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Power system requirements for high wind penetration

Part 3: Small island grid

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Abstract:

This report identifies the special features of island grids of Greece, regarding the production, transmission/distribution of electric power. In addition, the problems which occur from the use of wind power plants in island grids are presented. The results are based on experience derived from island grids in Greece.

Contents

STATUS, CONFIDENTIALITY AND ACCESSIBILITY									
Status				**Confidentiality**				**Accessibility**	
S0	Approved/Released	**X**		**R0**	General public			Private web site	**X**
S1	Reviewed			**R1**	Restricted to project members	**X**		Public web site	
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PL: *Project leader* **WPL:** *Work package leader* **TL:** *Task leader*

1.0 Intro

In this report the special features of island grids of Greece are described, regarding the production, transmission/distribution of Electric Energy. In addition, the problems which occur from the use of wind power plants in island grids are presented.

1.1 Island grids

1.1.1 Distinction between island grids and interconnected systems

The grids which operate in islands and therefore are not connected somehow to the network of the mainland are characterized as Island Grids. Those grids are autonomous systems which operate as “islands”. In this category, also autonomous systems which are not connected to stronger systems are included.

The advantages of an interconnected system compared with island grids are:

i. Fewer power plants: instead of one power plant for each facility that needs one, only one power plant is needed to cover all the needs and therefore the installation cost per kW is smaller.
ii. Ability to use larger and less expensive power plants in the system transmitting the power to the high load regions.
iii. Capability of coping with severe disorders of the system.
iv. Beneficial use of power due to different demand of the several regions or systems during the day.
v. Better load management regarding the installed capacity among the regions with different needs.

For the supply of the needs of island grids, the demand should not be greater than the installed capacity of those grids because in such case, the import of electric power is not possible as in the interconnected system. Therefore if the demand is greater, the solution of load rejection is used.

When island grids are studied the interest is focused on the following:

i. The production should be enough to supply the demand of the consumers so that the load rejections are reduced.
ii. The frequency should be kept within the approved limits around the value of 50 Hz.
iii. The power quality should be ensured according to the regulation EN 50160.
iv. The production should be scheduled so that the fuel refit is ensured (especially for smaller islands).
v. The efficient operation (from the financial point of view) of the system as possible.
vi. The operation of the system should be as safe and stabile as possible.

1.1.2 Categories

One way to distinguish the island grids depending on the installed capacity could be the following, [1]:

i. Very Small Island Grids

The islands that have peak load around 1 MW. Islands of that magnitude are some small islands in the Aegean or Ionian Sea and the basic feature is the use of diesel units with expensive fuel, and also plants using renewable energy sources.

ii. Small Island Grids

Islands with demand between 1-7 MW. In most of these cases, there are MV networks 15/20 kV and the production is based on diesel units or renewable energy sources. The power plants are known as Autonomous Power Plants.

iii. Medium Island Grids

Such grids are referring to islands of medium size and often are interconnection of grids of several neighbor islands. The demand is between 7-50 MW, and the transmission is also here based on a MV network 15/20 kV. The production includes larger diesel machines, which may consume crude oil and also there may be more than one wind farms.

iv. Large Island Grids

In this category grids with capacity over 50 MW are included, where the HV network is used for the transmission of the Electric Energy. Those islands are of great interest due to the complexity and the variety of the power plants they use.

1.2 Special features of island grids

Island grids have a unique character compared with the interconnected system. An island grid is smaller than the interconnected system, but it has special features regarding the control, the transmission and production of electric power and especially the penetration of wind power. The last one is vital for the Greek islands due to high wind potential available there.

(i) Control features

The main control of the load distribution among the power plants is done by the Load Dispatch Centers in collaboration with the RTU's of the SCADA tele-measurements system. Such systems are being used mostly in relatively large island grids (e.g. the power system of Crete). However the normal practice for the control is that the dispatch of the diesel units used in autonomous systems is not an automatic procedure. The operators of the diesel units usually define the setpoints of the units.

(ii) Features of the Electric Power Transmission System

It is well known that when the distances are large and when the amount of power that has to be transmitted is also high, the voltage of the transmission lines should be high enough to reduce the power losses on the lines. The island grids, in general, use MV lines of 15/20 kV due to the small distances and low levels of transmitted power. However, in large islands HV lines of 150 kV are used.

(iii) Special features of the load distribution

In island grids the load is very high during the summer season, mainly due to the tourist activity, and low during the winter season. As a result, the load curve has a very special form and the ratio low to high load is very small (seasonal load variation). This phenomenon poses specific standards regarding the type and size of the units that are used, and also the penetration level of wind power.

(iv) Island Grids and Wind Power

Due to high wind potential available in the islands, the wind power is of great interest in this case. However, there are several problems in these islands concerning the penetration level, which is kept low.
A major problem is the extremely low load during the winter season. The conventional generators (typically diesel units) and especially the base units operate usually close to their lowest technical limit. Increased production from wind farms in this case results in the conventional units producing even lower power. This endangers violating their low technical limits, and therefore reducing the reliability of the system in case there is a malfunction in one of the units, that are being used. Therefore, the constraints imposed by the conventional generators and security of

operation considerations result in significant and frequent wind power curtailments. According to a recent regulation, still used as a rule of thumb, the permissible installed wind power capacity in an island grid should not be greater than the 30% of the peak load during the previous year. There are some island grids, in which not only the lowest, but also the average load is lower than this percentage. All the above have as a result that the penetration of wind power in most of the island grids is kept below or around 10%.
In addition to this, most of the wind turbines installed so far are constant speed using induction generators. These systems are rather uncompromising during their operation, so that instantaneous variations of their power make their cooperation with the small power plants difficult during the periods of low load.
The installation of bigger wind turbines makes their cooperation with the autonomous power plants even worse, as the power variations due to variation of the wind speed are greater than in the interconnected systems. These variations cause several problems to the conventional units and increased needs of active power. Therefore, the installation of big wind turbines is only possible in large islands like Crete. Increase of the wind power installed capacity in the island grids can be achieved through effective methods of storage.
The installation of variable speed wind turbines contributes to an effective cooperation of the conventional units with the wind farm. These turbines have smoother power outputs, consume less reactive power, and in some cases they produce reactive power.

1.3 The Greek Island Grids

The small island networks with large wind power penetration are a special case: Sensitive protections result in frequent loss of large amounts of generation. Less sensitive settings in the protection equipment and grading between different installations (or generators within the same installation) are necessary. In any case, undetected islanding situations may arise for favorable production/load combinations in the islanded part. Good protection design minimizes the risk but cannot eliminate it. Induction generator self-excitation requires particular consideration, due to potential over voltages and increased risk of islanding. Networks with underground and submarine cables or large compensation are of greatest concern.
The connection of wind turbines (WTs) to the grid is often constrained by power quality considerations, i.e. by the concern of utilities for the possible deterioration of the voltage quality of the network. Several investigations have been performed over the years, analyzing the steady-state and fast voltage variations, flicker emissions, switching transients and harmonics, which contributed significantly in better understanding the possible effects of the WT connection. Significant standardization work has also been carried out, with a special reference to IEC Standard 61400-21 [3] regarding the power quality characterization of WTs intended for grid-connected operation.
Nevertheless, the existing regulations and technical evaluation procedures are focused on interconnected grids, of practically fixed frequency and relatively high short-circuit capacity, where the majority of installed wind capacity is connected. Power quality issues in weak island grids, including the effect from the WT connection and operation, have been hardly investigated and relatively scarce information exists on such systems. Although at principle the phenomena should be of similar nature, important differences exist due to the isolated mode of operation of these systems, which are typically fed by autonomous diesel power stations.
In Greece, more than 50 islands exist with relatively small, diesel powered grids, in many of which significant wind penetration levels have been reached (exceeding 50% during low load hours). Examples of island grids are groups of islands like Crete, Rodos and the rest of the Dodekanissa, Lesvos and the rest of the islands of N.E Aegean Sea, the Cyclades islands, the Sporades, Kithira, and many other smaller that are not interconnected due to their distance from the network of the mainland. Systems of interconnected islands like the system Paros-Naxos, Kos-Kalimnos are considered as island grids because they are not interconnected to the mainland grid. The grids of the Ionian islands are not considered as island grids, as the interconnection to the mainland has already been completed. A map showing the interconnections of the Greek islands is included here.

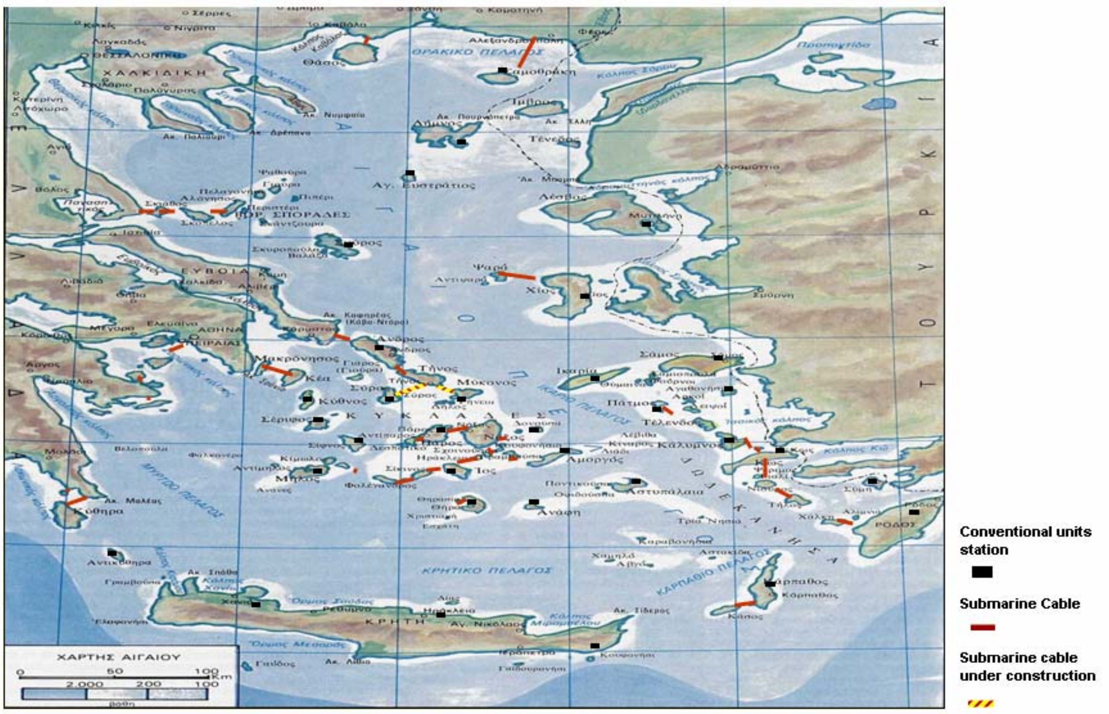


Figure 1.1. Map of the Greek islands and interconnections.

Due to the special features of the island grids, the Greek islands have given the opportunity for a very detailed research on the field of islanding phenomenon.

Autonomous power systems, such as those existing in small and medium-size islands, typically consist of medium voltage networks fed by conventional power stations and present characteristics not typical for large interconnected grids. The main factor differentiating the island grid from a weak distribution network in the interconnected system is the use of diesel generating units.

In the following sections, the facts from two island systems with significant wind penetration will be presented – the power system of Crete and the power system of Samos.

2.0 The Crete Power System

Operating island systems with large wind power penetration is a difficult task, taking into consideration the lack of grid code in the Greek island systems. Several conclusions have been made from the study if the Crete Power System, in which the highest wind power activity in the last years is noted. In 2000 the peak load has reached the magnitude of 550 MW and the total energy demand the amount of 2700GWh. The following figure shows the number of faults in transmission lines (1978-2004), [7]:

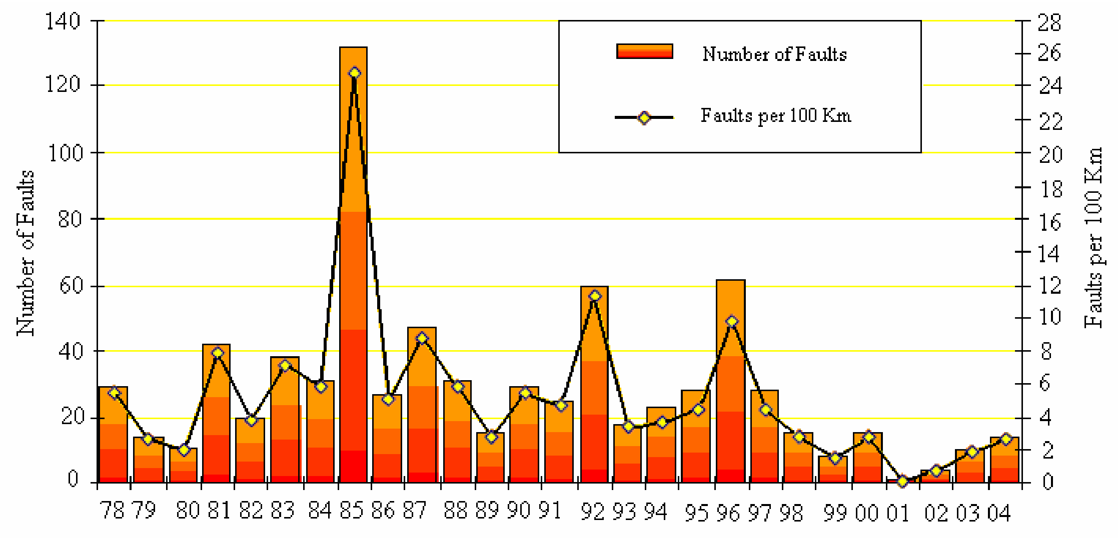


Figure 2.1. Number of faults (1978-2004).

An example of the voltage profile at fault's substation is given below:

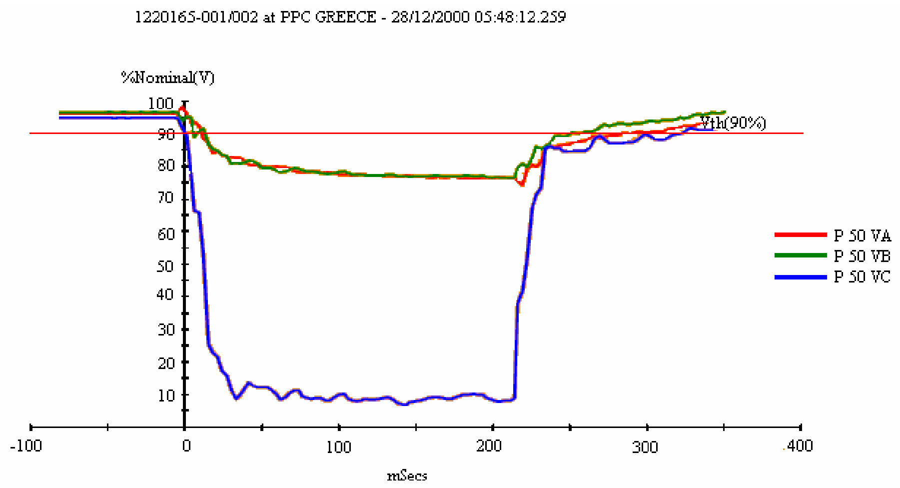


Figure 2.2. Voltage profile at fault's substation (single-face fault at 150kV buses).

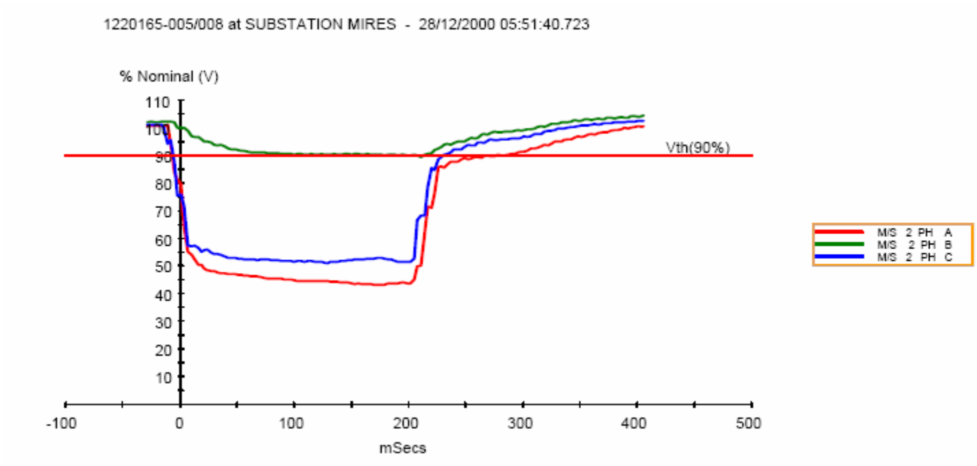


Figure 2.3. Voltage profile during same fault (20kV buses of a remote S/S).

The following Table gives details of the WFs in operation in the CPS:

c/n	W/F Name	First year of Operation	Location	Nr of W/T	Type of W/T	Receiving S/S	Owner ship	W/T Power [KW]	W/F Power [MW]
1	Toplou-1	1992	Moni Toplou	17	WINDMASTER	SITIA (Load Bus)	PPC	300	5,10
2	Toplou-2	1993		2	TACKE			500	1,00
		1995		1	NORDTANK				0,50
3	OAS	1995	Zakros	1	TACKE	SITIA (Load Bus)	Local Auth.	500	0,50
4	ROKAS	1998-2004	Modi	22	BONUS	SITIA (W/F Bus)	Private	600	13,20
5	IWECO	1999	Megali Vrisi	9	ZONT – 40	MOIRES (Load Bus)		550	4,95
6	AEOLOS	1999	Chandras	18		SITIA (W/F Bus)		550	9,90
7	ACHLADIA	1999	Ahladia	20	ENERCON E 40	Maronia		500	10,00
8	ANEMOESSA	1999	Ahladia	10				500	5,00
9	KRIA	1999	Kria	20				500	10,00
10	XIROLIMNI	2000	Sitia	17	NEG-MILON NM 70	SITIA (W/F Bus)	PPC	600	10,20
11	ENERCON-OAS	2002	Ahladia	5	ENERCON E 40	Maronia	Private	500	2,50
12	PLASTIKA KRITIS	2000-4	Vrouhas	9	VESTAS V 52	Ag. Nikolaos (Load Bus)		850	7,65
13	RWE	2004	Kria	4	NEG-MILON NM 70	Maronia		600	2,40
14	DOMOKI KRITIS	2004	Krousonas	5	VESTAS V 52	Iraklio III (Load		850	4,25

						Bus)			
Total Nr of W/T				**160**	**Total Installed Capacity**				**87,15**

Table 2.1. WFs in operation in the CPS.

The basic characteristics of the Crete Power System are:

- It is the largest autonomous System in Greece
- The rate of increase is big compared with the interconnected Greek Power System
- The daily and seasonal load variations are big (summer and evening peaks)
- Many disturbances lead to very severe voltage dips
- The distribution of WFs is unbalanced
- High efficiencies
- Higher yields during summer months bit lower, or almost zero, at evening peaks
- Serious output fluctuations causing the need for keeping spinning reserve
- Voltage compatibility problems in case the connecting point is the Load Bus:
  -Over or Under voltages
  -Voltage Unbalances
- No problem for Flicker, Harmonics, inrush Currents

According to PPC, the Greek Public Power Company, the major problem the island grids face, is the serious outages during transients. Thus, whenever there is voltage dip at the system, partial or total W/F outages appear with significant consequences on the stability of the system.

The voltage and frequency limits for the WTs in use are given in Table 2.2:

WT Manufacturer		BONUS		NEG MILON		ENERCON		ZOND		WINDMASTER TACKE NORDANK	
Limits		Voltage & Frequency limits [pu]	Time (sec)	Voltage & Frequency limits [pu]	Time (sec)	Voltage & Frequency limits [pu]	Time (sec)	Voltage & Frequency limits [pu]	Time (sec)	Voltage & Frequency limits [pu]	Time (sec)
Voltage Limits	High level Overvoltage	>1,085	0,50	>1,12	0,10			>1,10	0,25	>1,10	0,25
	Low level Overvoltage	1,06-1,085	60,00	1,10 to 1,12	60,00						
	Normal Voltage	0,90 to 1,06	Cont.	0,88 to 1,10	Cont.	0,77 to 1,27	Cont.	0,90 to 1,10	Cont.	0,90 to 1,10	Cont.
	Low level Undervoltage	0,90 to 0,80	60,00	0,80 to 0,88	60,00	0,63 to 0,77	1,50				
	High level Undervoltage	<0,795	0,5	<0,88	0,10	<0,63	0,30	<0,90	0,25	<0,90	0,25
Frequency limits	Overfrequency	>1,02	3,00	>1,02	0,20	>1,12	0,00	>1,10	3,00	>1,10	1,50
	Normal Frequency	0,94-1,02	Cont.	0,94-1,02	Cont.	0,94-1,12	Cont.	0,90 to 1,10	Cont.	0,9-1,10	Cont.
	Underfrequency	<0,94	3,00	<0,94	0,10	<0,92	0,00	<0,90	3,00	<0,90	1,50

Table 2.2. Voltage & Frequency limits (Normal, Up and Down limits).

These limits refer to the specific WTs and should not be taken as limits used in general.
The system experiences serious outages. The most serious fault-related events of the last years are summarized below:

Years	Number of WFs-Outages per year	Faults in HV grid	Faults in MV grid	Most serious event of year	
				Rejected load [MW]	Part of total [%]
1999	6	4	2	24	13,7
2000	19	13	6	43	15,6
2001	11	7	4	35,3	16,7
2002	4	0	4	30	12
2003	17	3	14	48,2	15
2004	7	3	4	19,2	18

Table 2.3. Most serious outages during the last years in the CPS.

As illustrated above, the main problem in island grids are the serious outages due to faults in the grids. This is of great importance as the penetration of wind power increases in the island grids. The grid code which is being prepared must set the required fault ride-through capabilities in order to ensure the minimum outages of WFs in such grids.

3.0 The Samos Power System

The second study case of Greek islands is the power system of Samos. The autonomous power system of Samos island is fed by a diesel power station (DPS), which, at the time of the measurements which were taken during a power quality measurement campaign in 1998, [2], had a total installed capacity of approximately 30 MW, comprising several units from 2.0 MW to 6.3 MW. Basic generators are two 6.3 MW units, followed by three 4 MW units, the main characteristics of which are summarized in Table 3.1 (unit numbering as used by the DPS operators).

DATA FOR THE DIESEL GENERATOR UNITS OF THE POWER STATION		
	Units # 11,12	**Units # 7,8,9**
Diesel Engine		
Fuel	Heavy Oil	Heavy oil
Aspiration	Turbocharged	Turbocharged
Cylinders	6	8
Strokes	2	4
Rated power (kW)	6300	3920
Fuel consumption (kg/MWh @ P_{rated})	181.7	216.4
Synchronous Generator		
Poles	48	12
Rated speed (rpm)	125	500
Rated power (kVA)	7900	4900
Rated voltage (kV)	6.3	6.3
Power factor	0.75-0.95	0.75-0.95
Characteristic frequencies		
Power stroke freq., f_{PS} (Hz)	2.083	4.17
Engine firing freq., f_F (Hz)	12.5	33.33

Table 3.1. Data for the diesel generator units of the power station

The distribution network of the island consists of several 15 kV medium voltage (MV) overhead feeders, departing from the DPS busbars. An important characteristic of the network is the length of the MV feeders (several tens of km per feeder), which creates voltage regulation problems.

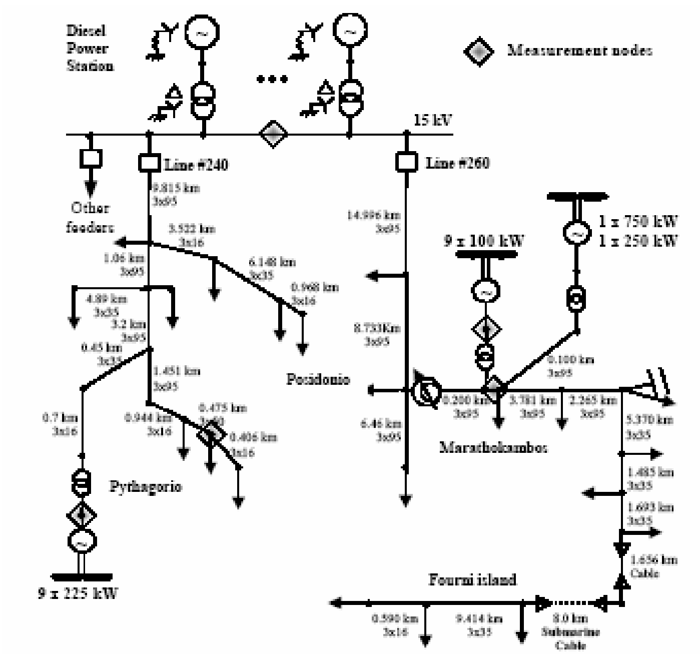


Figure 3.1. Electrical system of island Samos (only two MV feeders shown).

The consumer load during the summer period, when the measurements were taken, is predominantly touristic, varying approximately from 7 to 23 MW. At the time of the measurements three wind farms were operating on the island. One with 9x225 kW pitch controlled, constant speed machines, near the town of Pythagorio, and another two wind farms with stall regulated, constant speed WTs (9x100 kW old units and 750+250 kW recently installed ones), at Marathokambos. The wind farms are connected to two 15 kV feeders as shown in Fig.1.2.4-4 (Lines #240 and #260).

The results

According to this measurement campaign:

- The power factor of the DPS is very low (0.7-0.85): this is characteristic of the island load (to a large extent due to the air-conditioning units), but some days it is further decreased due to the operation of the wind farms. The poor power faxtor very often resulted in the synchronous generators of the DPS reaching their excitation limit. Thus, they were unable to maintain an increased voltage level at the DPS busbars (typically 15.75 kV, i.e. 1.05 p.u.), to compensate the voltage drop on the long distribution feeders. In general the voltage regulation on the island grid is very poor, even at the power station busbars, where the voltage drops below 0.95 p.u. in certain cases. The voltage deviation at remote nodes often exceeds -10%, which is typically steady-state under-voltage limit in MV networks ($\pm$10% according to [4], during the 95% of the time). Remedial action with installation of capacitors in the network, at the wind farms and possibly at the DPS busbars is urgently needed for the island system.
- The three phase voltages of the system exhibit an unbalance under all operating conditions, which is attributed to the non-uniform distribution of the single-phase consumer loads. The Voltage Unbalance Factor (VUF) (e.g. IEC 61000-2-1) is generally acceptable (lower than 2%), although higher values reaching 5% also exist during certain intervals. The operation of the wind turbines generally reduces the voltage unbalance.

• The system frequency, shown in Fig. 1.2.4-5, is well controlled. Maximum excursions do not exceed $\pm$0.5Hz, even during the strong wind period, which is well below the deviation limit set in [4] for non-interconnected systems ($\pm$1Hz during 95% of the time and $\pm$7.5Hz during 100% of the time). This is important because stability concerns are often a barrier to increasing wind penetration in island systems.

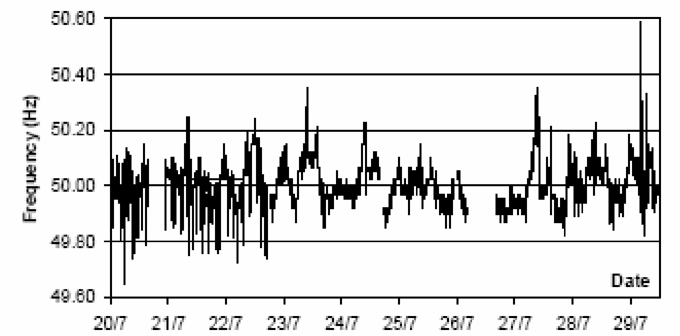


Figure 3.2. System frequency.

• The voltage flicker problem was found to be quite severe under all operating conditions. Flicker measurements and analysis of the data showed that the internal combustion engines of the DPS are the source of the high flicker levels in the network.

In total, although the penetration of wind power to non-interconnected island systems is dealt with severe conservatism, among other things for fears of power quality and frequency regulation issues, the field measurements performed demonstrate that such concerns are largely unfounded.

The increase wind penetration level in isolated power systems, as well at the distribution network level of interconnected systems, has accentuated the problems related with the integration of the wind turbines (WTs) in the electric power systems. Among the issues that frequently arise, are indicative of autonomous systems. Among the issues that frequently arise, are indicatively the following:

- Dynamic stability of autonomous systems
- Operation of protective devices (WT and line protections)
- Flicker emission and propagation
- Harmonics penetration
    - Other disturbances and abnormal operating conditions (e.g. self-excitation phenomena, islanding phenomenon)

In Fig. 4.1 the recorded diesel power station voltages (for the 3 phases) are shown for a remote fault on the grid, followed by operation of the feeder protections and the disconnection of one wind farm.

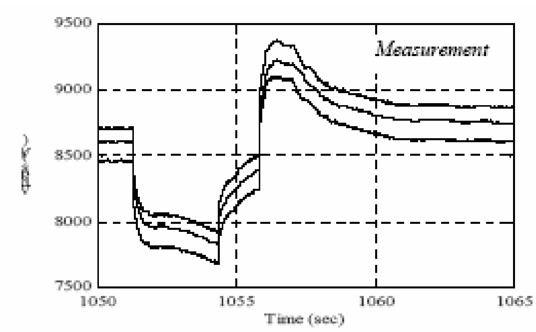


Figure 3.3. DPS phase voltages during a remote 3-phase fault on the grid. [5]

In Fig.4.2 the self-excited operation of a wind farm is demonstrated, following the opening of the circuit breaker at the departure of its feeder. The feeder includes a long submarine cable and consumer loads. Due to the favorable equilibrium, the voltage is sustained in the islanded part for several seconds.

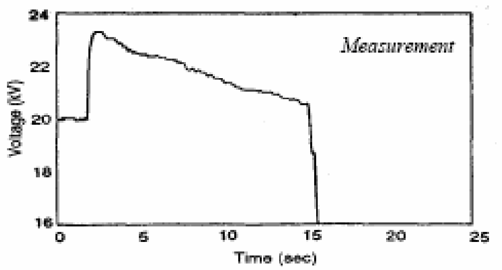


Figure 3.4. Islanded operation of a wind farm due to the self-excitation of the WT induction generators. [5]

4.0 Power limitations for wind farms operating in island systems

Wind farms operating in island systems are subject to output power limitations, related with technical constraints of the conventional generating units, namely the minimum loading levels of the thermal units (technical minima) and a dynamic penetration limit, applied for stability purposes. Evaluation of the expected wind energy yield in isolated island systems requires, therefore, proper consideration, not only of the prevailing wind conditions at the installation site, but also of the power limitations imposed by the system, which ultimately depend on the total load demand. The methodology applied in Greece for isolated island grids is presented in this section. The power restrictions are applied to existing and new wind farms, to schedule new wind capacity tenders and for the evaluation of the expected energy yield.

Islands are often characterized by significant wind potential, which would theoretically suffice to fully cover their electricity needs. For this reason, the exploitation of this potential is promoted by state and regulatory authorities, while investors and developers also express their interest, since a high yield can be guaranteed for their investment. On the other hand, island systems isolated from the mainland grid are fed by autonomous power stations, presenting a number of unique characteristics and special problems, which have been studied and documented in the last 15 years. The isolated nature of such systems results in limitations to the output of the wind farms and therefore to power curtailments during their operation, which prohibit the achievement of high wind penetration levels to fully exploit the existing wind potential. The evaluation of the expected energy yield from a wind farm is a prerequisite for the preliminary evaluation of its feasibility, for acquiring the required production permits. For wind turbines installed in the interconnected mainland system, with no constraints imposed on their operation and output power, this is a standard and straightforward procedure, requiring only a reliable assessment of the local wind potential. In the case of islands, the operation of the wind farms is subject to output power limitations, which are determined by the system load level and the conventional units in operation, and therefore vary with time. Hence, the evaluation of the expected energy production is a more complex issue, requiring the consideration of the system operation, in addition to the prevailing wind conditions at the installation site.

In most of the Greek islands, which are not interconnected to the mainland, wind generation is already installed or production permits have been granted. Scheduling of new wind capacity in these islands by the regulatory authority for energy (RAE), feasibility studies performed by the independent producers and the contracts signed between the producers and the distribution network operator (DNO), all require a fast, transparent, and reliable methodology for evaluating the energy yield of individual wind farms, as well as the absorption capability of the isolated island grids, [8].

4.1 Evaluation of energy production without operating constraints

The evaluation of the energy production of a WT operating without output power constraints (for instance a small machine, operating in a large interconnected power system) is a straightforward procedure, requiring the wind speed statistical distribution and the WT power curve:

$$E_W = T\int_0^\infty h(v)P_{PC}(v)dv = T\cdot\overline{P}_W \tag{1}$$

where $P_{PC}(v)$ is the analytical expression for the WT power curve
$h(v)$ is the probability density function of the horizontal wind speed component v at hub height
T is the integration time interval (typically 1 year=8760 h) and
$\overline{P}_W$ the average output power over the interval T

Wind statistics are usually described by the Weibull probability distribution function:

$$h(v) = \frac{k}{c}\left(\frac{v}{c}\right)^{k-1} e^{-\left(\frac{v}{c}\right)^k} \quad \text{for } 0\le v<\infty \tag{2}$$

Characteristic quantities of this distribution are the average wind speed:

$$\overline{V} = \int_0^\infty vh(v)dv = c\Gamma\left(1+\frac{1}{k}\right) \tag{3}$$

where Γ is the Gamma function and the maximum probability speed (*mode* wind speed):

$$V_{\text{mode}} = c\left(\frac{k-1}{k}\right)^{1/k} \tag{4}$$

Setting k=2, the frequently used Rayleigh distribution is obtained, for which:

$$h(v) = \frac{2}{c^2}ve^{-\left(\frac{v}{c}\right)^2} \tag{5}$$

$$\overline{V} = c\Gamma(1.5) \approx 0.9\cdot c \tag{6}$$

$$V_{\text{mode}} = \frac{1}{\sqrt{2}}c \approx 0.7\cdot c \tag{7}$$

From the theoretical energy yield, calculated from eqs. (1) or (2), the various losses are deduced, to obtain a more realistic estimate of the expected production:

$$E_{Wnet} = \eta\cdot E_W \tag{8}$$

where the aggregate “efficiency” factor η is not unusual to have values as low as 85%, since it includes the cumulative effect of a variety of factors (indicative values in parentheses):

- electrical losses along the wind farm internal and possibly the external interconnecting network (2-5%)
- availability of the wind turbines (95-98% for modern WTs)
- availability of the grid (90-98%, depending on voltage level, location etc.)
- power curve change due to icing, surface contamination, aging etc. (reduction of 1-5%)
- accuracy of the wind potential assessment at the installation site

In the case of wind farms, the total energy output is often approximated by simply multiplying the yield of one turbine by the number of machines and applying a suitable loss factor to account for wake effects and terrain irregularities within wind farms (of the order of 3-10%). In many cases, however, multiple measurements within the wind farm area in conjunction with sophisticated wind field models are utilized to obtain a more reliable estimation of wind speeds per individual wind turbine.

In the rest of this study the various losses are ignored, since their evaluation is always case specific. Nevertheless, once a specific value is available for the overall efficiency factor η, its inclusion is simple and straightforward, multiplying all energy output calculations. If one generic value were to be used, η=95% might be most appropriate.

Once the energy output estimation is available, the Capacity Factor (*CF*) can be found as

$$CF = \frac{E_W}{T \cdot P_{Wn}} = \frac{\overline{P}_W}{P_{Wn}} \tag{9}$$

where P_{Wn} is the WT or wind farm rated power. The *CF* is the single most important quantity is evaluating the feasibility of wind energy investments and may vary from as low as 20% up to 45%, for sites with very high wind speeds. Values between 30-35% are common in practice. Economically viable investments require a capacity factor definitely higher than 20%. *CF* values higher than 25% are normally required to attract investor interest, the accurate value depending always on market conditions, investment subsidization schemes etc.

4.2 Calculation of the power limitations in island systems

4.2.1 Nature of operating constraints

Wind turbines connected to isolated island grids are always subject to additional operating constraints (output power limitations), not applicable in the large interconnected systems (at least until today that the wind power penetration levels are still relatively low in mainland systems). These constraints are primarily related with the conventional thermal units and can be distinguished in two types, [8]:

A. Minimum loading levels (technical minima)

The majority of small and medium size island power systems are fed by diesel or heavy oil generating units. To avoid increased wear and maintenance requirements of the prime movers, these units are not operated below a certain threshold of their rated power, referred to as the "*technical minimum*". Hence, the output power P_D of such a unit is constrained:

$$P_{D\min} = c_T \cdot P_{Dn} \le P_D \le P_{Dn} \tag{10}$$

where c_T is the technical minimum factor and P_{Dn} the rated output power of the unit (the maximum permitted power is often used instead of the rated, especially for old units). Typical values of c_T are 30-50% for heavy oil units and 20-35% for diesel-fired units (including gas turbines), depending very much on the age and overall condition of the engine.

The active power equilibrium within the power system dictates that

$$P_D = P_L - P_W \tag{11}$$

where P_D is the total output of the conventional (diesel) units, P_W the total wind production and P_L the aggregate load demand of the system (including losses). Combining equations (10) and (113), the following constraint is deduced:

$$P_W \le P_L - \sum c_T P_{Dn} = P_{W\max}^T \tag{12}$$

where the summation is performed for all conventional units in operation.

Wind generation in island systems is often concentrated in restricted geographical regions, increasing thus the probability of an unexpected loss of the total available wind power. To avoid loss of load events in such a case, it is common practice for the system operators to maintain full spinning reserve in the conventional units, which suffices to cover the total load demand. Hence, assuming for simplicity a common technical minimum factor, c_T, for all units:

$$\sum P_{Dn} \ge P_L \Rightarrow P_{W\max}^T \le (1 - c_T) P_L \tag{13}$$

From eq. (13) it is evident that the higher the technical minimum of the conventional units, the lower the resulting wind penetration limit, $P_{W\max}^T$.

B. Dynamic penetration limit

The fluctuations of the wind farm output power are compensated by equal magnitude variations in the output of the conventional units. The larger and faster these variations are, the greater the resulting system frequency excursions. In addition, the continuous variation of the output power of the units has a detrimental effect on their operation, maintenance needs and life expectancy (which is difficult to assess and quantify). Most important, however, is that in the case of small island systems with distribution networks of a limited extent, the sudden loss of all available wind power is quite probable. This may happen due to faults along the interconnecting lines which trip the network overcurrent protection, voltage sags that exceed the ride-through capability of the wind turbines, or even due to fast increases of the wind speed, exceeding the WT cut out speed. In such cases, the conventional units already in operation are called upon to instantaneously compensate the resulting power deficit. If the wind generation loss is large, so will be the subsequent frequency excursions, which may trigger the network under-frequency protection, resulting in load curtailments, or in extreme cases leading to loss of synchronism events.

To counter this possibility, an additional "dynamic" penetration limit is enforced, quantified as:

$$P_W \leq c_D \sum P_{Dn} = P_{W\max}^D \tag{14}$$

The dynamic penetration limit factor, c_D, is a characteristic of the island system. Its values vary widely with the size of the system, the type of conventional units in operation, the dispersion of the wind generators within the system, as well as with operator practice. Typical values are around 30%, although conservative operating policies in large island systems often dictate values as low as 15%. On the other hand, limits in excess of 40% have also been occasionally applied in small islands, with no adverse consequences recorded.

4.2.2 Resulting wind power limitations

Based on the previous discussion, the constraint imposed on the total wind power injected to the system at any time is the following:

$$P_W \leq P_{W\max} = \min\left\{P_{W\max}^T, P_{W\max}^D\right\} \tag{15}$$

The individual constraints $P_{W\max}^T$ and $P_{W\max}^D$, given by eqs. (12) and (14), are time varying quantities determined from the load demand and the unit commitment algorithm/strategy applied.

The overall wind penetration limit, $P_{W\max}$, is characteristic for the isolated system. It does not depend on the installed and operating wind capacity, provided that the latter does not affect the dispatching algorithm of the conventional units. This is almost always the case in small and medium island systems, where full load spinning reserve is maintained and the power station operating policy is practically fixed.

The $P_{W\max}$ limit refers to the total installed and operating wind capacity within the island system. This limit is allocated to individual wind farms, in proportion to their rated (or contractually agreed) power:

$$P_{Wk} \leq P_{W\max,k} = \left(\frac{P_{Wn,k}}{P_{Wn,tot}}\right) P_{W\max} \tag{16}$$

where $P_{Wn,tot} = \sum_k P_{Wn,k}$ is the total wind capacity in the system and $P_{W\max,k}$ the output power limitation for wind farm *k*.

Because the limit $P_{W\max,k}$ may exceed the rated capacity $P_{Wn,k}$, the maximum output of wind farm *k* will be given by:

$$P_{W\max,k} = \min\left\{\left(\frac{P_{Wn,k}}{P_{Wn,tot}}\right) P_{W\max}, P_{Wn,k}\right\} \tag{17}$$

Realization of the aforementioned restrictions in the Greek islands is performed via the daily planning of the system operation. Based on the load forecasting and the availability of the conventional units, the output power limits for each wind farm are calculated on an hourly basis for the next 24 h and are notified in advance to the producers. The power limitations are also updated in real time (every 15 min). It is the obligation of the wind farm operators to observe the imposed output power limit during actual operation. For this purpose, power curtailments are required when wind conditions are favourable and the wind farm output power may exceed the imposed limit.
In case of pitch controlled and variable speed wind turbines, observing the restrictions is realized via proper regulation of the maximum power control inputs of the individual machines. In the case, however, of stall-controlled machines, one or more wind turbines may have to be disconnected, since it is not possible to achieve operation at partial load. To alleviate this handicap, exceeding the limit by a certain percentage is tolerated for this type of wind turbines.

4.2.3 Discussion on the methodology

The application of the methodology presented requires only the following basic data, available via the DNO and the wind farm developers:

System: Annual load probability density function
Rated capacities and dispatch order/algorithm of the conventional generators
Technical minima and dynamic penetration limit

Wind farm: Annual wind speed probability density function at the installation site
Wind turbine power curves

Given the system related data, wind power limitations are calculated for each system load level (bin) and the annual wind energy absorption capability of the system is then easily derived. Using the additional wind farm related data, an estimation of the expected wind energy yield of the specific installation is obtained.

The appeal of the method lies in its simplicity and transparency. It is a straightforward extension of the standard energy yield calculation, performed for WTs and wind farms to evaluate their energy output and capacity factor. Further, it can be easily applied by all interested parties (Regulator, DNO, developers), providing reasonably accurate estimates both of the system absorption capability and of the expected energy yield of specific wind farms.

The basic underlying assumption of the method is the statistical independence of the load and wind speed random variables. In the Greek islands, a weak negative correlation may exist between load level and wind speed, corresponding mainly to summertime intervals with high temperatures and low wind. These, however, are rather exceptional and short duration peaks, which do not affect significantly the overall (annual) energy calculations. Further, their effect is countered by the fact that the windy period in the Aegean Sea is in July and August, when the load (predominantly touristical) reaches its peak, favoring thus the absorption of wind energy.

A factor that may affect significantly the wind power limitations and hence the expected wind energy yield in island systems is the availability of the conventional generators, particularly in small islands with a limited number of diesel units. One generator going out of service may affect the whole dispatch algorithm of the power station, possibly committing units with a higher technical minimum and thus decreasing the wind energy absorption capability. The basic algorithm presented in the previous sections can be easily modified to take account of the scheduled maintenance of conventional units. The yearly period can be divided in subperiods, depending on the availability of the power station units. For each subperiod, different dispatch algorithms are used and hence different wind power limitations apply. In addition, different load and possibly wind statistics might apply (due to seasonal variations), if such data are available. The annual energy production is then equal to the sum of the subperiod energy yields.

The aforementioned methodology is applied in practice by the Greek Regulator for each island system, assuming different scenarios for the total wind power installed. For each scenario, a specific value for the overall *CF* of the island is determined, which apparently reduces as the total wind power increases. Based on these results, production license tenders for the development of new wind farm capacity are made by the Regulator, if the resulting overall *CF* for the island is greater than 27.5%, which is considered as the viability threshold for new investments.

4.2.4 Study case

Application of the methodology

The application of the methodology is illustrated through the realistic example of a small island system, with a peak load demand of approximately 5 MW, [8]. The load statistics of the system are derived from the 10 min data, recorded at the diesel power station. The total load energy demand is equal to 22,954 MWh per year.
The island is fed by a diesel power station comprising 5 diesel units, whose data are summarized in Table 4.2.4-1. In the same table, the dispatch order of the units is indicated, according to the operator practice (based on fuel consumption, maintenance requirements, age etc.). The technical minimum factor is c_T=50% for all units, whereas the dynamic penetration limit is assumed to be c_D=35%.

UNIT	MAN-1	MAN-2	MAN-3	MAN-4	CKD	Γ72
Rated power (kW)	750	750	750	750	2200	800
Technical minimum (kW)	375	375	375	375	1100	400
Fuel type	Heavy oil	Heavy oil	Heavy oil	Heavy oil	Heavy oil	Heavy oil
Dispatch order	1	2	3	4	5	6

Table 4.1. Characteristics and dispatch order of the diesel power station units

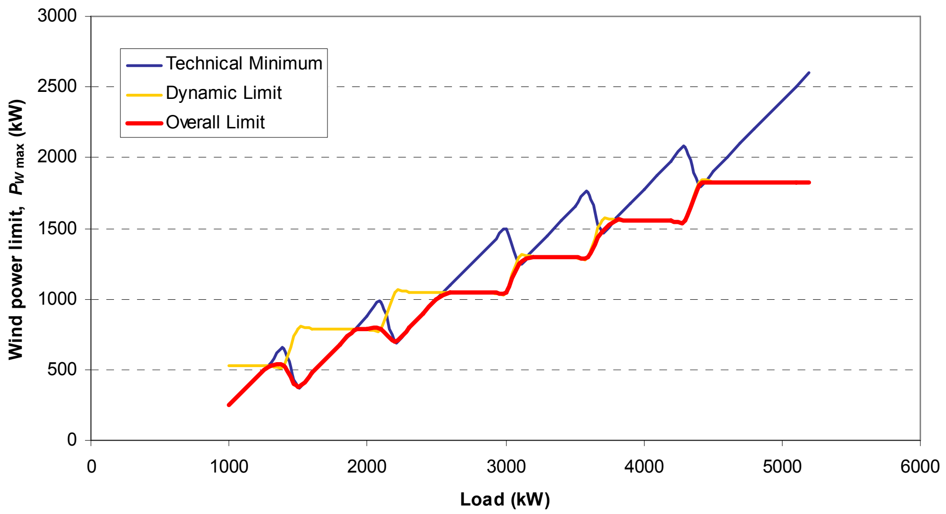


Fig. 4.1. Wind power limitations for the study case system, as a function of the load power.

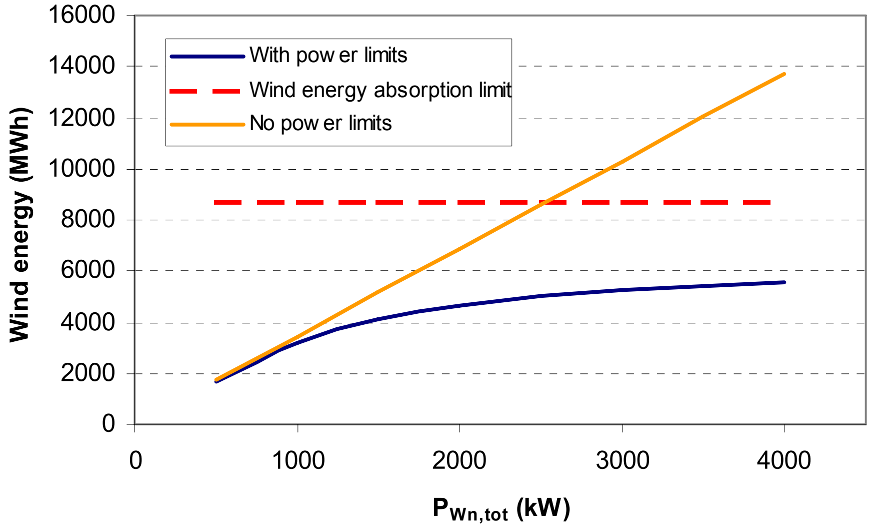


Fig. 4.2. Energy yield of the wind farm, as a function of its installed capacity.

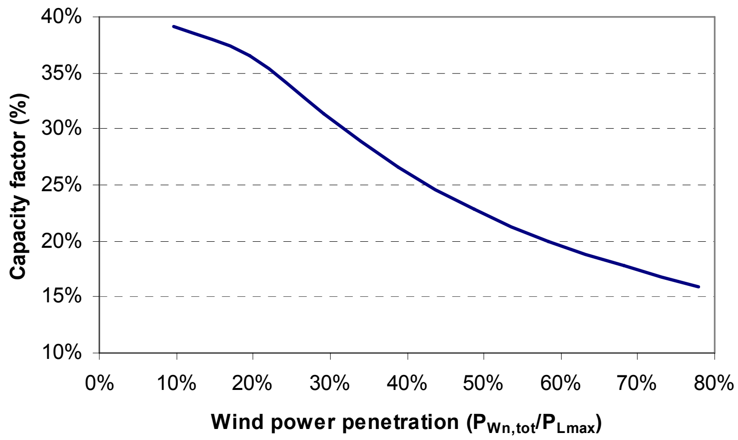


Fig. 4.3. Variation of the capacity factor with increasing wind penetration levels.

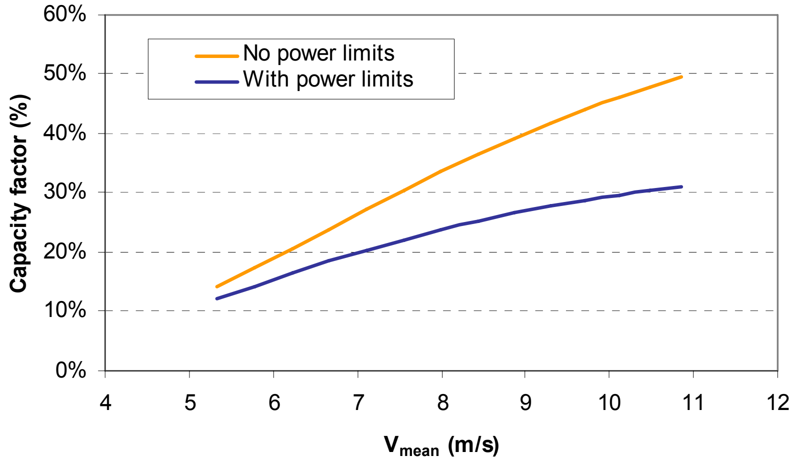
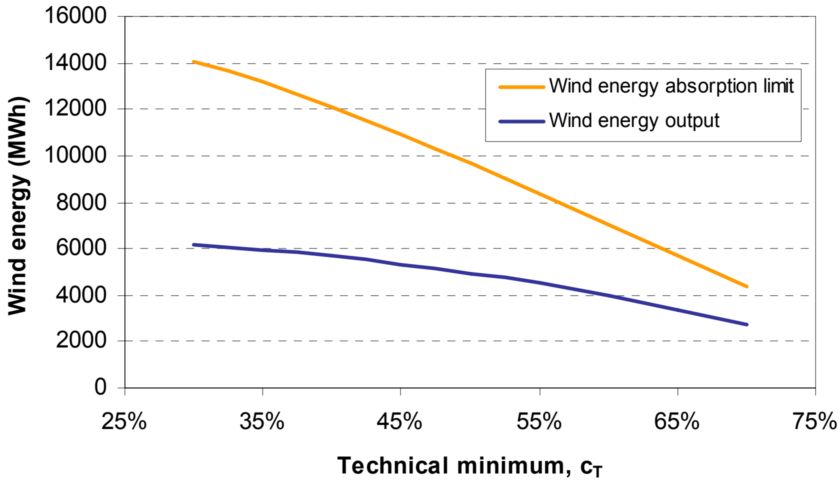
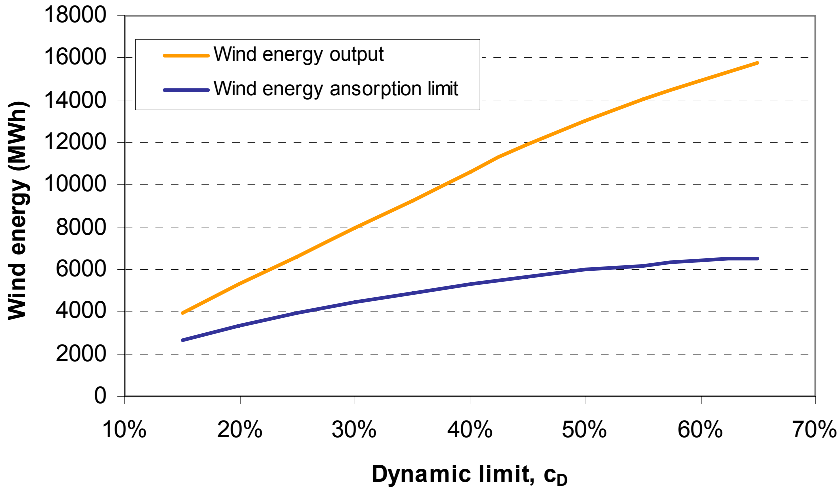


Fig. 4.4. Variation of the capacity factor with the mean annual wind speed, for wind farm operation with and without output power limitations.



(a)



(b)

Fig. 4.5. Effect of the diesel unit related constraints on the exploitation of wind energy. (a) Technical minimum factor and (b) Dynamic penetration limit.

5.0 A Technical Evaluation Framework for the Connection of Wind Turbines to the Distribution Network

In this section fundamental issues related to the interconnection of Distributed Generation (DG), focusing on wind power plants, to the grid are discussed and evaluation rules are presented, which address power quality considerations and are suitable for application by electric utility and DG engineers, [6]. The attention is focused on the steady state and fast voltage variations, flicker and harmonic emissions. The simplified evaluation procedures are largely based on the relevant IEC publications and reflect the current practice of several European utilities. A discussion of the interconnection protection requirements is also included. The requirements presented here (applicable not only in island grids but in the interconnected systems as well), refer to distributed generation in general.

5.1 Overview of Technical Requirements

The interconnection of DG sources to the grid is often regarded as a potential source of power quality disturbances and appropriate requirements and evaluation methodologies are applied. In general, they comprise two distinct stages. First, the expected disturbance is calculated at the Point of Common Coupling (PCC)[1] because of a specific DG installation. Then, suitable limits are applied to ensure that the expected disturbance level does not adversely affect other users of the network. Following the IEC 61000 definitions [9], *planning levels* are generally used as disturbance limits. Power quality phenomena taken into consideration are slow (steady-state) voltage variations, fast voltage changes, flicker and harmonic emissions.

Beyond the power quality issues, additional considerations and requirements include the following:

- Network capacity. Ratings of all network components must be sufficient to handle the power of the DG station.
- Short circuit capacity. DG source contribution should not lead to exceeding the design fault level of the network. This is issue is dealt with in more detail in [10].
- Switching and protection equipment. All DG installations are equipped with suitable interconnection protection, to enforce disconnection upon detection of abnormal grid conditions.
- Effect on network signaling systems. User equipment should not interfere with the operation of public network signaling systems (e.g. attenuate or amplify signals of the acoustic frequency ripple control systems).

5.2 Slow Voltage Variations

The statistical nature of voltage variations is recognized today and relevant norms have been issued, such as the European Norm EN 50160, [11], which imposes statistical limits, in the sense that a small probability of exceeding them is acceptable. However, checking the conformity against statistical limits at the planning stage calls for elaborate procedures, such as probabilistic load flow techniques. Such an approach is relatively difficult to apply, would require data usually unavailable in practice and completely defies the objective of simplicity and efficiency in the evaluation. For this reason, utility directives for the connection of DG adopt simpler and more straightforward procedures. The evaluation procedure presented in the following utilizes 10-min average values of the voltage and can be applied in two stages.

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

$$\varepsilon(\%) \cong \frac{100}{U_n^2}\left(R_k P_n + X_k Q_n\right) \leq 2\% \qquad (1)$$

[1] Dedicated interconnection lines are formally a part of the grid. For this reason, disturbance limits may also be enforced for the point of connection (CP) as well, albeit more lenient than for the PCC.

where P_n and Q_n are the DG rated (or maximum continuous) active and reactive powers, and $Z_k=R_k+jX_k$ the network short-circuit impedance at the PCC.
The 2% limit in eq. (1) is typical and relatively strict, since this is a “first stage” evaluation and, further, this limit is allocated to a single user, whereas the voltage level is determined by the aggregate effect of all connected consumers and generators.
In practical situations, eq. (1) will yield a voltage increase, due to the active power flow on the resistive part of the network impedance, which may be significant in case of weak grids. For this reason, slightly inductive power factor values are usually preferred (Q<0).

Since voltage variations are the aggregate effect of generating facilities and network loads, a second stage, more detailed evaluation involves load flow calculations in the network, taking into account the actual network configuration and loads. By solving the load flow for the 4 combinations of max/min load/generation, the maximum and minimum voltages, U_{max} and U_{min}, are determined for each node (usually, min load/max gen yields maximum voltages and max load/min gen minimum voltages). These voltages must then be appropriately bounded. In [12] the following requirements are set for the steady state voltage of all nodes (Fig. 5.2-1):

- The median voltage of any node k should lie within ±5% of the nominal voltage, a requirement dictated by the off-load tap changer of the MV/LV distribution transformers (±5% regulation, in steps of 2.5%):

$$0.95 \cdot U_n \le \frac{U_{\min,k} + U_{\max,k}}{2} \le 1.05 \cdot U_n \quad (2)$$

- The variation of the voltage around its median value should not exceed ±3% of the nominal, so that the LV network voltage deviations remain within ±8% (planning limit), after the median deviation is corrected by the fixed taps:

$$\frac{U_{\max,k} - U_{\min,k}}{2} \le 0.03 \cdot U_n \quad (3)$$

The requirements expressed by eqs. (2) and (3) determine the region of acceptable maximum and minimum node voltages illustrated in Fig. 5.2-1, against which the load flow results are compared.
In the four load-flow calculations proper account must be taken of the voltage regulating means of the network (OLTCs of HV/MV transformers, line voltage regulators, capacitor banks), which normally operate on time scales of 30 s-1 min or longer and therefore affect the steady-state (10-min average) values. Further, when dealing with sources with adjustable power factor (synchronous generators, PWM converters), this has to be accounted for in the load flow calculations.

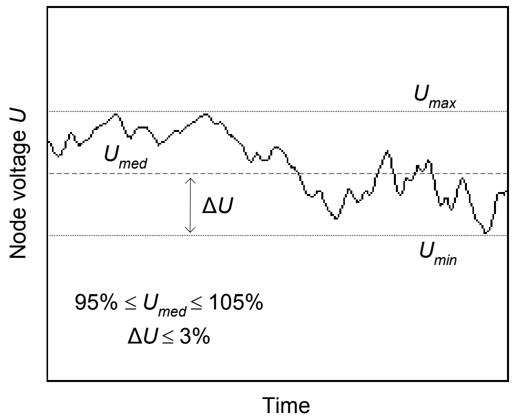


Fig. 5.1. Definition of maximum/minimum and median node voltage in steady state.

5.3 Rapid voltage changes – Flicker

Rapid voltage changes occur within the 10-min averaging interval used in the definition of *slow voltage variations*, typically on a time scale between half a period (10 ms at 50 Hz) and a few seconds. They are induced either by switching operations in the DG installation (usually start/stop operations of equipment) or by the variability of the output power during normal operation (e.g for wind turbines).

In the case of rapid voltage changes, both their magnitude and the resulting flicker emissions should be limited. Measures of the flicker emissions are the short-term, P_{st}, and long-term, P_{lt}, flicker severity indices.

Regarding switching operations, the limits imposed depend on the voltage level (LV or MV) where the installation is connected, the size of the equipment and the frequency of the operations. Taking into account the requirements of the relevant IEC documents, [13-16], the limits of Table 5.3-1 can be set for the relative (%) voltage change (see also Fig. 5.3-1).

An evaluation of the expected voltage change at the PCC at the cut-in of a DG unit is given by:

$$d_{\max}(\%) = 100 \cdot k_U(\psi_k)\frac{S_n}{S_k} \tag{4}$$

where $k_U(\psi_k)$ is the voltage change factor, defined for wind turbines in IEC 61400-21, [17], and included in their test certificates as a function of the angle ψ_k of the short-circuit impedance Z_k of the grid. Suitable values of k_U for installations with synchronous generators are discussed in [18]. For simplified calculations, k_U 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**.**

Eq. (4) is applied for the single unit in the power station, which creates the largest disturbance. Summation rules for simultaneous switchings of equipment need not be applied, due to the very low probability of coincident events.

For the case of wind turbines, flicker emissions resulting from switching operations can be calculated as ([17,19]):

$$P_{st} = \frac{18}{S_k}\left(\sum_{i=1}^{N} N_{10,i}\left(k_{f,i}(\psi_k)\cdot S_{n,i}\right)^{3.2}\right)^{1/3.2} \tag{5}$$

$$P_{lt} = \frac{8}{S_k}\left(\sum_{i=1}^{N} N_{120,i}\left(k_{f,i}(\psi_k)\cdot S_{n,i}\right)^{3.2}\right)^{1/3.2} \tag{6}$$

where N is the number of generators operating in parallel, $S_{n,i}$ the rated capacity and $k_{f,i}(\psi_k)$ the *flicker step factor* of unit *i* (defined in [17]). $N_{10,i}$ and $N_{120,i}$ are the maximum number of switching operations that can take place in a 10-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 (IEC 61000-3-3, [13], provides useful guidance), or by simulation using a software implementation of the flickermeter algorithm of IEC 61000-4-15, [20].

The following rule is commonly applied for the summation of flicker due to switching operations (used for P_{lt} as well):

$$P_{st} = \sqrt[3]{\sum_i P_{st,i}^3} \tag{7}$$

where the exponent may also be 3.2, instead of 3.0, as in eqs. (5) and (6).

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

$$P_{st} = P_{lt} = c(\psi_k, v_a)\frac{S}{S_k} \tag{8}$$

For the total flicker emissions of a wind farm comprising *N* WTs, the following relation is used:

$$P_{st} = P_{lt} = \frac{1}{S_k}\sqrt{\sum_{i=1}^{N}\left(c(\psi_k, v_a)\cdot S_{n,i}\right)^2} \tag{9}$$

where the flicker summation in normal operation is performed applying a quadratic summation rule.

Limits for flicker emissions are the same for normal operation and switchings. At the LV level, limits stipulated in IEC 61000-3-3 are $P_{st} \leq 1$ and $P_{lt} \leq 0.65$. At the MV level, the determination of limits is left to the utilities, which set the *planning levels* for their grids. Indicative values for planning levels in MV systems, according to IEC 61000-3-7, are $P_{st} \leq 0.9$ and $P_{lt} \leq 0.7$. The allocation of these global limits to individual installations is made according to the principles presented in the next section for harmonics (equations similar to (10) and (12) are applied).

		Frequency of switching operations, *r* (h^{-1}: *per hour,* d^{-1}: *per day)*		
LV		$r > 1\ h^{-1}$	$2\ d^{-1} < r < 1\ h^{-1}$	$r < 2\ d^{-1}$
LV	Steady-state change, d_c	≤ 3 %		
LV	Maximum change, d_{max}	≤ 4 %	≤ 5.5 %	≤ 7 %
MV		$r > 10\ h^{-1}$	$1\ h^{-1} < r \leq 10\ h^{-1}$	$r \leq 1\ h^{-1}$
MV	Steady-state change, d_c	-		
MV	Maximum change, d_{max}	≤ 2 %	≤ 3 %	≤ 4 %

Table 5.1. Magnitude limits for rapid voltage changes.

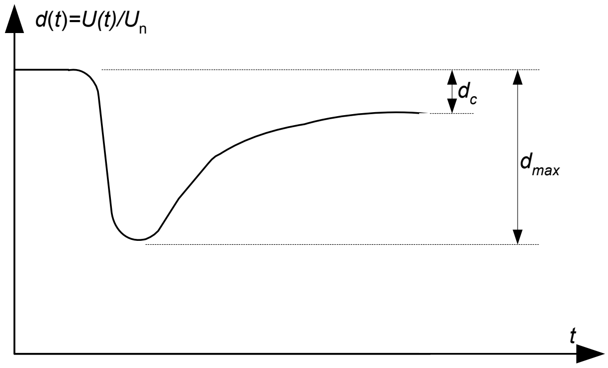


Figure 5.2. Fast voltage change pattern and characteristics.

5.4 Harmonics

The increasing use of power electronics at the front end of many DG types, e.g. variable speed WTs, poses harmonic control requirements for their connection to the grid. Several national and international standards and recommendations are available today (e.g. [21-24]), to elaborate appropriate evaluation procedures. In this section, an approach based on the IEC set of standards is presented, which comprises three basic steps: First, the definition of acceptable voltage distortion limits (planning levels), second, the allocation of global harmonic voltage limits to individual users (producers or consumers) and third, the determination of the corresponding current distortion limits for a specific installation.

For LV systems specific compatibility levels are given in IEC 61000-2-2, [25], which also serve as planning levels, and are included in Table 5.2. At higher voltage levels (MV and HV), 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 5.3-1 summarizes indicative planning levels from IEC 61000-3-6.

Odd harmonics ≠3k				Odd harmonics = 3k				Even harmonics			
Order h	Harmonic voltage (%)			Order h	Harmonic voltage (%)			Order h	Harmonic voltage (%)		
	LV	MV	HV		LV	MV	HV		LV	MV	HV
5	6	5	2	3	5	4	2	2	2	1.6	1.5
7	5	4	2	9	1.5	1.2	1	4	1	1	1
11	3.5	3	1.5	15	0.3	0.3	0.3	6	0.5	0.5	0.5
13	3	2.5	1.5	21	0.2	0.2	0.2	8	0.5	0.4	0.4
17	2	1.6	1	>21	0.2	0.2	0.2	10	0.5	0.4	0.4
19	1.5	1.2	1					12	0.2	0.2	0.2
23	1.5	1.2	0.7					>12	0.2	0.2	0.2
25	1.5	1.2	0.7								
>25	$0.2+1.3\cdot\left(\frac{25}{h}\right)$	$0.2+0.5\cdot\left(\frac{25}{h}\right)$	$0.2+0.5\cdot\left(\frac{25}{h}\right)$								
THD: 8 % at LV, 6.5 % at MV, 3% at HV											

Table 5.2. Planning levels for LV, MV and HV networks (IEC 61000-3-6, [24])

5.5 MV systems

The coordination of harmonic emission control at the different voltage levels (LV, MV and HV) of a power system requires that distortion transmitted from one level to another be taken into account. Hence, the distortion limit G_{hMV}, available to all installations connected to the MV system, is ([24]):

$$G_{hMV} = \sqrt[a]{L_{hMV}^{a} - \left(T_{hHM} \cdot L_{hHV}\right)^{a}} \qquad (10)$$

where L_{hMV} and L_{hHV} are the MV and HV planning levels for harmonic order h (from Table 2) and T_{hHM} the harmonic transfer coefficient from HV to MV level (ranging from below 1.0 to more than 3.0). a is the exponent of the harmonic summation rule:

$$U_h = \sqrt[a]{\sum_i U_{hi}^{a}} \text{ or } I_h = \sqrt[a]{\sum_i I_{hi}^{a}} \qquad (11)$$

IEC 61000-3-6 suggests a=1 for h<5, a=1.4 for 5≤h≤10 and a=2 for h>10, since harmonics of higher orders 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, $S_{n,i}$:

$$E_{Uhi} = G_{hMV}\sqrt[a]{\frac{S_{n,i}}{S_t}} = G_{hMV}\sqrt[a]{s_i} \qquad (12)$$

where S_t is the «total capacity» of the network (e.g. equal to the rated MVA of the feeding transformer). S_t can also be interpreted as the total capacity of the *distorting* equipment in the network, to avoid over-pessimistic results.

It is common practice in harmonic studies to regard the connected equipment as a harmonic current source (although this may not be correct in certain cases, e.g voltage controlled converters), 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:

$$U_{hi} = Z_h \cdot I_{hi} \le E_{Uhi} \Rightarrow I_{hi} \le E_{Ihi} = \frac{E_{Uhi}}{Z_h} \qquad (13)$$

where U_{hi} and I_{hi} are the h-order harmonic distortion of the voltage and current due to installation i and E_{Uhi}, E_{Ihi} the respective limits allocated to this installation.

For MV systems no standardized reference impedance is available and the harmonic impedance Z_h has to be evaluated for each specific network. For a purely inductive system (no shunt capacitance):

$$Z_h \approx h \cdot X_k \tag{14}$$

where the fundamental frequency inductive component X_k of the short circuit impedance at the PCC is evaluated from:

$$X_k = \frac{U_n^2 \sin \psi_k}{S_k} \tag{15}$$

However, since this is not a realistic assumption, a simplified approach can be established ([24]) with reference to Fig. 5.4-1, where all network capacitance is aggregated at the MV busbars and any possible resonance in the HV system is ignored. The capacitance in Fig. 5.4-1 accounts for the first order parallel resonance with the upstream system (but not for possible higher order resonances). If all resistances and system loads in Fig. 5.4-1 are ignored, the resonant frequency f_r and the respective harmonic order h_r (not necessarily an integer) are given by

$$f_r = f_1 \sqrt{\frac{S_{kS}}{Q_c}} \Rightarrow h_r = \frac{f_r}{f_1} = \sqrt{\frac{S_{kS}}{Q_c}} \tag{16}$$

where S_{kS} is the short circuit capacity at the MV busbars of the HV/MV substation and Q_c is the total capacitive reactive power of the MV network. A rough and conservative estimation of Z_h is then given by the "envelope impedance curve" of IEC 61000-3-6, shown in Fig. 5.4-2. The resonant amplification factor, k_r, 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 load. For installations with filters or significant PFC capacitance, in more complex networks or when resonant conditions exist in the HV network, the approach presented above is not suitable. Manual computation of Z_h is possible in certain cases but the application of harmonic load flow software is recommended.

The procedure described, although heavily simplified by research standards, may already be complicated enough for application in practical situations. To further facilitate the evaluation of low distortion equipment at the MV level, without resorting to the procedure described above, a "Stage 1" requirement may be formulated. Using eqs. (13)-(15) and the definition of the resonant amplification factor, k_r, from Fig. 5.4-2, it is derived:

$$U_{hi} \approx k_r \cdot h \cdot \frac{U_n^2}{S_k} \cdot \sin \psi_k \cdot I_{hi} \leq E_{Uhi} \tag{17}$$

For the "Stage 1" evaluation, a conservative approach is adopted. The resistive part of Z_k is ignored ($\sin\psi_k$=1) and the limit E_{Uhi} is deduced from the planning levels L_{hMV} (or G_{hMV}) in proportion to the ratio s_i (a=1 in eq. (12)). Then, from eq. (17):

$$\frac{I_{hi} / s_i}{S_k} \leq \frac{L_{hMV}}{k_r \cdot h \cdot U_n^2} = M_{hMV} \Rightarrow \frac{I_{hi}}{s_i} \leq M_{hMV} \cdot S_k \tag{18}$$

The limit M_{hMV} in eq. (18), expressed in A/MVA, is then directly evaluated using the nominal voltage of the network and assuming an appropriate value for k_r (k_r=5 would be a conservative approach). If eq.(18) is not satisfied, a more detailed evaluation has to be conducted, as discussed previously.

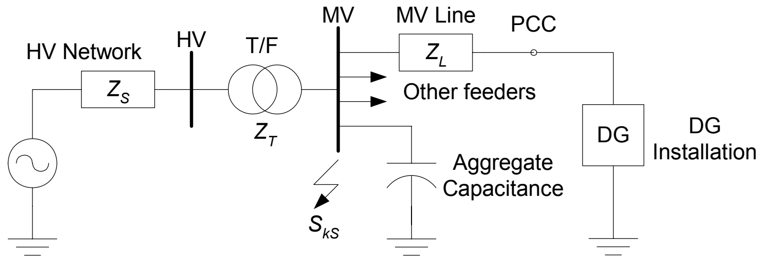


Figure 5.3. MV network equivalent for simplified harmonic analysis ([24]).

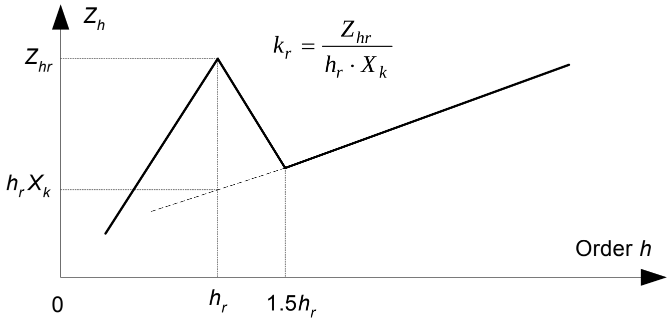


Figure 5.4. System harmonic impedance approximation, using the «envelope impedance curve» ([24]).

5.6 LV systems

The principles outlined in the previous section for MV systems are also applicable to the LV level. However, for LV systems IEC 725, [26], establishes a reference system impedance, permitting thus the direct determination of harmonic current limits. IEC 61000-3-2 provides limits for equipment with rated current ≤ 16 A/phase (Class A). For DG units with rated current between 16 and 75 A/phase, the limits of IEC 61000-3-4 are applicable, when connected to a PCC where the short circuit ratio is higher than 33. For DG installations with rated current higher than 75 A per phase, the Stage 1 evaluation procedure used for MV installations (eq. (18)) can be applied, using as emission limit:

$$I_h \leq M_{hLV} \cdot \frac{S_k}{\sin\psi_k} \qquad (19)$$

where M_{hLV} is the harmonic current limit per MVA of S_k. ψ_k is taken into account, because of the predominantly resistive character of the LV networks. M_{hLV} values can be derived based on eq. (18).

5.7 Interharmonics and higher order harmonics

The evaluation procedures outlined above cater for harmonic orders $h \leq 40$ (IEEE Std. 519, [32], provides limits up to the 50^{th} order), which is sufficient for line-commutated converters, as well as for voltage-source converters with a low switching frequency. However, the increasing utilization of fast switching PWM converters has extended the harmonic frequency spectrum well beyond 2 kHz, where limits and standardized evaluation methodologies are still unavailable. Due to the lack of relevant standards and experience in this range, a conservative approach is often adopted. A strict limit is set on the voltage distortion due to higher order and interharmonic components:

$$U_h \leq 0.2\ \%, \ h > 40 \text{ or } h \text{ non-integer}$$

which is in line with the interharmonics planning level suggested in IEC 61000-3-6.

An issue related to harmonics is also the possible interference of DG installations with mains signaling, such as ripple control systems. Such systems usually operate in the range 100 to 500

Hz (up to 2-3 kHz) by injecting a voltage signal of higher frequency on the power frequency voltage waveform. To ensure no interference, the injection of harmonics or interharmonics from the DG installations should be minimized at the ripple control frequency and its sidebands at frequencies differing by twice the fundamental frequency.

5.8 Interconnection Protection Requirements

The DG-utility interface protection is primarily intended to ensure the safety of other users of the network and of utility personnel and it should be properly coordinated with other protections of the grid. The protective functions incorporated therein may differ considerably, depending on the size, voltage level, type of DG equipment and the operation and protection scheme of the network. A comprehensive overview for small DG stations is provided in [27].

The primary function of the interconnection protection (besides fault detection via overcurrent relays) has always been the detection of islanding situations and the immediate disconnection of the generating equipment. In case of DG installations utilizing synchronous generators, islanding is a serious concern. If induction generators are used, the possibility of self-excited operation exists and such situations have been encountered in practice. An example is shown in Fig. 7, recorded on the Greek island of Chios, where about 5 MW of wind power are connected to a 20 kV line, which includes a 20 km section of submarine cable, [28]. The opening of the feeder circuit breaker resulted in a voltage swell in the isolated part, sustained for about 15 sec (the WT over-voltage protection was set high, due to the high normal operation voltage).

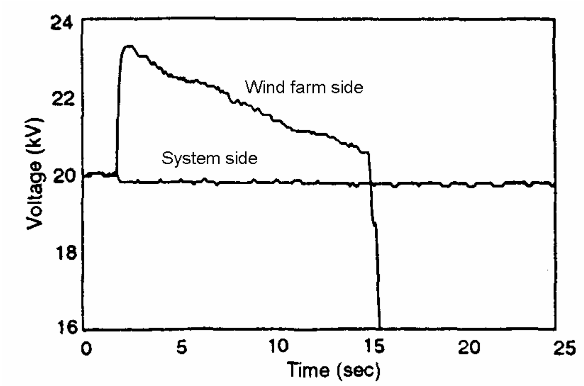


Figure 5.5. Recorded voltage during the isolated operation of a feeder with significant wind power, following the opening of the circuit breaker at its departure ([28]).

Typical minimum protective functions of the interconnection protection system are over-/under-voltage and over-/under-frequency, as shown in Fig.5.7-2. Zero-sequence (residual) voltage relays are also stipulated in many cases (depending on the MV network neutral earthing arrangements and step-up transformer connections). In Table 5.7-1, two groups of indicative relay settings (Type A and Type B) are provided and discussed in the following.

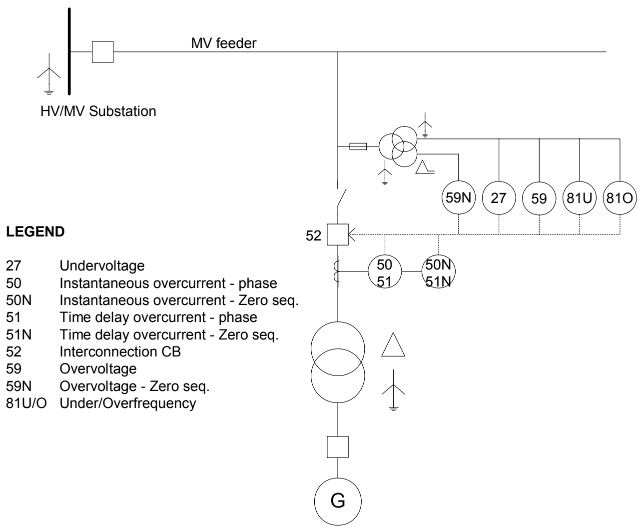


Figure 5.6. Basic functions of the interconnection protection system.

Relay	Settings Type A		Settings Type B	
	Threshold	Delay	Threshold	Delay
27	$0.85 \cdot U_n$	0.3 s	$0.80 \cdot U_n$	1.2 s
59	$1.10 \cdot U_n$	0.3 s	$1.15 \cdot U_n$	1.2 s
81U	49.5 Hz	0.3 s	47.5 Hz	1.2 s
81O	50.5 Hz	0.3 s	51.5 Hz	1.2 s

Table 5.7. Indicative settings for the interconnection protection relays.

Strict settings are needed in the voltage and frequency protection, to achieve sensitive islanding detection, as well as fast disconnection of DG sources in lines with fast reclosing schemes (ensuring disconnection before reclosing, to prevent unacceptable stresses, [29]). These requirements are fulfilled by the settings Type A in Table 5.7-1. The 0.3 s activation time is short enough to ensure disconnection before the first reclosing of the feeder breaker (approximately 0.5 s after initiation of the fault). At the same time, it is also long enough to avoid tripping by voltage dips due to faults on adjacent feeders, cleared in the first reclosing cycle (with instantaneous overcurrent relays, dips last approximately 0.1-0.15 s). Transfer-trip schemes can also be used between the line and the DG breaker, a solution considered for relatively large installations.

Fast activation times, however, lead to increased “nuisance” trips of the DG station, which may pose a threat to the stability of systems with high levels of DG penetration. In such cases, maintaining generation capacity in operation during critical disturbances takes precedence over other considerations, leading to the adoption of less sensitive protection settings. The Type B settings in Table 5.7-1, applicable for DG stations connected to the MV network of island grids, ensure adequate ride-through for voltage sags due to faults cleared by inverse-time overcurrent relays of the feeder breakers. They are also much less sensitive to temporary voltage and frequency excursions, common in small isolated power systems.

Besides adopting less sensitive protection settings, to maintain generation capacity in operation during critical disturbances, imposes also requirements for the fault ride-through capability of DG units. A characteristic example is the requirement first imposed by the German utility E.ON. to all large wind farms connected to its system, that their generators should ride through all voltage sags lying above the magnitude-duration characteristic of Fig. 9, [30,31].

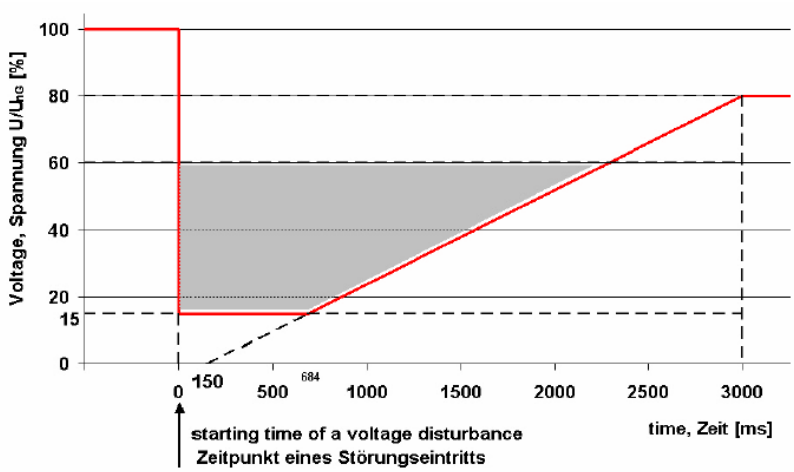


Figure 5.8. Voltage sag immunity requirements imposed to large wind farms by a German utility (E.ON. Netz GmbH, [30]).

In addition, in all countries experiencing high DG penetrations (mainly wind power), the grid codes now impose strict requirements on all stations connected to the grid (initially only for HV level installations, now gradually for the MV level as well), in order to assure that they actively assist the grid, by properly regulating their output active and reactive power, both in normal operation and during contingencies [32]. For such requirements to be met, the design of the DG units themselves has to be revised (fast action of pitch controllers, moderate over-speed allowance, possibly incorporation of storage at the DC-link, installation of SVCs at the generator terminals for conventional induction generators etc.). For small island grids specific fault ride-through requirements should be imposed, due to the restricted scale of those grids.
At present, this discussion is relevant for large DG installations connected to the HV and MV level. In the case of LV installations, the functional requirements for the utility interface concentrate mostly on the islanding detection, which in general is the responsibility of the manufacturer to provide as an integrated part of the equipment. The protection functions of LV DG equipment will be heavily revised in the medium- or long-term, due to the increasing momentum of the "Microgrid" concept, i.e. the possibility for parts of LV networks with sufficient distributed generation to intentionally isolate and operate autonomously from the main grid ([33-35]).

Technical requirements and assessment criteria were presented for power quality related issues, including steady state and rapid voltage variations, flicker and harmonic emissions, which are suitable for practical application. These criteria and procedures are largely based on the set of relevant IEC publications, as well as on current utility practice.
It is certain that the technological advancements will call for continuous update of the evaluation methodologies. For instance, active front-end converters, with load balancing, flicker cancellation and active filtering capabilities, may soon find their way into commercial DG equipment. The operating paradigm of distribution networks with significant DG resources will also evolve, towards an "active" network principle. Further, apart from the core technical issues, it is also certain that other market and regulatory factors will affect critically the degree of future DG penetration and the criteria and requirements for their integration.

6.0 Conclusions – further work

In order to increase the penetration in the island grids there are some small and some large scale interventions that can be done. On the wind-farm level, voltage support facilities must be provided at the existing wind farms in addition to upgraded grid connections. When talking about new wind-farms, one should consider the effect of geo-diversity and also more grid friendly wind turbines. On the system level, first of all strengthening the system is vital as well as taking into consideration the spinning reserve. Moreover, supportive infrastructures should be provided like the SCADA system, a well prepare Grid Code, highly qualified personnel in Dispatch Center, and sophisticated software tools, like the MORE CARE EMS software. Toward increasing penetration, the designer should also study the option of energy storage systems like pump storage systems, flying wheels, compressed air, and batteries. Of course the interconnection with the mainland system always remains a possibility.

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