector of unknown variables can be solved using the following procedure

$$\mathbf{y}_{\mathbf{it}} = \mathbf{g}(\mathbf{x}_{\mathbf{it}}) \tag{6.70}$$

$$\Delta\mathbf{y}_{\mathbf{it}} = \mathbf{y} - \mathbf{g}(\mathbf{x}_{\mathbf{it}}) \tag{6.71}$$

$$\Delta\mathbf{x}_{\mathbf{it}} = \mathbf{x} - \mathbf{x}_{\mathbf{it}} \tag{6.72}$$

$$\Delta\mathbf{y}_{\mathbf{it}} = \mathbf{J}\Delta\mathbf{x}_{\mathbf{it}} \tag{6.73}$$

$$\mathbf{x}_{\mathbf{it}+1} = \mathbf{x}_{\mathbf{it}} + \Delta\mathbf{x}_{\mathbf{it}} \tag{6.74}$$

6.5 Application to a dispersed generation scheme

Figure 6.4 represents the essential features of a distribution network into which a generator is embedded at bus D. The connection of this network to the transmission grid is represented by a single generator in series with a transformer supplying bus A. Since bus S has been chosen as the slack bus, this generator will supply the active power required to balance the system.

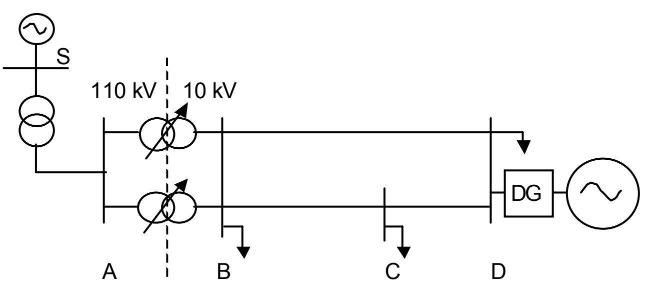


Figure 6.4 Portion of a distribution system with a dispersed generator. His network is connected to the transmission system at bus S and the dispersed generator is connected at bus D

Table 6.1 gives the parameters of the lines and transformers. The voltage at bus S is assumed to be held constant at its nominal value by the source generator, while the tap-changers on the transformers between buses A and B maintain the voltage at bus B at its nominal value.

Table 6.1 Parameters for the network used for power flow studies

From bus	To bus	Type	R [p.u]	X [p.u.]
S	A	Transformer	0.0	0.6670
A	B	Transformer	0.00994	0.20880
A	B	Transformer	0.00921	0.21700
B	C	Line	0.04460	0.19170
B	D	Line	0.21460	0.34290
C	D	Line	0.23900	0.41630

Let us first consider the case where the system is supplying its maximum load when the embedded generator is not producing any power. Figure 6.5 summarizes the voltages, injections and flows that have been calculated for these conditions using a power flow program [35]. These results demonstrate that this system is relatively 'weak': the voltage at bus D (0.953 p.u.) is marginally acceptable even though the voltage at bus B is held at its nominal value through the action of the tap-changing transformers. The active and reactive losses are also quite significant. It should be noted that these losses cause a difference between the active and reactive flows at the two ends of the lines and transformers. To keep the figure readable, only one value is given for these flows. This explains why the power balance may not appear to be respected at all buses in these figures.
If the embedded generator produces 20 MW at unity power factor, Figure 6.6 shows that the voltage profile is much more satisfactory. The losses are considerably reduced because the generation is much closer to the load and the lines carry much reduced flows.

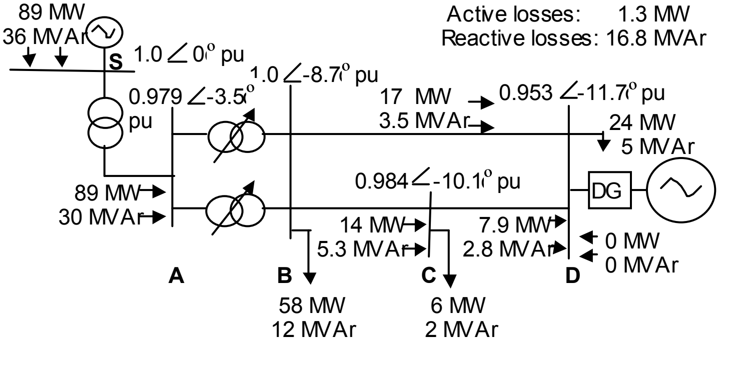


Figure 6.5 Power flow for maximum load and no dispersed generation

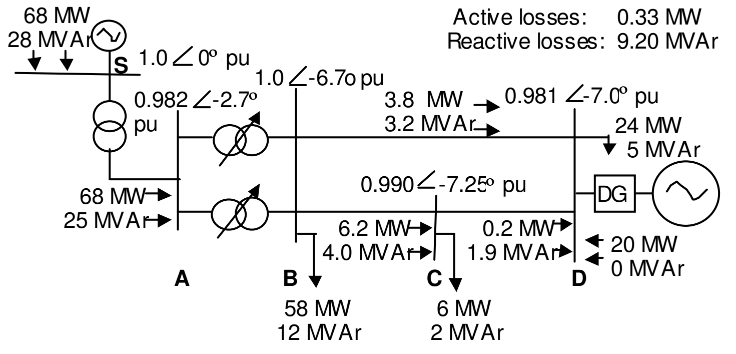


Figure 6.6 Power flow for maximum load and embedded generation at unity power factor

A further reduction in losses and an even better voltage profile can be achieved if, instead of operating at unity power factor, the embedded generator produces some reactive power. This case is illustrated in Figure 6.7. It is interesting to note that, under these circumstances, the active and reactive powers flow in opposite directions on two of the lines. On the other hand, if, as shown in Figure 6.8, the embedded generator consumes reactive power (as an induction generator always does), the voltage profile and the losses are somewhat worse than in the unity power factor case.

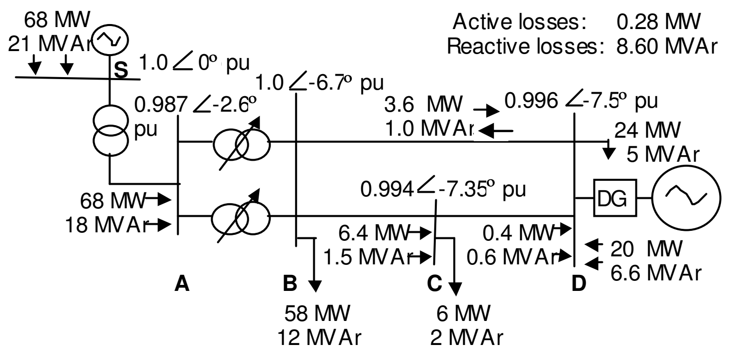


Figure 6.7 Power flow for maximum load and embedded generation at 0.95 power factor lagging (producing reactive power)

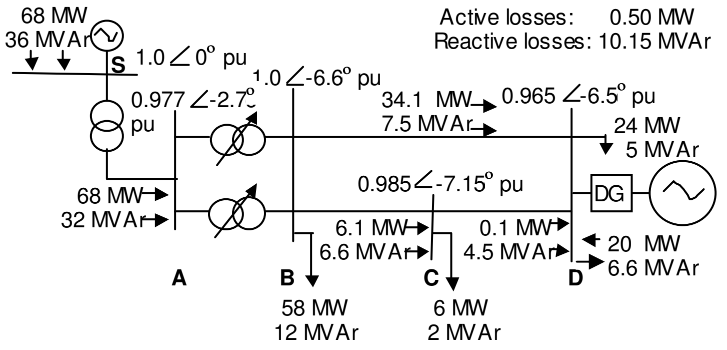


Figure 6.8 Power flow for maximum load and embedded generation at 0.95 power factor lagging (consumes reactive power)

If the embedded generator continues to produce its nominal power during periods of minimum load, the local generation may exceed the local consumption. In such cases, the pattern of flows is reversed and the distribution network injects power into the transmission grid. This case is illustrated by Figure 6.9, where the loads have been set at 10% of the maximum. The voltage phasor at bus D is not only the largest in magnitude but also leads all the other voltages. The source generator (which represents the rest of the system) absorbs the excess generation but supplies the necessary reactive power.

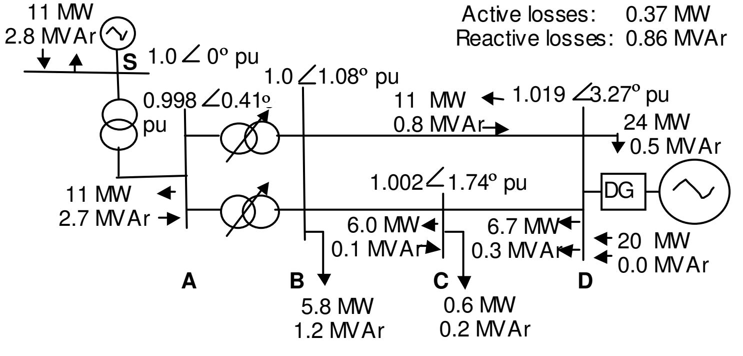


Figure 6.9 Power flow for minimum load and embedded generation at unity power factor

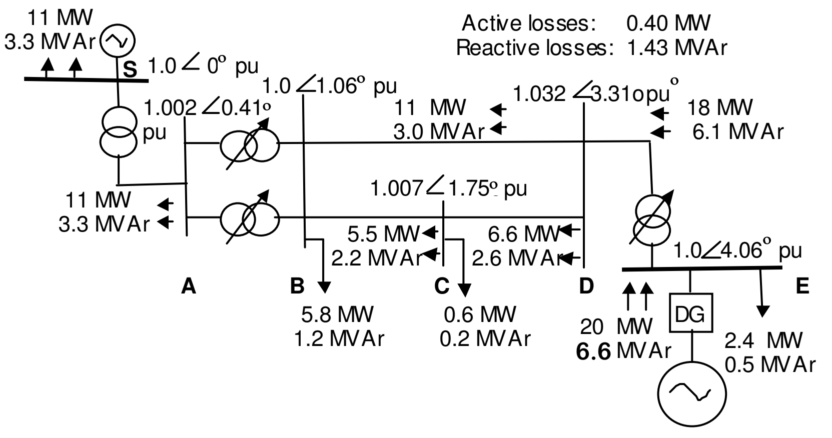


Figure 6.10 Power flow for minimum load and embedded generation at 0.95 power factor lagging on a voltage controlled bus

Some distribution network operators have expressed concerns that a reversal in the normal direction of flows caused by the presence of an embedded generator could interfere with the voltage regulation function of tap-changing transformers. To investigate these concerns, the embedded generator has been moved to the secondary side of a 110/10kV, tap-changing transformer. The automatic voltage controller of this transformer has been set to control the 10 kV busbar voltage only. Any current compounding scheme (e.g. line drop compensation or negative reactance compounding) may be adversely affected by embedded generators.

Figure 6.10 illustrates the case where the embedded generator produces not only 20 MW but also 6.6 MVAr for the minimum load conditions. It can be seen in this figure that the active and reactive powers flow from the embedded generator to the transmission grid. Even under these unusual conditions, the voltage at the 10 kV bus E is kept at its nominal value by the tap-changing transformer.

7. Impact of dispersed generators on short-circuit currents in electrical power network

The design of distribution networks is driven by two fundamental goals: delivering an acceptable quality of supply to consumers under normal conditions and protecting the integrity of the system when the network is affected by faults. A number of factors can damage a distribution network: strong winds or accumulation of ice can break overhead conductors, careless street digging can rupture cables and natural decay or rodents can weaken insulation. Such damage creates a fault or short circuit, i.e. an easier path for the current. Faults are not only a safety hazard but large fault currents can seriously damage equipment. Fault calculation programs are used to calculate the fault currents that would occur for different network configurations and fault locations. Their results are used not only to check that the components of the network have a sufficient rating to withstand the fault current but also to verify that these fault currents are sufficiently large for protection devices to detect the fault.

Conductors in distribution networks are separated from earth and from each other by a variety of insulating materials: air, paper or polymers. Occasionally, an unpredictable event ruptures this insulation, creating a short circuit between conductors or between conductors and earth. This abnormal conducting path is called a fault. Being able to predict the value of the current in faults is very important for two main reasons. First, this current may be so large that it could damage the distribution plant or exceed the rating of the breakers that are supposed to interrupt it. Paradoxically, the second reason for calculating fault currents is to check that they are not too small for the fault to be detected. Devising a protection system capable of discriminating between a large (but normal) load current and a small fault current is difficult. Since failing to detect a fault is an unacceptable safety risk, the distribution system must be designed in such a way that fault currents are large enough to be detected under all operating conditions. A distinction must be made between balanced and unbalanced faults. Balanced faults affect all three phases of the network in a similar manner and the symmetry between the voltages and currents in the three phases is not altered. A single-phase representation of the network can therefore be used when studying such faults. On the other hand, unbalanced faults create an

asymmetry in the network and require a more complex analysis based on symmetrical components.
This section begins with an explanation of balanced fault calculations using a simple four-bus example. These calculations are then generalized to networks of arbitrary size and complexity and then to unbalanced faults. Finally, these concepts are illustrated using examples from an embedded generation scheme.

7.1 Balanced Fault calculations

The operation of a power system departs from normal after the occurrence of a fault. Faults create abnormal operating conditions – usually excessive currents and voltages at certain points of the system. Therefore systems are equipped with various types of protective devices. Various types of short-circuit faults that can occur in electrical networks are illustrated in Figure 7.1.

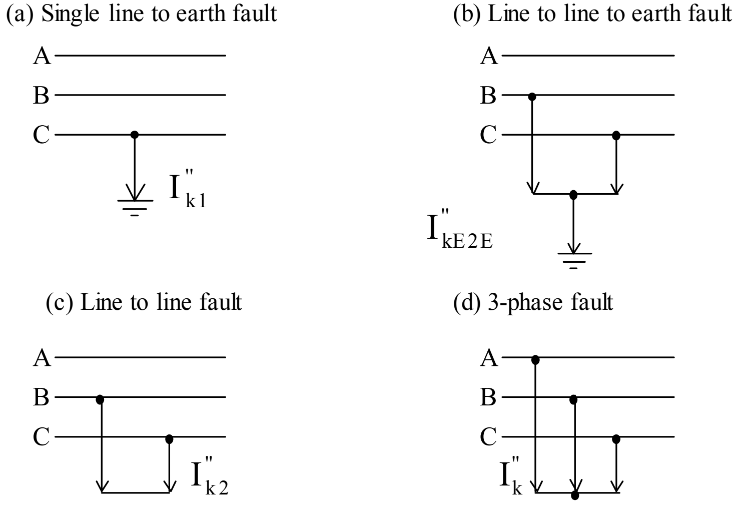


Figure 7.1. Equivalent circuits of symmetrical (d) and unsymmetrical faults (a-c)

Although the symmetrical three-phase short circuit is relatively uncommon, it is the most severe fault and therefore determines the rating of a line-protecting circuit breaker. A fault study analysis for a given power system comprises:

- Determination of the maximum and minimum three-phase short-circuit currents.

- Determination of unsymmetrical fault currents, as in single line-to-ground, double line-to-ground, line-to-line and open-circuit breakers.
- Determination of the ratings of required circuit breakers.
- Analysis of configurations of protective relaying.
- Determination of voltage levels at critical points during a fault.

Short circuit currents are generally many times greater than rated loading currents. Maximal short circuit currents involve high dynamic and thermal stresses, which can lead to the destruction of the equipment and be dangerous for personnel. Minimal short circuit currents also have to be calculated, because they are significant in the determination of protective devices for lines, transformers and other equipments.

In case of a symmetrical short-circuit the three voltages at the short-circuit point are all zero, regardless of whether the short-circuit point is connected to earth or not. The calculations therefore can be carried out only for a single phase, in the same way as in load flow analysis. Short-circuit currents are generated mainly by synchronous generators, synchronous and asynchronous motors. A radial or meshed network structure determines the paths of short-circuit current. The duration of short circuit depends on the protective devices and switchgear installed in the power system. Short-circuit currents are dangerous and they should be switched off very quickly. Modern circuit breakers usually operate in 2-5 cycles, i.e. in 0.02 - 0.2 s.

Symmetrical three-phase fault calculations can be carried out on a per-phase basis, so that only single-phase equivalent circuit needs to be used in the analysis. Figure 7.2 shows the equivalent circuit of a single-phase system without load. The generator is an ideal sinusoidal voltage source

$$u = U_m \sin(\omega \mathrm{t} + \psi_u) \tag{7.1}$$

where

$U_m = \sqrt{2}\,\mathrm{U}$ - the voltage peak,

U – *rms* value of the voltage,

$\omega = 2\pi f$ - the angular velocity,

f - frequency,

ψ_u - initial voltage phase angle at time t = 0.

The peak voltage, the angular velocity, the circuit resistance and reactance have the constant values.

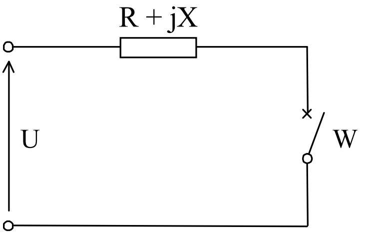


Figure 7.2. One phase representation of a 3-phase short circuit, where *W* depicts circuit breaker.

Transient state is described by the following differential equation

$$Ri + L\frac{di}{dt} = U_m \sin(\omega t + \psi_u) \tag{7.2}$$

where i means instantaneous value of the short circuit current. The initial value of short circuit current is zero, $I\,(t = 0) = 0$.
The wave-form of the short-circuit current is the solution of the differential equation (7.2)

$$i = \frac{U_m}{Z}\sin(\omega t + \psi_u - \varphi) - \frac{U_m}{Z} e^{-\frac{R}{L}t} \sin(\psi_u - \varphi) \tag{7.3}$$

$$Z = \sqrt{R^2 + X^2} \tag{7.4}$$

$$\varphi = arctg(\frac{\omega L}{R}) \tag{7.5}$$

where

Z - magnitude of the system short-circuit impedance,

φ - phase angle of the system short-circuit impedance.

The short-circuit current can be expressed as the sum of AC (alternate current) and DC (direct current) components

$$i = i_{AC} + i_{DC} \tag{7.6}$$

$$i_{AC} = \frac{U_m}{Z}\sin(\omega t + \psi_u - \varphi) \tag{7.7}$$

$$i_{DC} = -\frac{U_m}{Z} e^{-\frac{R}{L}t} \sin(\psi_u - \varphi) \tag{7.8}$$

The transient DC current decreases from the initial value to zero according to an exponential function with the time constant

$$\tau_a = \frac{L}{R} \tag{7.9}$$

Figure 7.3 illustrates the example results of the short-circuit analysis.

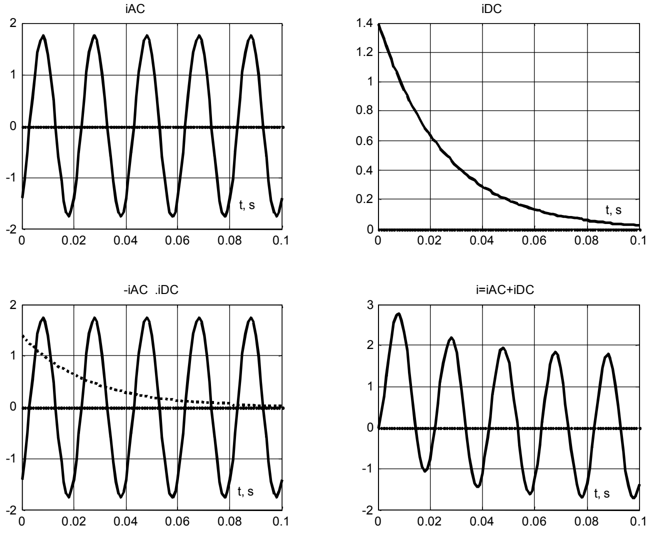


Figure 7.3. Time functions of a short-circuit current for the following circuit variables : *R*=0.1p.u., *X*=0.8p.u., *U* = 1 p.u, psi*U*=30°

The time variation of the short-circuit current is considerably affected by the specific characteristics of the generators. In the case of a no-load generator, voltage may be assumed to be constant and the decay characteristic of short circuit current can be treated as the result of an increase in the generator impedances. Three reactances of generator can be distinguished (Figure 7.4):

- subtransient reactance X_d'',
- transient reactance X_d',
- synchronous reactance X_d.

The symbol *d* signifies that the reactances are related to a rotor position that the winding axis of the rotor coincides with that of stator (*d* - direct axis). The generator also possesses reactances in the quadrate axis *q*, which is taken into consideration in more detailed study of the transient behavior of a generator. For short-circuit study using the direct axis gives sufficient accuracy.

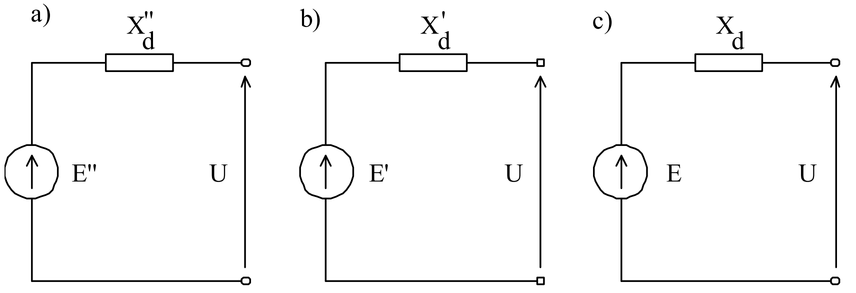


Figure 7.4. Equivalent circuits of generator in subtransient, transient and synchronous states for: *(a)* the subtransient period, *(b)* the transient period, *(c)* the steady-state period.

The subtransient reactance embraces the leakage reactances of the stator and rotor windings, taking into account the rotor leakage of the damper winding or bars of the solid rotor construction. The value of the subtransient reactance is related to the rated generator impedance:

$$Z_{GN} = \frac{U_{NG}^2}{S_{NG}} \tag{7.10}$$

where

S_{NG} - rated generator power, MV·A,

U_{NG} - rated generator voltage, kV.

Practically, the subtransient generator reactance is given in per unit representation

$$X_d'' = \frac{X_{d\Omega}''}{Z_{GN}} = X_{d\Omega}'' \frac{S_{NG}}{U_{NG}^2} \tag{7.11}$$

Its average value is in the range

$$X_d'' = (0.1 \div 0.2)\,\text{pu} \tag{7.12}$$

The transient reactance consists of the leakage reactances of the stator and field windings of generator. It is larger than the subtransient reactance

$$X_d' / X_d'' \approx (1.2 \div 1.6) \tag{7.13}$$

The synchronous reactance is the sum of the stator leakage reactance and the armature-reactance (the main field reactance) and has relatively large value

$$X_d \approx 2 \tag{7.14}$$

7.1.1 Thevenin's theorem in short-circuit analysis

A short-circuit represents a structural network change caused by the additional impedance (or, in the case of a symmetric short, three equal impedances) at the fault lacation. The changes in voltages and currents that will result from this structural change can be conveniently analyzed by means of Thevenin's theorem.

The changes that take place in the network voltages and currents due to the addition of an impedance between two network nodes are identical with those voltages and currents that would be caused by an emf placed in series with the impedance and having a magnitude and polarity equal to the prefault voltage that existed between the nodes in question and all other active sources being zeroed.

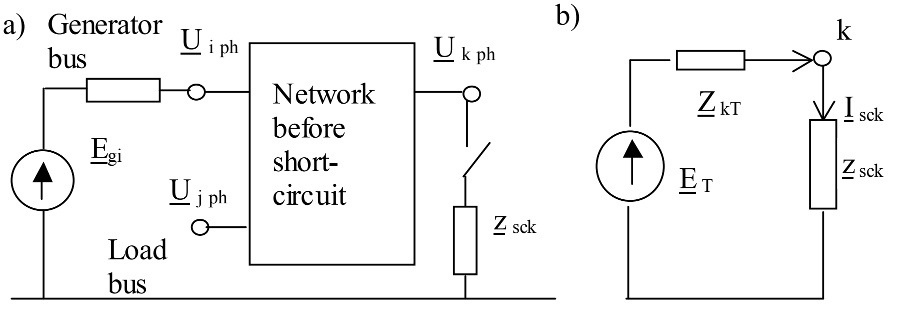


Figure 7.5. Thevenin's theorem in short-circuit analysis; *a)* before short-circuit, *b)* short-circuit with Thevenin's impedance

We shall find the theorem extremely useful in this chapter and the text in determining the system-wide effects of short-circuit. The following assumption are taken into considerations while short-circuit analysis:

- Electrical power system is treated as a linear circuit,
- No-load state before short-circuit,
- Shunt parameters are neglected.

Short-circuit current resulting from Thevenin's theorem can be expressed as

$$\underline{I}_{sck} = \frac{\underline{E}_T}{\underline{Z}_{kT} + \underline{z}_{sck}} = \frac{cU_{Nk}}{\sqrt{3}(\underline{Z}_{kT} + \underline{z}_{sck})} \tag{7.15}$$

where

$\underline{E}_T = \dfrac{cU_{Nk}}{\sqrt{3}}$ - Thevenin's *emf* at the *k*-th node,

c - the source voltage factor,

U_{Nk} - the nominal network voltage at the *k*-th node,

$\underline{Z}_{kT}$ - Thevenin's impedance seen from the *k*-th node,

$\underline{z}_{sck}$ - very small impedance between the *k*-th node and ground.

The aim of the analysis is to calculate the initial short-circuit current which equals the magnitude of the complex short circuit current

$$I_k^{''} = \left|\underline{I}_{sck}\right| \tag{7.16}$$

Hence, from (7.15), after simplification, we obtain the formula for calculating the intial 3-phase short-circuit current

$$I_k^{''} = \left|\underline{I}_{zk}\right| = \frac{cU_{Nk}}{\sqrt{3}\left|\underline{Z}_{kT} + \underline{z}_{zk}\right|} \tag{7.17}$$

The equivalent voltage source for the calculation of short-circuit current includes neglected load current, shunt parameters and possible 5% voltage increase before short-circuit. The source voltage factor c has the following value:

- $c = 1.05$ in low voltage systems,
- $c = 1.1$ in medium and high voltage systems.

In short-circuit calculations, the product of the prefault bus voltage and the fault current is referred to as short-circuit capacity or fault level of the bus. By definition, it has the value:

$$S_k^{''} = \sqrt{3} I_k^{''} U_{Nk}, MVA \tag{7.18}$$

where

$I_k^{''}$ is the initial symmetrical short-circuit current in kilo amperes,

U_{Nk} - the nominal phase system voltage in kilovolts.

Clearly, the fault levels increase with system voltage. At 220 kV fault levels can reach as much as 15 000 MV·A. The strongest networks have fault levels approaching even 100 GV·A. The short-circuit capability $S_k^{''}$ has a tendency to grow as new generators are added and additional lines are built.

7.1.2. Equivalent short-circuit parameters of power system elements

Generator

Generator is modeled as a subtransient reactance

$$X_G = X_d^{''} \frac{U_{NG}^2}{S_{NG}} \tag{7.19}$$

where

U_{NG} - the generator rated voltage in kV,

S_{NG} - the generator rated power in MVA,

X_d'' - subtransient reactance of a generator in pu.

Network feeder

The equivalent reactance of the outer network at the feeder connection point Q is determined using short-circuit capacity with c = 1.1

$$S_{kQ}'' = \sqrt{3}\, U_{NQ} I_{kQ}'' = \sqrt{3}\, U_{NQ} \frac{cU_{NQ}}{\sqrt{3}\, X_{kQ}} = \frac{cU_{NQ}^2}{X_{kQ}} \tag{7.20}$$

and

$$X_{kQ} = \frac{cU_{NQ}^2}{S_{kQ}''} \tag{7.21}$$

The equivalent reactance referred to the low-voltage side of the transformer can be calculated using transformation ratio t_N

$$X_{kQt} = \frac{cU_{NQ}^2}{S_{kQ}''} \frac{1}{t_N^2} \tag{7.22}$$

where

t_n means the rated transformation ratio at which the tap-changer is in the main position.

Line

Line resistance and reactance are used in short-circuit calculations

$$R_L = R_L' l \tag{7.23}$$

$$X_L = X_L' \cdot l \tag{7.24}$$

where

R_L', X_L' - the 1 km resistance and reactance in Ω/km,

l - the line length in km.

Current limiting reactor

The resistance of a reactor is usually very small and can be neglected. The reactance is calculated using the following formula

$$X_\mathrm{D} = u_\mathrm{k} \frac{U_{ND}}{\sqrt{3} I_{ND}} \tag{7.25}$$

where

U_{ND} - the rated voltage in kV,

I_{ND} - the rated current in kA,

u_k - the short-circuit voltage in pu.

Transformer

A two winding transformer is modeled as resistance and reactance using rated active losses and rated short-circuit voltage

$$u_R = \frac{P_{Cu}}{S_{NG}} \tag{7.26}$$

$$u_X = \sqrt{u_k^2 - u_R^2} \tag{7.27}$$

$$R_T = u_R \frac{U_{NT}^2}{S_{NT}} \tag{7.28}$$

$$X_T = u_X \frac{U_{NT}^2}{S_{NT}} \tag{7.29}$$

Rated voltage is taken either on the high voltage side $U_{NT} = U_{NHT}$ or low-voltage side $U_{NT} = U_{NHL}$.

Network with many nominal voltage levels

All branch resistances and reactances should be converted to a nominal network voltage at the point where the short-circuit occurs

$$X_k = X(t_{N1})^2 ...(t_{Ni})^2 ...(t_{Nm})^2 \tag{7.30}$$

where

$t_{Ni} = \frac{U_{NHTi}}{U_{NLTi}} = const$ - rated transformer ratio of the i-th transformer.

Example 7.1

Calculate 3-phase short-circuit in power system shown in Figure 7.6a. Figure 7.6b shows the equivalent scheme. Use the following rated parameters neglecting all resistances

generator: S_{NG} = 25 MV·A, U_{NG} = 10.5 kV, $X_d^{''} = 0.12$

transformer T1: S_{NT} = 40 MV·A, u_k = 10% , U_{NH} = 115 kV, U_{NL} = 11 kV

transformer T2: S_{NT} = 25 MV·A, u_k = 10% , U_{NH} = 115 kV, U_{NL} = 6.3 kV

line: $X_L^{'} = 0{,}4\ \Omega$/km, U_{NL} = 110 kV, l = 25 km

Solution

As discussed above, the first step is to calculate all equivalent reactances seen from the point of short-circuit point.

Generator G

$X_{NG} = x_d^{"} \frac{U_{NG}^2}{S_{NG}} = 0.12 \frac{10.5^2}{25} = 0.5292\Omega$ - rated generator reactance

$X_G = X_{NG} \left(\frac{U_{NHT1}}{U_{NLT1}} \right)^2 \left(\frac{U_{NLT2}}{U_{NHT2}} \right)^2 = 0.5292 \left(\frac{115}{11} \right)^2 \left(\frac{6.3}{115} \right)^2 = 0.1736\Omega$ - generator reactance seen from the short-circuit point.

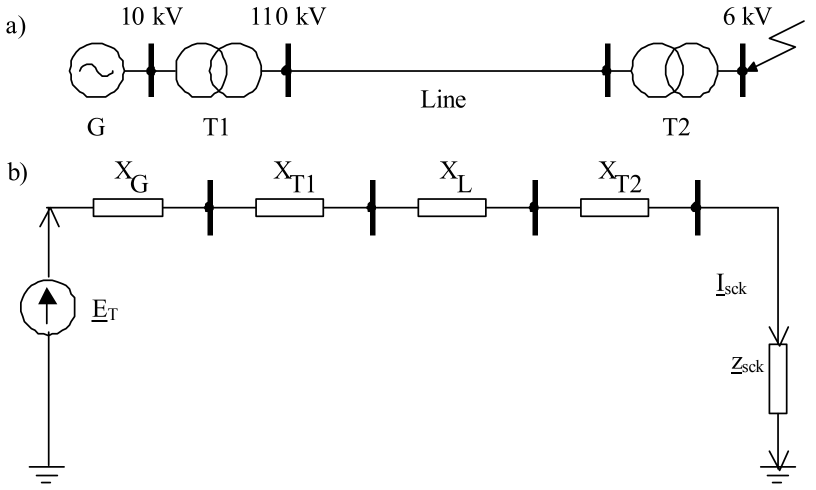


Figure 7.6. Single-phase representation of the 3-phase short-circuit in a system with a generator *G* connected through a transformer T1, a transmission line and transformer T2 to a short circuit impedance.

Transformer T1

$X_{NHT1} = u_X \frac{U_{NH}^2}{S_{NT}} = 0.10 \frac{115^2}{40} = 33.0625\Omega$ - the rated transformer reactance,

$X_{T1} = X_{NHT1} \left(\frac{U_{NLT2}}{U_{NHT2}} \right)^2 = 33.0625 \left(\frac{6.3}{115} \right)^2 = 0.0992\Omega$ - the transformer reactance seen from the short-circuit point.

Line

$X_{NL} = X'l = 0.4 \cdot 25 = 10\Omega$ - the rated line reactance,

$X_L = X_{NL} \left(\frac{U_{NLT2}}{U_{NHT2}} \right)^2 = 10 \left(\frac{6.3}{115} \right)^2 = 0.03\Omega$ - the line reactance seen from the short-circuit point.

Transformer T2

$$X_{T2} = u_X \frac{U_{NL}^2}{S_{NT}} = 0.10 \frac{6.3^2}{25} = 0.1588\Omega$$

Adding all circuit reactances we can calculate Thevenin's reactance

$X_{kT} = X_G + X_{T1} + X_L + X_{T2} = 0.1736 + 0.0992 + 0.03 + 0.1588 = 0.4616$ Ω

and finally the initial short-circuit current

$$I_k^{"} = \frac{cU_{Nk}}{\sqrt{3}Z_{kT}} = \frac{1.1 \cdot 6}{\sqrt{3}\ 0.4616} = 8.2550\ kA$$

7.1.3 Symmetrical short-circuit analysis in meshed network

The equivalent circuits of generator, line and transformer discussed in previous chapter are directly applicable here. However additional assumption should be introduced for the multi-generator meshed power system.

- Injected nodal current is signed as positive (+) and received nodal current as negative (-).
- No-load case is studied and therefore nodal load currents are equal to zero.
- Generator is modeled as subtransient *emf* $\underline{E}^{"}$ with series subtransient reactance $X_d^{"}$ and therefore nodal generator currents before short-circuit equal zero.
- The prefault bus voltages are equal to the nominal voltage of network.

The *n*-bus system can be represented by the short-circuit nodal admittance matrix $\mathbf{Y_{sc}}$. In terms of this matrix, power system is treated as a linear electrical circuit and therefore its short-circuit state is determined by the following matrix equation

$$\mathbf{I_{sc}} = \mathbf{Y_{sc}} \mathbf{U_{sc}} \tag{7.31}$$

where

$\mathbf{I_{sc}}$ - the vector of nodal short-circuit currents,
$\mathbf{U_{sc}}$ - the vector of nodal short-circuit voltage drops,
$\mathbf{Y_{sc}}$ - the short-circuit admittance matrix.

Since the symmetrical short-circuit occurs only at the *k*-th node then we have

$$\mathbf{I_{sc}} = [0\ \ldots\ -\underline{I}_{sck}\ \ldots\ 0]^T \tag{7.32}$$

where $\underline{I}_{sck}$ is the short-circuit current flowing from the *k*-th node to ground. All loads are neglected and the prefault nodal voltages are considered to be equal to the nominal network voltages

$$\mathbf{U_p} = \mathbf{U_N} \tag{7.33}$$

The nodal short-circuit voltage drops can be calculated using the inversion of the short-circuit admittance matrix

$$\mathbf{U_{sc}} = \mathbf{Y_{sc}^{-1}} \mathbf{I_{sc}} = \mathbf{Z_{sc}} \mathbf{I_{sc}} \tag{7.34}$$

$$\mathbf{Z_{sc}} = \mathbf{Y_{sc}^{-1}} \tag{7.35}$$

where $\mathbf{Z}$ means the short-circuit nodal impedance matrix.
The bus voltages are the sum of prefault and short-circuit voltage drops

$$\mathbf{U} = \mathbf{U_p} + \mathbf{U_{sc}} = \mathbf{U_p} + \mathbf{Z_{sc}} \mathbf{I_{sc}} \tag{7.36}$$

Selecting row k we obtain

$$\underline{U}_k = \underline{U}_{pk} - \underline{Z}_{kk} \underline{I}_{sck} \tag{7.37}$$

The nodal voltage at the k-th node depends on the fault impedance $\underline{z}_{sck}$

$$\underline{U}_{sck} = \underline{z}_{sck} \underline{I}_{sck} \tag{7.38}$$

So we have

$$\underline{U}_{pk} - \underline{Z}_{kk} \underline{I}_{sck} = \underline{z}_{sck} \underline{I}_{sck} \tag{7.39}$$

The short-circuit current at the k-th node (the fault current) is

$$\underline{I}_{sck} = \frac{\underline{U}_{pk}}{\underline{Z}_{kk} + \underline{z}_{sck}} \tag{7.40}$$

where

$\underline{Z}_{kk}$ - the self short-circuit impedance of the k-th node.
$\underline{z}_{sck}$ - the fault impedance.
$\underline{U}_{pk}$ - the nodal voltage at the k-th node before short-circuit.

The formula (7.40) may be compared with the short-circuit current formula using Thevenin's theorem

$$\underline{I}_{sck} = \frac{\underline{E}_T}{\underline{Z}_{kT} + \underline{z}_{sck}} \tag{7.41}$$

One can notice that the self short-circuit impedance of the k-th node is equal to Thevenin's impedance seen from the k-th node $\underline{Z}_{kk} = \underline{Z}_{kT}$.
Having calculated the k-th node short-circuit current, the voltage at any other i-th node can be obtained

$$\underline{U}_i = \underline{U}_{pi} - \underline{Z}_{ik} \underline{I}_{sck} \tag{7.42}$$

$$\underline{U}_i = \underline{U}_{pi} - \underline{Z}_{ik} \frac{\underline{U}_{pk}}{\underline{Z}_{kk} + \underline{z}_{sck}} \tag{7.43}$$

From the above equations it is clear that the fault voltages at every node in the power system may be calculated and each calculation require only one column of the impedance matrix. If $i = k$ then the voltage at the k-th node during the fault is

$$\underline{U}_k = \underline{U}_{pk} - \underline{Z}_{kk} \frac{\underline{U}_{pk}}{\underline{Z}_{kk} + \underline{z}_{sck}} \tag{7.44}$$

$$\underline{U}_{zk} = \underline{U}_{pk} \frac{\underline{z}_{sck}}{\underline{Z}_{kk} + \underline{z}_{sck}} \tag{7.45}$$

Using nodal voltages during the fault it becomes easy to calculate any branch current from node *i*-th to node *j*-th:

$$\underline{I}_{scij} = \frac{\underline{U}_i - \underline{U}_j}{\underline{z}_{ij}} \tag{7.46}$$

where

$\underline{z}_{ij}$ means the impedance of the branch connecting the nodes *i* and *j*.

In case of a generator node, and the contributing its short-circuit current $\underline{I}_{gisck}$, the subtransient *emf* $\underline{E}_i''$ of the generation and the subtransient generator's reactance $\underline{z}_{gi} = jX_{di}''$ need to be taken into consideration. First, the value of the subtransient *emf* is considered as unchanged before and during the short circuit. Next, all bus loads are neglected and therefore there is no generator current at the *i-th* generator node $\underline{I}_{gio} = 0$ before short-circuit occurred at the *k-th* node. Therefore

$$\underline{E}_i'' = \underline{U}_{pi} + \underline{z}_{gi}\underline{I}_{gio} = \underline{U}_{pi} \tag{7.47}$$

During the short-circuit at the k-th node, the generator at the i-th bus produces the contributing short-circuit current I_{gisck} , so the subtransient generator *emf* equals

$$\underline{E}_i'' = \underline{U}_i + \underline{z}_{gi}\underline{I}_{gisck} \tag{7.48}$$

On the other hand we have

$$\underline{U}_i = \underline{U}_{pi} - \underline{Z}_{ik}\underline{I}_{sck} \tag{7.49}$$

Substituting (7.49) to (7.48) we obtain

$$\underline{E}_i'' = \underline{U}_{pi} - Z_{ik}I_{sck} + \underline{z}_{gi}\underline{I}_{gisck} \tag{7.50}$$

Using the prefault condition (7.47) we have

$$\underline{E}_i'' = \underline{E}_i'' - Z_{ik}I_{sck} + \underline{z}_{gi}\underline{I}_{gisck} \tag{7.51}$$

$$Z_{ik}I_{sck} = \underline{z}_{gi}\underline{I}_{gisck} \tag{7.52}$$

Finally, we obtain the formula for calculating the contributing short-circuit current at the *i-th* node when the short circuit occurs at the *k-th* node

$$I''_{gisck} = \frac{\underline{Z}_{ik}}{\underline{z}_{gi}} \underline{I}_{sck} = \underline{c}_{gisck} \underline{I}_{sck} \tag{7.53}$$

where $\underline{c}_{gisck}$ is the complex contribution coefficient of the *i-th* generator in the short-circuit at the *k-th* node

$$\underline{c}_{gisck} = \frac{\underline{Z}_{ik}}{\underline{z}_{gi}} \tag{7.54}$$

For the magnitude of the short circuit currents, i.e. for initial short-circuit currents we have

$$I''_{gisck} = \frac{Z_{ik}}{z_{gi}} I''_{k} = c_{gisck} I''_{k} \tag{7.55}$$

where c_{gisck} is the contributing coefficient of the *i-th* generator in the initial short-circuit current at the *k-th* node

$$c_{gisck} = \frac{Z_{ik}}{z_{gi}} \tag{7.56}$$

Example 7.2

Calculate short-circuit currents using the nodal impedance matrix of a power system shown in Figure 7.7. Use the following rated parameters neglecting all resistances

generator G1: S_{NG} = 25 MV·A, U_{NG} = 10.5 kV, X''_d = 0.12

generator G2: S_{NG} = 10 MV·A, U_{NG} = 6.3 kV, X''_d = 0.16

short-circuit capacity of the network feeder: S''_{kQ} =2500 MV·A

transformer T1: S_{NT} = 40 MV·A, u_k = 10% , U_{NH} = 115 kV, U_{NL} = 11 kV

transformer T2: S_{NT} = 25 MV·A, u_k = 10% , U_{NH} = 115 kV, U_{NL} = 6.3 kV

line: X' = 0,4 Ω/km, U_{NL} = 110 kV, l = 25 km

Solution

The common voltage level 110 kV is chosen for calculating equivalent parameters.

Generator G1

$X_{NG1} = X''_d \frac{U^2_{NG1}}{S_{NG1}} = 0.12 \cdot \frac{10.5^2}{25} = 0.5292\Omega$ - the rated G1 generator reactance,

$$X_{G1110kV} = X_{NG1}\left(\frac{U_{NHT1}}{U_{NLT1}}\right)^2 = 0.5292\left(\frac{115}{11}\right)^2 = 57.8402\Omega$$ - the G1 generator reactance referred to the system voltage level 110 kV,

$\underline{y}_{G1} = -j/57.8402 = -j0.0173\ S$ - the generator G1 admittance.

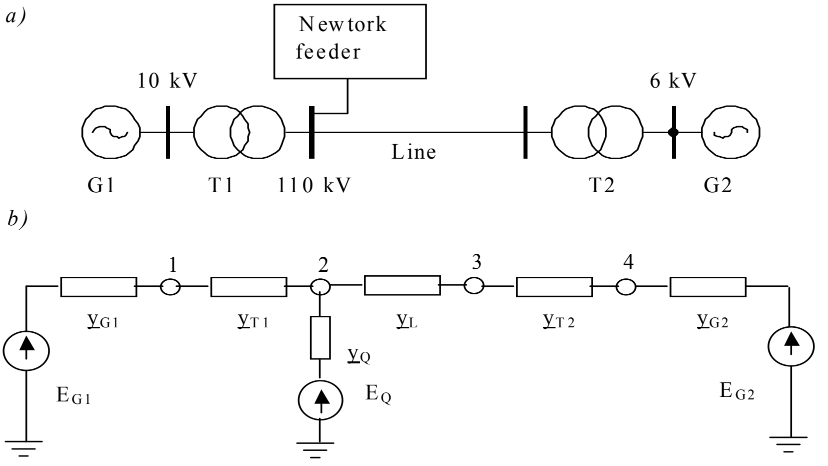


Figure 7.7 A four-bas example system (a) and its equivalent circuit (b).

Generator G2

$$X_{NG2} = X_d^{"}\frac{U_{NG2}^2}{S_{NG2}} = 0.16\frac{6.3^2}{10} = 0.635\Omega,$$

$$X_{G2110kV} = X_{NG2}\left(\frac{U_{NHT2}}{U_{NLT2}}\right)^2 = 0.635\left(\frac{115}{6.3}\right)^2 = 211.5867\Omega,$$

$\underline{y}_{G2} = -j/211.5867 = -j0.0047$ S.

Network feeder

$$X_Q = \frac{1.1U_{NQ}^2}{S_{kQ}^{"}} = \frac{1.1\cdot 110^2}{2500} = 5.324\Omega$$ - the network feeder reactance,

$\underline{y}_Q = -j/5.3240 = -j0.1878$ S - the network feeder admittance.

Transformer T1

$$X_{NT1} = u_k\frac{U_{NHT1}^2}{S_{NT1}} = 0.10\cdot\frac{115^2}{40} = 33.0625\Omega$$ - the rated transformer T1 reactance referred to the system voltage 110 kV level,

$\underline{y}_{T1} = -j/33.0625 = -j0.0302\ S$ - the transformer T1 admittance.

Transformer T2

$X_{NT2} = u_k \dfrac{U_{NHT2}^2}{S_{NT2}} = 0.10 \cdot \dfrac{115^2}{25} = 52.9\Omega$ - the rated transformer T2 reactance referred to the system voltage 110 kV level,

$\underline{y}_{T2}$ = -j/52.9 = -j0.0189 S - the transformer T2 admittance.

Line

$X_L = X'l = 0.4 \cdot 25 = 10\Omega$ - the rated line reactance,

$\underline{y}_L$ = - j/10 = - j0.1 S - the line admittance.

The short-circuit nodal admittance matrix is created using the following formula

$$\mathbf{Y_{sc}} = \begin{bmatrix} \underline{y}_{G1} + \underline{y}_{T1} & -\underline{y}_{T1} & 0 & 0 \\ -\underline{y}_{T1} & \underline{y}_{T1} + \underline{y}_Q + \underline{y}_L & -\underline{y}_L & 0 \\ 0 & -y_L & \underline{y}_L + \underline{y}_{T2} & -\underline{y}_{T2} \\ 0 & 0 & -\underline{y}_{T2} & \underline{y}_{T2} + \underline{y}_{G2} \end{bmatrix}$$

After substitution of relevant branch admittances we obtain

$$\mathbf{Y_{sc}} = \begin{bmatrix} -j0.0475 & j0.0302 & 0 & 0 \\ j0.0302 & -j0.3181 & j0.1 & 0 \\ 0 & j0.1 & -j0.1189 & j0.0189 \\ 0 & 0 & j0.0189 & -j0.0236 \end{bmatrix}$$

Inversion of the nodal admittance matrix gives the nodal short-circuit impedance matrix

$$\mathbf{Z_{sc}} = j \begin{bmatrix} 23.0368 & 3.1426 & 3.0281 & 2.4224 \\ 3.1426 & 4.9389 & 4.7590 & 3.8072 \\ 3.0281 & 4.7590 & 14.2213 & 11.3769 \\ 2.4224 & 3.8072 & 11.3769 & 51.4209 \end{bmatrix}$$

Short circuit at Node 1

Thevenin's impedance seen from the 1-st node equals

$$Z_{11} = X_{11} = 23.0368\ \Omega$$

This impedance should be transformed to the voltage level of 10 kV

$$Z_{11\_10kV} = Z_{11}\left(\frac{U_{NLT1}}{U_{NHT1}}\right)^2 = 23.0368\left(\frac{11}{115}\right)^2 = 0.211\Omega$$

Hence, the initial short-circuit current at the 1-st node has the following value

$$I_k^" = \frac{cU_{Nk}}{\sqrt{3}Z_{kT}} = \frac{1.1 \cdot 10}{\sqrt{3}\ 0.211} = 30.1\ kA$$

7.1.4 Application to an embedded generation scheme

We will now use the small system introduced in Figure 6.4 to illustrate the concepts developed in the previous sections. Let us first consider the case of Figure 7.8 where the embedded generator is disconnected from the system.

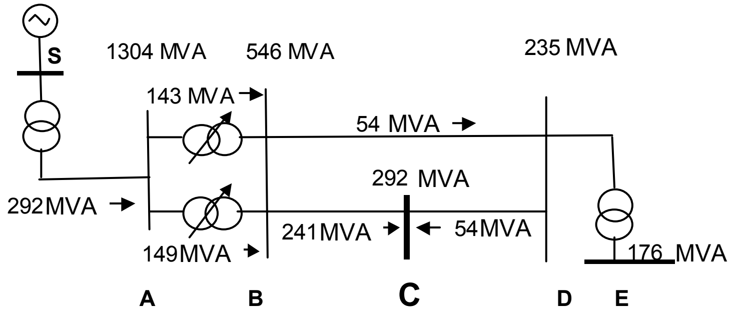


Figure 7.8 MVA fault levels for balanced three-phase faults at the various buses in the system. The arrows show the MVA flows for a fault at bus C. The system is assumed to be unloaded prior to the fault

The fault levels have been calculated (using a commercial program [35]) for faults at various buses in the system and are shown next to the bus names. It is clear that the fault level decreases as the distance between the fault and the source increases. This figure also shows the flows that would result from a fault at busbar C. Note that the sum of the branch flows at bus C is only roughly equal to the fault level at this bus because the flows are expressed in MVA and the corresponding currents have slightly different phases.

Figure 7.9 shows that the presence of an embedded generation significantly increases the fault levels in the system. In particular, 58 MVA would be drawn from this generator by a fault at bus C.

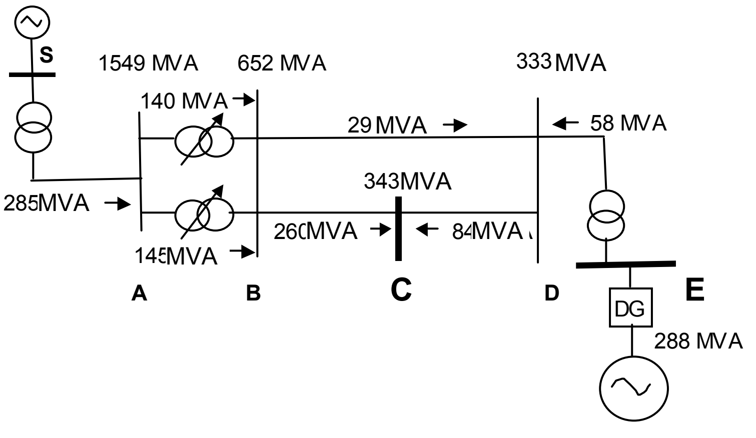


Figure 7.9 MVA fault levels for balanced three-phase faults at the various buses in the system, including the contribution of the embedded generator at bus E. The arrows show the MVA flows for a fault at bus C. The system is assumed to be unloaded prior to the fault

7.2 Unbalanced faults

Since balanced faults affect all three phases in an identical manner, the symmetry of the network is preserved and the fault current is balanced, albeit larger than a normal load current. The network impedances that must be considered in the calculation of balanced fault currents are therefore the ‘normal’ impedances of the network. A majority of the faults that occur in a network, however, do not affect all three phases in the same manner. Such faults are called unbalanced because they destroy the three-phase symmetry of the network. Unbalanced faults usually involve a short circuit between one line and the earth, between two lines or between two lines and the earth. Since the currents that result from such faults are not symmetrical, carrying out the analysis in terms of the actual phase quantities is difficult. Transforming the actual phase quantities into a set of abstract variables called symmetrical components considerably simplifies the calculation of unbalanced fault currents. It can be shown [5] that any set of unbalanced phase quantities (voltages or currents) can be decomposed into three components:

- a positive sequence component consisting of three balanced voltages or currents in a normal (positive) phase sequence;
- a negative sequence component consisting of three balanced voltages or currents in a reverse (negative) phase sequence;
- a zero sequence component consisting of three voltages or currents of equal magnitude and phase.

Using the symmetrical component transformation matrix **S**

$$\mathbf{S} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \tag{7.57}$$

an unbalanced set of three phasors one be transformed into two balanced three-phase systems of different phase sequence sets and one-zero phase sequence set of components:

$$\mathbf{I}_{012} = \mathbf{S} \cdot \mathbf{I}_{ABC} \tag{7.58}$$

$$\mathbf{U}_{012} = \mathbf{S} \cdot \mathbf{U}_{ABC} \tag{7.59}$$

The following operator needs to be the opposite introduced. The operator *a* causes a counterclockwise rotation by 120º (just as the j operator produces a 90º rotation) and can be expressed

$$a = e^{j2\pi/3} = \cos(120°) + j\sin(120°) = -0.5 + j\frac{\sqrt{3}}{2} \tag{7.60}$$

Consequently, using properties of the operator *a,* we may write the components of given sequence. Equation (7.58) and (7.59) are so important that we rewrite them out in the component form:

currents *voltages*

$$\underline{I}_0 = \frac{1}{3}(\underline{I}_A + \underline{I}_B + \underline{I}_C), \quad \underline{U}_0 = \frac{1}{3}(\underline{U}_A + \underline{U}_B + \underline{U}_C) \tag{7.61}$$

$$\underline{I}_1 = \frac{1}{3}(\underline{I}_A + a\underline{I}_B + a^2\underline{I}_C), \quad \underline{U}_1 = \frac{1}{3}(\underline{U}_A + a\underline{U}_B + a^2\underline{U}_C) \tag{7.62}$$

$$\underline{I}_2 = \frac{1}{3}(\underline{I}_A + a^2\underline{I}_B + a\underline{I}_C), \quad \underline{U}_2 = \frac{1}{3}(\underline{U}_A + a^2\underline{U}_B + a\underline{U}_C) \tag{7.63}$$

A zero-phase sequence system is one in which all phasors are of equal magnitude and angle. If *A,B,C* sequence is taken as the positive phase sequence then *A,C,B* represents the negative phase sequence. It should be noted that for both positive and negative phase sequences, the direction of rotation of phasors is taken to be anticlockwise. The component synthesis can be used to determine the original phasors in terms of symmetrical components:

$$\mathbf{I_{ABC}} = \mathbf{S^{-1}}\ \mathbf{I_{012}} \tag{7.64}$$

$$\mathbf{U_{ABC}} = \mathbf{S^{-1}}\ \mathbf{U_{012}} \tag{7.65}$$

where

$$\mathbf{S}^{-1} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \tag{7.66}$$

For each original phasor we may rewrite equation (7.64 and 7.65) as follows:

original currents *original voltages*

$$\underline{I}_A = \underline{I}_0 + \underline{I}_1 + \underline{I}_2, \qquad \underline{U}_A = \underline{U}_0 + \underline{U}_1 + \underline{U}_2 \tag{7.67}$$

$$\underline{I}_B = \underline{I}_0 + a^2\underline{I}_1 + a\underline{I}_2, \qquad \underline{U}_B = \underline{U}_0 + a^2\underline{U}_1 + a\underline{U}_2 \tag{7.68}$$

$$I_C = \underline{I}_0 + a\underline{I}_1 + a^2\underline{I}_2, \qquad \underline{U}_C = \underline{U}_0 + a\underline{U}_1 + a^2\underline{U}_2 \tag{7.69}$$

The formula of the three-phase complex power in an unbalanced state

$$P + jQ = \underline{U}_A \underline{I}_A^* + \underline{U}_B \underline{I}_B^* + \underline{U}_C \underline{I}_C^* = \mathbf{U}_{ABC}^T \mathbf{I}_{ABC}^* \tag{7.70}$$

can be rewritten using the symmetrical components

$$P + jQ = (\mathbf{S}^{-1}\mathbf{U}_{012})^T (\mathbf{S}^{-1}\mathbf{I}_{012})^* = \mathbf{U}_{012}^T \mathbf{S}^{-1T} \mathbf{S}^{-1*} \mathbf{I}_{012}^* \tag{7.71}$$

Note that

$$\mathbf{S}^{-1T} \cdot \mathbf{S}^{-1*} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} = \begin{bmatrix} 3 & & \\ & 3 & \\ & & 3 \end{bmatrix} \tag{7.72}$$

hence

$$\mathrm{S} = P + jQ = 3\,\mathbf{U}_{012}^T \mathbf{I}_{012}^* = 3\underline{U}_0 \underline{I}_0^* + 3\underline{U}_1 \underline{I}_1^* + 3\underline{U}_2 \underline{I}_2^* \tag{7.73}$$

It means that the total three-phase complex power in the unbalanced system can be computed as the sum of the symmetrical component powers. Thus, the sequence power in one-third the power in terms of phase quantities.

7.2.1 Unsymmetrical component equivalent circuits

Unloaded grounded generator

We will assume nonsymmetrical load of the generator. Synchronous generators in power system may be grounded or not. Usually they are ungrounded. When an unbalanced fault occurs at the terminal of the unloaded grounded generator the current flows in *A,B,C* branches and in the neutral branch.

$$\mathbf{U_{ABC}} = \mathbf{E_{ABC}} - \mathbf{Z}\ \mathbf{I_{ABC}} = \mathbf{S^{-1}}\ \mathbf{U_{012}} = \mathbf{S^{-1}}\ \mathbf{E_{012}} - \mathbf{Z}\ \mathbf{S^{-1}}\ \mathbf{I_{012}} \tag{7.74}$$

After multiplication both side of the above equation by the matrix **S** we obtain

$$\mathbf{U_{012}} = \mathbf{E_{012}} - \mathbf{Z_{012}}\, \mathbf{I_{012}} \tag{7.75}$$

where

$\mathbf{Z_{012}} = \mathbf{S\, Z\, S^{-1}}$ - the impedance matrix in symmetrical components 0, 1, 2.

The detailed form of the generator impedance matrix is as follows

$$\mathbf{Z_{012}} = \begin{bmatrix} K+L+M & 0 & 0 \\ 0 & K+a^2L+aM & 0 \\ 0 & 0 & K+aL+a^2M \end{bmatrix} = \begin{bmatrix} \underline{Z}_0 & 0 & 0 \\ 0 & \underline{Z}_1 & 0 \\ 0 & 0 & \underline{Z}_2 \end{bmatrix} \tag{7.76}$$

It is common to neglect resistance and therefore all sequence impedances for a synchronous machine are reactive. At this point we introduce the generator sequence impedances.

Positive-sequence impedance of a synchronous generator

$$\underline{Z}_1 = K + a^2L + aM$$

$$\underline{Z}_1 = jX_1 = j\,X''_d \tag{7.77}$$

Negative-sequence impedance of a synchronous generator

$$\underline{Z}_2 = \underline{Z}_1 = K + aL + a^2M$$

$$\underline{Z}_2 = jX_2 = j\sqrt{X''_d X''_q} \tag{7.78}$$

Zero-sequence impedance of a synchronous generator

$$\underline{Z}_0 = K + L + M$$

$$X_0 = (0.1 \div 0.6)\, X_1 \tag{7.79}$$

Consequently, the unbalanced state of a synchronous generator can be described using symmetrical components

$$\mathbf{U_{012}} = \mathbf{E_{012}} - \mathbf{Z_{012}}\, \mathbf{I_{012}} = \begin{bmatrix} \underline{E}_0 \\ \underline{E}_1 \\ \underline{E}_2 \end{bmatrix} - \begin{bmatrix} \underline{Z}_0 & 0 & 0 \\ 0 & \underline{Z}_1 & 0 \\ 0 & 0 & \underline{Z}_2 \end{bmatrix} \begin{bmatrix} \underline{I}_0 \\ \underline{I}_1 \\ \underline{I}_2 \end{bmatrix} \tag{7.80}$$

The generated voltages are of positive sequence only, since the generator is designed to supply balanced 3-phase voltages

$$\underline{E}_A = \underline{E},\ \ \underline{E}_B = a^2\underline{E},\ \ \underline{E}_C = a\underline{E} \tag{7.81}$$

Using symmetrical components we get

$$\mathbf{E_{012}} = \mathbf{S}\cdot\mathbf{E_{ABC}} =$$

$$\frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} \underline{E} \\ a^2\underline{E} \\ a\underline{E} \end{bmatrix} = \frac{1}{3}\begin{bmatrix} (1+a^2+a)\underline{E} \\ (1+2a^3)\underline{E} \\ (1+a^4+a^2)\underline{E} \end{bmatrix} = \begin{bmatrix} 0 \\ \underline{E} \\ 0 \end{bmatrix} = \begin{bmatrix} \underline{E}_0 \\ \underline{E}_1 \\ \underline{E}_2 \end{bmatrix} \tag{7.82}$$

Hence, we have

$\underline{E}_0 = 0$ - *emf* for zero-sequence component,
$\underline{E}_1 = \underline{E}$ - *emf* for positive-sequence component,
$\underline{E}_2 = 0$ - *emf* for negative-sequence component.

From (8.25) we can write

$$\begin{bmatrix} \underline{U}_0 \\ \underline{U}_1 \\ \underline{U}_2 \end{bmatrix} = \begin{bmatrix} 0 \\ \underline{E}_1 \\ 0 \end{bmatrix} - \begin{bmatrix} \underline{Z}_0 & 0 & 0 \\ 0 & \underline{Z}_1 & 0 \\ 0 & 0 & \underline{Z}_2 \end{bmatrix}\begin{bmatrix} \underline{I}_0 \\ \underline{I}_1 \\ \underline{I}_2 \end{bmatrix} \tag{7.83}$$

Following the above considerations one can make some important observations:

- As the $\mathbf{Z_{012}}$ matrix turned out to be diagonal obviously there is no coupling between the three sequence component systems.
- Only the positive-sequence circuit has an induced *emf*.
- The negative- and zero-sequence components contain no *emfs* but include the impedances of the generator to negative- and zero-sequence currents, respectively.

When the **neutral point of a generator is grounded through the impedance** $\underline{z}_N$ then the neutral point voltage equals

$$\underline{U}_N = 3\underline{z}_N\,\underline{I}_0 \tag{7.84}$$

and therefore

$$\underline{U}_0 = 0 - (\underline{Z}_0 + 3\underline{z}_N)\underline{I}_0 \tag{7.85}$$

Now we can summarize briefly on how to determine the generator sequence impedances. For assumed generators, lines, and transformers all sequence impedances may be often assessed as purely reactive. The words “impedance” and “reactance” will thus be used interchangeably.

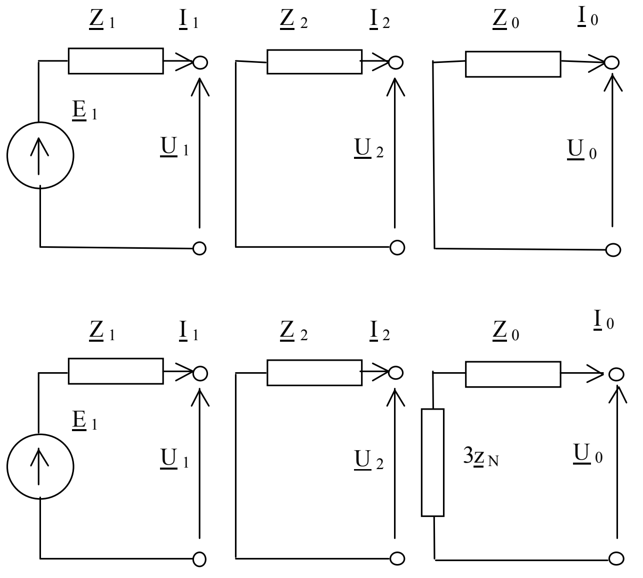


Figure 7.10 Scheme of generator sequence networks for a) the unloaded grounded generator b) the unloaded grounded generator through the $\underline{z}_n$ impedance

Synchronous motors and reactive power compensators (synchronous capacitors)

In practice, the manufacturer gives the impedance data. For a short-circuit period less than 0.2 s, synchronous motors and synchronous capacitors can be treated with sufficient accuracy in the same way as synchronous generators. In a longer short-circuit period they lapse into asynchronous operation and they are disconnected.

Induction motors

Since induction machines have no excitation windings their short-circuit currents decay very rapidly. They have only positive- and negative-sequence impedance. The zero-sequence impedance is infinitive.

Sequence impedance of static elements of power system

For static elements we have $L = M$, so we have

- zero-sequence impedance

$$\underline{Z}_0 = K + L + M = K + 2L = K + 2M \qquad (7.86)$$

- positive-sequence impedance

$$\underline{Z}_1 = K + a^2L + aL = K + L(a + a^2) = K - L = K - M \qquad (7.87)$$

- negative-sequence impedance

$$\underline{Z}_2 = K + aL + a^2L = K + L(a + a^2) = K - L = K - M \qquad (7.88)$$

We can make the following observations.

- For a passive component we have the same impedance to positive and negative sequence currents ($\underline{Z}_1 = \underline{Z}_2$).
- $\underline{Z}_0$ is significantly larger than $\underline{Z}_1$ and $\underline{Z}_2$.
- The $\mathbf{Z}_{012}$ matrix is diagonal.

Overhead lines

The positive-sequence and negative-sequence impedances are equal. The effect of mutual impedance is neglected for positive- and negative-sequence impedances (it is less then 5%). However, in the zero-sequence system the mutual impedance has a large effect. The effect of earth wires is very considerable.

The zero-sequence resistance may be assessed as follows:

$$R_0 = R_1 + 0.15 l_{line} \qquad (7.89)$$

where l_{line} is the length of line.

Zero-sequence reactance is usually given as the k coefficient

$$k = X_0 / X_1 \qquad 2 < k < 4 \qquad (7.90)$$

Table 7.1: Sample impedances of overhead lines

U_N,kV	R_1,Ω/km	X_1,Ω/km	B_1,μS/km	R_0,Ω/km	X_0,Ω/km	B_0,μS/km
The 110 kV line AFL-6 240 with one earth wire						
110	0.12	0.41	2.774	0.29	1.03	1.684
The 20 kV line AFL-6 70 without earth wire						
20	0.44	0.37	3.336	0.59	1.55	1.284

Cables

It is unfeasible to give any formula for the resistance and reactance calculation with sufficient accuracy. Manufacturers usually provide values of zero-sequence impedances. If manufacturer data is not available, then the zero-sequence impedance can be assessed as follows:

$$X_0 = (3 \div 5)\, X_1 \text{ - three-phase phase cable} \qquad (7.91)$$

$$X_0 = X_1 \text{ - one phase cable} \qquad (7.92)$$

where $X_1 \approx 0{,}1$ Ω/km.

Transformers

The positive-sequence impedance of a 3-phase transformer equals to its short-circuit impedance. The negative-sequence impedance is identical in magnitude as the positive-sequence impedance. However assessing the zero-sequence impedance requires some additional considerations.

Zero-sequence impedance of transformers

The zero-sequence currents are of the same magnitude and phase in all phases of the system. Obviously, zero-sequence currents will flow only if a return path exists. Since zero-sequence currents may be flowing in the ground, the ground is not necessarily of the same potential at all points. Therefore the reference node of the zero-sequence network does not represent a ground of a uniform potential. The impedance of the ground and ground wires need to be included in the zero-sequence network. For Y-connected circuits without grounding the sum of the currents flowing into the neutral point in three phases is zero. Evidently, if sum of currents is zero, there are no zero-sequence components and the impedance to zero-sequence current is infinite. If the neutral of a Y-connected circuit is grounded the zero-sequence impedance appears in the circuit. A delta connected circuit provide no return path for zero-sequence currents. These currents circulate inside the delta circuit. The zero-sequence impedance of a transformer depends upon the arrangement of the windings and upon the type of the core - three-limbed, five-limbed, or single-phase cores. The zero-sequence impedance is significant only in a power system where the windings are star-connected and the star point is grounded. An exception is an autotransformer, whose zero-sequence impedance has an effect on the system even though its star point is not earthed. Magnetization reactance X_{μ} should be considered for zero-sequence transformer current. For 4-, 5- core transformers and single core transformers the reluctance is very small and then the magnetizing reactance is infinitive $X_{0\mu} = \infty$. However for a 3-core transformer the reluctance is larger and the magnetizing reactance usually equals $\underline{X}_{0\mu} = 6X_{1,}$ where X_1 is the transformer positive-sequence reactance. Note, in Poland 90% of transformer are 3-core transformer.

Case YNyn - both neutral grounded

Figure 7.11 presents equivalent circuits of a transformer: a) - key diagram, b) - measurement diagram, c) - measurement diagram. The grounded branch has impedance $\underline{Z}_{gH}$ (primary side) and $\underline{Z}_{gL}$ (secondary side). If both neutrals are grounded then a path through the transformer for zero-sequence currents exists in both windings. In the equivalent circuits, two sides of the transformer are connected to zero-sequence impedances of the transformer in the same manner as was followed in the positive- and negative-sequence networks. Symbols used in Figure 7.11 have the following meanings

- $\underline{Z}_T$ - the short circuit impedance referred to the primary side,
- $\underline{Z}_{gH}$ - the grounded impedance on the primary side,
- $\underline{Z}'_{gL}$ - the grounded impedance on the secondary side.

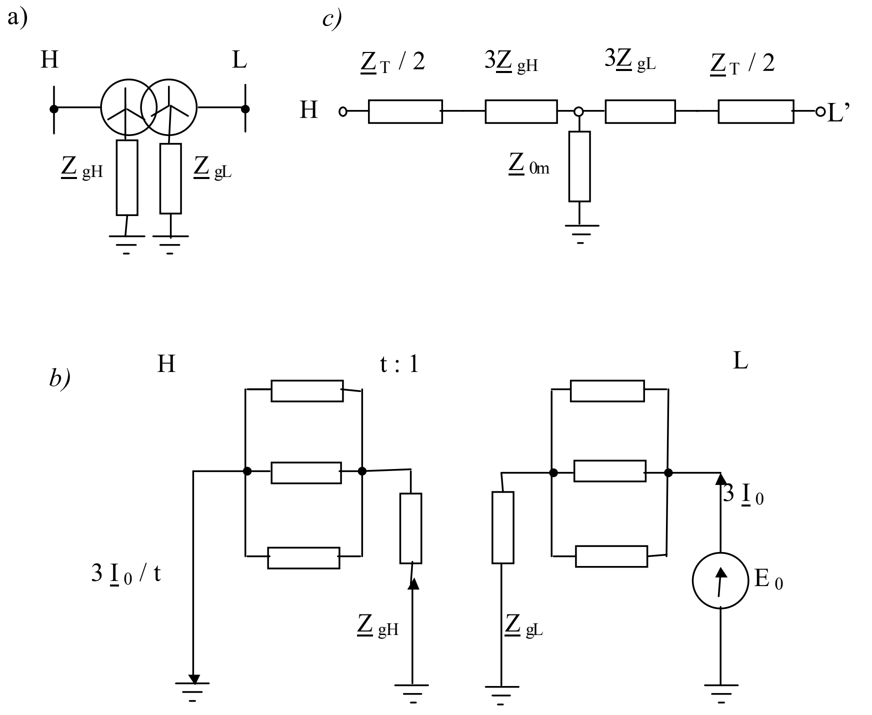


Figure 7.11 Case of YNyn transformer windings, a) key diagram, b) measurement diagram, c) equivalent diagram.

Case YNd - grounded Y on the primary side and delta of the secondary side.

Relevant diagrams are presented in Figure 7.12. If the neutral of Y-d connection is grounded, then zero-sequence currents have a path to ground through the grounded Y, while corresponding induced currents can circulate within the delta circuit. The zero-sequence current circulating in the delta circuit to will not flow in the lines connected to the delta winding. The equivalent circuit on the Y side through includes the equivalent impedance of the transformer connected to the reference node. On the delta side there is no connection to the reference node. If the connection from neutral to ground contains an impedance Z_{gH} , the zero-sequence equivalent circuit must have an impedance equal $3Z_{gH}$. Practically, the grounding impedance may be neglected $Z_{gH} = 0$. Hence we have the following formula for obtaining the zero-sequence impedance

$$\underline{Z}_0 = 0.5\underline{Z}_T + \frac{0.5\underline{Z}_T\underline{Z}_{0\mu}}{0.5\underline{Z}_T + \underline{Z}_{0\mu}} \tag{7.93}$$

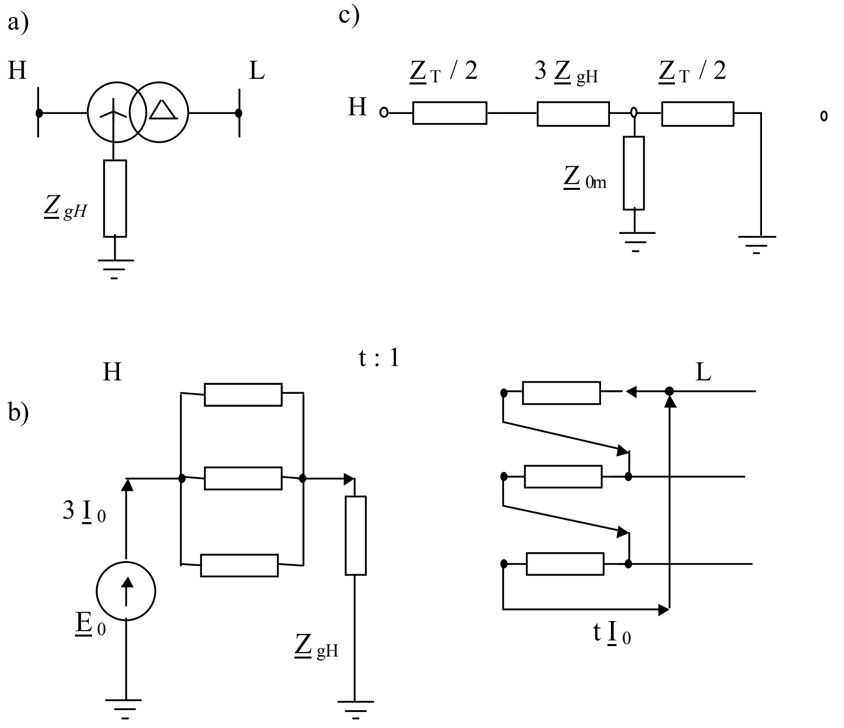


Figure 7.12 Case of YNd transformer windings, a) key diagram, b) measurement diagram, c) equivalent diagram.

Case YNy - one neutral grounded

If one of the neutrals is grounded, zero-sequence current can not flow. The absence of a path through one winding prevents current in the other. An open circuit exists for zero-sequence current between the two parts of the system connected by the transformer. Neglecting the grounding impedance $Z_{gH} = 0$ we have

$$\underline{Z}_0 = 0.5\underline{Z}_T + \underline{Z}_{0\mu} \tag{7.94}$$

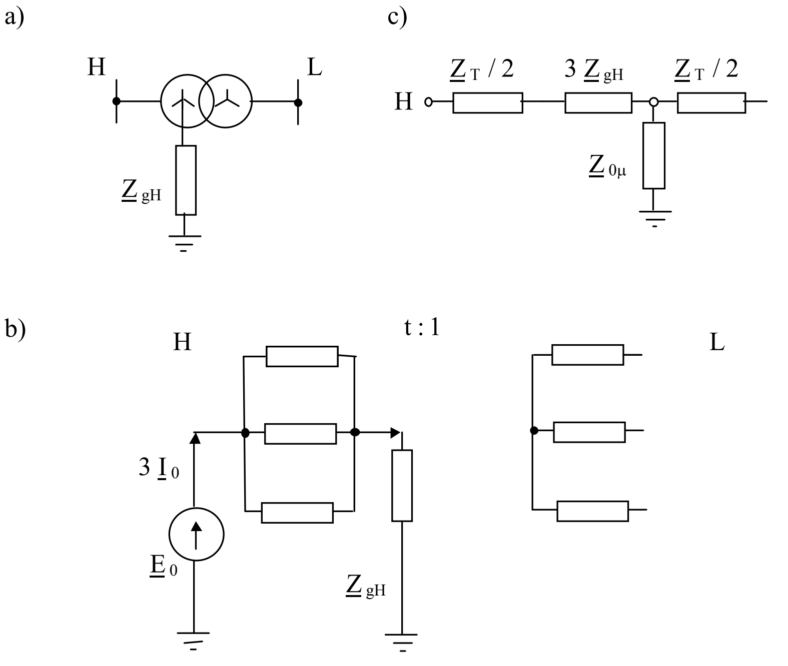


Figure 7.13 Case of YNy transformer windings, a) key diagram,
b) measurement diagram , c) equivalent diagram.

Three-winding transformer

All the above rules can be applied to three-winding transformers.

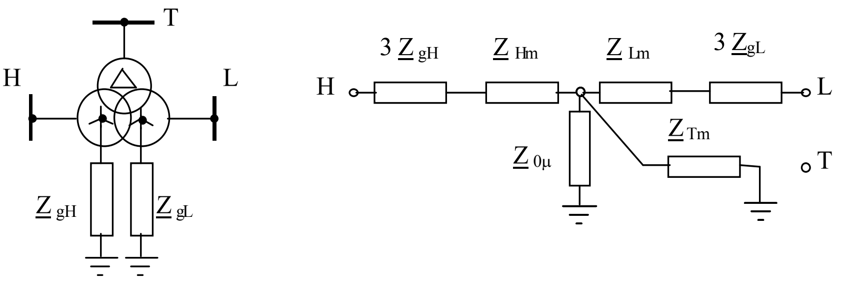


Figure 7.14. Three-winding transformer - the case of YNdyn

7.2.2 Application to an embedded generation scheme

To compute the fault levels for unbalanced faults, we must know the configuration of the transformer windings. Figure 7.15 gives that information for the small system that we have already used in previous examples. This combination of winding configurations is typical of what we might find in a distribution system with embedded generation. The low-voltage side of the 110/20 kV transformers connecting buses A and B is star-connected and the neutral point is connected to earth through a resistance R_0. The value of R_0 is selected so that a line-to-ground fault on the low-voltage side would give rise to a 1 kA fault current. In addition, we must know, for each system component, not only its positive sequence impedance but also its negative and zero sequence impedance. While the negative sequence impedance of lines, cables and transformers is often assumed equal to the positive sequence impedance, the zero sequence impedance is usually significantly different. Table 7.2 gives these values for the relevant components of the small system of our example.

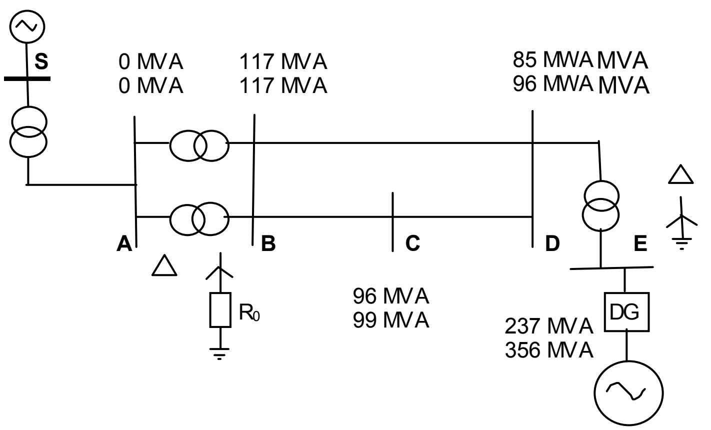


Figure 7.15 MVA fault levels for single line-to-ground faults at various buses in the system. The upper number corresponds to the case where the embedded generator is not connected to the system and the lower number to the case where it is. The system is assumed to be unloaded prior to the fault

Figure 7.15 gives two values of the fault level at each bus. The upper one corresponds to the case where the embedded generator at bus E is not connected to the system and the lower one to the case where it is connected. We observe that, contrary to the situation for balanced faults, the embedded generator does not significantly increase the fault level, except in the close vicinity of bus E. This is due to the fact that the fault current at buses B, C and D is limited mostly by the equivalent zero sequence impedance, which is dominated by the resistance R_0. A single line-to-ground fault at bus A would not produce any fault current as there is no path to earth represented in that part of the network. Finally, it is interesting to note that the fault level at bus E is higher for a single line-to-ground fault than for a balanced three-phase fault.

Table 7.2 Zero sequence impedances for the network used for unbalanced fault studies

From bus	To bus	Type	R_0 [p.u.]	X_0 [p.u.]
A	B	Transformer	5.0250	0.2088
A	B	Transformer	5.0250	0.2170
B	C	Line	0.1440	0.9248
B	D	Line	0.3755	1.5920
C	D	Line	0.4397	2.0050

Standards for fault calculations

The purpose of the previous sections was to introduce the basic concepts and methods used for calculating fault levels and fault currents. The reader should be aware that certain standards must be followed when these calculations are performed to design an embedded generation scheme. IEC 60909 [39] shows how manual calculations may be performed, while Engineering Recommendation G74 [40] provides the basis for computer-based methods.

8. Dispersed generator contribution to voltage regulation in electrical power system

The connection of variable power sources to the system causes voltage fluctuations. This problem might become a real problem when larger penetration of uncertainty DG sources exists in the system. This may impact the system security operation, when the system is not strong and spinning reserve is not large enough to cover the variation of those uncertainty resources. The impact of DG depends on the applied technologies. The synchronous generators equipped with exciter and governor control system help to restore the voltage after a disturbance happening in the system. The connection of large induction might cause a big voltage dip when starting. A soft-start circuit is suggested to use with this technology.

The distribution system in the Poland includes 230 V/400 V, 10 kV- 30 kV, 110 kV; 220 kV and 400 kV other countries have similar voltage levels. As mentioned in Section 7, the fault level at the point of connection which is a measure of network strength, is an important design parameter, not only for predicting currents under fault conditions, but also for predicting performance under normal operating conditions and in particular, voltage rise ΔU. The fault level at the PCC is very important when considering connecting a generator because it largely determines the effect that the generator will have on the network. A low fault level implies a high network source impedance, and a relatively large change in voltage at the PCC caused by extraction or injection of active or reactive power. The impact of a renewable energy generator on the network is therefore very dependent on the fault level at the point of connection as well as on the size of the proposed generator.

Table 8.1 Design rules for a particular voltage level

Network location	**Max capacity of DG**
230/400 kV	200-250 kVA
Out of 10 kV or 11 kV network	2-3 MVA
At 11,5 busbar	8 MVA
On 15 kV or 30 kV network or busbar	6.5-10 MVA
On 110 kV network	10-40 MVA

The appropriate voltage at which to connect a distributed generator is largely dependent on its rated capacity. There are many other factors, as will be seen, and so a range of indicative figures are used as guidelines. Of course, whether a network is weak or not is entirely in relation to the size of the generator being considered. It is therefore common to express a proposed renewable energy source capacity (in MW) as a percentage of the fault level (in MVA) that can be labelled ‘short circuit ratio’. This can provide a rough guide to acceptability. Typical figures for wind farms range from 2 to 24%. Table 8.1 gives rough figures for the maximum capacity of a DG that can be connected at a particular voltage level. These rules should ensure that the influence of the generator on the voltage at the point of connection is acceptable. Connecting at a higher voltage is usually more expensive because of the increased costs of transformers and switchgear and most likely because of the longer line required to make connection with the existing network. Connecting at too low a voltage may not be allowed if the generator were to result in an excessive effect on the local network. This can lead to a situation where the developer of the renewable energy system wishes to connect at one voltage level for economic reasons, while the network operator suggests connection at the next level up.

8.1 Voltage effect

The connection of a distributed generator usually has the effect of raising the voltage at the PCC and this can lead to overvoltages for nearby customers. The need to limit this voltage rise, rather than exceeding the thermal capacity of the line, often determines the limiting size of generator that may be connected to a particular location. An initial estimate of the voltage rise caused by connection of a generator can be obtained from analysis of the system as represented in a simplified form by Figure 8.2. The network up to the point of common coupling can be represented as a Thévenin equivalent with the Thévenin impedance $\mathbf{Z}_{th}$ estimated from the fault level and X-upon-R ratio at the PCC (see Section 7). The values in the Thévenin equivalent circuit shown in Figure 8.1 must be calculated for the particular node in question.

The magnitude of $\mathbf{Z}_{th}$ can be found from the fault level at the node by

$$\left|Z_{th}\right| = \frac{U^2}{S_k} \tag{8.1}$$

where U is the nominal line-to-line voltage.

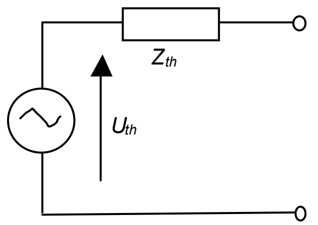


Figure 8.1 Thévenin equivalent circuit

The angle of $\mathbf{Z_{th}}$ could also have been found from the fault level, if only $\mathbf{I_{sc}}$ and $\mathbf{S_k}$ had been calculated and stored as complex numbers. Instead of this, normal practice is to express the fault level as a scalar and to express the associated angle as an *X*/*R* ratio, which can be used in

$$\mathbf{Z_{th}} = R_{th} + jX_{th} \tag{8.2}$$

The Thévenin source voltage can often be taken as the nominal voltage at the point of interest, being careful to use the phase-to-neutral or line-to-line value consistent with the calculation. The *X*-upon-*R* ratio is then used to find the resistance and reactance from Equestion 8.2. The voltage rise ΔU can then be found using a scalar relationship

$$\Delta U \approx \frac{PR + QX}{U} \tag{8.3}$$

where

P and *Q* are positive if the active and reactive powers are positive, i.e. have the directions shown in Figure 8.2 .

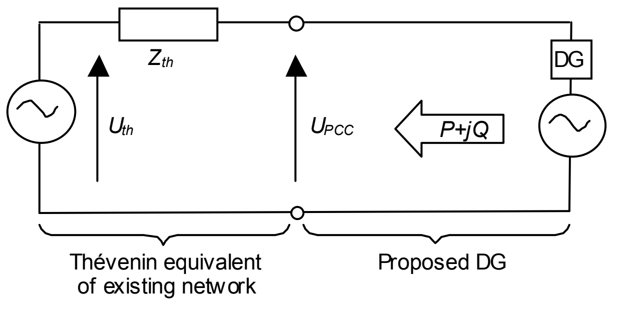


Figure 8.2 Equivalent circuit for estimating voltage rise

If an induction generator is connected directly to the network, Q has a negative value. The allowable voltage rise is dependent on how the network is currently operated i.e. how close the existing voltages get to the allowable maximum. Typically, a rise of 1% would be a concern to the network operator. Voltage rise is often the main consideration for wind farms, which tend to be in rural areas, connected by long and relatively high impedance lines. Voltage rise often puts a limit on the amount of generation that can be connected in a particular rural area. This can occur long before there is any chance of the power flow actually reversing or of the thermal limits of the lines being reached. In some situations, calculations (or load flow modelling) show that voltages will exceed acceptable limits for only a few hours in a typical year. In this case, it may be cost effective to constrain generation during those hours. The lost revenue may be small in comparison to the cost of installing a stronger line. Voltage rise can be mitigated through the extraction of reactive power at the PCC. With induction generators (the norm for smaller wind turbines), this can sometimes be achieved by removing some or all power - factor correction capacitors. With synchronous generators (more common in hydro and biomass fuelled systems), the excitation can be adjusted. However, an embedded generator will normally be charged for any reactive power that it consumes except in low voltage networks (400/230 V) where reactive power is not normally metered. Thus, the normal initial design objective is to operate with a power factor near to unity.

8.2 Automatic Voltage Control – Tap Changers

The simple picture presented so far is complicated in practice by the existence of automatic voltage - control mechanisms in distribution networks. The most common mechanisms are automatic on-load tap changers, which are fitted to most transformers throughout the system, except the final distribution transformers In the network shown in Figure 8.1, the primary substation is equipped with an automatic voltage controller, which uses a tap changer to adjust the turns - ratio of the transformer. Closed - loop control ensures that the voltage on the transformer secondary is kept close to 11 kV. This compensates for variations on the 110 kV side and the current - dependent voltage drops within the transformer itself. Automatic tap changers affect the steady state ΔU voltage - rise analysis presented in the previous section. In particular, the Thévenin impedance $\mathbf{Z}_{th}$ must be adjusted, because its calculation was based on the fault level, which naturally included the impedance upstream of the voltage controller. With the

automatic voltage controller active, the Thévenin voltage is the fixed voltage at the transformer secondary. To correct for this, the fault level and *X*-upon-*R* ratio at the fixed voltage node (transformer secondary) must be known so that the upstream impedance may be calculated and deducted appropriately.
To complicate matters further some automatic voltage controllers do not simply keep the voltage constant. For example, some provide line - drop compensation, which is a way of estimating and allowing for the voltage drop in the downstream line. Other controllers use a technique known as negative reactance compounding, which allows dissimilar transformers or transformers at separate substations to be operated in parallel. Unfortunately, controllers using these techniques can be affected by the changes in the substation power factor that can be caused by distributed generation. To prevent such changes in the power factor, some embedded generators are designed to operate at the same power - factor as the typical loads. Problems of this nature could be avoided if the distributed generators are of a type that could generate and control reactive power. In practice this option has not been fully exploited in the low voltage distribution networks, but with the ongoing development of more sophisticated and low cost power electronic interfaces it is likely to be of importance in the future.

8.3 Active and Reactive Power from Renewable Energy Generators

As mentioned earlier, the large generators of conventional power systems have their individual Automatic Voltage Regulators (AVRs) set to maintain the generator bus voltage virtually constant. Generators fed from renewable energy sources are substantially smaller in rating and are, in general, connected to the distribution rather than the transmission network. For these reasons, conventional generator control schemes have not been considered appropriate for small embedded renewable energy supplied generators. For example, a fixed speed wind turbine driving an induction generator is expected to inject into the network whatever power is converted from the wind up to the rated wind speed, beyond which the power is limited by aerodynamic means at the rated output. It is also expected to absorb whatever reactive power the induction generator requires from the network, minus any locally generated Q from power factor correction capacitors. The situation is similar with small hydro systems interfaced to the grid through induction generators.

Energy from photovoltaic, wave and tidal schemes and MW size wind turbines will invariably be fed to the grid through a pulse-width modulation (PWM) power electronic converter. This provides the facility of reactive power injection/extraction at the point of connection.

To summarize, for relatively small embedded renewable energy generators connected to strong networks the P injection depends solely on the renewable energy source (wind, sun, water) level at the time and the Q injection either on the natural generator Q/P characteristics or on the control characteristics of the power electronic converter. In the latter case the converter could be regulated to inject active power at unity power factor, thus avoiding any Q exchanges with the network, and charges for reactive power. It is also possible that a mutually beneficial formula could be agreed between the owner of the renewable generator and the utility so that the Q generated/consumed by the converter is adjusted to suit the local network.

Generators that are very small individually have negligible influence on system frequency. However, when large numbers of such generators are connected their aggregate impact can be significant. In fact, as penetration levels of wind power increase, as for example in Denmark where the annual level exceeds 20%, and much higher levels will occur at times, utilities will require that renewable generators are designed to contribute positively to power system frequency and voltage stability during contingencies, but more of this later. In a similar manner, it might be expected that in future scenarios with substantial PU generation, that the PU converters might be required to be controlled in relation to system frequency.

9. Dispersed generator contribution to frequency regulation in electrical power system

The main impact of dispersed generation on central generation is to reduce the mean of the power output of the central generators but, often, to increase the variance. In a large electrical power system, consumer demand can be estimated quite accurately by the generator dispatching authority. Dispersed generation will introduce additional uncertainty in these estimates and so may require additional reserve plant. In Europe, considerable effort has been made to predict the output of wind farms by forecasting wind speeds, and dispersed CHP plants by forecasting heat demand. Both forecasts are based on meteorological techniques. As dispersed generation supplies an increasing proportion of the customer load, particularly during times of low demand, the provision of generation reserve and frequency control becomes an important issue. Conventional central generating plant (i.e. steam or hydro-sets) is able to provide these important ancillary services which are necessary for the power system to function. If dispersed generation displaces such plant then these services must be provided by others and the associated additional costs will then reduce the value of the dispersed generation output. This point is discussed in detail in the evidence of the National Grid Company.

9.1 Impact of Renewable Generation on Frequency

The introduction of variable renewable energy (RE) generation into a network will have an impact and incur associated costs in two main categories [41]:

- The first can be labelled as the *balancing impact* and relates to the management of demand fluctuations from seconds to hours.
- The second, referred to as the *reliability impact* relates to the requirement that there is enough generation to meet the peak demand.

Both balancing and reliability involve statistical calculations. The introduction of variable RE generation introduces additional uncertainties that can be quantified in terms of operational penalties that have to be taken into account when the value of electricity from RE sources is calculated.

There is a widespread, but mistaken, belief that operation of an electricity system with renewables causes serious problems. A common misconception is that significant additional plant must be held in readiness, to come on - line when the output from the wind plant ceases. This would indeed be true in an island situation, with, for example, wind the principal source of supply. Modest amounts of variable renewables within an integrated electricity system pose, however, no threat whatsoever to system operation. The reason for this is that these amounts do not add significantly to the uncertainties in predicting the generation to ensure a balance between supply and demand. Therefore the risk of changes in the output from variable renewable sources has only a small influence on the needs for reserves. In the following sections the discussion will be limited mainly to the integration issues of wind power because this is currently the non schedulable renewable energy source making the largest impact, and is likely to remain so for the foreseeable future.

9.1.1 Aggregation of Sources

The smoothing benefit arising from aggregation is of vital importance to electricity utilities. The more uncorrelated the demand among consumers, the more effective the overall smoothing. For a large power system this statistical effect is dramatic and is illustrated by the characteristic demand profile - a typical demand curve over a day for the whole country [42]. As a consequence it is much easier to predict, and the generation required to supply this aggregate load can be scheduled and controlled very efficiently, as will be discussed later. The value of interconnection to form large power systems should now be clear: it allows demand aggregation and the benefits that stem from this, primarily through the easier matching of supply and demand.

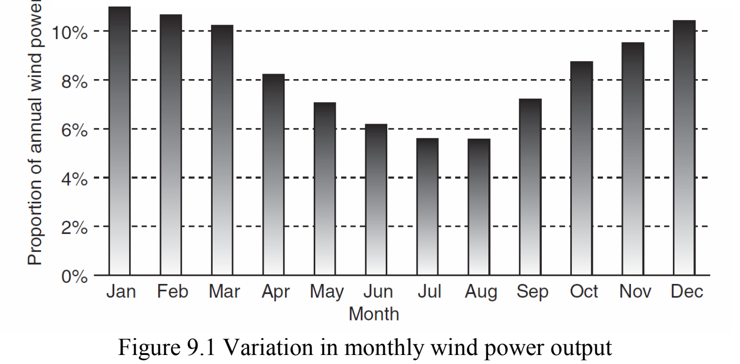


Figure 9.1 Variation in monthly wind power output

Some proponents of renewable energy suggest that national grids will become redundant once generators are located near to consumers, but this is a misconception unless an unprecedented breakthrough in energy storage technology is achieved. Indeed, given the intrinsic variability of many dispersed renewable energy sources, interconnection may well prove to be even more valuable in the future. As described above how integrated electricity systems benefit immeasurably from the aggregation of consumer demand. Fluctuating sources can benefit in the same way. A typical flowchart of specific and average hourly wind speed confirms the benefits of adding the output of geographically dispersed wind sites. Aggregation here has provided its usual benefits by smoothing the output over short and medium timescales.

The Monthly Distribution of Energy

The seasonal wind power availability from dispersed sites (shown in Figure 9.1) indicates limited production during summer and greater than average production during winter [43] . On average twice as much electricity is generated during the winter compared to the summer months. This pattern matches the seasonal demand pattern.

The Daily Distribution of Energy

Figure 9.2 shows that, on average, wind power availability is higher during the daytime than at night. This trend is present irrespective of the time of year and is of benefit in a system where the demand peaks during the afternoon period when the wind power availability is near its maximum.

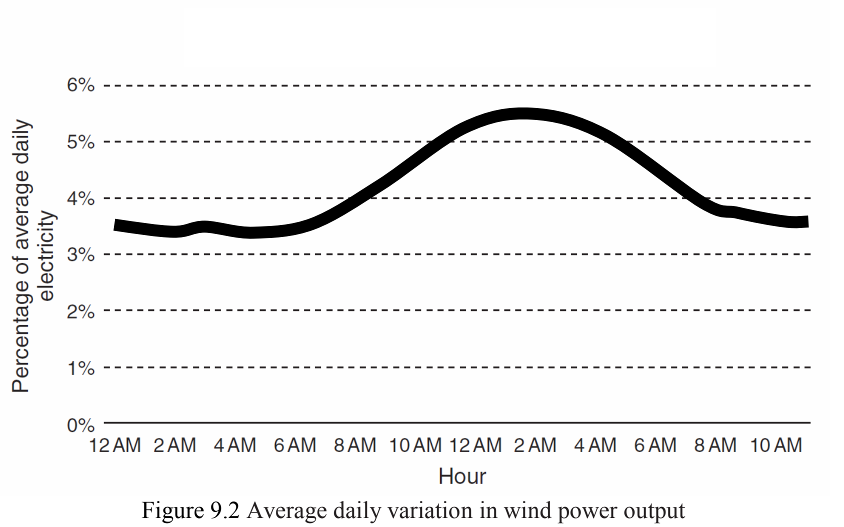


Figure 9.2 Average daily variation in wind power output

Short Term Variability

The variability of wind power will cause changes in the power generated from one hour to the next. The maximum expected rate of change from hour to hour provides an indication of the reserves required to deal with shortfalls in supplying demand. Wind speed variations within the 15 – 25 m/s band will result in no change of power as the wind turbine will be operating at full output for winds in this range. However variations within the band 4 – 15 m/s will result in substantial power changes. The degree of dispersion of the resource will again be of advantage as increments of wind at one site will be compensated by decrements at another. Whereas a single wind farm can exhibit hour to hour power swings of up to 60% of installed capacity this figure is
less than 20% for aggregated wind farms. These maximum changes are likely to occur about once a year. These figures are significant because they indicate the requirement of fast response part loaded thermal plant.

9.2 Frequency Response Services from Renewables

With the anticipated rise in the penetration of variable renewables, power systems will be required to accommodate increasing second to second imbalances between generation and demand requiring enhanced frequency control balancing services. Some renewable generation in principle may contribute to frequency regulation services, but this would require headroom in the form of part - loading. Technologies that could potentially provide such services are biomass, water power, photovoltaics and variable speed wind turbines. Economics dictate that energy from renewable sources should generally be used as fully as possible whenever available. Although this seems to contradict the idea of part loading such plant, there are some occasions when priorities may dictate otherwise. With large penetrations from renewables there will be occasions, for instance during low demand days over summer, when the number of conventional generators needed to supply the residual load will be so few that an adequate level of response and reserve may be difficult to maintain. Under such conditions renewable generators could be unloaded and instructed to take part in frequency regulation. In a privatized system the opportunity benefits of running in this mode must more than compensate the loss of revenue from generating at less than the maximum potential.

Wind power

This area is perhaps the most difficult in which to obtain agreement between network engineers and wind farm providers. Network providers and operators seek to be reassured that the network will remain stable under all conditions. Early wind power technology was mainly based on simple fixed one or two speed stall - regulated wind turbines with little control over the dynamic performance of the generator. However, over recent years active stall and pitch regulated variable speed wind turbines have been developed that are capable of increased conversion efficiencies but also of substantial control capabilities. In principle, modern wind turbines are capable of providing a continuous response by fast increase in power from part loading through blade pitch control in response to drops in frequency and through the same mechanism provide high frequency response through fast reduction in power in response to increases in frequency. As wind power capacity has increased there is an increasing demand for wind capacity to be dispatchable and to behave more like conventional generation. Very large wind farms are now expected to conform to connection standards that limit ramp rates for increase in power and also to contribute to frequency regulation under times of high network stress. These requirements are increasingly included in the national *grid codes* that regulate access to the public networks (Table 9.1). In these early days it is unclear to what extent this will result in wind power being curtailed, for example to comply with given ramp rates, and to what extent such constraints add value to the system operator. Conventional steam generation plant assists the network frequency stability at the onset of a sudden imbalance of demand over supply by slowing down. Wind turbines respond differently. The stored energy is in the rotor inertia and fixed speed turbines will provide a limited benefit from their inertia provided that the voltage and frequency remain within their operating limits. Variable - speed wind turbines will not normally provide this benefit as their speed is controlled to maximize the energy production from the prevailing wind. Large wind turbines are now almost always of the variable speed type and as they increasingly displace conventional generation the total system inertia from such generation will decrease. Consequently the rate of change of frequency and the depth of the frequency dip caused by a sudden loss of generation will both increase. However, variable speed wind turbines could be controlled in principle to provide a proportionately greater inertial energy to the system than conventional plant of the same rating. Such sophisticated control arrangements to support system functions are likely to be requested by utilities as wind penetration increases. Finally, grid codes require wind turbines to maintain power infeeds to the system even under transient local voltage reductions. Such reductions are usually due to fault conditions in the vicinity of the wind farm. It can be shown that maintenance of power infeed from all generators is essential to ensure system recovery after a fault clearance.

Table 9.1 Grid Code requirements for wind farm operation at off-nominal frequencies [54]

Endurance time		Australia (Hz)	Denmark (Hz)	Germany (Hz)	Ireland (Hz)
Normal	Max	50.1	51.0	50.6	50.4
>1h	Min	49.7	49.0	49.0	49.5
1h limits	Over	50.1	51.0	50.6	52.1
	Under	49.7	49.0	49.0	47.6
0.5h limits	Over	50.1	51.0	50.6	52.0
	Under	49.7	49.0	49.0	47.6
Minutes	Over	50.1	51.0	51.5	52.0
	Under	49.7	47.6	48.6	47.6
Second	Over	50.6	53.0	51.5	52.0
	Under	49.4	47.0	47.5	47.1
<Second	Over	52	53.0	51.5	52.0
	Under	47	47.0	47.6	47.1

Utilities carry out studies and tests to ensure that the loss of any infeed does not cause instability of other generation and that remaining generation provides a response in proportion to the decreasing system frequency. Plant must therefore be capable of operating within a frequency range and should be equipped with a control mechanism capable of adjusting the output in response to the frequency. Power systems operate ordinarily within a 1 per cent frequency bandwidth around the nominal frequency, and this poses no problems for wind generators. Loss of significant generation, interconnection or load can cause a system to operate, for a time, at up to 104 per cent or down to 94 per cent of nominal frequency. Load shedding or plant tripping may follow to restore the frequency to within the normal range. As a result, most Grid Codes require that plant is capable of remaining stably connected for defined periods throughout this frequency spectrum. Increasing the turbine output during times of system energy deficiency causes the generation–load energy balance to be restored, preventing the system frequency from falling to the point where there is automatic load disconnection. Grid Codes specify response, droop and dead-band characteristics. Typically load pick up over the pre-emergency condition is specified for 3- and 10-seconds post-event. Droop is usually specified as the percentage change in frequency that will cause a 100 per cent change in output of a unit. The droop refers only to the control system that issues the signal, and is no guarantee that the plant will respond eventually. The actual response is the load-lift measured in defined post-event periods. The dead-band is the normal operating range of frequency movement for which no emergency response is expected. Utilities carry out compliance testing to ensure that new or re-commissioned plant meet the Grid Code requirements on the principle that plant must be capable of sharing he pain of a system disturbance. In case of traditional plant, precise conditions are established and the governor set-point is adjusted up by say 0.5 Hz to simulate a frequency fall. The plant response is timed and values for, say, 3-seconds, 10-seconds and long-term load-lift are recorded. The latter gives the instantaneous droop at the plant pre-loading test point. The problem with carrying out these tests for a wind turbine is that the source power is varying. It may therefore be necessary to record the plant performance over a range of real system events and assess average performance against accurately clocked wind speed while in spilled-wind operating mode. This makes Grid Code compliance a lengthy process during which a wind farm can only be entitled to temporary connection permission.

Biofuels

Traditional thermal plant could be described as *capacity limited*, i.e. capable of theoretically generating its rated output continuously, as gas, coal, oil or fissionable material is abundantly available on demand. In contrast, an energy crop based plant could be described as *energy limited* because the locally harvested fuel is limited in nature and may or may not be capable of sustaining all year round continuous plant generation at full capacity. Transporting biomass fuel from remote areas would not be economical. A biomass plant would be expected to operate as a base - load generator running as far as possible at full output. Such plant would be able to contribute to continuous low or high frequency response services similarly to a conventional plant. For a low frequency response the plant would need to run part - loaded, a convenient strategy providing extra income if, say, due to a low crop yield year the stored fuel would not be capable of servicing continuous full output. The land filled gas plant size is in the range of 0.5 – 1.5 MW and because of their small size they would not be suitable for the provision of frequency regulation services.

Water Power

Small and medium sized hydro schemes without significant storage capacity are characterized by substantial variability of output depending on rainfall. Because of this and their small size they are not suitable for frequency regulation duties. Tidal schemes could be very large indeed and their output would be highly predictable. Such plant would incur exceptionally high upfront capital costs and long payback periods. Operation revenue is vital to service the large loans and it is unlikely that frequency response revenue based on part - loading would be attractive enough. As such schemes are not yet in the planning stages, the jury is still out on their frequency control capabilities. The comments made above on wind power generally apply with reservations to future wave power schemes. As the technology is still in its infancy and commercial schemes are not yet in existence, it is not known how their dynamics may be capable of responding to signals derived from frequency deviations.

Photovoltaics

Here a distinction should be made between large concentrated *PU* installations and numerous roof top systems. For large installations, the comments on wind power apply albeit with some reservations. As the *PU* systems are interfaced to the grids through power electronic converters and as no mechanical inertia is involved, the speed of response in increments or decrements in power flow can be very fast indeed. On the other hand, solar radiation tends to vary more slowly than wind in the short term, and is fairly predictable. As with other renewables, in the future, *PU* systems may be required to operate at part load, thus providing ‘ headroom ’ for continuous or ‘occasional’ frequency control. At this stage of *PU* technology, roof installations are not yet numerous enough to provide a credible frequency response service. However, in years to come if, as predicted, costs plummet and installations are numbered in millions, it is conceivable that the local inverters are fitted with sophisticated controllers to assist system frequency stability.

10. Impact of dispersed generation on transient processes in electrical power system

10.1 Classification of Power System Stability

A typical modern power system is a high-order multivariable process whose dynamic response is influenced by a wide array of devices with different characteristics and response rates. Stability is a condition of equilibrium between opposing forces. Depending on the network topology, system operating condition and the form of disturbance, different sets of opposing forces may experience sustained imbalance leading to different forms of instability. Power system stability is the ability of an electric Power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact. In this section, we provide a systematic basis for classification of power system stability.

The classification of power system stability proposed here is based on the following considerations [43]:

- The physical nature of the resulting mode of instability as indicated by the main system variable in which instability can be observed.
- The size of the disturbance considered, which influences the method of calculation and prediction of stability.
- The devices, processes, and the time span that must be taken into consideration in order to assess stability.

Figure 10.1 gives the overall picture of the power system stability problem, identifying its categories and subcategories. The following are descriptions of the corresponding forms of stability phenomena.

Rotor angle stability

Rotor angle stability refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators. The rotor angle stability problem involves the study of the electromechanical oscillations inherent in power systems. A fundamental factor in this problem is the manner in which the power outputs of synchronous machines vary as their rotor angles change. Under steady-state conditions, there is equilibrium between the input mechanical torque and the output electromagnetic torque of each generator, and the speed remains constant. If the system is perturbed, this equilibrium is upset, resulting in acceleration or deceleration of the rotors of the machines according to the laws of motion of a rotating body. If one generator temporarily runs faster than another, the angular position of its rotor relative to that of the slower machine will advance. The resulting angular difference transfers part of the load from the slow machine to the fast machine, depending on the power-angle relationship. This tends to reduce the speed difference and hence the angular separation.

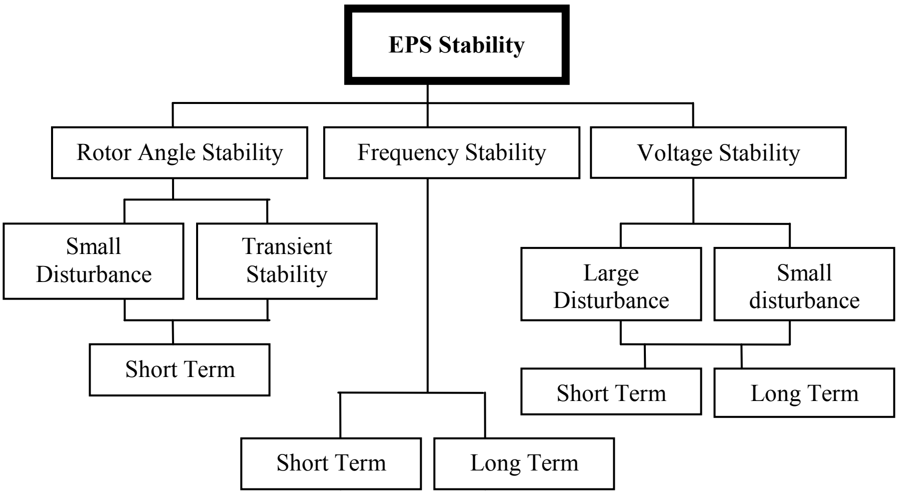


Figure 10.1 Classification of power system stability

The power-angle relationship is highly nonlinear. Beyond a certain limit, an increase in angular separation is accompanied by a decrease in power transfer such that the angular separation is increased further. Instability results if the system cannot absorb the kinetic energy corresponding to these rotor speed differences. For any given situation, the stability of the system depends on whether or not the deviations in angular positions of the rotors result in sufficient restoring torques [43]. Loss of synchronism can occur between one machine and the rest of the system, or between groups of machines, with synchronism maintained within each group after separating from each other. The change in electromagnetic torque of a synchronous machine following a perturbation can be resolved into two components:

- Synchronizing torque component, in phase with rotor angle deviation.
- Damping torque component, in phase with the speed deviation.

System stability depends on the existence of both components of torque for each of the synchronous machines. Lack of sufficient synchronizing torque results in aperiodic or nonoscillatory instability, whereas lack of damping torque results in oscillatory instability.

For convenience in analysis and for gaining useful insight into the nature of stability problems, it is useful to characterize rotor angle stability in terms of the following two subcategories:

- Small-disturbance (or small-signal) rotor angle stability is concerned with the ability of the power system to maintain synchronism under small disturbances. The disturbances are considered to be sufficiently small that linearization of system equations is permissible for purposes of analysis [44].
    - Small-disturbance stability depends on the initial operating state of the system. Instability that may result can be of two forms:
        - increase in rotor angle through a nonoscillatory or aperiodic mode due to lack of synchronizing torque, or
        - rotor oscillations of increasing amplitude due to lack of sufficient damping torque.
    - In today's power systems, small-disturbance rotor angle stability problem is usually associated with insufficient damping of oscillations. The aperiodic instability problem has been largely eliminated by use of continuously acting generator voltage regulators; however, this problem can still occur when generators operate with constant excitation when subjected to the actions of excitation limiters (field current limiters).
    - Small-disturbance rotor angle stability problems may be either local or global in nature. Local problems involve a small part of the power system, and are usually associated with rotor angle oscillations of a single power plant against the rest of the power system. Such oscillations are called local plant mode oscillations. Stability (damping) of these oscillations depends on the strength of the transmission

system as seen by the power plant, generator excitation control systems and plant output [43].
    - Global problems are caused by interactions among large groups of generators and have widespread effects. They involve oscillations of a group of generators in one area swinging against a group of generators in another area. Such oscillations are called inter-area mode oscillations. Their characteristics are very complex and significantly differ from those of local plant mode oscillations. Load characteristics, in particular, have a major effect on the stability of inter-area modes [43].
    - The time frame of interest in small-disturbance stability studies is on the order of 10 to 20 seconds following a disturbance.
- Large-disturbance rotor angle stability or transient stability, as it is commonly referred to, is concerned with the ability of the power system to maintain synchronism when subjected to a severe disturbance, such as a short circuit on a transmission line. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship.
    - Transient stability depends on both the initial operating state of the system and the severity of the disturbance. Instability is usually in the form of aperiodic angular separation due to insufficient synchronizing torque, manifesting as first swing instability. However, in large power systems, transient instability may not always occur as first swing instability associated with a single mode; it could be a result of superposition of a slow inter-area swing mode and a local-plant swing mode causing a large excursion of rotor angle beyond the first swing. It could also be a result of nonlinear effects affecting a single mode causing instability beyond the first swing.
    - The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance. It may extend to 10–20 seconds for very large systems with dominant inter-area swings.

As identified in Figure 10.1, small-disturbance rotor angle stability as well as transient stability are categorized as short term phenomena. The term dynamic stability also appears in the literature as a class of rotor angle stability. However, it has been used to

denote different phenomena by different authors. In the North American literature, it has been used mostly to denote small-disturbance stability in the presence of automatic controls (particularly, the generation excitation controls) as distinct from the
classical “steady-state stability” with no generator controls [45]. In the European literature, it has been used to denote transient stability.

Voltage Stability
Voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. It depends on the ability to maintain/restore equilibrium between load demand and load supply from the power system. Instability that may result occurs in the form of a progressive fall or rise of voltages of some buses. A possible outcome of voltage instability is loss of load in an area, or tripping of transmission lines and other elements by their protective systems leading to cascading outages. Loss of synchronism of some generators may result from these outages or from operating conditions that violate field current limit [46].
Progressive drop in bus voltages can also be associated with rotor angle instability. For example, the loss of synchronism of machines as rotor angles between two groups of machines approach 180 causes rapid drop in voltages at intermediate points in the network close to the electrical center. Normally, protective systems operate to separate the two groups of machines and the voltages recover to levels depending on the post-separation conditions. If, however, the system is not so separated, the voltages near the electrical center rapidly oscillate between high and low values as a result of repeated “pole slips” between the two groups of machines. In contrast, the type of sustained fall of voltage that is related to voltage instability involves loads and may occur where rotor angle stability is not an issue.
The term *voltage collapse* is also often used. It is the process by which the sequence of events accompanying voltage instability leads to a blackout or abnormally low voltages in a significant part of the power system [43]. Stable (steady) operation at low voltage may continue after transformer tap changers reach their boost limit, with intentional and/or unintentional tripping of some load. Remaining load tends to be voltage sensitive, and the connected demand at normal voltage is not met.
The driving force for voltage instability is usually the loads; in response to a disturbance, power consumed by the loads tends to be restored by the action of motor slip adjustment, distribution voltage regulators, tap-changing transformers, and thermostats. Restored loads increase the stress on the high voltage network by increasing the reactive power consumption and causing

further voltage reduction. A run-down situation causing voltage instability occurs when load dynamics attempt to restore power consumption beyond the capability of the transmission network and the connected generation [47].
A major factor contributing to voltage instability is the voltage drop that occurs when active and reactive power flow through inductive reactances of the transmission network; this limits the capability of the transmission network for power transfer and voltage support. The power transfer and voltage support are further limited when some of the generators hit their field or armature current time-overload capability limits. Voltage stability is threatened when a disturbance increases the reactive power demand beyond the sustainable capacity of the available reactive power resources.
While the most common form of voltage instability is the progressive drop of bus voltages, the risk of over voltage instability also exists and has been experienced at least on one system [48]. It is caused by a capacitive behavior of the network (EHV transmission lines operating below surge impedance loading) as well as by under excitation limiters preventing generators and/or synchronous compensators from absorbing the excess reactive power. In this case, the instability is associated with the inability of the combined generation and transmission system to operate below some load level. In their attempt to restore this load power, transformer tap changers cause long-term voltage instability.
Voltage stability problems may also be experienced at then terminals of HVDC links used for either long distance or back-to-back applications. They are usually associated with HVDC links connected to weak ac systems and may occur at rectifier or inverter stations, and are associated with the unfavorable reactive power "load" characteristics of the converters. The HVDC link control strategies have a very significant influence on such problems, since the active and reactive power at the ac/dc junction are determined by the controls. If the resulting loading on the ac transmission stresses it beyond its capability, voltage instability occurs. Such a phenomenon is relatively fast with the time frame of interest being in the order of one second or less. Voltage instability may also be associated with converter transformer tap-changer controls, which is a considerably slower phenomenon [49]. Recent developments in HVDC technology (voltage source converters and capacitor commutated converters) have significantly increased the limits for stable operation of HVDC links in weak systems as compared with the limits for line commutated converters.
One form of voltage stability problem that results in uncontrolled over voltages is the self-excitation of synchronous machines. This can arise if the capacitive load of a synchronous machine is too large. Examples of excessive capacitive loads that can initiate self-excitation are open ended

high voltage lines and shunt capacitors and filter banks from HVDC stations. The over voltages that result when generator load changes to capacitive are characterized by an instantaneous rise at the instant of change followed by a more gradual rise. This latter rise depends on the relation between the capacitive load component and machine reactances together with the excitation system of the synchronous machine. Negative field current capability of the exciter is a feature that has a positive influence on the limits for self-excitation.
As in the case of rotor angle stability, it is useful to classify voltage stability into the following subcategories:

- Large-disturbance voltage stability refers to the system's ability to maintain steady voltages following large disturbances such as system faults, loss of generation, or circuit contingencies. This ability is determined by the system and load characteristics, and the interactions of both continuous and discrete controls and protections. Determination of large-disturbance voltage stability requires the examination of the nonlinear response of the power system over a period of time sufficient to capture the performance and interactions of such devices as motors, under load transformer tap changers, and generator field-current limiters. The study period of interest may extend from a few seconds to tens of minutes.
- Small-disturbance voltage stability refers to the system's ability to maintain steady voltages when subjected to small perturbations such as incremental changes in system load. This form of stability is influenced by the characteristics of loads, continuous controls, and discrete controls at a given instant of time. This concept is useful in determining, at any instant, how the system voltages will respond to small system changes. With appropriate assumptions, system equations can be linearized for analysis thereby allowing computation of valuable sensitivity information useful in identifying factors influencing stability. This linearization, however, cannot account for nonlinear effects such as tap changer controls (discrete tap steps, and time delays). Therefore, a combination of linear and nonlinear analyzes is used in a complementary manner [43].

Frequency stability

Frequency stability refers to the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load. It depends on the ability to maintain/restore equilibrium between system generation and load, with minimum unintentional loss of load. Instability that may result occurs in the form of sustained frequency swings leading to tripping of generating units and/or loads.

Severe system upsets generally result in large excursions of frequency, power flows, voltage, and other system variables, thereby invoking the actions of processes, controls, and protections that are not modeled in conventional transient stability or voltage stability studies. These processes may be very slow, such as boiler dynamics, or only triggered for extreme system conditions, such as volts/Hz protection tripping generators. In large interconnected power systems, this type of situation is most commonly associated with conditions following splitting of systems into islands. Stability in this case is a question of whether or not each island will reach a state of operating equilibrium with minimal unintentional loss of load. It is determined by the overall response of the island as evidenced by its mean frequency, rather than relative motion of machines. Generally, frequency stability problems are associated with inadequacies in equipment responses, poor coordination of control and protection equipment, or insufficient generation reserve. Examples of such problems are reported in reference [50].

During frequency excursions, the characteristic times of the processes and devices that are activated will range from fraction of seconds, corresponding to the response of devices such as under-frequency load shedding and generator controls and protections, to several minutes, corresponding to the response of devices such as prime mover energy supply systems and load voltage regulators. Therefore, as identified in Figure 10.1, frequency stability may be a *short-term* phenomenon or a *long-term* phenomenon. An example of short-term frequency instability is the formation of an under-generated island with insufficient under-frequency load shedding such that frequency decays rapidly causing blackout of the island within a few seconds. On the other hand, more complex situations in which frequency instability is caused by steam turbine over speed controls or boiler/reactor protection and controls are longer-term phenomena with the time frame of interest ranging from tens of seconds to several minutes [43].

During frequency excursions, voltage magnitudes may change significantly, especially for islanding conditions with under frequency load shedding that unloads the system. Voltage magnitude changes, which may be higher in percentage than frequency changes, affect the load-generation imbalance. High voltage may cause undesirable generator tripping by poorly designed or coordinated loss of excitation relays or volts/Hz relays. In an overloaded system, low voltage may cause undesirable operation of impedance relays.

10.2 Stability studies in larger systems

While the analysis presented above provides useful insights into the mechanisms leading to transient instability in power systems, it relies on a series of simplifying assumptions that may not be justified in an actual power system:

- Modelling the system as a single generator connected to an infinite bus may not be acceptable if several embedded generators are connected to a relatively weak network. It may be necessary to model the dynamic interactions between these generators or between one of these generators and large rotating loads.
- The generator was modelled as a constant voltage behind a single reactance. This very simple model does not reflect the complexity of the dynamics of synchronous generators and may give a misleading measure of the system stability. In particular, it neglects the stabilizing effect of the generator's excitation system.
- Since electrical and mechanical losses have been neglected, the system has no damping. This approximation distorts the oscillations taking place after a fault and overstates the risk of instability.
- Finally, it may be necessary to model the effect of faults at different locations in the network rather than simply at the terminals of the generator.

Removing these limitations requires the use of much more complex models for the generators, for the network and for the controllers. Unfortunately, the equal area criterion no longer holds under these conditions and another stability assessment method must be implemented. Most commercial-grade stability assessment programs rely on the numerical solution of the differential and algebraic equations describing the power system. The solution of these equations tracks the evolution of the system following a disturbance. If it shows the rotor angle of one or more generators drifting away from the angles of the rest of the generators, the system is deemed unstable. On the other hand, if all variables settle into an acceptable new steady state, the system is considered stable.

The model of each generating unit contains between two and eight non-linear differential equations, not counting those required for modeling the excitation system. The differential equations of all the generators are coupled through the algebraic equations describing the network. This coupling requires the solution of a power flow at each time step of the solution of the differential equations.

Induction generators

Historically, induction generators have not been significant in large power systems and so they have not been represented explicitly in many power system analysis programs. The behavior of large induction motors can be important in transient stability studies, particularly of industrial systems, e.g. oil facilities, and so induction motor models are usually included in transient stability programs. These can be used to give a representation of induction generators merely by changing the sign of the applied torque. However, the models used for these generators have often been based on a representation of a voltage source behind a transient reactance similar to that used for simple transient modeling of synchronous generators. The main simplifying assumption is that stator electrical transients are neglected and there is no provision for saturation of the magnetic circuits to be included. Such models may not be reliable for operation at elevated voltages or for investigating rapid transients such as those due to faults. More sophisticated models of induction generators are available in electromagnetic transient programs or can be found in advanced textbooks [35].

10.3 Application to a distributed resources scheme

To illustrate the concepts discussed in the previous sections, we will consider the small system shown in Figure 10.2. Let us first assume that faults at bus D are cleared in 100 ms and that the generator at bus E is producing 20 MW. Figure 10.2 shows the oscillations in the rotor angle of this generator following such a fault at bus D. The generator initially accelerates and the rotor angle reaches a maximum value of approximately 120 degrees 150 ms after the fault.

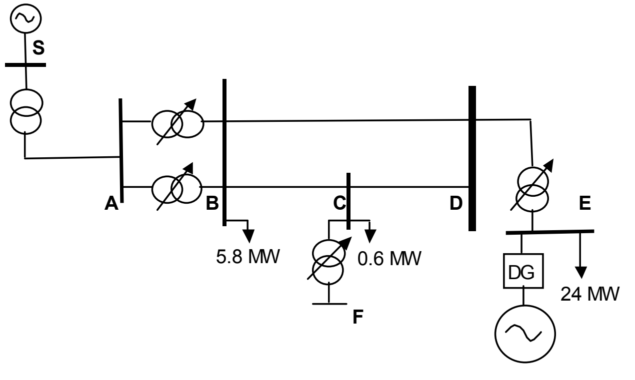


Figure 10.2 Small system used to illustrate the stability studies

It is clear from the figure that Figure 10.3 stability is maintained. Let us now suppose that the protection system and the switchgear at bus B are such that faults are cleared after only 200 ms. Figure 10.4 shows that stability would be lost even if the generator was only producing 11.6 MW. 320 ms after the fault, the rotor angle reaches 180 degrees and 'slips a pole'. At that point, the equipment protecting the generator would immediately take it off-line to protect it from damage. Stability problems could be avoided by further reducing the active power output of the generator.

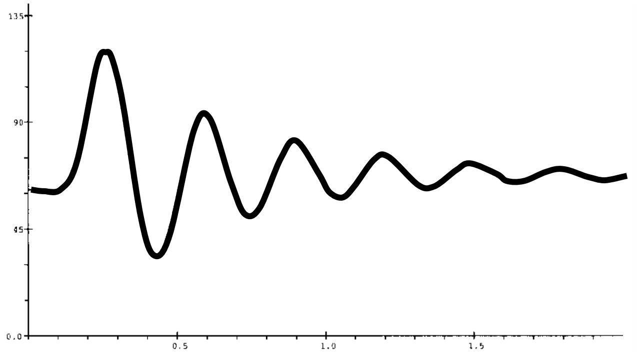


Figure 10.3 Oscillations in the rotor angle of the embedded generator at bus E following a fault at bus D when this generator produces 20 MW. The fault is applied at t = 100 ms and cleared at t = 200 ms

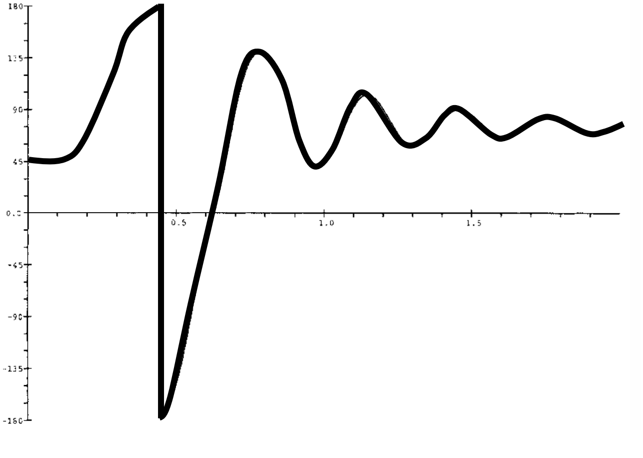


Figure 10.4 Oscillations in the rotor angle of the embedded generator at bus E following a fault at bus D when this generator produces 11.6 MW. The fault is applied at t = 100 ms and cleared at t = 300 ms. Note that this particular computer program keeps all angles as being between +180 degrees and –180 degrees. There is thus no discontinuity in angle at t = 445 ms – simply a modulus operation

Figure 10.5 illustrates the marginally stable case where the generator produces 11.5 MW. The rotor angle reaches a maximum angle of 165 degrees before dropping. Note that this angle will ultimately return to its original steady-state value of about 45 degrees but that this may take some time, as the system is marginally stable. Figure 10.6 illustrates the effect of a fault at bus F, in another 11 kV section of the system. Such faults may occasionally take up to 2 s to clear. However, since the reactance between the fault and the embedded generator is large, the system remains stable even for such a long clearing time. It should be noted that the reactance of the transformer between buses C and F has been adjusted to produce an almost critical case. Therefore, the rotor angle of the generator does take some time to return to its prefault steady-state value.

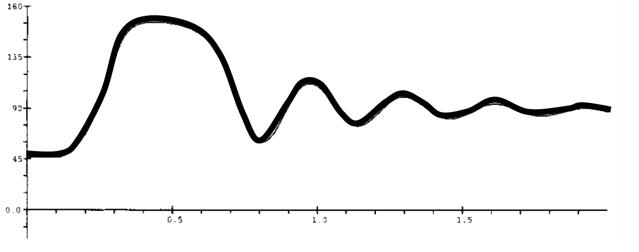


Figure 10.5 Oscillations in the rotor angle of the embedded generator at bus E following a fault at bus D when this generator produces 11.5 MW. The fault is applied at t = 100 ms and cleared at t = 300 ms

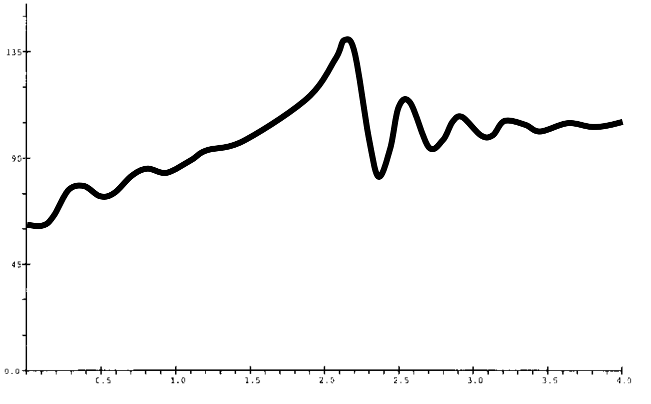


Figure 10.6 Oscillations in the rotor angle of the embedded generator at bus E following a fault at bus F when this generator produces 20 MW. The fault is applied at t = 0.1 s and cleared at t = 2.1 s

11. Impact of dispersed generators on relay protection of electrical power network

The primary purpose of power system protection is to ensure safe operation of power systems, thus to care for the safety of people, personnel and equipment. The standard of protection increases with system importance. Thus a simple cartridge fuse may be used to protect an LV circuit whereas dual main protection based upon different protection principles may be used on the super-grid network. For example, an asynchronous coupling of networks results in high currents. Earth faults can cause high touch voltages and therefore endanger people. The general problem is always voltage and/or current out of limit. Hence, the aim is to avoid over-currents and overvoltages to guarantee secure operation of power systems. The costs and complication of protection rise accordingly and this reflects either the strategic worth of rapid fault clearance to maintain generator stability or the importance of the integrity of a particular part of the system. Many transmission and distribution systems are re-closed automatically after a fault to minimize customer outage. Many distribution systems are operated as closed loop or ring networks. Such systems are protected using directional over-current and earth fault schemes with plain over-current and earth fault backup. The relays are time graded from the source substation, and any attempt to introduce a significant alternative source around the ring would result in inappropriate tripping for a fault. Most wind farm protection is a developer's internal matter. However, a prudent network operator will seek assurance that the protection design, installation, commissioning and maintenance are such that the grid is not threatened.

11.1 Protection Issues with DG

The overall problem when integrating DG in existing networks is that distribution systems are planned as passive networks, carrying the power unidirectional from the central generation (High Voltage - HV level) downstream to the loads at Medium Voltage/Low Voltage (MV/LV) level. The protection system design in common MV and LV distribution networks is determined by a passive paradigm, i.e. no generation is expected in the network [2]. With distributed sources, the networks get active and conventional protection turns out to be unsuitable. The following sections will outline the most important issues.

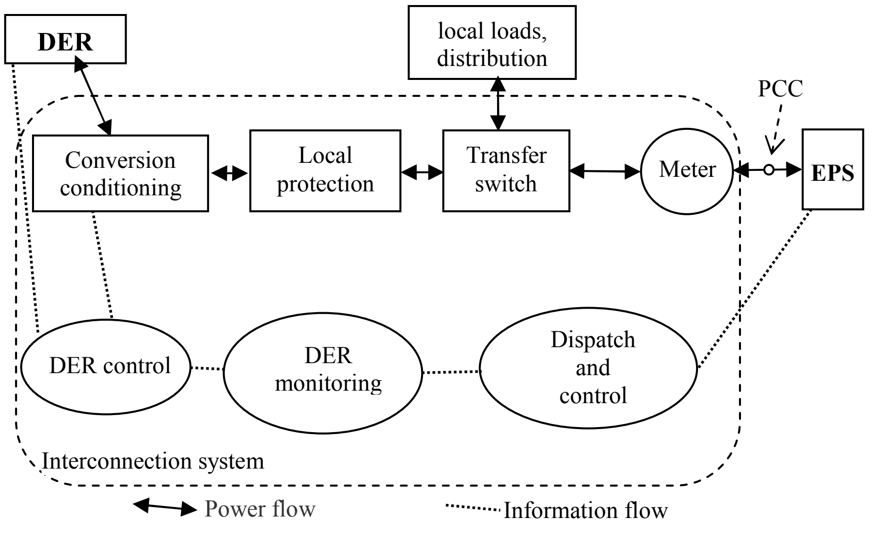


Figure 11.1 Interconnection system functional scheme - EPS - Electric Power System; DER - Distributed Energy Resource; PCC -Point of Common Coupling

11.1.1 Short Circuit Power and Fault Current Level

The fault current level describes the effect of faults in terms of current or power. It gives an indication of the short circuit current or (apparent) power boost. In Chapter 7 the fault level *fl* in p.u. is defined as

$$fl = i = \frac{1}{|z_{th}|} \tag{11.1}$$

where i is the fault current related to the nominal current and zth is the inner impedance of the Thevenin representation of the network in p.u. Examples for this value are given in Chapter 7, typical fault levels in distribution networks are in a range of 10-15 p.u., where 1 p.u. corresponds to the rated current. This is, phase-phase or phase-earth faults normally result in an overcurrent which is significantly higher than the operational or nominal current. The amplitude of the fault current is dependent on the fault impedance, for phase-earth faults it is also highly dependent on the grounding. This is a very basic precondition for the function of (instantaneous) over current protection. The fault current has to be distinguishable from the normal operational current. To fulfill that, there has to be a powerful source providing a high fault current until the relay triggers. Especially power electronic converters are often equipped with controllers that prevent high currents. If, for example, a remote part of a distribution network is equipped with large PV installations, it could happen that in case of a failure there is almost no significant rise of the phase current and the fault is therefore not detected from the overcurrent protection system. The question arises, why one needs to care about a fault if there is no fault current. The answer is that dangerous touch voltages may occur even if the current is low. Furthermore permanent faults may spread out and destroy more equipment.

With DC in the network, the fault impedance z_{th} can also decrease due to parallel circuits, therefore the fault level increases and there could be unexpected high fault currents in case of a failure. This situation puts components at risk since they were not designed to operate under such circumstances.

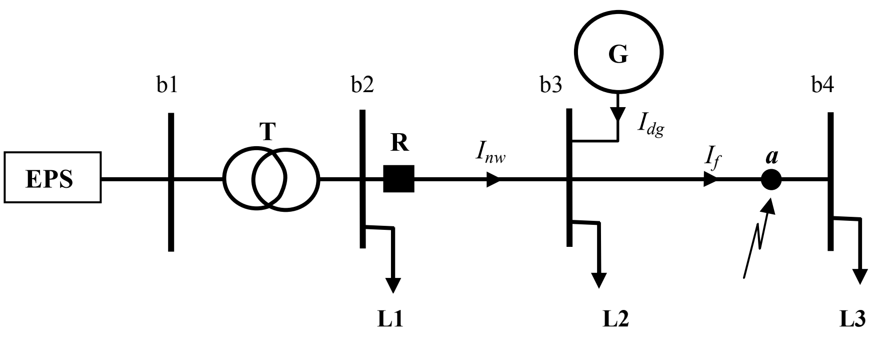


Figure 11.2 Short circuit at point **a**. Current from transmission network I_{nw}, current from embedded generator I_{dg}.

For correct operation it is also important that the relay measures the real fault current which was expected and taken under consideration when the relay was set up. Figure 11.2 shows a distribution feeder with an embedded generator that supplies part of the local loads. Assuming a short circuit at point **a**, the generator will also contribute to the total fault current

$$I_f = I_{nw} + I_{dg} \tag{11.2}$$

but the relay R will only measure the current coming from the network infeed I_{nw}. This is, the relay detects only a part of the real fault current and may therefore not trigger properly. As mentioned in [2] there is an increased risk especially for high impedance faults that over-current protection with inverse time-current characteristic may not trigger in sufficient time. One

can find another influence of DC on fault currents when assuming a short circuit at the bus bar **b₂** in Figure 11.2. In this case, the fault current contribution from the generator passes the relay in reverse direction what can cause problems if directional relays are used. DC can also affect the current direction during normal operation, this issue is explained in section 11.1.3.
Concluding the issues concerning short circuit faults it can be stated that dispersed generation affects:

- amplitude,
- direction and
- duration (indirectly)

of fault currents. The last point is a result of inverse time-current characteristics (or grading, respectively).

11.1.2 Reduced Reach of Impedance Relays

The phenomena of reduced reach of distance relays due to embedded power infeed is mentioned in [51,52] and other references. In [2] this problem is considered for conventional power systems. The reach of an impedance relay is the maximum fault distance that triggers the relay in a certain impedance zone, or in a certain time due to its setting. This maximum distance corresponds to a maximum fault impedance or a minimum fault current that is detected. Considering Figure 11.2, one can calculate the voltage measured by the relay *R* in case of a short circuit at **a** (load currents are neglected for this consideration):

$$U_r = I_{nw} Z_{23} + (I_{nw} + I_{dg}) \cdot Z_{3a} \tag{11.3}$$

where Z_{23} is the line impedance from bus $\mathbf{b_2}$ to bus $\mathbf{b_3}$ and Z_{3a} is the impedance between bus $\mathbf{b_3}$ and the fault location at **a**. This voltage is increased due to the additional infeed at bus $\mathbf{b_3}$. Hence, the impedance measured by the relay *R*

$$Z_r = \frac{U_r}{I_{nw}} = Z_{23} + Z_{3a} + \underbrace{\frac{I_{dg}}{I_{nw}} \cdot Z_{3a}}_{\text{disturbance}} \tag{11.4}$$

is higher than the real fault impedance (as seen from *R*) what corresponds to an apparently increased fault distance. Consequently, the relay may trigger in higher grading time in another distance zone. For certain relay settings which were determined during planning studies, the fault has to be closer to the relay to operate it within the originally intended distance zone. The active area of the relay is therefore shortened, its reach is reduced. Note that the apparent impedance varies with I_{dg}/I_{nw}.

11.1.3 Reverse Power Flow and Voltage Profile

Radial distribution networks are usually designed for unidirectional power flow, from the infeed downstream to the loads. This assumption is reflected in standard protection schemes with directional over-current relays. With a generator on the distribution feeder, the load flow situation may change. If the local production exceeds the local consumption, power flow changes its direction [53]. Reverse power flow is problematic if it is not considered in the protection system design. Moreover, reverse power flow implies a reverse voltage gradient along a radial feeder. Dispersed generation always affectss the voltage profile along a distribution line. Beside power quality issues, this could cause a violation of voltage limits and additional voltage stress for the equipment. The voltage increase/drop ΔU due to power in-/outfeed can be approximated with [54]

$$\Delta U \approx \frac{P_{dg} R_{th} + Q_{dg} X_{th}}{U_n} \tag{11.5}$$

where U_n is the nominal voltage of the system, $R_{th} + j \cdot X_{th}$ is the line impedance (Thevenin equivalent respectively) and $P_{dg} + j \cdot Q_{dg}$ is the power infeed of the DG.

An analytical method of calculating the influence of DC on the voltage profile of distribution feeders is presented in [55-57]. Figure 11.3 shows the voltage gradient along a distribution feeder with and without embedded generation. The power flow direction corresponds to the sign of the voltage gradient. In this situation the power flow direction between bus $\mathbf{b_2}$ and $\mathbf{b_3}$ is changed due to the infeed at bus $\mathbf{b_3}$. Especially in highly loaded or weak networks dispersed generation can also influence the voltage profile in a positive way and turn into a power quality benefit. Reference [56] describes another issue concerning the voltage profile on distribution feeders. Usually tap changing transformers are used for the voltage regulation in distribution networks which change the taps, i.e. their turns ratio, due to the load current. If the DG is located near the network infeed (e.g. at bus $\mathbf{b_2}$ in Figure 11.3), it influences tap-changing because the DG infeed decreases the resulting load for the transformer. Hence tap-changing characteristics will be shifted, the infeed voltage will not be regulated correctly.

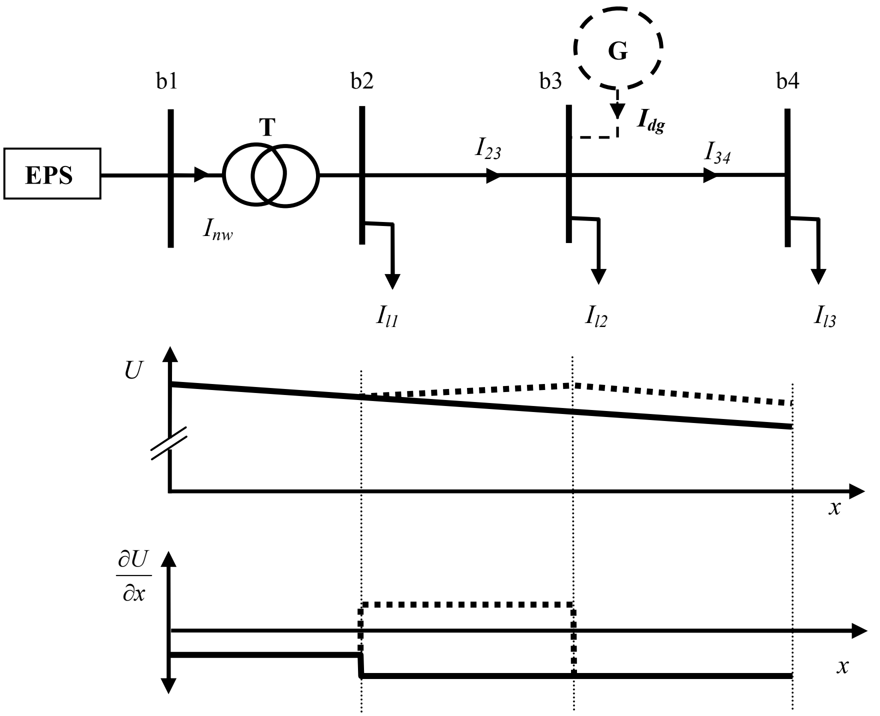


Figure 11.3 Voltage profile and gradient on a distribution feeder with and without contribution of generator G. Solid line: $I_{dg} = 0$, downstream power flow; dahsed line: $I_{dg} > I_{l2} + I_{l3}$, reverse power flow between $\mathbf{b_2}$ and $\mathbf{b_3}$.

11.1.4 Islanding and Auto Reclosure

Critical situations can occur if a part of the utility network is islanded and an integrated DG unit is connected. This situation is commonly referred to as Loss of Mains (LOM) or Loss of Grid (LOG). When LOM occurs, neither the voltage nor the frequency are controlled by the utility supply. Normally, islanding is the consequence of a fault in the network. If an embedded generator continues its operation after the utility supply was disconnected, faults may not clear since the arc is still charged. Small embedded generators (or grid interfaces respectively) are often not equipped with voltage control, therefore the voltage magnitude of an islanded network is not kept between desired limits, and undefined voltage magnitudes may occur during island operation. Another result of missing control might be frequency instability. Since real systems are never balanced exactly, the frequency will change due to active power unbalance. Uncontrolled frequency represents a high risk for machines and drives. Since arc faults normally clear after a short interruption of the supply, automatic (instantaneous) reclosure is a common relay feature. With a continuously operating generator in the network, two problems may arise when the utility network is automatically reconnected after a short interruption:

- The fault may not have cleared since the arc was fed from the DG unit, therefore instantaneous reclosure may not succeed.
- In the islanded part of the grid, the frequency may have changed due to active power unbalance (even if there is active power control, the island will not run synchronously with the utility system). Reclosing the switch would couple two asynchronously operating systems.

Extended dead time (t_i in figure 11.4) has to be regarded between the separation of the DG unit and the reconnection of the utility supply to make fault clearing possible. Common off-time settings of auto reclosure relays are between 100 ms and 1000 ms. With DG in the network, the total off-time has to be prolonged. Reference [58] recommends a reclosure interval of 1 s or more for distribution feeders with embedded generators.

A linear approximation for the frequency change during island operation is given in [59]. The rate of change of frequency is expressed as a function of the active power unbalance:

$$\Delta P = \sum P_{dg} - \sum P_l \tag{11.6}$$

the inertia constant of the machine H, the machines' rated power S_n and the frequency f_s before LOM:

$$\frac{df}{dt} = \frac{\Delta P f_s}{2 S_n H} \tag{11.7}$$

It is straight forward to calculate the frequency change

$$\Delta f = \frac{\Delta P f_s}{2 S_n H} \cdot t_i \tag{11.8}$$

This approach does only consider the frequency change due to islanding, the fault is not regarded. Figure 11.4 shows an example of an auto reclosure procedure where an embedded generator is not disconnecting although it is islanded with the local grid. Here it is assumed that there is a lack of active power after islanding, i.e. $\sum P_{dg} < \sum P_l$, therefore the island frequency decreases. LOM and automatic reclosure are some of the most challenging issues of DC protection and therefore a lot of research has been done in that area. The only solution to this problem seems to be disconnecting the DC unit as soon as LOM occurs. Thus it is necessary to detect islands fast and reliably. Several islanding detection methods are presented in the next section.

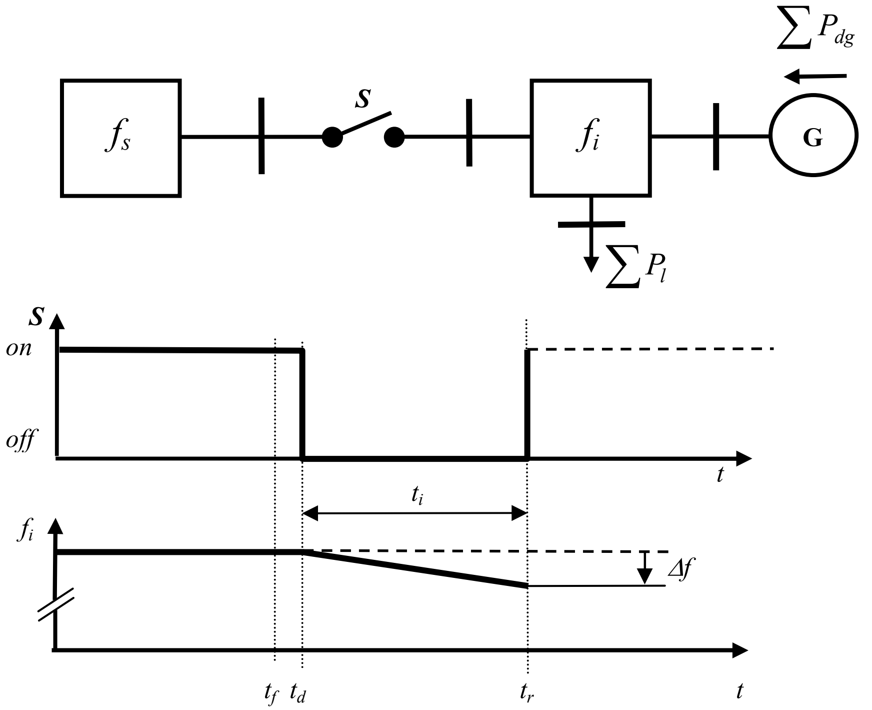


Figure 11.4 Auto reclosure procedure: fault occurs at t_f, disconnection of at t_d, reconnection at t_r, reclosure interval t_i; state of utility switch S, utility synchronous frequency f_s, island frequency f_i, frequency drop Δf.

11.2 Current Practice - Island Detection

The difficulties with islanded DC have been outlined in section 11.1.4. To prevent island operation the protection system has to detect islands quickly and reliably. This is the task of loss of mains protection. Reference [60] divides island detection into passive and active methods. Some of them will be outlined in the following sections.

11.2.1 Passive Methods

These methods detect loss of mains by passively measuring or monitoring the system state.

Undervoltage/Overvoltage A clear indication of lost utility supply is very low voltage. If there are uncontrolled generators in the network, the voltage can also rise (for example due to resonance) and exceed the upper limit. Therefore, under- and overvoltage relays are a simple islanding protection method. In larger islands the voltage collapse will take some time, therefore this kind of LOM protection is often too slow.

Underfrequency/Overfrequency As mentioned, real systems are never balanced exactly. After LOM happened, the frequency in the island changes due to equation (11.7). Hence frequency out of limits can indicate island operation. The frequency does not change instantaneously but continuously, thus frequency relaying is a rather slow method.

Voltage Vector Shift (VVS) This method is outlined in [2] and others, it is also referred to as phase displacement [60] or phase jump [58] method. Figure 11.5 shows the situation when part of the load is fed from an embedded generator and the rest is supplied from a distribution network. The distribution network and the embedded generator are represented by equivalent circuits both operating on the local load. After the utility switch S disconnects the local load has to be supplied from the generator G. Assuming constant load, the transmission angle, i.e. the voltage phase difference between the generator and the load terminal has to rapidly increase due to the sudden power flow increase. This increased transmission angle is shown in Figure 11.5. Dotted lines represent parallel supply, solid phasors show the situation after islanding. Due to the vector jump the duration of the concerned period is extended [53]. Voltage vector relays monitor the duration of every half cycle and initiate tripping if a certain limit is exceed. Common voltage vector shift relays trip with $\vartheta_{pickup} = 6...12^o$

Rate of Change of Voltage Loss of mains detection due to the rate of change of voltage is introduced in [59]. Usually voltage changes are slow in large interconnected power systems. If a distribution system gets separated, a rate of change of voltage occurs that is significantly higher than during normal operation. Therefore rate of change of voltage can be used to detect island operation. A major handicap of this method is that it is sensitive to network disturbances other than LOM.

Rate of Change of Frequency (ROCOF) As discussed in section 11.1.4, the frequency in an island will change rapidly due to active power unbalance. The corresponding frequency slope can be used to detect loss of mains. Whenever *df/dt* exceeds a certain limit, relays are tripped. Typical pickup values are set in a range of 0.1 to 1.0 Hz/s, the operating time is between 0.2 and 0.5 s. A problem with ROCOF protection is unwanted tripping resulting from frequency excursions due to loss of bulk supply, for example faults in the transmission grid. Another reason for malfunction is phase shift caused from other network disturbances.

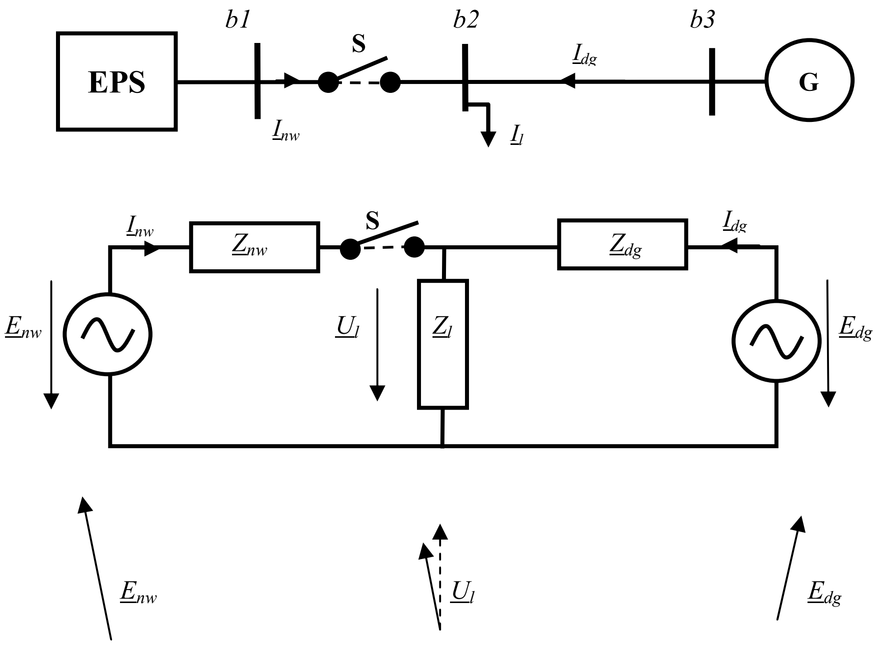


Figure 11.5 Voltage vector shift after islanding. Thevenin eqivalent of the network with E_{nw}, Z_{nw} and of the generator with E_{dg}, Z_{dg} respectively

Rate of Change of Power and Power Factor Loss of grid algorithms based on the rate of change of the generator active power output are outlined in [59,61]. In [62] the instantaneous power is derived from the generator voltages and currents and then the rate of change of power is used in a limiting function that prohibits mal-function due to system disturbances. The results of the studies in [62] show that the algorithm needs at least six cycles (120 ms) to detect LOM what is rather slow as compared with other LOM detection methods. Reference [60] presents simulation results arguing that the most sensitive variables to system disturbances are time derivative of voltage, current, impedance, absolute change of voltage, current, current angle, impedance and changes in power factor, whereas some of these are redundant. Certain situations are studied and a suitable logic for a LOM relay is derived using the rate of change of voltage and changes in power factor.

Elliptical Trajectories Whenever a fault occurs on a line, the corresponding voltage an current changes at the sending end are related to each other by an elliptical trajectory. The trajectory of voltage and current change (in combination with scaling factors) is described by an orbital equation. The investigations in [63] show that the shape of this trajectory changes significantly after islanding.

12.2.2 Active Methods

Beside passive measurements and monitoring, there are active methods of LOM detection where the detection system (relay) is actively interacting with the power system in order to get an indication for island operation.

Reactive Error Export This highly reliable means of LOM detection is shortly discussed in [64]. For this method, the generator is controlled on a certain reactive power output. Whenever islanding occurs, it is assumed that it is not possible to deliver the specified amount of reactive power to the local grid since there is no corresponding load. This reactive export error is taken as an indicator for LOM.

Fault Level Monitoring The fault level in a certain point of the grid can be measured using a point-on-wave switched thyristor [64]. The valve is triggered close to the voltage zero crossing and the current through a shunt inductor is measured. The system impedance and the fault level can be quickly calculated (every half cycle) with the disadvantage of slightly changed voltage shape near the zero crossover.

System Impedance Monitoring In [64] a method is introduced that detects LOM by actively monitoring the system impedance. A high frequency source (a few volts at a frequency of a few kHz) is connected via a coupling capacitor at the interconnection point. As pictured in Fig. 11.6, the capacitor is in series with the equivalent network impedance. When the systems are synchronized, the impedance $Z_{dg}||Z_{nw}$ is low, therefore the HF-ripple at coupling point is negligible. After islanding, the impedance increases dramatically to Z_{dg} and the divided HF-signal is clearly detectable.

Frequency Shift Inverter-interfaced DC can be protected against LOM using frequency shift methods [65]. The output current of the converter is controlled to a frequency which is slightly different from the nominal frequency of the system. This is done by varying the power factor during a cycle and re-synchronization at the begin of a new cycle. Under normal conditions, the terminal frequency is dictated by the powerful bulk supply. If the mains supply is lost, frequency will drift until a certain shutdown level is exceed.

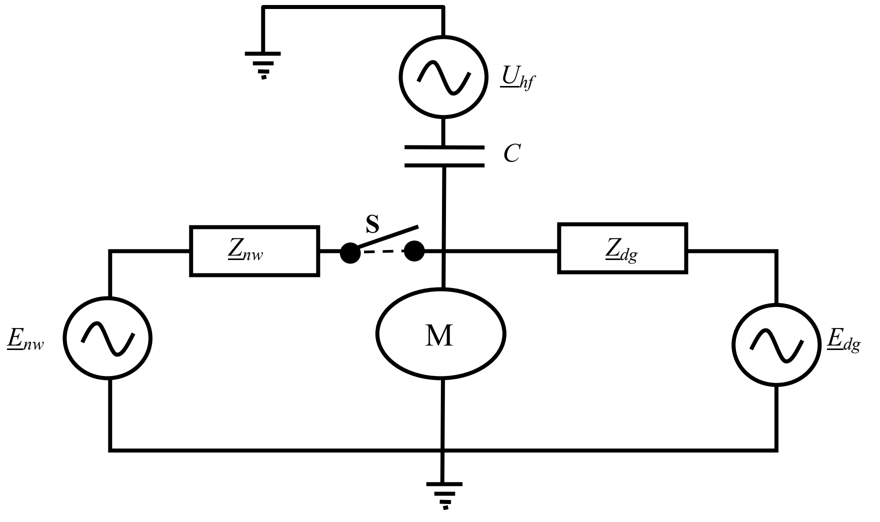


Figure 11.6: System impedance monitoring. The meter M will measure an increased HF signal when the utility network is disconnected

Voltage Pulse Perturbation and Correlation In [65] two methods of islanding detection for inverter-connected DC are presented that use a perturbation signal of the output voltage. For the first method, the inverter output is perturbed with a square pulse. This square pulse appears in both the inner voltage of the source and the voltage at interconnection point. If islanding happens, the apparent impedance at the generator terminal increases and therefore the perturbation can be measured at the point of common coupling (similar to system impedance monitoring). The second method uses a correlation function to detect LOM. The inner voltage of the source is randomly perturbed and correlated with the voltage change at the interconnection point. During normal operation, the apparent impedance is low and the voltage waveform at the interconnection point will not reflect the perturbation signal. After islanding the modulation signal will appear in both the inner voltage and the voltage at the interconnection point what results in a strong correlation.

12. The effect of dispersed generators on power quality and reliability of electrical power network

Voltage flicker, steps, dips, harmonics and phase imbalance may all degrade what is loosely described as *power quality*. Such undesirable occurrences can be caused just as much by loads as by generators. In general, it is the responsibility of the operator of the load or generator not to unduly affect the power quality for other users in the area. However, the impact of any load or generator is dependent not only on its own characteristics but also on the strength of the network to which it is connected. Network operators are paying increasing attention to power quality. This is not specifically in relation to distributed generation but mainly because of regulatory obligations set up to protect consumers from the generation of harmonics caused by the plethora of electronic devices on the network. Over the last 15 years both operators and customers have taken an increasing interest in the quality of the power, or more precisely the quality of the voltage, which is delivered by distribution networks. This interest has been stimulated by a number of factors, including [66]:

- increasingly sensitive load equipment, which often includes computer-based controllers and power electronic converters which can be sensitive to variations in voltage magnitude, phase and frequency,
- the proliferation of power electronic switching devices on the network, including the power supplies of small items of equipment such as PCs and domestic equipment, and the rise in background harmonic voltage levels on the electricity supply network,
- increased sophistication of industrial and commercial customers of the network and concern over the effect, and commercial consequences, of perceived poor power quality on their equipment and hence production. This particularly concerns the effect of voltage dips or sags on continuous industrial processes.

Although the main issues of power quality are common to any distribution network, whether active or passive, the addition of embedded generation can have a significant effect and, as usual, increases the complexity of this aspect of distribution engineering. Some forms of embedded generation can introduce non-sinusoidal currents into the distribution network and so degrade power quality by causing harmonic voltage distortion while other types can cause unacceptable variations in *rms* voltage magnitudes. Perhaps surprisingly, embedded generators may also improve network power quality by effectively increasing the short-circuit level of part of the distribution network. Figure 12.1 shows a representation of how network power quality issues may be viewed. Figure 12.1*a* shows the various effects which may be considered to originate in the transmission and distribution networks and which can affect the voltage to which loads and generators are connected. Thus, voltage sags (i.e. a decrease to between 0.1 and 0.9 per unit voltage for a period of up to 1 min), which are usually caused by faults on the transmission/distribution network, will impact on both loads and embedded generators. During severe voltage sags, spinning loads will tend to slow down and stall while rotating generating plant will accelerate, towards potential transient instability. In both cases the depressed voltage may cause contactors to open and voltage sensitive control circuits to mal-operate. Voltage swells are transient rises in power frequency voltage, usually caused by faults or switching operations, but are less common than sags. Ambient harmonic voltage distortion is increasing in many power systems, and in Poland it is not uncommon to find levels witch, at some times of the day, the level which is considered desirable by network planners [67]. Harmonic voltage distortions will have a similar effect of increasing losses in rotating machines being operated either as generators or motors and may also disturb the control systems of power electronic converters. It is common practice to use power factor correction capacitors with induction generators witch, of course, will have a low impedance to harmonic currents and the potential harmonic resonances with the inductive reactance of other items of plant on the network elements.

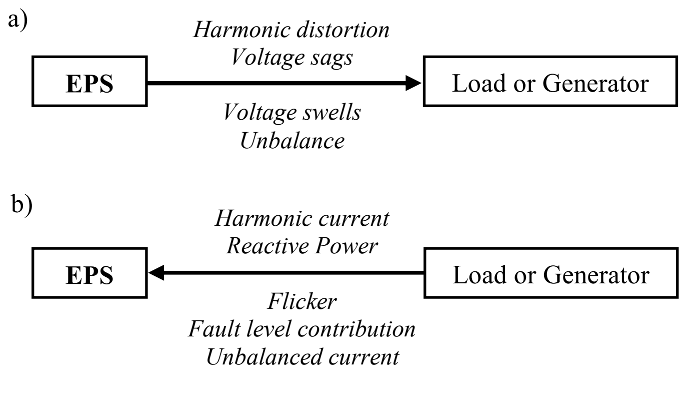


Figure 12.1 Origin of power quality issues

Network voltage unbalance will also affect rotating machines by increasing losses and introducing torque ripple. Voltage unbalance can also cause power converters to inject unexpected harmonic currents back into the network unless their design has included consideration of an unbalanced supply. The response of embedded generators to disturbances originating on the transmission/distribution network will be broadly similar to that of large loads. However, large industrial loads will tend to be connected to strong networks with high short-circuit levels, and in general better power quality, while a distinguishing feature of embedded generation using some types of renewable energy is that they are connected to weak networks and the rating of the generation can be a significant fraction of the network short-circuit level. Figure 12.1b gives a list of how loads or an embedded generator may introduce disturbances into the distribution network and so cause a reduction in power quality. Thus, either a load or a generator which uses a power electronic converter may inject harmonic currents into the network. Similarly, unbalanced operation of either a load or generator will lead to negative phase sequence currents being injected into the network which, in turn, will cause network voltage unbalance. As has been discussed earlier, generators can either produce or absorb reactive power while exporting active power and, depending on the details of the network, load and generation, this may lead to undesirable steady-state voltage variations. Voltage flicker refers to the effect of dynamic changes in voltage caused either by loads (arc-furnaces are a well known example) or by generators, e.g. wind turbines. Both spinning motor loads and embedded generators using directly connected rotating machines will increase the network fault level and so will affect power quality, often may improve it. Only generators are capable of supplying sustained active power which may lead to excessive voltages on the network. There is considerable similarity between the power quality issues of embedded generators and large loads and, in general, the same standards are applied to both.

The impact of a 'perfect' embedded generator on network power quality is illustrated in Figure 12.2. The 'perfect' generator is considered to supply perfectly sinusoidal current. Figure 12.2a shows simply a distorting load connected to a distribution system which is represented by a source impedance, $Z_s(h)$, connected to an infinite busbar. The source impedance varies with frequency and so is represented as a function of the harmonic number (h). The distorting load can be considered as a source of distorted current, $I_d(h)$. Neglecting other loads and using the principle of superposition the voltage distortion introduced by this load can be simply found by applying Ohm's Law and finding the voltage distortion across the source impedance:

$$\overline{U}_d(h) = \overline{I_d}(h) \times \overline{Z}_s(h) \quad (12.1)$$

Figure 12.2b shows the 'perfect' embedded generator added to the network. If the principle of superposition is again used to investigate the effect of the distorted current then the voltage source of the embedded generator is considered as a short-circuit. Thus, the effect of adding the 'perfect' generator is to raise the fault level of the network and effectively to introduce the generator impedance $Z_g(h)$ in parallel with the source impedance $Z_s(h)$. For the same injected current distortion $I_d(h)$ the resultant voltage distortion is now $U'_d(h)$ which, in this simple example, is merely

$$\overline{U}'_d(h) = \overline{U}_d(h) \times \overline{Z}_g(h) / \left(\overline{Z}_s(h) + \overline{Z}_g(h)\right) \quad (12.2)$$

The nature of the distorted load current determines which impedance is required. For fundamental current then, Z_s is merely the source 50Hz impedance, while Z_g may need to include either the transient or synchronous reactance of the generator depending on the frequency of variations in I_d. A similar representation can be used for calculations of harmonic voltages in which case harmonic impedances are required. For calculation of unbalanced voltages, negative phase sequence impedances must be used.

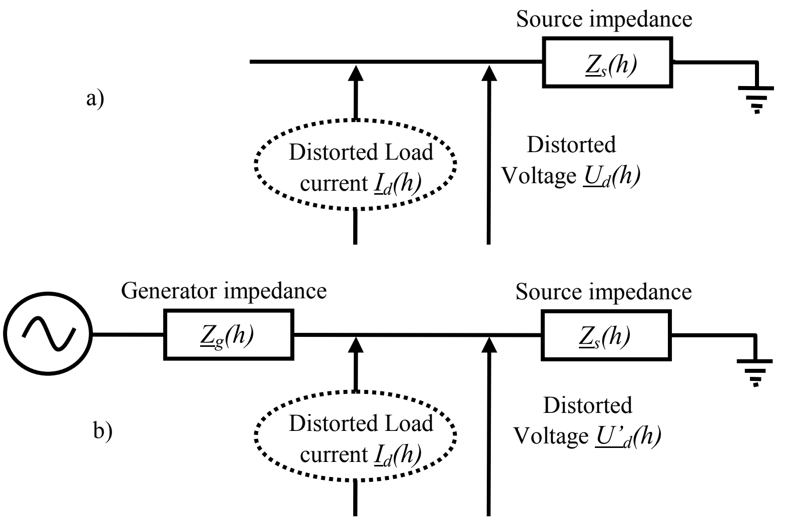


Figure 12.2 Effect of a 'perfect' embedded generator on network power quality

Of course, if the embedded generator itself produces distorted current (e.g. a small PU inverter using a line commutated bridge), then these will add to any distorted current injected by the load. This is shown in Figure 12.3, rather simply with the internal impedance of the load and generator ignored, to indicate that the voltage distortion U''_d is now increased to

$$\overline{U}''_d(h) = \overline{Z}_s(h) \times \left(\overline{I}_d + \overline{I}_g\right) \tag{12.3}$$

Including distorted currents the frequencies and phases must be taken into account. If the phase relationship between harmonic currents is not known then a root of the sum-of-squares addition may be appropriate. Eqns. (12.1)–(12.3) indicate the main effects on power quality of adding distributed generation to a distribution network. In practice, more realistic models with more complex software programs are used. Harmonic analysis programs are well established to investigation of how harmonic voltage distortion is affected by injection of harmonic currents [68], although there is considerable difficulty with determination of harmonic impedances for items of plant and, in particular, in deciding on suitable representation of loads. Loads are an important source of damping of harmonic resonances and so can affect the magnitudes of network harmonic voltages considerably. Recently developed programs are able to predict the effect of embedded generation plant on voltage flicker, although so far they are dedicated to particular generation technologies [69]. If necessary, electro-magnetic simulations may be undertaken to examine the response of the network to embedded generation in the time domain.

Wind turbines are a good example of embedded generation plant for which power quality considerations are important. Individual units can be large, up to 1.5 MW, and are often connected to distribution circuits with a high source impedance. The turbines will either use induction generators (fixed rotor speed) or power electronic converters (variable rotor speed).

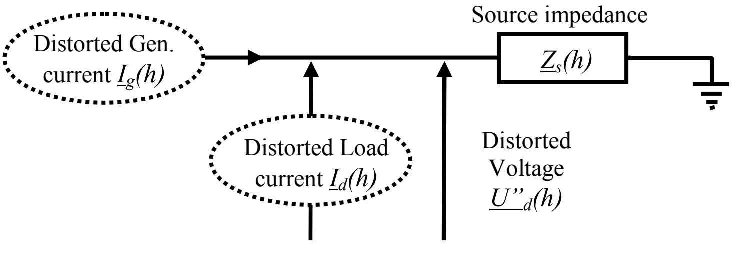


Figure 12.3 Effect of an embedded generator producing a distorted current on network power quality

For those designs which use power electronic converters the issues of harmonic distortion of the network voltage must be carefully considered while the connection of fixed-speed turbines to the network needs to be managed carefully if excessive transients are to be avoided. During normal operation wind turbines produce a continuously variable output power. The power variations are mainly caused by the effects of turbulence in the wind and tower shadow – the reduction in wind speed close to the tower. These effects lead to periodic power pulsations at the frequency at which the blades pass the tower (typically around 1 Hz for a large turbine), which are superimposed on the slower variations caused by meteorological changes in wind speed. There may also be higher frequency power variations (at a few Hz) caused by the dynamics of the turbine. Variable-speed operation of the rotor has the advantage that many of the faster power variations are not transmitted to the network but are smoothed by the flywheel action of the rotor. However, fixed speed operation, using a low-slip induction generator, will lead to cyclic variations in output power and hence network voltage.

Reference [70] carried out a comprehensive two year measurement campaign to investigate the effect of a wind farm on the power quality of the 33 kV network to which it was connected. The 7.2 MW wind farm of 24 × 300 kW fixed-speed induction generator turbines was connected to a weak 33 kV overhead network with a short-circuit level of 78 MVA. Each wind turbine was capable of operating at two speeds by reconnection of the generator windings and power factor correction capacitors were connected to each unit once the turbine started generating. The wind turbines were located along a ridge at an elevation of 400 m in complex upland terrain and so were subject to turbulent winds. Measurements to assess power quality were taken at the connection to the distribution network and at two wind turbines. The results are interesting as they indicate a complex relationship of a general improvement in power quality due to the connection of the generators, and hence the increase in fault level, and a slight increase in harmonic voltages caused by resonances of the generator windings with the power factor correction capacitors. In detail the measurements indicated the following:

- The operation of the wind farm raised the mean of the 33 kV voltage slightly but reduced its standard deviation. This was expected as, in this case, the product of injected active power and network resistance was approximately equal to the product of the reactive power absorbed and the inductive reactance of the 33 kV circuit. The effect of the generators was to increase the fault level and so ‘stabilize’ the network but with little effect on the steady-state voltage.

- The connection of increasing numbers of induction generators caused a dramatic reduction in negative phase sequence voltage from 1.5% with no generators connected to less than 0.4% with all generators operating. This was, of course, at the expense of significant negative phase sequence currents flowing in the generators and associated heating and losses.
- The wind farm slightly reduced the voltage flicker measured at the point of connection. This was a complex effect with the generators raising the fault level but also introducing fluctuations in current.
- There was a slight increase in total harmonic voltage distortion with the wind farm in operation, mainly caused by a rise in the 5th and 7th harmonics when the low-speed, high-impedance winding of each generator was in service. This increase was probably associated with a parallel resonance of the high-impedance winding of the generators and the power factor correction capacitors.

These results are typical of the experience of connecting wind farms, with large numbers of relatively small induction generators, on to rural distribution circuits. In a number of studies some aspects of power quality have been shown to be improved by the effective increase in the fault level. However, the impact of embedded generation plant on the distribution network will vary according to circumstances, and each project must be evaluated individually. In particular, large-single generators, as opposed to a group of smaller generators, will require careful attention.

12.1 Voltage flicker

Voltage flicker describes dynamic variations in the network voltage which may be caused either by embedded generators or by loads. The origin of the term is the effect of the voltage fluctuations on the brightness of incandescent lights and the subsequent annoyance to customers [71]. Human sensitivity to variations of light intensity is frequency dependent, and Figure 12.4 indicates the magnitude of sinusoidal voltage changes which laboratory tests have shown are likely to be perceptible to observers [72]. It may be seen that the eye is most sensitive to voltage variations around 10 Hz. The various national and international standards for flicker on networks are based on curves of this type. Traditionally voltage flicker was of concern when the connection of large fluctuating loads (e.g. arc furnaces, rock crushing machinery, sawmills, etc.) was under consideration. However, it is of considerable significance for embedded generation, which:

(i) often uses relatively large individual items of plant compared to load equipment;

(ii) may start and stop frequently;

(iii) may be subject to continuous variations in input power from a fluctuating energy source. Items of embedded generation plant which require assessment for potential nuisance caused by voltage flicker include:

- connection and disconnection of induction generators,
- operation of wind turbines,
- operation of photovoltaic generators.

Flicker is usually evaluated over a 10 min period to give a 'short-term severity value' P_{st}. The P_{st} value is obtained from a 10 min time series of measured network voltage using an algorithm based on the nuisance perceived by the human eye in fluctuating light [72]. P_{st} is linear with respect to the magnitudes of the voltage change but, of course, includes the frequency dependency indicated in Figure 12.4. Twelve P_{st} values may then be combined using a root of the sum of the cubes calculation to give a 'long-term severity value' P_{lt} over a 2 h period.

Some assessment of the effect of connection and disconnection of embedded induction generators can be made based on the established manual calculation procedure for large motors. However, these manual techniques were not developed specifically for generators and there can be additional complications of deciding the power factor to assume for the distorted current being drawn through an operating antiparallel thyristor soft-start unit and the effect of applied torque on the shaft of the generator. Therefore, for wind turbines an alternative procedure based on a series of measurements made at a test site has been proposed [73].

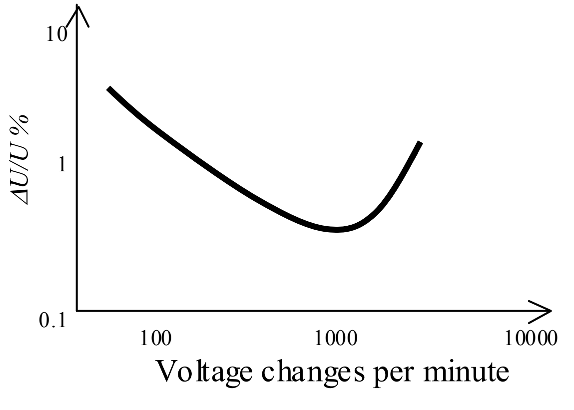


Figure 12.4 Influence of frequency and the perceptibility of sinusoidal voltage changes

Determination of the voltage flicker caused by variations in real power output due to fluctuations in renewable energy sources is also difficult as this will depend on the resource, the characteristics of the generator and the impedance of the network. Simple measurement of voltage variations at the terminals of a test unit is not satisfactory as ambient levels of flicker in the network will influence the results, and the X/R ratio of the source impedance at the test site will obviously have a great impact on the outcome. For wind turbines, a procedure has been proposed where both voltage and current measurements are made of the output of a test turbine and used for synthesis of the voltage variations which would be caused on distribution networks with defined fault levels and X/R ratios of their source impedance. These voltage variations are then passed through a flicker algorithm to calculate the flicker which the test turbine would cause on the defined networks. When the installation of the particular turbine is considered at a point on the real distribution network these test results are then scaled to reflect the actual fault level and interpolated for the X/R ratio of the point of connection. A correction is also applied for the annual mean wind speed [73].

If a number of generators are subject to uncorrelated variations in torque then their power outputs and impact on network flicker will reduce as

$$\frac{\Delta P}{P} = \frac{1}{\sqrt{n}} \times \frac{\Delta p}{p} \tag{12.4}$$

where

n is the number of generators,

P and p are the rated power of the wind farm and wind turbine, respectively, and

ΔP and Δp are the magnitudes of their power fluctuation.

There is some evidence that on some sites wind turbines can fall into synchronised operation, and in this case the voltage variations become cumulative and so increase the flicker in a linear manner. The cause of this synchronous operation is not completely clear but it is thought to be due to interactions on the electrical system caused by variations in network voltage. A range of permissible limits for flicker on distribution networks is given in national and international standards. Reference [71] specifies an absolute maximum value of P_{st} on a network, from all sources, to be 1.0 with a 2h P_{lt} value of 0.6. Reference [72], which specifically excludes embedded generation from its scope, is significantly less stringent, specifying that over a one week period P_{lt} must be less than 1 for 95% of the time. Reference [74] describes P_{st} limits from a number of utilities in the range 0.25–0.5 but also notes the rather different approach adopted by IEC 1000 [75], which uses a more complex methodology to allocate equitably the flicker capacity among all users of the network.

12.2 Harmonics

Embedded generation can influence the harmonic performance of distribution networks in a number of ways. Power electronic converters used for interfaceing generation equipment can cause harmonic currents to flow, but conventional rotating plant (e.g. synchronous or induction generators) will alter the harmonic impedance of the network and hence its response to other harmonic sources. Further, the introduction of shunt capacitor banks used for compensation of induction generators may lead to resonances. Power electronic converters for interfacing large (> 1MW) embedded generation plant are still not widespread, with the possible exception of some designs of variable-speed wind turbines, but the future increased use of such equipment may be anticipated together with rapid changes in converter topologies and devices. In the last 10 years the voltage source converter has become common, but prior to that, line commutated, thyristor-based converters were used for some embedded generators. Figure 12.5 shows a simple 6-pulse, current source, line commutated bridge arrangement of the type used in some early photovoltaic and wind turbine schemes. This is a well established technology which has been widely used for industrial equipment and is the basis for contemporary high voltage direct current transmission plant. With a firing angle of the thyristors of between 0 and 90° the bridge acts as a rectifier with power flow from the network to the generation device while inverter operation is achieved by delaying the firing angle of the thryistors to beyond 90°. The disadvantages of this technology are well known:

- high characteristic harmonics and
- poor power factor.

However, the arrangement is simple and robust with relatively low losses. It also has the advantage that islanded operation is not possible as the converter needs the commutating voltage of the network to operate.

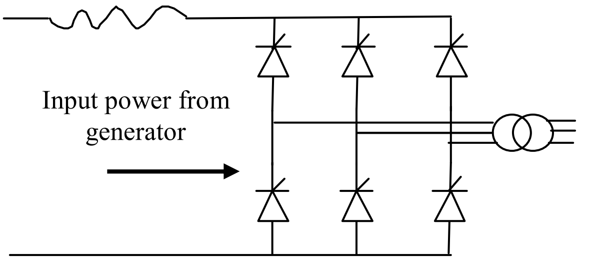


Figure 12.5 Line commutated converter

Traditionally, state-owned electric power utilities have paid considerable attention to electrical losses as their investment appraisals were undertaken using long time horizons (20–40 years) and low discount rates (4–8%). In this financial environment electrical losses become very important as the costs incurred throughout the life of the plant are significant. Investment in industrial plant is assessed using much higher discount rates (perhaps 15–20%) with much shorter project lifetimes (perhaps 5–10 years) and so electrical losses are much less significant. Embedded generation falls somewhere between these two extremes but currently schemes are often assessed using relatively short time-scales and high discount rates reflecting the perceived risk in the projects and the source of funds. As embedded generation becomes a commercially well established activity it is likely that investment decisions will be carried out in a manner similar to that used for other utility generating plant and so electrical losses will become more important. In that case the use of line commutated converters together with other low-loss converter designs may become more attractive and the difficulties of high harmonic distortion accepted for the gains in efficiency.
The poor harmonic performance of the line commutated converter can be improved by using multiple bridges connected through transformers with two secondary windings with differing vector groups. This has the advantage of truly canceling the low-order harmonics rather than merely shifting the harmonic energy higher up the spectrum, as occurs with the rapid switching of forced commutated converters. However, there is considerable additional complexity in the transformers and in the generation equipment. A possible requirement to filter some of the remaining harmonics to meet EMC regulations will remain. The power factor is effectively determined by the DC link voltage which must be kept to a safe value to avoid commutation failure. Power factor correction capacitors and any filters are generally fitted to the high-voltage side of the transformer to avoid interaction with the

converter. The modern equivalent of The harmonic performance quoted for IGBTs converter is shown in Table 12.1 [76].

Table 12.1 Typical harmonic currents from a sinusoidal rectifier compared to those of 6-pulse and 12-pulse large industrial AC drives

Harmonic number	Network current harmonics (%)		
	Sinusoidal rectifier	6-pulse large industrial drive	12-pulse large industrial drive
1	100	100	100
3	1.9	-	-
5	2.8	21-26	2-4
7	0.5	7-11	1
11	0.16	8-9	8-9
13	0.3	5-7	5-7
17	0	4-5	0-1
19	0.125	3-5	0-1

The reduction in low-order harmonic currents is striking although it may be seen that, in practice, the magnitude of the harmonic currents may differ significantly from that suggested by simple theory. In addition, the output current of the sinusoidal rectifier will have significant energy at around the switching frequency of the devices (i.e. in the 2–6 kHz region) even though these high-frequency currents are relatively easy to filter they do require consideration.

12.3 Voltage unbalance

Three-phase induction machines have a low negative phase sequence impedance and so will draw large currents if their terminal voltage is unbalanced. This leads to overheating and also ripple on the shaft torque. It is a reasonably common experience for small embedded induction generators to experience nuisance tripping on rural 10 kV distribution networks caused by network voltage unbalance. Unless special arrangements are made small embedded generators may be designed for a network voltage unbalance (negative phase sequence voltage) of 1% with the unbalanced current protection set accordingly. Synchronous machines may also be sensitive to network voltage unbalance as their damper windings will react in the same way as the squirrel cage of the induction generator. Power electronic converters are likely to respond to voltage unbalance by an increase in non-characteristic harmonics and possible nuisance tripping. At present, the majority of embedded generators are three-phase and so do not cause an increase in voltage unbalance on the network. However, if domestic CHP or photovoltaic systems become common then there is an obvious problem that those houses with such equipment will load the distribution network less than those only with load. In Poland, only single-phase supplies are offered to most domestic dwellings and so if domestic generation becomes widespread then distribution on utilities will be faced with the task of balancing the low voltage feeders to ensure that each phase is approximately equally loaded and the neutral current is minimized for this new operating condition.

13. Autonomous generation of DER

There are presently some two billion people in the world without access to mains electricity and wind turbines, in conjunction with other generators, e.g., biomass turbines, diesel engines, may in the future be an effective means of providing some of these people with power. However, autonomous power systems are extremely difficult to design and operate reliably, particularly in remote areas of the world and with limited budgets. A small autonomous AC power system has all the technical challenges of a large national electricity system but, due to the low inertia of the plant, requires a very fast, sophisticated control system to maintain stable operation. Over the last 20 years there have been a number of attempts to operate autonomous wind-methane gas or wind–diesel systems on islands throughout the world but with only limited success. This class of installation has its own particular problems and again, given the very limited size of the market at present, this specialist area is not dealt with. An actively managed distribution network with locally generated power that approximately balances the demand could theoretically be run autonomously if connection to the mains were to be lost due to a fault. Such operation would require some sophisticated local control actions to first maintain the frequency close to the nominal value and then to reconnect the islanded system back to the mains when the fault is cleared. The capability to island could increase the reliability of supply to the local consumers but at the cost of more complex software and hardware. The desirability of such operation depends crucially on the typical reliability of supply experienced by the consumers. If the reliability is high, say one short interruption per year on average, the benefits of islanding may be doubtful. Chapter 13 is aimed at studying development of methods and guidelines rather than "universal solutions" for the use of wind energy in isolated communities and it reports on the findings barriers removal and engineering methods development, with a focus on analysis and specification of user demands and priorities, numerical modeling requirements as well as wind power impact on power quality and power system operation. It is generally expected that hybrid power could contribute significantly to the electricity supply in power systems of small and medium sized isolated communities. The market for such applications of wind–methane gas hybrid power has not yet materialized. Wind power in isolated power systems has the main market potentials in developing countries (i.e. Bangladesh, Egypt). Most remote rural communities in Alaska use diesel to generate electricity. But the recent rapid development of a worldwide commercial wind industry, along with the rise in diesel fuel prices, has increased interest in wind power in rural Alaska - both to reduce energy costs and to provide local, renewable, sustainable energy. Diesel Engine-Gensets provide a good backup for system reliability. In case of a micro-processor operated Solar-Wind-Diesel Hybrid System (i.e. Occupied Palestinian Territories), the electricity availability from each source, including the storage battery bank are sensed and controlled/fed to a common busbar, thus providing an optimum mix of electricity from each individual source in the grid, the diesel being given the last priority, for obvious reasons of operating costs and environmental consideration. The money available worldwide for this technological development is limited and the necessary R&D and pilot programmes have difficult conditions. Consequently, technology developed exclusively for developing countries rarely becomes attractive for consumers, investors and funding agencies.

13.1 Hybrid Wind and Gas Turbine System

In this section, the dynamic system analysis and simulation of an isolated electric power system consisting of a gas turbine synchronous generator and a permanent magnet synchronous generator (PMSG) for a direct driven wind turbine are presented. The influence of the power generation penetrations of wind on the hybrid system consisting of the wind turbine, the gas turbine and a load is shown.

13.1.1 Configuration of Wind-Gas Systems

A schematic configuration of the studied hybrid wind and gas turbine system is shown in Figure 13.1, where the wind turbine, gas turbine generating set and system resistance load are connected in parallel to form a small isolated system. The wind power conversion unit consists of a wind turbine, a PMSG and an AC/DC/AC converter that is shown in details in the next section. In the gas turbine generating, a synchronous generator is directly connected to the ac resistance load, and then the governor of the gas engine maintains a constant speed of the generator due to the restriction of the ac load operation frequency at the generator terminal. The gas engine has different rated capacities. The variable speed operation is considered for the gas engine to lower the fuel consumption. In systems with turbines connected to the AC bus, the critical consideration is the variation of the power output from wind turbines and its impact on the operation of the power system and on power quality. This impact increases as the level of penetration increases. When incorporating renewable based technologies into isolated power supply systems, the amount of energy that will be obtained from the renewable sources will strongly influence the technical layout, performance and economics of the system. The instantaneous power penetration P_p [77] of wind is explained:

$$P_p = \frac{P_{\text{wind}}}{P_{\text{load}}} \tag{13.1}$$

Thus, it is the ratio of how much wind power is being produced at any specific instant. Instantaneous penetration is primarily a technical measure, as it greatly determines the layout, components and control principles to be applied in the system. Thus, the power penetration of wind is taken into account.

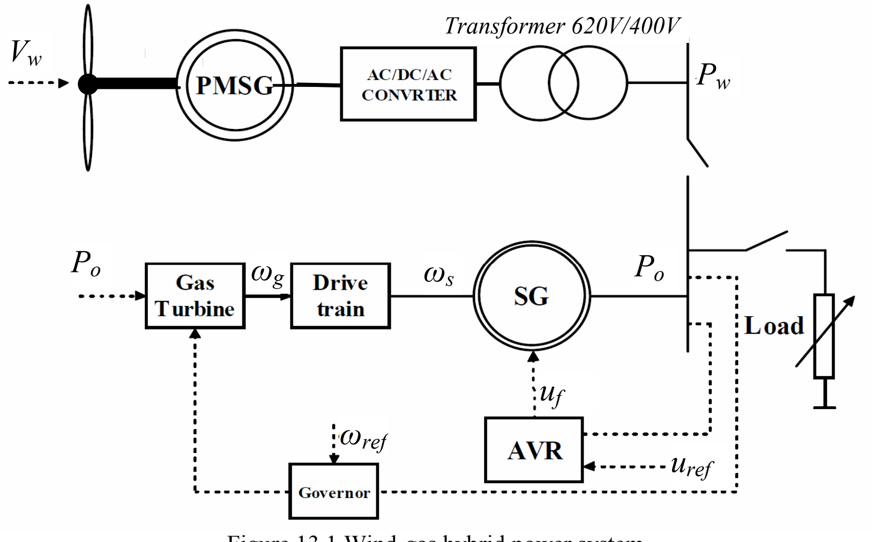


Figure 13.1 Wind-gas hybrid power system

13.1.2 Generator system

Figure 13.2 shows a simple schematic representation of a single shaft open cycle gas turbine for the gas turbine generating set in the small isolated system [78]. This is the standard gas turbine configuration used for electricity generation. The working fluid (air) is compressed by the compressor and then transported to the combustor. Inside the combustor, the air is mixed with the fuel and the mixture is ignited, causing turbine rotation and the production of mechanical power Pg. The synchronous generator associated parameters are given in Table 13.1.

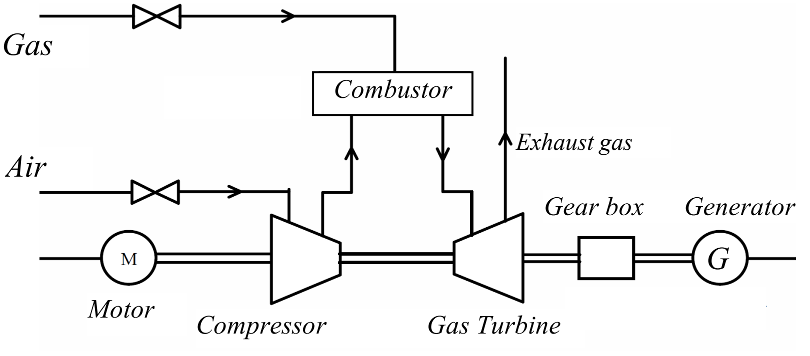


Figure 13.2 Single shaft open cycle gas turbine

Table 13.1 Synchronous Generator- sample parameters

kVA Based Rating	1100 kVA
Rated Speed	1500 r/m
Rated Line-Line Voltage	480 V
Power Factor	0.8
Direct Axis Synchronous X_d	3.00
Direct Axis Transient X'_d	0.20
Direct Axis Subtransient X''_d	0.18
Direct Axis Short Circuit Transient T'_d	0.15 s
Direct Axis Short Circuit Subtransient T''_d	0.01 s
Quadrature Axis Synchronous X_q	2.08
Quadrature Axis Subtransient X''_q	0.26

13.1.3 Wind Power Conversions

The percentage of electricity wind power supplies in a wind-diesel system is known as wind penetration. Variable speed directly driven multiple-pole PMSG wind power architecture offers key maintenance and reliability incentives in the context of offshore wind power. Neither a gearbox nor slip-rings are required, both of which require regular maintenance and are probable causes of mechanical failure [79]. A PMSG wind turbine architecture is appropriate for the burgeoning offshore environment, and capable of enhanced contribution to control and stability enhancement of the host AC grid network. A simple parameters of the 6-phase PMSG are shown in Table 13.2.

Table 13.2 Permanent Magnet Generator
– sample parameters

Rated Power output	1.5 MW
Rated Speed	18 r/m
Number of Pole Pairs	88
Rated Line Current	640 A
Rated Line Voltage	620 V
Synchronous Inductance	3 mH
Stator Phase Resistor	0.02

The 1.5MW PMSG direct drive wind turbine has a 6-phase permanent magnet synchronous generator, multiple boost converter and dual three-phase PWM inverter, all the devices are designed to limit harmonic and produce unity power factor and high purity sine wave current to the network. In case of the usage of synchronous generator, 6-phase diode rectifier with boost chopper is more cost effective solution for AC-DC converter than 3-phase IGBT PWM converter. It is constituted by a 6-phase permanent magnet synchronous generator, 6-phase diode rectifier circuit, multiple boost converter, break chopper and dual three-phase PWM inverter. The proposed system can not only yield high power density of generator and capacity of power converters, but also reduce the voltage ripple at the output of rectifiers. A 6-phase, full-controlled ac-to-dc power converter is used to convert varying voltages from 6-phase permanent-magnet synchronous generator to constant dc voltage. The current control method of dual 3-phase synchronous rotating frame transformation is proposed to reduce the current harmonics and increase the power factor on input side of generator, and thereby increase the efficiency of the power converter. The power curve of the PMSG wind turbine is shown in Figure 13.3, according to which a maximum power point tracking [80] is realized.

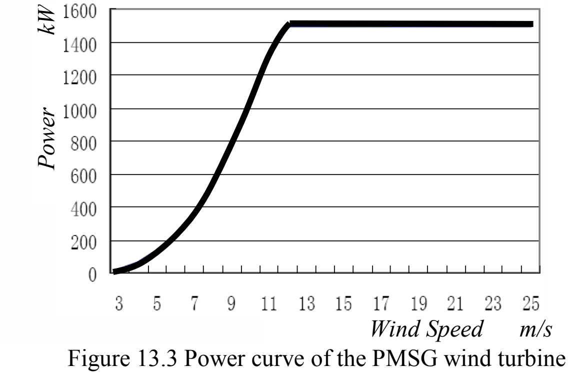


Figure 13.3 Power curve of the PMSG wind turbine

System Operating Modes look at different aspects of major power system components in the hybrid system network. The main component gas generating set must respond properly to changes in the power balance and frequency variations in the hybrid system as the wind is varying. The power balance in the studied system and the net frequency is maintained by the gas generator control. When the power generation penetration of wind reaches a higher level, the gas generator can not maintain the net frequency and power balance.

13.2 Hybrid Wind and Gas Turbine System

Wind-diesel systems can be classified into low, medium, and high penetration systems. All three types of systems have been built in rural Alaska. The amount of wind power on the grid determines what ancillary equipment is needed for power control and energy storage. Figure 13.4 shows the basic configuration of conventional diesel-only systems and examples of low, medium, and high penetration systems but there are also many other variations in configurations. Also, the numbers shown in Figure 13.1 are approximate. The broad differences in systems with different levels of wind penetration are:

- Low-penetration systems cost less to build and do not overly complicate the existing power plant. But wind energy generates only up to 20% of electric demand and does not reduce fuel use as much.
- Medium-penetration systems are costlier to build and more complex to operate, but wind energy generates up to half of electric demand, displaces up to half the diesel, and potentially provides energy for space heating or other uses - like electric cars.
- High-penetration systems are the costliest and the most complex to operate, but wind generation has the potential to supply a large percentage of electric demand and also provide considerable energy for heating or other uses.

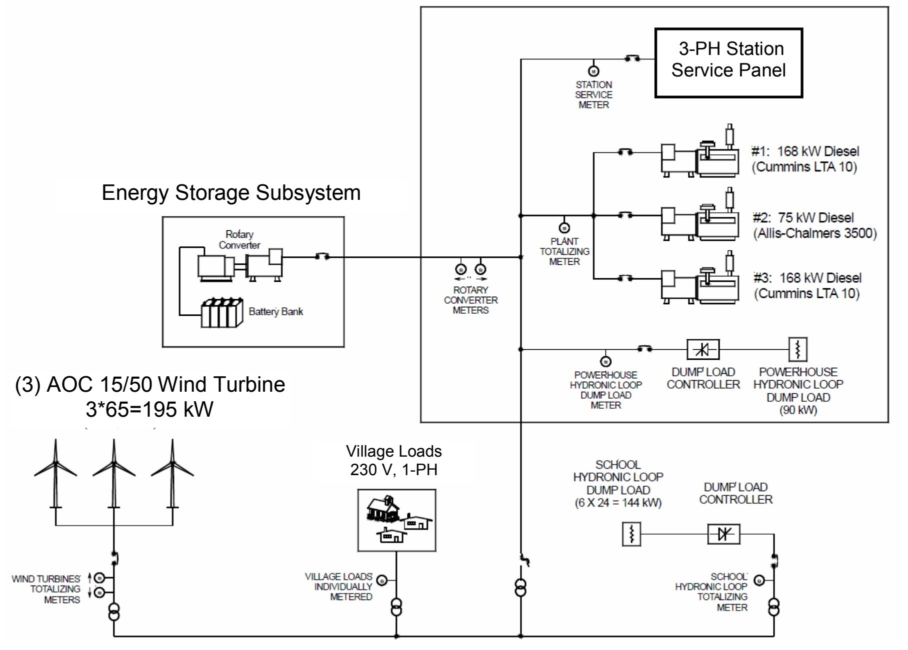


Figure 13.4 A sample of wind-diesel hybrid power system

Figure 13.4 is a one-line diagram of the system showing the principal power components, which are itemized in Table 13.3.

Table 13.3 Power Components in a simple wind-diesel system

QTY	COMPONENT	RATING
2	Wind Turbine	65 kW
1	Diesel Gen.	75 kW
2	Diesel Gen.	168 kW
1	Local Dump Load Controller	89 kW
1	Remote Dump Load Controller	144 kW
1	Rotary Converter	156 kVA
1	Auxiliary Battery Charger	300 VDC 30 A
200	Battery Cell	1.2 VDC 130 Ah

The two wind turbines use 480 volt 3-phase induction generators and connect directly to the medium voltage village distribution system through step-up transformers. The diesel generators are of the synchronous type, also

480 volt 3-phase. The dump load controllers each consist of a computer-controlled bank of solid-state relays, each of which controls power flow to a 480 volt 3-phase heating element in an electric boiler. The relays may be switched on and off rapidly, thereby providing precise real time control over electric power to the dump loads.

The rotary converter is an electromechanical bidirectional AC/DC power converter. It consists of an AC synchronous generator shaft coupled to a DC motor. When in use, the AC machine is connected to the 480 VAC bus of the power plant. When the DC machine is in use, it is connected to the battery bank. As will be explained later in detail, by controlling the field current in the AC and DC machines, one can control the flow of both real (kW) and reactive (kVAR) power between the AC bus and the rotary converter. Being shaft-coupled, the DC machine always spins at the same speed as the AC machine. Electrically, however, the AC machine can operate independently from the DC machine. The AC machine can on-line (connected to the AC bus) without the DC machine being on-line (connected to the battery bank). In this state, the rotary converter is operating simply as a synchronous condenser. There is no equivalent operating state involving only the DC machine, which cannot be on-line unless the AC machine is also on-line. Though not shown in Figure 13.4, there is also a small 10 HP pony motor used to spin the rotary converter up from rest to synchronous speed so that the AC machine may be connected to the AC bus. The pony motor is connected to the AC machine by a large timing belt. How these components interact to provide continuous high-quality power is explained in the various chapters of this report. If the reader is unfamiliar with concepts of real and reactive power and the basic methods of frequency and voltage control, it may be helpful to first read Chapter 6 on power flow management before Chapter 5 on modeling of DG component.

13.2.1 System Operating Modes

There are five possible system operating modes. Each of these modes implies the availability of a particular set of power system components. The current operating mode says nothing about the actual operating state of the systems (i.e., which components are actually on-line), only which components could be on-line. The various operating modes and their characteristics are summarized in Table 13.4.

Table 13.4 Wind-Diesel System Operating Modes

MODE	DESCRIPTION	AUTO DISPATCH	DIESEL GENSET	WTG	DUMP LOADS	AC MACH.	DC MACH	BATT.
manual	Diesel genset mode. Diesels dispatched manually from operator interface. System defaults to his mode when bus de-energized.							
0	Diesel genset mode. At least one diesel runs continuously. No wind turbines available. Diesel gensets dispatched automatically to meet load.							
1	At least one diesel always running. Wind turbines run whenever wind is available. Diesel genset controls system frequency and voltage. Dump load ensures minimum load on diesel.							
2	Diesel runs only if wind turbines cannot meet the load with adequate margin. When diesel is ON, diesel genset controls system frequency and voltage, and dump load ensures minimum average load on diesel. If not needed for reactive power, AC machine turned off to eliminate parasitic loss. When diesel is OFF, AC machine controls system voltage, dump load controls system frequency.							
3	Same as Mode 2, except: When diesel is ON, excess diesel power is used to charge battery. If load briefly exceeds wind power plus on-line diesel capacity, power is drawn from battery as needed to prevent another diesel from coming on. The diesel genset controls system voltage and frequency. When diesel is OFF, excess wind power is first used to charge the battery. Additional excess power is sent to the dump load. If wind power is briefly insufficient to meet the load, power is drawn from the battery as necessary to keep a diesel from being turned on. The AC machine controls system voltage. The DC machine controls system frequency, unless dump load is required, in which case dump load controls frequency.							

Once the system operator places the system in a particular mode, it will remain in that mode until the operator requests a different operating mode, or until a required component becomes unavailable. In that case, the control system will automatically drop down to the next lowest operating mode that does not require that component. Structuring the control system in terms of distinct operating modes based on component availability makes the controller more robust and fault tolerant. Mode 3 is the normal and intended operating mode for the system. This mode requires the availability of all system components. Suppose there were a fault in the battery bank or DC machine, making the energy storage function unavailable. In that case, if there were a single rigid system control algorithm that assumed the availability of energy storage, then the entire automatic control system could not function, and the power system would be reduced to manual diesel operation until the fault was repaired. With the distinct operating modes, however, the system would simply drop into Mode 2 and continue to function, now as a no-storage wind-diesel system. Thus, the failure of a particular component does not necessarily render the system inoperative.

13.2.2 System Operating States

The *system operating state* refers to the set of power sources that are actually on-line at any given time. 10 different operating states are possible, as shown in Table 13.5. The integer state designations refer to the various possible combinations of *real* power sources. Note that the AC machine by itself (without the DC machine) is not considered a real power source. Thus, both States 1A and 1B refer to the situation where diesel is the only generating source on-line. In State 1B, the AC machine is acting only as a synchronous condenser. State 2, in which both the diesel(s) and the wind turbine(s) are on-line, is similarly divided into States 2A and 2B, depending on whether or not the AC machine is on-line. Certain combinations of components are not possible and therefore do not have state designations.

Table 13.5 Definition of System Operating States

STATE	**COMPONENT STATUS**				**FREQUENCY CONTROL**
	DIESEL	**WTG**	**AC MACH.**	**BATTERY DC MACH.**	
0					System de-energized
1A					diesiel
1B					diesiel
2A					diesiel
2B					diesiel
3					dump load
4					diesiel
5					diesiel
6					battery
7					baterry

For example, the DC machine cannot be on-line unless the AC machine is on-line, so there are not defined states where that is the case. The system state usually is not something that the operator need be concerned with. System state information is used internally by the system controller to determine which set of component dispatch algorithms to use at any given time.

13.2.3 Determining Diesel Capacity Required

Diesel Capacity Required is defined as the minimum amount of diesel capacity that must be online to ensure that the primary load is always met. This amount depends on the primary load on the bus (the load that must be met) and the power available from all other sources. Diesel Capacity Required may be significantly greater than the instantaneous load on the diesels at any given instant. Load and wind power fluctuations, combined with the fact that diesel capacity cannot be added instantaneously, require that a certain reserve capacity be maintained. At any instant, the wind power could drop, increasing the load that must be met by the diesels. Without any reserve capacity, this would result in a power outage because another diesel could not be started and brought on-line instantaneously. Diesel Dispatch is based on both statistical and instantaneous dispatch criteria. Statistical dispatch criteria can increase or decrease Diesel Capacity Required in order to start or stop a diesel. Instantaneous dispatch criteria can only increase Diesel Capacity Required to immediately start a diesel if there is insufficient power available on the bus to supply the load. The system state is the combination of power sources on-line at any given moment. There are four different sources of real and/or reactive power:

- Diesels
- Wind turbines
- AC machine
- Battery bank/DC machine.

In many cases, the system controller will have advanced notice that a generating component will soon go off-line. For example, a component warning, a component disable request, or mode change request all may indicate the imminent (but not immediate) loss of a component, possibly changing the system operating state. Diesel Capacity Required will increase when a power source component goes off-line. To prevent possible loss of load when a component goes off-line, diesel dispatch must determine Diesel Capacity Required based on the projected system state rather than the current system state. The projected system state is the combination of power sources expected to be on-line in the near future. There are statistical diesel dispatch modes corresponding to each projected system state, with a separate set of dispatch criteria for each mode, to handle the various possible projected states. Statistical Diesel Dispatch will determine the appropriate statistical diesel dispatch mode and evaluate the corresponding criteria once every minute, or whenever conditions indicate a system component(s) is about to be taken off-line, e.g., the occurrence of system warnings, component warnings, component disable requests, and/or mode change requests.

14. Microgrids

Several country specific strict definitions are available for DG all over the world depending upon plant rating, generation voltage level, etc. However, the impact of DG on the power system is normally the same irrespective of these different definitions. According to several research studies some universally accepted common attributes of DG are as follows [81]:

- It is neither centrally planned by the power utility nor centrally dispatched.
- It is normally smaller than 50 MW.
- The power sources or distributed generators are usually connected to the distribution system which are typically of voltages 230/380 V up to 110 kV.

Chapter 14 mainly deals with the concept, technical features, operational and management issues, economic viability and market participation in deregulated environment of DG systems and the integration of DERs in the form of Microgrid and active distribution networks in a broad perspective.

14.1 Active distribution network

Electricity networks are in the era of major transition from stable passive distribution networks with unidirectional electricity transportation to active distribution networks with bidirectional electricity transportation. Distribution networks without any DG units are passive since the electrical power is supplied by the national grid system to the customers embedded in the distribution networks. It becomes active when DG units are added to the distribution system leading to bidirectional power flows in the networks. To effect this transition developing countries should emphasize the development of sustainable electricity infrastructure while the developed countries should take up the technical and economic challenges for the transformation of distribution networks. The UK industry regulator, the Office of Gas and Electricity Markets (Ofgem), has named this challenge as 'Rewiring Britain'. Active distribution networks need to incorporate flexible and intelligent control with distributed intelligent systems. In order to harness clean energy from renewable DERs active distribution networks should also employ future network technologies leading to smartgrid or Microgrid networks.

Present 'fit-and-forget' strategy of DG employment needs to be changed in active network management. It should incorporate integration of DGs in distribution networks and demand side management. It has been demonstrated by the UK-based Centre for Distributed Generation and Sustainable Electrical Energy (www.sedg.ac.uk) that the application of active network management methods can greatly support more DG connections as compared to networks without active management.

Several Department of Trade and Industry (DTI) and Ofgem reports clearly indicate that intelligent active distribution networks have gained momentum. Several factors are in favor of the evolution of active distribution networks, e.g [82].

- pressing customer expectations of high-quality reliable power distribution,
- increasing desire of policy makers for accommodation of renewable DERs with energy storage devices,
- carbon commitment in reducing emissions by 50% by 2050,
- motivating the distribution network operators (DNOs) towards better asset utilization and management by deferral of replacement of age-old assets, etc.

In order to implement evolutionary active distribution networks for flexible and intelligent operation and control, extensive research is necessary. The focus of the research should be mainly in the following areas [81]:

- wide area active control,
- adaptive protection and control,
- network management devices,
- real-time network simulation,
- advanced sensors and measurements,
- distributed pervasive communication,
- knowledge extraction by intelligent methods and
- novel design of transmission and distribution systems.

14.2 Concept of Microgrid

Microgrids are small-scale, low voltage combined heat and power (LV CHP) supply networks designed to supply electrical and heat loads for a small community, such as a housing estate or a suburban locality, or an academic or public community such as a university or school, a commercial area, an industrial site, a trading estate or a municipal region. Microgrid is essentially an active distribution network because it is the conglomerate of DG systems and different loads at distribution voltage level. The generators or micro

sources employed in a Microgrid are usually renewable/non-conventional DERs integrated together to generate power at distribution voltage. From operational point of view, the microsources must be equipped with power electronic interfaces (PEIs) and controls to provide the required flexibility to ensure operation as a single aggregated system and to maintain the specified power quality and energy output. This control flexibility would allow the Microgrid to present itself to the main utility power system as a single controlled unit that meets local energy needs for reliability and security.
The key differences between a Microgrid and a conventional power plant are as follows [82]:

- Microsources are of much smaller capacity with respect to the large generators in conventional power plants.
- Power generated at distribution voltage can be directly fed to the utility distribution network.
- Microsources are normally installed close to the customers' premises so that the electrical/heat loads can be efficiently supplied with satisfactory voltage and frequency profile and negligible line losses.

The technical features of a Microgrid make it suitable for supplying power to remote areas of a country where supply from the national grid system is either difficult to avail due to the topology or frequently disrupted due to severe climatic conditions or man-made disturbances. From grid point of view, the main advantage of a Microgrid is that it is treated as a controlled entity within the power system. It can be operated as a single aggregated load. This ascertains its easy controllability and compliance with grid rules and regulations without hampering the reliability and security of the power utility. From customers' point of view, Microgrids are beneficial for locally meeting their electrical/heat requirements. They can supply uninterruptible power, improve local reliability, reduce feeder losses and provide local voltage support. From environmental point of view, Microgrids reduce environmental pollution and global warming through utilization of low-carbon technology. However, to achieve a stable and secure operation, a number of technical, regulatory and economic issues have to be resolved before Microgrids can become commonplace. Some problem areas that would require due attention are the intermittent and climate-dependent nature of generation of the DERs, low energy content of the fuels and lack of standards and regulations for operating the Microgrids in synchronism with the power utility. The study of such issues would require extensive real-time and off line research, which can be taken up by the leading engineering and research institutes across the globe.

14.3 Microgrid configuration

A typical Microgrid configuration is shown in Figure 14.1. It consists of electrical/ heat loads and microsources connected through an LV distribution network. The loads (especially the heat loads) and the sources are placed close together to minimize heat loss during heat transmission. The micro sources have plug-and-play features. They are provided with power electronic interfaces to implement the control, metering and protection functions during stand-alone and grid-connected modes of operation. These features also help seamless transition of Microgrid from one mode to another. The Microgrid consists of three radial feeders (A, Band C) to supply the electrical and heat loads. It also has two CHP and two non-CHP micro sources and storage devices.

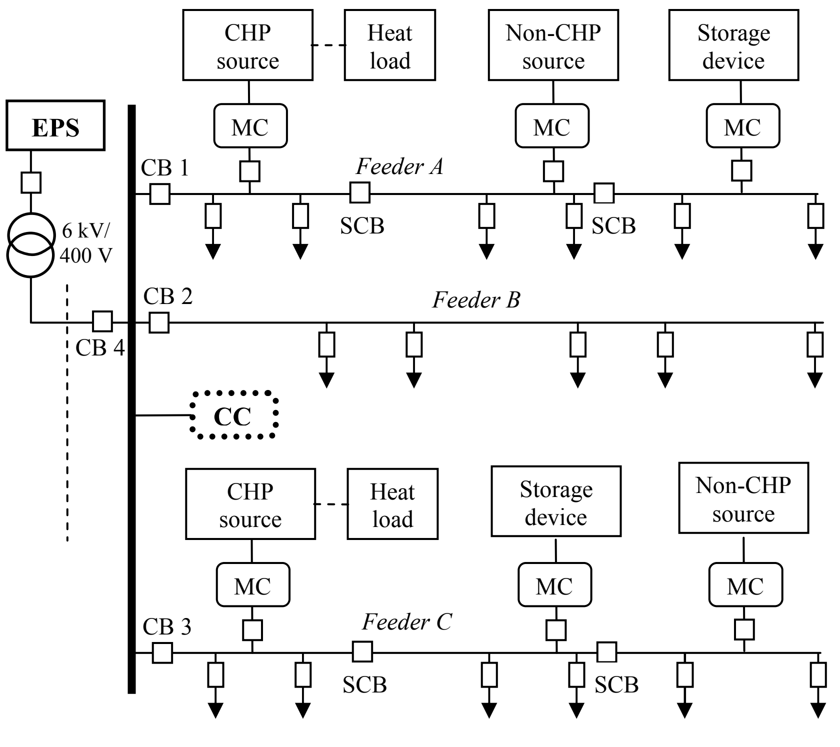


Figure 14.1 A typical Microgrid configuration: CHP – Combined heat and power, MC – Microsource controller, SCB – Sectionalizing circuit breaker, CC - Central controller, CB – Circuit breaker

Microsources and storage devices are connected to feeders A and C through micro source controllers (MCs). Some loads on feeders A and C are assumed to be priority loads (i.e. requiring uninterrupted power supply), while others are non-priority loads. Feeder B, however, contains only non-priority electrical loads.
The Microgrid is coupled with the main medium voltage (MV) utility grid (denoted as 'main grid ') through the PCC (point of common coupling) circuit breaker CB4 as per standard interface regulations. CB4 is operated to connect and disconnect the entire Microgrid from the main grid as per the selected mode of operation. Feeders A, B and C can however be connected and disconnected by operating breakers CBI, CB2 and CB3, respectively. The microsources on feeders A and C are placed quite apart from the Microgrid bus to ensure reduction in line losses, good voltage profile and optimal use of waste heat. Although the control of power flow and voltage profile along radial feeders is quite complicated when several micro sources are connected to a common radial feeder and not to a common generator bus, this configuration is necessary to avail the plug-and-play feature of the microsources.

The Microgrid is operated in two modes [82]:

- grid-connected and
- standalone.

In grid-connected mode, the Microgrid remains connected to the main grid either totally or partially, and imports or exports power from or to the main grid. In case of any disturbance in the main grid, the Microgrid switches over to stand-alone mode while still feeding power to the priority loads. This can be achieved by either:

(i) disconnecting the entire Microgrid by opening CB4 or
(ii) disconnecting feeders A and C by opening CBI and CB3.

For option (i), the Microgrid will operate as an autonomous system with all the microsources feeding all the loads in feeders A, B and C, whereas for option (ii), feeders A and C will supply only the priority loads while feeder B will be left to ride through the disturbance.
The operation and management of Microgrid in different modes is controlled and coordinated through local microsource controllers (MCs) and the central controller (CC) whose functions are enlisted as follows [81]:

1. Microsource controller - The main function of MC is to independently control the power flow and load-end voltage profile of the microsource in response to any disturbance and load changes. Here 'independently' implies without any communications from the CC. MC also participates in economic generation scheduling, load

tracking/management and demand side management by controlling the storage devices. It must also ensure that each microsource rapidly picks up its generation to supply its share of load in stand-alone mode and automatically comes back to the grid-connected mode with the help of CC. The most significant aspect of MC is its quickness in responding to the locally monitored voltages and currents irrespective of the data from the neighbouring MCs. This control feature enables micro sources to act as plug-and-play devices and facilitates the addition of new microsources at any point of Microgrid without affecting the control and protection of the existing units. Two other key features are that an MC will not interact independently with other MCs in the Microgrid and that it will override the CC directives that may seem dangerous for its microsource.

2. Central controller - The CC executes the overall control of Microgrid operation and protection through the MCs. Its objectives are
    - to maintain specified voltage and frequency at the load end through power-frequency (P-f) and voltage control and
    - to ensure energy optimization for the Microgrid. The CC also performs protection co-ordination and provides the power dispatch and voltage set points for all the MCs. CC is designed to operate in automatic mode with provision for manual intervention as and when necessary. Two main functional modules of CC are Energy Management Module (EMM) and Protection Co-ordination Module (PCM).

- Energy Management Module - EMM provides the set points for active and reactive power output, voltage and frequency to each Me. This function is co-ordinated through state-of-the-art communication and artificial intelligence techniques. The values of the set points are decided according to the operational needs of the Microgrid. The EMM must see that
    - Microsources supply heat and electrical loads to customer satisfaction.
    - Microgrids operate satisfactorily as per the operational a priori contracts with main grid.
    - Microgrids satisfy its obligatory bindings in minimising system losses and emissions of greenhouse gases and particulates.

- Microsources operate at their highest possible efficiencies.

- Protection Co-ordination Module - PCM responds to Microgrid and main grid faults and loss of grid (LOG) scenarios in a way so as to ensure correct protection co-ordination of the Microgrid. It also adapts to the change in fault current levels during changeover from grid-connected to stand-alone mode. For achieving this, there is proper communication between the PCM and the MCs and upstream main grid controllers. For main grid fault, PCM immediately switches over the Microgrid to stand-alone mode for supplying power to the priority loads at a significantly lower incremental cost. However, for some minor faults, the PCM allows the Microgrid to ride through in the grid-connected mode for some time and it continues if any temporary fault is removed. Besides, if the grid fault endangers the stability of the Microgrid, then PCM may disconnect the Microgrid fully from all main grid loads (e.g. feeder B), although in that case, effective utilisation of the Microgrid would be lost in exporting power. If a fault occurs within a portion of the Microgrid feeder (e.g. feeder A or C), the smallest possible feeder zone is eliminated to maintain supply to the healthy parts of the feeder. Under-frequency and under voltage protection schemes with bus voltage support are normally used for protecting the sensitive loads. PCM also helps to re-synchronize the Microgrid to the main grid after the initiation of switchover to the grid connected mode of operation through suitable re closing schemes.

The functions of the CC in the grid-connected mode are as follows:

- Monitoring system diagnostics by collecting information from the microsources and loads.
- Performing state estimation and security assessment evaluation, economic generation scheduling and active and reactive power control of the micro sources and demand side management functions by using collected information.
- Ensuring synchronized operation with the main grid maintaining the power exchange at priori contract points.

The functions of the CC in the stand-alone mode are as follows:

- Performing active and reactive power control of the micro sources in order to maintain stable voltage and frequency at load ends.
- Adopting load interruption/load shedding strategies using demand side management with storage device support for maintaining power balance and bus voltage.
- Initiating a local black start to ensure improved reliability and continuity of service.

- Switching over the Microgrid to grid-connected mode after main grid supply is restored without hampering the stability of either grid.

Since Microgrids are designed to generate power at distribution voltage level along with utilisation of waste heat, they have restricted energy handling capability. Therefore, their maximum capacity is normally restricted to approximately 10 MVA as per Institute of Electrical and Electronics Engineers (IEEE) recommendations. Hence, it is possible to supply a large load pocket from several Microgrids through a common distribution network, by splitting the load pocket into several controllable load units, with each unit being supplied by one Microgrid. In this way, Microgrids can be interconnected to form much larger power pools for meeting bulk power demands. For interconnected Microgrids, each CC must execute its control in close co-ordination with the neighbouring CCs. Thus, an interconnected Microgrid would achieve greater stability and controllability with a distributed control structure. It would also have more redundancy to ensure better supply reliability.

14.4 Technical advantages of Microgrid

The development of Microgrid is very promising for the electric energy industry because of the following advantages:

(1) *Environmental issues* - It is needless to say that Microgrids would have much lesser environmental impact than the large conventional thermal power stations. However, it must be mentioned that the successful implementation of carbon capture and storage (CCS) schemes for thermal power plants will drastically reduce the environmental impacts. Nevertheless, some of the benefits of Microgrid in this regard are as follows:
   - Reduction in gaseous and particulate emissions due to close control of the combustion process may ultimately help combat global warming.
   - Physical proximity of customers with microsources may help to increase the awareness of customers towards judicious energy usage.

(2) *Operation and investment issues* - Reduction of physical and electrical distance between micro source and loads can contribute to:
   - Improvement of reactive support of the whole system, thus enhancing the voltage profile.
   - Reduction of T&D feeder congestion.
   - Reduction of T&D losses to about 3%.
   - Reduction/postponement of investments in the expansion of transmission and generation systems by proper asset management.

(3) *Power quality* - Improvement in power quality and reliability is achieved due to:
- Decentralization of supply.
- Better match of supply and demand.
- Reduction of the impact of large-scale transmission and generation outages.
- Minimization of downtimes and enhancement of the restoration process through black start operations of micro sources.

(4) *Cost saving*- The following cost savings are achieved in Microgrid:
- A significant saving comes from utilization of waste heat in CHP mode of operation. Moreover, as the CHP sources are located close to the customer loads, no substantial infrastructure is required for heat transmission. This gives a total energy efficiency of more than 80% as compared to a maximum of 40% for a conventional power system.
- Cost saving is also effected through integration of several micro sources. As they are locally placed in plug-and-play mode, the T&D costs are drastically reduced or eliminated. When combined into a Microgrid, the generated electricity can be shared locally among the customers, which again reduces the need to import/export power to/from the main grid over longer feeders.

(5) *Market issues* - The following advantages are attained in case of market participation:
- The development of market-driven operation procedures of the Microgrids will lead to a significant reduction of market power exerted by the established generation companies.
- The Microgrids may be used to provide ancillary services.
- Widespread application of modular plug-and-play microsources may contribute to a reduction in energy price in the power market.
- The appropriate economic balance between network investment and DG utilization is likely to reduce the long-term electricity customer prices by about 10%.

14.5 Challenges of Microgrid development

In spite of potential benefits, development of Microgrids suffers from several challenges and potential drawbacks as explained [82]:

1) *High costs of distributed energy resources* - The high installation cost for Microgrids is a great disadvantage. This can be reduced by arranging some form of subsidies from government bodies to encourage investments. This should be done at least for a transitory period for meeting up environmental and carbon capture goals. There is a global

target set to enhance renewable green power generation to 20% by 2020 and to reduce carbon emission by 50% by 2050.

2) *Technical difficulties* - These are related to the lack of technical experience in controlling a large number of plug- and-play micro sources. This aspect requires extensive real-time and off line research on management, protection and control aspects of Microgrids and also on the choice, sizing and placement of micro sources. Specific telecommunication infrastructures and communication protocols must be developed in this area. Research is going on for the implementation and roll-out of lEe 61850 in communication for Microgrid and active distribution networks. However, lack of proper communication infra-structure in rural areas is a potential drawback in the implementation of rural Microgrids. Besides, economic implementation of seamless switching between operating modes is still a major challenge since the available solutions for redo sing adaptive protection with synchronism check are quite expensive.
3) *Absence of standards* - Since Microgrid is a comparatively new area, standards are not yet available for addressing operation and protection issues. Power quality data for different types of sources, standards and protocols for integration of microsources and their participation in conventional and deregulated power markets, safety and protection guidelines, etc., should be laid down. Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547) should be reassessed and restructured for the successful implementation of Microgrid and active distribution networks.
4) *Administrative and legal barriers* - In most countries, no standard legislation and regulations are available to regulate the operation of Microgrids. Governments of some countries are encouraging the establishment of green power Microgrids, but standard regulations are yet to be framed for implementation in future.
5) *Market monopoly* - If the Microgrids are allowed to supply energy autonomously to priority loads during any main grid contingency, the main question that arises is who will then control energy supply prices during the period over which main grid is not available. Since the main grid will be disconnected and the current electricity market will lose its control on the energy price, Microgrids might retail energy at a very high price exploiting market monopoly. Thus, suitable market infrastructure needs to be designed and implemented for sustaining development of Microgrids.

14.6 Management and operational issues of a Microgrid

Major management and operational issues related to a Microgrid are as follows [82]:

1) For maintaining power quality, active and reactive power balance must be maintained within the Microgrid on a short-term basis.
2) A Microgrid should operate stand-alone in regions where utility supply is not available or in grid-connected mode within a larger utility distribution network. Microgrid operator should be able to choose the mode of operation within proper regulatory framework.
3) Generation, supply and storage of energy must be suitably planned with respect to load demand on the Microgrid and long-term energy balance.
4) Supervisory control and data acquisition (SCADA) based metering, control and protection functions should be incorporated in the Microgrid CCs and MCs. Provisions must be made for system diagnostics through state estimation functions.
5) Economic operation should be ensured through generation scheduling, economic load dispatch and optimal power flow operations.
6) System security must be maintained through contingency analysis and emergency operations (like demand side management, load shedding, islanding or shutdown of any unit). Under contingency conditions, economic rescheduling of generation should be done to take care of system loading and load-end voltage/frequency.
7) Temporary mismatch between generation and load should be alleviated through proper load forecasting and demand side management. The shifting of loads might help to flatten the demand curve and hence to reduce storage capacity.
8) Suitable telecommunication infrastructures and communication protocols must be employed for overall energy management, protection and control. Carrier communication and IEC 61850 communication infrastructures are most likely to be employed.

The capacity of Microgrid being sufficiently small, the stability of main grid is not affected when it is connected to the main grid. However, in future, when Microgrids will become more commonplace with higher penetration of DERs, the stability and security of the main grid will be influenced significantly. In such case, the dynamic interactions between Microgrid and the main grid will be a key issue in the operation and management of both the grids. However, as of now, since the DERs in Microgrids are mainly meant to ensure only local energy balance within a small load pocket, the effects of DER penetration are likely to have a low impact on the main grid. Nevertheless, Microgrids need to be designed properly to take care of their dynamic impacts on main grid such that overall stability and reliability of the whole system is significantly improved.

15. Practical analysis of the impact of wind farms on transmission or distribution network

15.1 Power load flow model of Wind Power Plants (WPS) connected to the High Voltage grid (HV grid -400/220/110 kV)

Figure no. 15.1 shows a single line diagram and a simplified equivalent circuit of a power load flow model of typical integration of WPS with 400/220/110 kV power system.

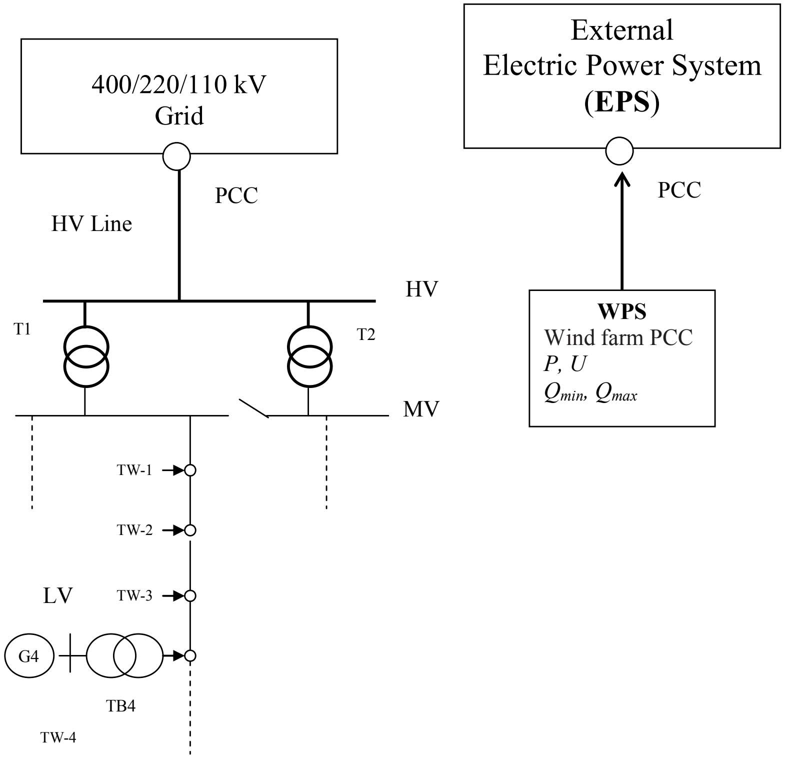


Figure 15.1 Example network with a wind farm (single line diagram and a simplified equivalent). Note: PCC - Point of Common Coupling, P – output active power from wind power, U regulated voltage at the point of PCC of the reactive power from Q_{min} to Q_{max}

Taking into account load flow the fact that the wind farm is composed of several wind turbines is crucial. A single wind turbine consists of a generator that operates on low voltage (LV) and booster transformer transforming voltage to medium level (ML). The particular turbines are grouped and connected with cables to MV system station (110kV/MV) or LV/MV. A quite often phenomenon is an overhead line between a 110 kV system station (or LV system station) and a point of common coupling (PCC).
From the point of voltage regulation all wind power plants connected to high voltage (HV) grids should be regulating voltage in PCC within a boundaries of power factor CF=$cos\varphi$, which in accordance with common assumptions are $cos\varphi_{min}$ = 0.975 cap. (capacity) and $cos\varphi_{max}$ = 0.975 ind. (induction)

Simplifying assumption adopted in an elaboration of the power load flow model of WPS integrated with HV grid

- WPS is integrated with a bus, which is assumed to be *PU* bus with a restriction of a reactive power,
- Active power *P* results from rated power of wind turbine,
- WPS keeps fixed voltage *U* at the bus within boundaries of power factor $cos\varphi$, which is commonly defined as $cos\varphi_{min}$ = 0.975 cap. and $cos\varphi_{max}$ = 0.975 ind, that is equal to the value of tangent power $tg_{\varphi min}$ = -0.2279 i $tg_{\varphi max}$ = 0.2279.
- Having reached capacity limits of reactive power's production WPS operates with reactive *power* $Q_{min} = Ptg\varphi_{min}$ or $Q_{max} = Ptg\varphi_{max}$. Under those conditions the bus becomes PQ bus.

15.2 A short circuit model of WPS integrated with HV grids 400/220/110 kV

The short circuit model of WPS needs to be developed more than the power load flow model. A short-circuit reactance of a generator, a booster transformer as well as a short-circuit reactance of a transformer integrating internal cables system of WPS with HV grid (400/220/110 kV) play a crucial role in an analysis of short-circuit. Figure 15.2 indicates a standard circuit: WPS – 400/220/110 kV grid and an equivalent short-circuit. According to the principles of short-circuit's calculation some simplifications can be introduced, provided that the estimated value of short-circuit current would be higher than values obtained on the basis of a detailed short-circuit model.

Under those conditions the resistance in equivalent circuits should be passed over. In accordance to Thevenin's theorem it can be assumed the whole WPS can be replaced with short-circuit reactance X_{WPS} taken from PCC and Thevenin's *emf* (*electromotive force*) equals to adjusted nominal voltage

$$E_{WPS} = cU_N / \sqrt{3} \tag{15.1}$$

where: c – the source voltage factor. Note that c=1.1 in medium and high voltage systems, U_N – the nominal network voltage in PCC.

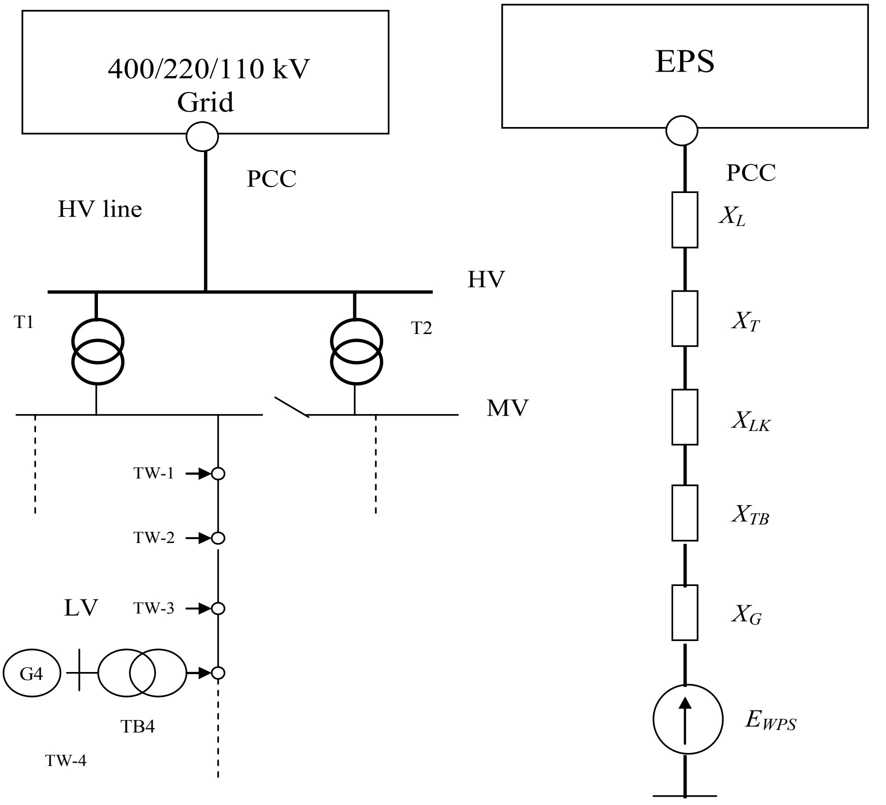


Figure 15.2. System circuit diagram and equivalent circuit for calculating the short circuit currents. Note PCC - Point of Common Coupling, XL is the HV (110kV) line reactance, XT 110 kV/MV or HV/MV transformer reactance, XLK - reactance of the internal network cable, X_{TB} is the total reactance seen from the primary side of the turbine booster transformers, X_G is the total reactance of all generators, E_{WPS} – *emf* of WPS.

The equivalent reactance of WPS is a sum of equivalent reactance of given elements of circuit: WPS – 400/220/110 kV grid

$$X_{FW} = X_G + X_{TB} + X_{LK} + X_T + X_L \tag{15.2}$$

The best way is to calculate equivalent reactance in per unit (p. u.). These per unit data are representative for a wide range of wind turbine's sizes and therefore suitable for applications' users of many electrical simulation programs. Then the equivalent reactance of WPS per unit is equal to:

$$X_{WPS} = x_{WPS} Z_{NWPS} = (x_G + x_{TB} + x_{LK} + x_T + x_L)\frac{U_{NWPS}^2}{S_{NWPS}} \tag{15.3}$$

where:

U_{NWPS} – nominal voltage in PCC

S_{NWPS} - rated apparent power of wind farm,

x - p.u. reactance.

Reactance of internal cables lines as well as a reactance of a (usually short) overhead line can be neglected. Having the equivalent reactance of internal cables lines and reactance of a overhead line ignored, the formula (15.3) can be replaced with:

$$X_{WPS} = x_{WPS} Z_{NWPS} = (x_G + x_{TB} + x_T)\frac{U_{NWPS}^2}{S_{NWPS}} \tag{15.4}$$

The way of estimation of given equivalent p. u. reactance will be discussed below. It should allow to verify the value of neglected reactance. A single wind turbine consists of a generator that operates on low voltage LV an MV/LV booster transformer.

The doubly-fed induction generators (DFIG) are most popular. Generation technologies that used DFIGs with a rating of up to 3MW and combined a large number of these within one power station (i.e. wind farms) were unheard of in the power industry. The synchronous generators equipped in a Voltage Source Converter (VSC) with a regulation of active voltage are also applied for the large WPS. The difference between synchronous and asynchronous generators is in a value of short-circuit current, please see table 15.1.

Table 15.1 Rated and short-circuit parameters of wind generators installed in wind farms and connected to national HV grid

Wind turbine power	Wind-turbine types	Category	U_N	I_N	Z_N	$K_r = I_k'' / I_N$	I_K''	X_G	x_G
MW	-	-	V	A	Ω	-	A	Ω	pu
2	Vestas V90	M-1	690	1675	0.238	5.47	9165	0.262	0.20
2	Vestas V80	M-1	690	1675	0.238	5.47	9165	0.262	0.20
1.65	Vestas V66	M-0	690	1382	0.288	8	11058	0.317	0.14
2.5	Nordex N80	M-1	660	2190	0.174	5.47	11977	0.192	0.20
2.5	NORDEX N90 LS	M-1	660	2190	0.174	5.47	11977	0.192	0.20
2.5	NORDEX N100	M-1	660	2190	0.174	5.47	11977	0.192	0.20
2	Gamesa Eolica G90	M-1	690	1675	0.238	5.47	9165	0.262	0.20
1.5	Neg Micon NM 72c/1500	M-0	690	1257	0.317	8	10053	0.349	0.14
1.5	**Neg Micon NM82/1500**	**M-0**	**690**	**1257**	**0.317**	**8**	**10053**	**0.349**	**0.14**
1.5	GE 1.5sL	M-1	690	1257	0.317	5.47	6874	0.349	0.20
1.5	GE 1.5 XLE	M-1	690	1257	0.317	5.47	6874	0.349	0.20
2.5	GE 2.5 xl	M-4	10500	138	44.048	1.39	191	48.510	0.79
2.5	GE 2.5	M-4	10500	138	44.048	1.39	191	48.510	0.79
2.3	GE 2.3	M-4	10500	127	47.878	1.39	176	52.728	0.79
2.3	Siemens SWT 2.3-93	M-3	690	1927	0.207	1.39	2678	0.228	0.79
1.5	Vensys	M-4	690	1257	0.317	1.39	1747	0.349	0.79
1.5	REpower MD 70	M-1	690	1257	0.317	5.47	6874	0.349	0.20
1.5	REpower MD 77	M-1	690	1257	0.317	5.47	6874	0.349	0.20
2	REpower MM92	M-1	690	1675	0.238	5.47	9165	0.262	0.20
2.5	Fuhrlander FL2500	M-1	690	2094	0.190	5.47	11456	0.209	0.20
1.5	Fuhrlander FL MD 77	M-1	690	1257	0.317	5.47	6874	0.349	0.20
2	Enercon E-82	M-4	400	2890	0.080	1.39	4017	0.088	0.79
2.3	Enercon E-70 E4	M-5	400	3324	0.069	1.2	3988	0.077	0.92

Determination of the category:

- M-0 k=8.0 Induction generator IG standard (typical asynchronous generators),
- M-1 k=5.47 DFIG standard (doubly fed induction asynchronous generator),

- M-2 k=2.0 DFIG-FRT (the Fault Ride Through capability of the wind farm),
- M-3 k=1.39 Asynchro-FC (Full Converter),
- M-4 k=1.39 Synchro-FC (Full Converter),
- M-5 k=1.38 Synchro-FC FRT (Fault Ride Through).

A given active power P of turbine in MW is the same way its apparent power S_{NWPS} in MVA. A nominal impedance of WPS can be calculated from the following formula:

$$Z_{NFW} = \frac{U_{NFW}^2}{S_{NFW}} \tag{15.5}$$

The short-circuit reactance of generator inside the wind turbine

The short-circuit reactance of generator can be estimated using the formula for an initial short-circuit current of three-phase fault

$$X_{GTW} = \frac{cU_N}{\sqrt{3}I_K^{"}} \tag{15.6}$$

The short-circuit reactance can be also expressed in per unit in relation to nominal impedance

$$x_{GTW} = \frac{X_{GTW}}{Z_{NTW}} \tag{15.7}$$

Taking into account short-circuit a single generator is characterized by multiplicity of the short-circuit current in relation to nominal current of turbine (inrush current factor).

$$K_r = I_K^{"} / I_N \tag{15.8}$$

The short-circuit reactance of generator can be determined in 'per unit' on the basis of the in-rush current factor K_r:

$$x_{GTW} = \frac{X_{GTW}}{Z_{NTW}} = \frac{\dfrac{cU_N}{\sqrt{3}I_K^{"}}}{\dfrac{U_N}{\sqrt{3}I_N}} = \frac{I_N}{I_K^{"}} = \frac{c}{K_r} \tag{15.9}$$

The calculation of the short-circuit reactance for given types of turbines are collected in table 15.1.
WPS usually consists of n wind turbines: $S_{NWPS} = n \cdot S_{NTW}$
As a result the equivalent short-circuit reactance of whole WPS (expressed in per unit) is:

$$x_G = \frac{1}{n} x_{GTW} \frac{S_{NWPS}}{S_{NTW}} = \frac{1}{n} x_{GTW} n = x_{GTW} \tag{15.10}$$

The equivalent short-circuit reactance of booster transformer

A short-circuit voltage of booster transformer averages $u_K = 0.06$ that implicates the reactance of booster transformer in per unit is equal to:

$$x_{TBTW} = u_K = 0.06 \tag{15.11}$$

As the WPS is made up of n wind turbines (i.e. parallel integration of n booster transformers) we obtain:

$$x_{TB} = \frac{1}{n} x_{TBWPS} \frac{S_{NWPS}}{S_{NTW}} = \frac{1}{n} x_{TBWPS}\ n = x_{TBWPS} \tag{15.12}$$

The equivalent short-circuit reactance of 110kV/MV or LV/MV transformer

Power from WPS is sent to the 400/220/110 kV grid having 2 transformers (110kV/MV or LV/MV). During the short-circuit both transformers can be treated as if they were working in parallel because of symmetry of loads. As a result it can be assumed that nominal voltage of the equivalent LV/MV transformer is equal to nominal voltage of WPS. The short – circuit voltage for such a transformer is approximately $u_K = 0.11$, which gives the reactance of transformer (p. u.):

$$x_T = u_K = 0.11 \tag{15.13}$$

The equivalent short-circuit reactance of WPS

Taking into account estimations of equivalent reactance of individual elements of wind farm - EPS connection a formula for calculation of WPS' total equivalent short – circuit reactance integrated with 400/220/110 kV grid is

$$X_{WPS} = x_{WPS} Z_{NWPS} = (c / K_r + 0.06 + 0.11) Z_{NWPS} = (1/K_r + 0.17)\frac{U_{NWPS}^2}{S_{NWPS}} \tag{15.14}$$

Since the reactance of internal cable and overhead line has been neglected the value of WPS short-circuit reactance calculated according to (15.14) can be slightly underestimated. The underestimation can be considered as negligibly small since the short circuit reactance of the external system is 10 times smaller then the short circuit reactance of WPS

The equivalent short-circuit reactance of WPS for zero sequence impedance

The calculation of an equivalent reactance for zero-sequence impedance is crucial in case of ground faults. It is essential to include magnetizing impedance $\underline{Z}_{0\mu}$. Inside four or five columns transformer and in set of three single-phase transformers the magnetic fluxes are consistent and the phase-coherent magnetic flux circulates in the iron core. That is manifested by a low reluctance (magnetic resistance). It means that the reactance is extremely high, $\underline{Z}_{0\mu} = \infty$.
In three-column transformer the zero-component magnetic flux circulates partly in the air, in transformer tank and transformer oil. However, for a 3-core transformer the reluctance is larger and the magnetizing reactance usually is $\underline{X}_{0\mu} = 5X_T$. Therefore $\underline{Z}_{0\mu} << \infty$. Note, in Poland 90% of transformer are 3-core transformer. Three-phase booster transformers are connected in Delta to Delta (MV/LV) or Wye to Delta (high voltage transmissions) configurations. Therefore, the zero-sequence impedance of WPS – EPS circuit is affecting the Thevenin zero sequence equivalent circuit of HV connection line and HV/MV booster transformer only since the booster transformer is connected in Delta to Delta (MV/LV) or Wye to Delta (high voltage transmissions) configurations (see Figure 15.3).
For a YG-Delta connected transformer, zero sequence current can freely circulate in the delta winding. As long as zero sequence is concerned, the transformer acts as if it was short-circuited no matter if the winding is loaded or not. The delta connection suppresses the flow of zero sequence flux and it does not really matter whether there is a flux return path or not. It explains why, for YG-Delta connection, the zero sequence circuit basically is the same no matter if the transformer is a three-legged core type or not.

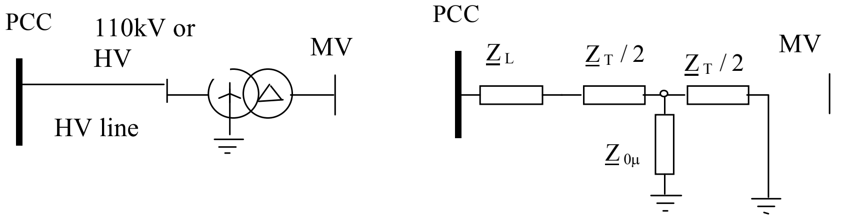


Figure 15.3 Zero sequence impedance equivalent circuit of WPS-EPS circuit. Note, booster transformer is YG-Delta connected.

The WPS zero sequence reactance as seen from the PCC can be found from (expressed in p.u.) the equation:

$$x_{WPS0} = x_{L0} + 0.5x_T + \frac{0.5x_T x_{0\mu}}{0.5x_T + x_{0\mu}} \approx x_{L0} + 0.85x_T \qquad (15.15)$$

Zero sequence reactance is 3 times lower than the positive sequence one, therefore is:

$$x_{L110kV0} = 3x_{L110kV} = 3 \cdot 0.0165 \approx 0.05 \qquad (15.16)$$

The transformer zero sequence reactance can be described by the following equation:

$$x_{T0} = 0.85x_T = 0.85 \cdot 0.11 \approx 0.09 \qquad (15.17)$$

Finally, the following equation provides a good estimate of the WPS zero sequence reactance as seen from the PCC:

$$x_{FW0} = x_{L0} + x_{T0} = 0.05 + 0.09 = 0.14 \approx x_T + 0.02 \qquad (15.18)$$

As can be seen the WPS zero sequence reactance is somewhat bigger than the fault voltage.

15.3 Modeling of Wind Farms in the Load Flow Analysis for a distribution MV network

The voltage level in the transmission system is kept at a technical and economical optimum by adjustment of the reactive power supplied or consumed. Transferring power from WPS to the MV system influences the voltage level at connection point of the consumer and at the connection point of the wind farm. The intensity of that process depends on

- the total installed wind power capacity,

- methods for connecting wind farms to the grid,
- and the total power system load requirement.

Normally, the voltage level in the distributed medium-voltage grid needs to be within U_n±10%. Normally, wind farms require a certain voltage level at the connection point as wind turbines are usually designed to operate within a specific voltage range (e.g. nominal voltage ±10 %). For the consumers, the requirements are rather homogeneous, since all consumers use the same type of equipment. For wind farms the requirements can be sometimes relaxed, since wind farms can be designed to handle different quality levels. Figure 15.4 shows the electrical connection of designed wind farm. It summarizes the voltages, injections and flows that can be calculated for rated conditions using a commercial power flow program [35].

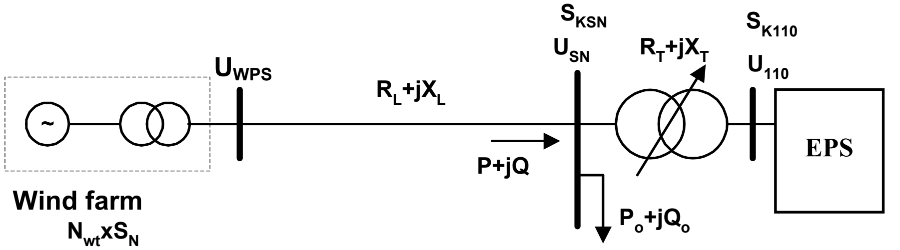


Figure 15.4 A simplified single-line diagram of the local 20 kV network with WPS used to illustrate the voltage imbalances. Note: N_{WT}- number of wind turbines are aggregated, S_N- Rated apparent power of a wind turbine, S_{K110}, S_{KSN} – the short circuit power in the 110 kV and MV substation, respectively.

The most distinctive thing is that the connection to the MV system stations at grid supply point (GSP) is effected by dedicated line which is not used by consumers. This is particularly good way of connecting WPS because it limits WPS’ influence on the standard conditions of electricity distribution licenses. Supposing that Transformer Tap Changer Controller holds the power supply voltage practically constant (independently from the load) on MV GSP substation, the voltage U_{WPS} on MV system stations 20 kV at WPS’ substation is given by:

$$\underline{U}_{WPS} = U_{SN} + \frac{R_L P + X_L Q}{U_{SN}} + j\frac{X_L P - R_L Q}{U_{SN}} \tag{15.19}$$

where R_L - line resistance,

X_L - line reactance,

P,Q - total transmitted active power and reactive power on the line, respectively.

The loss reduction value concerns the capability of wind power to reduce grid losses within the system. Wind power plants are often located rather far away in the distribution grid on comparatively low voltage level. That is different from large power stations which are located close to the transmission network. If the load close to the wind power plants is the same size as the wind power plant, the power does not have to be transported far, which means that the losses are reduced resulting from wind power generation. In that case, the loss reduction value of wind power is positive. However, voltage drop on power line consists of series losses and shunt ones. Assuming the U_{SN} voltage lies along real axis, the value of voltage U_{WPS} in substation is mainly influenced by series loss only. That simplification gives

$$\Delta U = \frac{R_L P + X_L Q}{U_{SN}} \tag{15.20}$$

and shows very clearly the U_{WPS} voltage at WPS substation depends on resistance and reactance of overhead connecting power line and it will be higher if the power transmitted power lines increase. If it is assumed that connecting power line will be a cable (the reactance of cable is many times smaller than overhead line's reactance) and the wind turbines work with power factor $\cos\varphi$ close to one ($Q\cong 0$), the expected value of ΔU should be low and consequently small voltage deviations (drop) shall occur. Additionally, it should be emphasized that the voltage drop will occur only in connecting line, not directly at consumers.

The presented argumentation should show the consequences of choosing the type of wind turbines to the grid connection and its impact on power transfer. In reality, the power flowing at MV system stations at GSP is not known, in contrast to power generated at WPS. Therefore, the formula for voltage drop cannot be used directly. It can be resolved by power flow software and iterative methods.

A rapid voltage fluctuations during switching operations have a relatively short duration, a few seconds, so there is no time to switch mechanical devices. In addition, the large concentration of induction motors (IMs) and distributed generation in some actual power systems causes an impact on short-term voltage stability, making it a more complex issue to control. Adequate short-term voltage control will reduce the activation of protective relays and reduce the reactive power injection from the generation side; hence as a consequence there will be less power losses on the distribution and transmission network. Grid codes with regard to the connection of large wind farms to the electric power systems give some rules that the voltage drops caused by load changes and switching processes in network at normal conditions will not exceed $4\%U_n$. However, under specific circumstances and few times a day, the short drops reaching $6\%U_n$ can occurred. The exemplary, acceptable and dynamic voltage drops in correlation with the frequency of their occurrence are shown in Table 15.2.

Table 15.2. A possible limit values of rapid change of the RMS voltage of MV-connected wind turbines

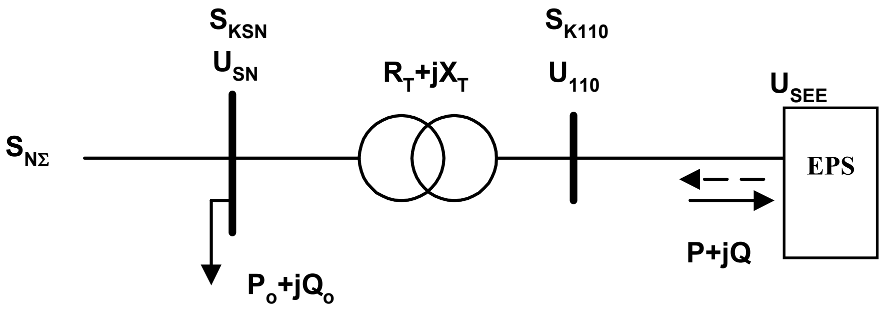
The frequency of rapid voltage changes per hour r/hour	$d=\Delta U_{dyn} / U_n$ a voltage level 35 kV and higher voltage levels	$d=\Delta U_{dyn} / U_n$ a voltage level 110 kV and higher voltage levels
r≤1	4%	3%
1< r≤10	3%	2.5%
10< r≤100	2%	1.5%
100< r≤1000	1.25%	1%

In case of wind turbines, quick and relative voltage fluctuations at connection point which are results of power station work should satisfy the following condition:

$$d \le \frac{\Delta U_{dyn}}{U_n} \cdot 100\% \tag{15.21}$$

Normally, the Grid Codes require that wind turbine will not cause rapid voltage drops which exceed 3%. When voltage drops become repeated, the individual drop cannot exceed 2.5% for frequency up to 10 disruptions / hour and 1.5% for frequency up to 100 disruptions / hour. Those requirements are also applied for in-rush currents during startup and shutdown of wind turbines

Sudden farm shutdown can cause rapid voltage drops. In that case shutdown all of the turbines should be taken into account. That situation is prone to appear during disruptions in MV grid powered by GSP or during violent gusts of wind (if the wind Speer exceed the cut-out wind speed - 25m/sec). That situation can be illustrated by equivalent circuit and its internal dependencies. The constant voltage in electric system should be assumed this time. It can be equal to$1.05U_n$ and must occur after equivalent impedance. Sudden WPS' shutdown will cause voltage drops on MV system stations and on 110 kV system stations at GSP.



Rys.15.5. Scheme for the calculation of rapid voltage changes caused by the sudden shutdown of the wind farm.

This rapid voltage drops will be regulated by the actions of tap-changer transformer regulator in transmission power system and GSP, however, it will happen with significant lag (few minutes). The rapid voltage drop on MV system stations at GSP which will be noticed by consumers powered by this sections of system stations is the most important aspect of that analysis. In that situation the U_{MV} voltage on MV system stations at GPS is equal to:

$$\underline{U}_{MV} = U_{EPS} + \frac{RP + XQ}{U_{EPS}} + j\frac{XP - RQ}{U_{EPS}} \tag{15.22}$$

where

$R = R_T + R_{EPS}$ – total resistance of the transformer and system,

$X = X_T + X_{EPS}$ – total reactance of the transformer and system,

P, Q - active and reactive power injection for the 110 kV lines from MV system,

U_{110} – voltage on the 110 kV substation converted to the level of SN,

U_{EPS} – voltage on the 110 kV power system, behind the short-circuit impedance equivalent, converted to the level of SN.

Similar to the previous case, considering only the series losses and fact that WPS works with power factor close to one, it can be observed that voltage drop on MV system stations will be caused by active power change (which flows through transformer and 110kV system) created after turning the WPS off. That change will be even higher if the WPS transfers reactive power from or to the grid before its shutdown. The voltage U_{MV} calculation based on simplified formula is impossible, because the P i Q power is unknown. The only known factor is the power on MV system stations side, which results of generated power, line losses and grid load balance. Because of that, the calculation of quick voltage drops caused by sudden turning WPS off is only possible with help of power flow software which applies iterative methods.

15.4 Short-circuit model of WPS connected to MV grid

The calculation of short circuit are carried out to determine short circuit power at PCC. In considered case at MV system station at GSP under normal and maintenance conditions of power supply from 110 kV. The minimum short-circuit power level at PCC decides about the intensity of voltage fluctuations which are result of WPS' operation especially caused by active and reactive power generation variations and by the number of wind turbine switching operations. The influence of described above effected is weaker as the short-circuit power at PCC is higher. It can be explained as follows:

1) Thevenin's *emf* is equal to the voltage at an idle state of circuit

$$E_T = U_n / \sqrt{3} \tag{15.23}$$

2) Assuming that inrush current has only a reactive current component in a three-phase system, the formula for voltage during WG start-up at PCC can be defined as follows:

$$U_k / \sqrt{3} = E_T - X_Q I_k = U_n / \sqrt{3} - X_Q I_k \tag{15.24}$$

$$U_k = U_n - \sqrt{3} X_Q I_k \tag{15.25}$$

3) Voltage drops at PCC in relation to voltage before WPS connection is:

$$\Delta U = \frac{U_0 - U_k}{U_n} = \frac{U_n - (U_n - \sqrt{3} X_Q I_k)}{U_n} = \frac{X_Q}{U_n}\sqrt{3} \cdot I_k = \frac{X_Q}{cU_n^2} c \cdot \sqrt{3} \cdot I_k \cdot U_n \tag{15.26}$$

$$\Delta U = \frac{X_Q}{cU_n^2} c \cdot \sqrt{3} k \cdot I_n \cdot U_n = \frac{c \cdot k \cdot S_{nWPS}}{S''_{k110kV}} = \frac{S_{\max WPS}}{S''_{k110kV}} \tag{15.27}$$

where c – the source voltage factor. Note that c=1.1 in medium and high voltage
systems,

k – inrush current factor.

4) Finally, the maximum quick voltage deviation at PCC can be estimated by the maximum apparent power and short-circuit apparent power of the grid before WPS connection

$$\Delta U = \frac{S_{\max WPS}}{S''_{k110kV}} \tag{15.28}$$

New grid guideline, however, require that the ratio of short-circuit power at PCC to the total sum of all connected sources' nominal power should be equal at least 20.

$$S_K \big/ S_{N\Sigma} \geq 20 \tag{15.29}$$

If the above condition is not fulfilled, it does not mean that the WPS with fixed power cannot be connected in considered point. In such cases it should be proved that acceptable power quality indices (voltage distortion index, light intensity variations, harmonics and voltage unbalance) will not be exceeded. Many specialists emphasize the fact, that recently the condition of relation of short circuit powers for asynchronous generator sources (especially for wind turbines) operating with start- up phase was introduced. That start – up phase was often accompanied with high voltage sags. Nowadays, modern wind turbines are equipped with 'soft start' devices which cause the start-up current to be limited to the nominal current level. In such situation, the condition, regardless of its calculation methods, cannot be considered as crucial in order to verify possibility of connecting WPS characterized with given power level.

15.5 An example of the wind turbines impact on MV distribution network

The main result of impact of wind turbines on the grid concerning power quality are voltage changes and fluctuations, especially at the local level. Other parameters are reactive power, flicker, power peaks and in-rush currents. Figure 15.6 shows a schematic diagram of an experimental MV system. It consists of a 3 wind turbines connected through an impedance to the strong MV grid, represented by infinite bus.

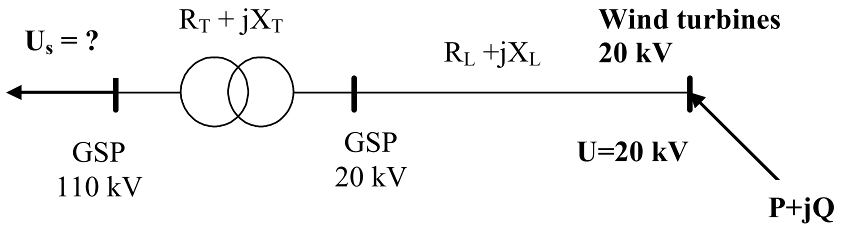


Figure 15.6 Small power system used to illustrate the WPS impact on MV distribution network

The transformer and cable line are represented by their series parameters related to the level of 20 kV. The parameters of the equivalent circuit model elements are

$R_T = 0.14\ \Omega$ $X_T = 3.48\ \Omega$ - booster transformer,

$R_L = 0.29\ \Omega$ $X_T = 0.19\ \Omega$ - line connecting power station with GSP.

In addition, short-circuit power running on 110 kV GSP bus is known, and:

$$S''_{k110kV} = 2386 \text{ MVA}$$

The rated power of the attached power station consisting of three 2.0 MW VESTAS wind turbines is

$$S_{nWPS} = 6.249 \text{ MVA}$$

It is necessary to analyze the impact of the WPS on the distribution network.

Solution

Rapid /dynamic/voltage changes

Using the Thevenin theorem, on the basis of a simple correlation (15.28) the voltage fluctuations can be estimated. A circuit representing EPS before integration with a wind turbine is shown in Figure 15.7a., whereas Figure 15.7b depicts a circuit after integration with the wind turbine collecting the maximum current at a start-up.

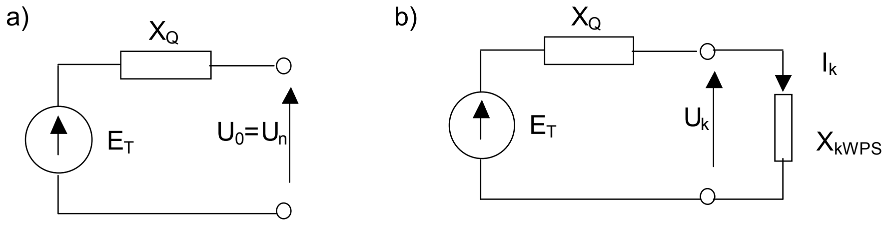


Figure 15.7 Two equivalent circuits for rapid voltage changes, a) before and b) after grid connection of a wind turbine

Due to the fact that the generator VESTAS 2.0 MW is equipped with an automatic regulation of reactive power, inrush current does not exceed the rated current (k = 1). Therefore, the maximum increase of the apparent wind turbine system's power is:

$$S_{maxWPS} = ckS_{nWPS} = 1.1 \cdot 1 \cdot 6.249 = 6.9 \text{ MVA}$$

and as a consequence the maximum voltage deviation on 110 kV GSP substation will be:

$$\Delta U = \frac{S_{\max EW}}{S''_{k110kV}} = \frac{6.9}{2386} = 0.0029$$

or in percentage $\Delta U = 0.3\%$.

Voltage deviation

The voltage deviations in the normal operation are caused by the flows of active and reactive power flowing in the cable line LK connecting the 20 kV wind turbine substation with 20 kV GSP substation.

Therefore:

$$R = R_T + R_L = 0.14 + 0.29 = 0.43\ \Omega$$
$$X = X_T + X_L = 3.48 + 0.19 = 3.67\ \Omega$$

In the wind turbine system's substation 20 kV there is the point where electricity is traded for the purposes of settlement under the trading and settlement code. Due to the fact that $tg\varphi$ at the trading point can't be greater than 0.4, and a total active power of wind generators units is 6 MW, we can assume:

P_g = 6 MW $\quad$ $Q = Ptg\varphi$ = 6·0.4 = 2.4 MW

The voltage at the PCC seen from the 110 kV grid can be calculated from the formula:

$$U_s = \sqrt{(U_s + U_a)^2 + (U_b)^2}$$

where:

$U_a = \dfrac{PR + QX}{U}$ - series voltage drop along the transmission line,

$U_b = \dfrac{PX - QR}{U}$ - the shunt voltage drop across the transmission line.

Active power flows to the receiving node, therefore is value must be preceded by a minus (negative reactive power » voltage raise at receiving end)

P = - P_g = - 6 MW

Reactive power is consumed by the wind turbine system, therefore it has a plus sign

Q = 2.4 MW

After substituting and calculations we obtain

$$U_a = \frac{PR + QX}{U} = \frac{-6 \cdot 0.43 + 2.4 \cdot 3.67}{20} = 0.31 kV$$

$$U_b = \frac{PX - QR}{U} = \frac{-6 \cdot 3.67 - 2.4 \cdot 0.43}{20} = -1.15 kV$$

$$U_s = \sqrt{(U_s + U_a)^2 + (U_b)^2} = \sqrt{(20 + 0.31)^2 + (-1.15)^2} = 20.34 kV$$

$$U_{s110kV} = U_s \frac{110}{20} = 111.9kV$$

|Voltage deviations at the point of common coupling of WTS integrated with110 kV grid is:

$$\Delta U = \frac{U - U_n}{U_n} 100\% = \frac{111.9 - 110}{110} 100\% = \frac{190}{110}\% = 1.7\%$$

It means that to existing voltage deviations at point of common coupling the Wind Turbine System will increase voltage by 1,7%, provided that it does not work an automatic on-load tap changer.

In some EU countries (eg. Germany- Renewable Energy Sources Act) there is requirement that the voltage change in a 110 kV grid caused by common coupling of the Wind Turbine should not be lower than 2%, what is fulfilled in the case of the tested plant.

Symmetrical short-circuit analysis

Schematic diagram and equivalent circuits for the calculations required in the circuit are shown in Figure15.8.

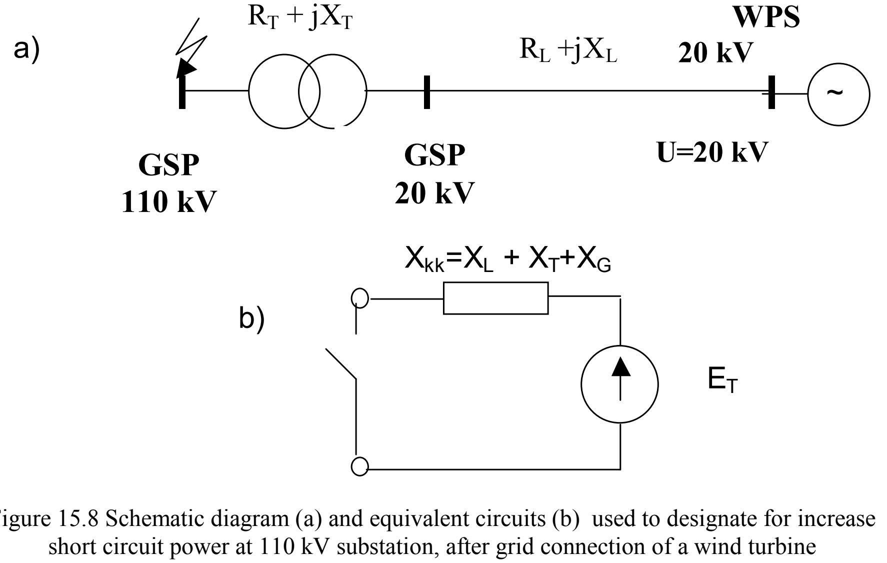


Figure 15.8 Schematic diagram (a) and equivalent circuits (b) used to designate for increase short circuit power at 110 kV substation, after grid connection of a wind turbine

The principle of superposition may be applied to the short-circuit power on the 110 kV GSP substation after common coupling wind turbine point is the total of short-circuit power at the site before connecting and pre-fault active power capacity of the wind turbines with induction generator unit and:

$$S''_{kQ} = S''_{k110kV} + S''_{k110kVWPS}$$

In accordance with Thevenin theorem initial short-circuit current on the 110 kV GSP substation derived from induction generators can be estimated from the formula:

$$I''_k = \frac{cU_{nk}}{\sqrt{3}X_{kk}}$$

where:

X_{kk} – the reactance seen from the short-circuit point, all *esm's* are short-

circuited.

The short-circuit reactance seen from the 110 kV GSP substation is:

$$X_{kk} = X_{kk20kV}t^2 = (X_L + X_T + X_G)t^2$$

where:

t = 110/20 kV - the rated transformer ratio.

The line reactance is X_L = 0.19 Ω, transformer X_T = 3.48 Ω. Generator unit's short-circuit reactance derives from inrush current $I_k = k{\cdot}I_n$ (k=1) and rated apparent power of a wind turbine S_{nWPS} so that:

$$X_G = \frac{U_n^2}{kS_{nEW}} = \frac{20^2}{6.0249} = 64\Omega$$

Having substituted the appropriate values we obtain:

$$X_{kk} = X_{kk20kV}t^2 = (X_L + X_T + X_G)t^2 = (0.19 + 3.48 + 64)(110/20)^2$$

$$X_{kk} = X_{kk20kV}t^2 = 67.67 \cdot (5.05)^2 = 2047\Omega$$

$$I''_k = \frac{cU_{nk}}{\sqrt{3}X_{kk}} = \frac{1.1 \cdot 110}{2047\sqrt{3}} = 0.341kA$$

$$S''_{k110kVWPS} = \sqrt{3}U_n I''_k = \sqrt{3}\ \ 110 \cdot 0.341 = 6.5MVA$$

Short-circuit power after connecting the wind turbine is:

$$S''_{kQ} = S''_{k110kV} + S''_{k110kVWPS} = 2386 + 6.5 = 2392.5 \text{ MVA}$$

Percentage increase in power is

$$\Delta S''_{kQ\%} = \frac{S''_{k110kVEW}}{S''_{k110kV}} 100\% = \frac{6.5}{2386} 100\% = 0.27\%$$

The power increase is so low that it does not affect the strength of the short-circuit power devices connected to the 110 kV GSP substation.

15.6 Flicker emission analysis of wind turbines

Wind turbines connected to electrical grids may affect considerably the quality of the supply, due to the fluctuating character of their output power. An important effect from their connection are the rapid fluctuations of the supply voltage, usually referred to as "flicker". Electrical flicker is a measure of the voltage variation which may cause disturbance for the consumer. Flicker emissions are not only produced during start-up, but also during the continuous operation of the wind turbine. The flicker emission produced during normal operation is mainly caused by variations in the produced power due to wind-speed variations, the wind gradient and the tower shadow effect. As shown in Figure 15.9, wind farm (WPS Ch) is connected to 20 kV local substation at 110/20 kV grid supply point (GSP Ch). At the source terminals the concentrated local load is connected, which corresponds to the system loads near the PCC, i.e. the point where the WT is connected to the grid. The local load is considered mainly in order to investigate the effect of its size and characteristics on the produced flicker.

The 20 kV distribution network on which the case study is carried out is shown in Figure 15.9. The network is fed from a 110 kV network (substation S_{K110}) through a T1 transformer. A GSP substation operates in a radial configuration and it is located between the 400/110kV Cz and 110 kV Kon substations during normal operation. In the case of maintenance work it is fed from a single 110 kV radial line S-462 or S-429.

During normal operations a T-1 transformer with 16 MVA power is employed in GSP Ch. A T-2 transformer with 25 MVA power remains as an emergency reserve auxiliary transformer T-2. A20 kV. Automatic Transfer Switching Equipment is operating. Distributed wind generation is connected at bus 6, where power factor correction is also connected. Branch parameters of this network are given in Table 15.5.

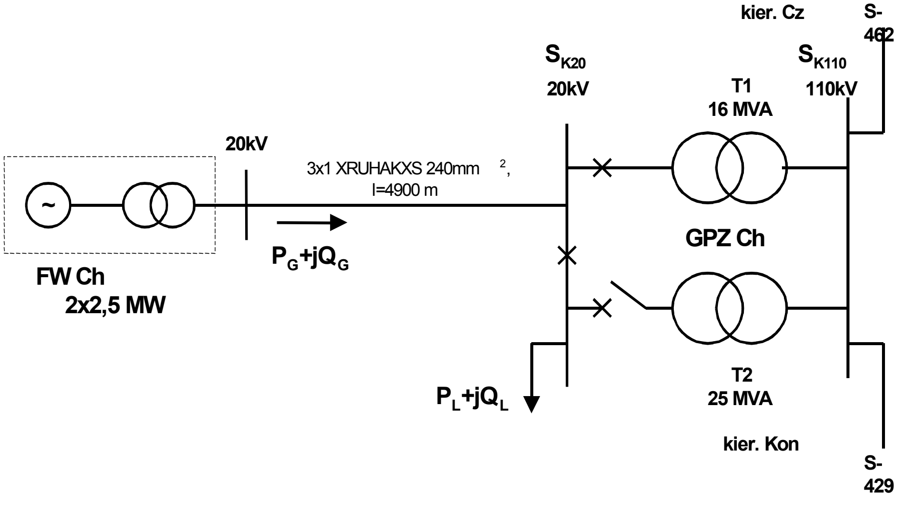


Figure 15.9 Test system for investigating the voltage control capabilities of 2 wind turbines

Table no 15.3 and 15.4 specify short-circuit power, loads and voltage levels at GSP Ch substation during different condition operating of the power system.

Table. 15.3. The short-circuit power and equivalent reactance of the grid 110 kV at GSP Ch

Options of power supply	S_K	X_{Q_110}	X_{Q_20}	R_{Q_20}=0,1X_{Q_20}
	MVA	Ω	Ω	Ω
S-462	745	17.87	0.654	0.066
S-429	635	20.96	0.767	0.077
S-462 + S-429	1380	9.64	0.353	0.035

Table 15.4. Rated and short-circuit parameters of 115/22kV transformer at GSP Ch

Transf.	Rated parameters						Short-circuit paramet. considering a 20 kV base			
	S_{nT}	U_{nG}	U_{nD}	u''_k	dP_{cu}	Io	Z_{20T}	R_{20T}	X_{20T}	B_{20T}
	MVA	kV	kV	-	kW	%I_{nT}	Ω	Ω	Ω	µS
T-1, YNd11	16	115±10%	22	0.1096	68.80	0.21	3.251	0.128	3.248	69.4
T-2. YNd11	25	115±16%	22	0.1093	130.0	0.39	2.075	0.099	2.073	201.0

Table 15.5. Branch parameters of the distribution power line chosen for the connection between the 2 turbines and GSP Ch.

Branch	r'_1	x'_1	b'_1	l	R_1	X_1	B_1
	Ω/km	/km	μS/km	km	Ω	Ω	μS
3 x XRUHAKXS 1x240mm^2	0.128	0.110	94.0	4.9	0.627	0.539	460.6

Table 15.6. The resultant annual energy produced and curtailed with installed capacity from 6MW to 7,5MW at GSP Ch

Options of power supply	R_{k20}	X_{k20}	Z_{k20}	I_{K20}	S_{K20}	$S_{K20}/S_{N\Sigma}$		ψ_k
	Ω	Ω	Ω	kA	MVA	5MW	7,5MW	degree
(S-462) - T1	0.193	3.902	3.907	3.25	112.62	22.5	15.0	87
(S-462) - T2	0.164	2.727	2.732	4.66	161.08	32.2	21.5	87
(S-429) - T1	0.204	4.015	4.021	3.16	109.44	21.9	14.6	87
(S-429) - T2	0.175	2.840	2.845	4.47	154.64	30.9	20.6	87
(S-462 + S-429) - T1	0.163	3.601	3.605	3.53	122.05	24.4	16.3	87
(S-462 + S-429) – T2	0.134	2.426	2.430	5.23	181.11	36.2	24.1	87

Conclusions:

1. A relation of short-circuit power to power of WPS is higher than 20 in any option of power supply of 5MW at WPS. In case of integration of 7,5 MW at WPS it will be hold only with 20 kV grid supplied form 25MVA T-2 transformer.
2. In case a failure to fulfill a condition $S_K/S_{N\Sigma}>20$ occurs, a connection of WPS with given power, in given location needs tests concerning its influence on power quality indices in order to verify its acceptability.

Rapid voltage variation caused by integration with wind turbines.

The switching frequency defines the operational frequency range. It is assumed that a smooth connection of the generator to the grid is conducted singularly and as a result all the calculation should be performed for a single turbine. The results are valid for WPS that consists of both 2 or 3 turbines.
According to producer for network impedance phase angle ψ_k=87 a voltage change factor $k_U(\psi_k)$ is equal to 0,1, both with cut-in wind speed (wind turbine startup at cut-in wind speed) and with the operation range of wind speed.

Table 15.7. Values shown for the rapid voltage variation during integration with a single turbine

Options of power supply	SN/SK20	ψk	kU(ψk)	$d_{\%} = k_U(\psi_k) \cdot \frac{S_N}{S_{K20}} \cdot 100\%$	Maximum number of switchings within a 1 h period r
	-	degree	-	%	-
(S-462) - T1	0.0222	87	0.1	0.222	100<r≤1000
(S-462) - T2	0.0155	87	0.1	0.155	100<r≤1000
(S-429) - T1	0.0228	87	0.1	0.228	100<r≤1000
(S-429) - T2	0.0162	87	0.1	0.162	100<r≤1000
(S-462 + S-429) - T1	0.0205	87	0.1	0.205	100<r≤1000
(S-462 + S-429) – T2	0.0138	87	0.1	0.138	100<r≤1000

Conclusions:

1. Rapid voltage variation during integration with a single turbine in any option does not overcome 0,25%. In accordance with an operating instruction manual for switching frequency higher than 100/h the acceptable value is 1,5%

Flicker emissions during the continuous operation of a wind turbine

For N_{wt} the same wind turbines characterized with unit power S_N, the relation is as follows:

$$P_{st\Sigma} = P_{lt\Sigma} = \frac{S_N}{S_{K20}} c(\psi_k, \upsilon_a)\sqrt{N_{wt}}$$

where:

N_{wt} - Number of wind turbines

Taking characteristics of the wind turbine with network impedance phase angle ψ_k=86°, a value of indicator $c(\psi_k, \nu_a)$=2 for annual average wind speed from range (6-10)m/s a flicker indicators were calculated. The results for varied power supply and for 2 or 3 wind turbines are gathered in table 15.8

Table 15.8. Flicker indicators for 2 and 3 turbines with 2.5 MW each in different options of power supply

Options of power supply	S_N/S_{K20}	ψ_k	$c(\psi_k, \nu_a)$	$P_{st\Sigma}=P_{lt\Sigma}$	$P_{st\Sigma}=P_{lt\Sigma}$	E_{Plt}
	-	degree	-	2 turbines	3 turbines	-
(S-462) - T1	0.0222	87	2	0.06	0.08	0.25
(S-462) - T2	0.0155	87	2	0.04	0.05	

(S-429) - T1	0.0228	87	2	0.06	0.08	
(S-429) - T2	0.0162	87	2	0.05	0.06	
(S-462 + S-429) - T1	0.0205	87	2	0.06	0.07	
(S-462 + S-429) – T2	0.0138	87	2	0.04	0.05	

Conclusions:

1. Flicker emission during the continuous operation of a wind turbine does not overcome an acceptable level in any of considered options of power supply, both for 2 or 3 turbines with power 2.5 MW each.

Flicker emissions during the switching operation of a wind turbine

For N_{wt} the same wind turbines characterized with unit power S_N, the following relations can be described

$$P_{st\Sigma} = \frac{18}{S_{K20}}\left(N_{wt} N_{10}[k_f(\psi_k)\cdot S_N]^{3,2}\right)^{0,31}$$

$$P_{lt\Sigma} = \frac{8}{S_{K20}}\left(N_{wt} N_{120}[k_f(\psi_k)\cdot S_N]^{3,2}\right)^{0,31}$$

Considering characteristics of the wind turbine it can be obtained:

- integration with the cut-in wind speed:

  $N_{10} = 1$, $N_{120} = 10$, $k_f(\psi_k) = 0.1$

- integration with the operation range of wind speed:

  $N_{10} = 1$, $N_{120} = 1$, $k_f(\psi_k) = 0.1$

Table 15.9 Flicker indicators during the switching operations for 2 turbines with 2.5 MW each – for different options of power supply

Options of power supply	S_{K20}	Cut-in wind speed		Rated wind speed		E_{Pst}	E_{Plt}
-	MVA	$P_{st\Sigma}$	$P_{lt\Sigma}$	$P_{st\Sigma}$	$P_{lt\Sigma}$	-	-
(S-462) - T1	112.62	0.050	0.045	0.050	0.022	0.35	0.25
(S-462) - T2	161.08	0.035	0.032	0.035	0.016		
(S-429) - T1	109.44	0.052	0.047	0.052	0.023		
(S-429) - T2	154.64	0.036	0.033	0.036	0.016		
(S-462 + S-429) - T1	122.05	0.046	0.042	0.046	0.021		
(S-462 + S-429) – T2	181.11	0.031	0.028	0.031	0.014		

Table 15.10. Flicker indicators during the switching operations for 3 turbines with 2.5 MW each
– for different options of power supply

Options of power supply	S_{K20}	Cut-in wind speed		Rated wind speed		E_{Pst}	E_{Plt}
-	MVA	$P_{st\Sigma}$	$P_{lt\Sigma}$	$P_{st\Sigma}$	$P_{lt\Sigma}$	-	-
(S-462) - T1	112.62	0.057	0.052	0.057	0.025	0.35	0.25
(S-462) - T2	161.08	0.040	0.036	0.040	0.018		
(S-429) - T1	109.44	0.058	0.053	0.058	0.026		
(S-429) - T2	154.64	0.041	0.038	0.041	0.018		
(S-462 + S-429) - T1	122.05	0.052	0.048	0.052	0.023		
(S-462 + S-429) – T2	181.11	0.035	0.032	0.035	0.016		

Conclusions:

1. Flicker emissions during the switching operation of a wind turbine does not overcome an acceptable level in any of considered options of power supply, both for 2 or 3 turbines with power 2.5 MW each.

15.7 Flicker propagation analysis in a power network

The term ‘flicker’ means the flickering of light caused by fluctuations of the mains voltage, which can cause distortions or inconvenience to people as well as other electrical consumers. Flicker is defined as the fluctuation of voltage in a frequency range of up to 35Hz. Flicker is a minor problem for the grid connection of today’s wind turbines. In the mid-1990s, when most of the turbines were small fixed-speed turbines (Type A), flicker sometimes was a limiting issue. Contemporary wind turbines, especially variable-speed turbines (Types C and D), have improved flicker’s behavior. In order to explain the flicker emission from wind to the electricity grid the Thevenin Equivalent Circuit (TEC) can be studied using the network equivalent, depicted in Figure 15.10.

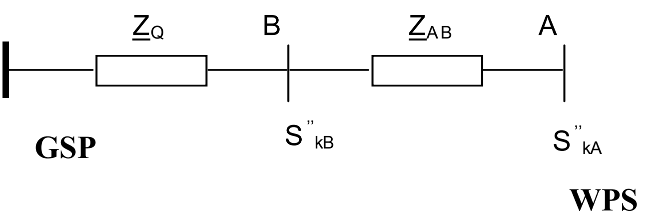


Figure 15.10. Model of a network equivalent for flicke

The flicker from wind turbine is already present in the node A. It should also be noted that short-circuit power of node A is equal to S''_{kA} and node B can be the 110 kV bus-bar system of transformer substation in GPS Ch. Short-circuit power of node B is equal to S''_{kB}.

We assumed that a voltage measurements were carried out with a flickermeter at node A. The flickermeter takes voltage as an input and gives the flicker severity as an output. The flicker severity can be given as a short-term value, P_{stA}, measured over a period of 10 minutes. In the example network P_{st} was calculated within the period of 10 minutes.

The question arises over the way of estimation of flicker severity's rate P_{stB} at node B on the basis of measurements concerning flicker severity P_{stA} at node A.

According to IEC 61000-3-7 (Ed.2.0 2002) (Assessment of Emission Limits for Fluctuating Loads in MV and HV Power Systems), the following equation needs to be applied to determine the flicker severity P_{stB} at node B that originates from one source connected to a common point:

$$P_{stB} \approx \frac{X_Q}{X_Q + X_{AB}} P_{stA} \approx \left| \frac{\underline{Z}_Q}{\underline{Z}_Q + \underline{Z}_{AB}} \right| P_{stA} = \frac{S''_{kA}}{S''_{kB}} P_{stA}$$

where:

X_Q, $\underline{Z}_Q$, S''_{kB} - X is the reactance, $\underline{Z}_Q$ is the impedance and S''_{kB} is the short circuit power as seen from the node B.

X_{AB}, $\underline{Z}_{AB}$ – reactance and impedance of grid connections between nodes A-B, respectively

S''_{kA} - is the short circuit power at the node A, where the flicker severity was measured over a period of 10 minutes by using a flickermeter.

A proposal for voltage flicker propagation along a network.

The short-circuit capacities have continued to increase and the rate of the flicker coefficient P_{st} has continued to decrease from a power company to GSP. The flicker coefficient is the normalized measure of the maximum flicker emission (99th percentile) from a wind turbine during continuous operations and can be calculated from the following equation:

$$P_{stB} = \frac{S''_{kA}}{S''_{kB}} P_{stA}$$

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