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Steady-State Assessment of the DG Impact on Voltage Control and Loss Allocation

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1. Introduction

The introduction of distributed generation (DG) affects the operational characteristics of the distribution systems. The impact depends on the level of penetration of DG, as well as on the possibility of operating significant portions of the distribution system as micro-grids, or to allow temporary operation of intentional islands.

In the electrical sector, the major changes occurred in the last two decades led to modify the structure of the electricity business from a vertically integrated utility (VIU) system, in which the four major functions of the electrical chain (that is, generation, transmission, distribution and retail) were operated by the same company, to an unbundled system in which these functions are separated and are performed by different companies.

One of the main effects of unbundling has been the decoupling of the function of generator with respect to the one of the distribution network operator (DNO). A plurality of local generators connected to the today's distribution systems are owned and managed independently of the DNO. The objectives themselves at the local generation site management may differ from the ones of the DNO. More specifically:

- at the local generation site, the main goals are to provide energy to the local users, to sell excess electricity to the grid when the electricity price makes it convenient, and to reduce the internal losses;
- the DNO's main objectives are to run the distribution system in a reliable, safe and secure way, without exceeding the operational limits on voltages and currents, maintaining reduced losses and satisfactorily high power quality levels;
- emerging options include the role of energy service companies or organised consortia in managing local generators located at different points in the networks in an integrated way, mainly for economic purposes, or the comprehensive management of portions of the networks with generators and loads as micro-grids.

This chapter illustrates and discusses some specific aspects concerning voltage control, reactive power support and loss allocation. Other operational issues such as short-circuit capability and protection, DG dynamics, possible DG contribution to ancillary services, reliability and power quality, interactions with heat/cooling equipment, storage units and other components, and the economics of DG operation, are not addressed here.

2. Voltage control and reactive power support

2.1. General aspects

The increased presence of DG calls for revisiting the current distribution system operation practices (Borbely & Kreider, 2001; Pepermans et al., 2005). The time and spatial variation of generation and loads and the contribution of different types of voltage-controllable local generators to distribution system voltage control need to be addressed under a comprehensive approach. This section recalls the characteristics and modelling of the voltage controllers, including the standard voltage controller and the modified combined voltage/reactive power controller for synchronous machines, the grid interconnection through induction generators, and different types of static converter-interfaced DG. Furthermore, this section illustrates and discusses the general formulation of the voltage control as an optimisation problem, by using an objective function based on the voltage deviations with respect to given voltage references, taking into account methods and variants proposed in the literature. Specific aspects include the conceptual challenges of voltage control with DG and the discussion on the peculiarities of voltage control in urban and rural areas.

In traditional distribution systems, without DG, the voltage variations at the network nodes are mainly due to the evolution of the voltage at the supply side or to load variations. For a MV distribution system, voltage control is typically centralized at the HV/MV supply substation level, with voltage controller with load compensation, which drives the under-load tap changer (ULTC) of the substation transformer, and with possible power factor correction capacitors connected at the MV busbars. Under this type of control, if all the network loads are passive and of resistive-inductive type, the active and reactive power flows in the network branches are typically unidirectional from the supply node to the loads, and the voltage profile is decreasing in each path starting from the supply node to reach a terminal node. The presence of a significant amount of local power factor correction capacitors at some network nodes could reverse the direction of the reactive power flows in some network branches, but the voltage profile in the distribution system normally remains decreasing from the supply node the terminal nodes, with the exception of very particular cases with branches supplying highly capacitive loads. For decreasing voltage profiles, voltage control can be set up at centralized level on the basis of the study of reference cases for the distribution network with maximum and minimum loading levels.

The inclusion of DG in a radial distribution system could change the situation (Hadjsaid et al., 1999). A low/moderate amount of local generation reduces the net amount of local load, without changing the direction of the power flow, and this reflects in improving the voltage profile. Yet, an increasing amount of local generation may change the direction of the power flow in the line connecting the local generator, and in other distribution system branches. In the branches in which the power flow has been reverted, the voltage rises rather than dropping, leading in general to a voltage profile in the network non-monotonically decreasing. Voltage rise has then to be considered as a specific issue (Section 2.5).

For voltage control purposes, a relevant factor is the X/R ratio between the series parameters of the system branches. Local voltage control is more effective when the X/R ratio is high, such as in aerial lines. For instance, considering aerial lines with series reactance X_A and resistance R_A, and cable lines with corresponding X_C and R_C parameters, indicatively $X_A \sim 4 X_C$ and $R_A << R_C$.

Furthermore, local voltage control is more effective in rural than in urban distribution systems. In fact, in *rural* distribution systems the network is weaker than in urban areas, with lower short-circuit capacity, the lines are mainly aerial and relatively long, and potentially large customers could be located far from the HV/MV substation. This leads to relatively large variations in the voltage profile and high sensitivity to power quality aspects. On these considerations, exploiting local voltage control could be useful to alleviate the effects on the voltage variations, but voltage controllability is limited by the reactive power capabilities of the local generators (Section 2.3.2). Conversely, *urban* distribution systems are typically robust, with relatively short lines (mainly cables) and voltage control prevailing from the HV/MV substations. This makes local voltage control generally not efficient when the size of the local generator is much smaller than the short circuit power of the supply grid.
The specific objectives of the local DG units connected to the grid are of different types, (Vovos et al., 2007) including:

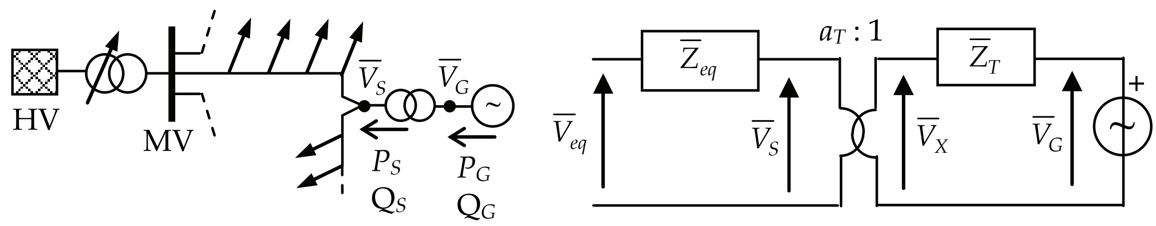
- *Participation in voltage control*: this is the basic requirement in transmission system operation, where primary and/or secondary voltage control are of concern. Similar possibilities for coordinated control are now emerging also in distribution systems with multiple distributed generators, in the light of possible operation as virtual power plants (Pudjianto et al., 2007) or as parts of micro-grids (Nikkhajoei & Lasseter, 2009).
- *Fixed power factor operation*: maintaining the power factor (seen at the network side) at a given value corresponds to consider the local generator as a negative load, with no participation in voltage control. The power factor value depends on possible needs for reactive support provision (in the point of view of the DNO), while power factor close to unity is typically preferred by the operator managing the local unit, because of the corresponding reduction of the internal losses.

However, since the local generation units are generally owned and managed independently of each other, there is little or no coordination of the local generators with the centralized distribution system controls. The objectives of managing the local units (maximization of efficiency and profitability of the local system) could be to some extent conflicting with those of the distributor (system losses minimization or voltage support optimization).
In the presence of DG, generation and load patterns exhibit variability in time and space, leading to various operating conditions, whose range of variation cannot be simply synthesised on the basis of reference cases with maximum and minimum loading levels. Moreover, the output from some DG sources (such as wind and photovoltaic systems) depends on random parameters, making it necessary to extend the tools used for evaluating the voltage profiles to the use of probabilistic power flow calculation techniques.

2.2. The distribution system seen from the local generator terminals

2.2.1. External characteristics at the network connection node

The main concepts are illustrated with reference to a single local generator with transformer connected to the MV distribution network. Fig. 1 shows the network structure and the local system model.



a) network structure b) local system model

Fig. 1. Model of the local generator and its connecting transformer.

For a radial network, the equivalent impedance $\overline{Z}_{eq} = R_{eq} + jX_{eq}$ indicated in Fig. 1 can be approximated in different ways. For relatively fast variations, namely, faster than the response of the automatic voltage regulator (AVR) acting on the tap changer of the HV/MV substation transformer, the equivalent impedance includes the HV/MV transformer impedance $\overline{Z}_H = R_H + jX_H$, and the sum $\overline{Z}_{line} = R_{line} + jX_{line}$ of the line impedances between the MV terminals of the HV/MV transformed and the MV side of the local generation site, thus obtaining $\overline{Z}_{eq} = \overline{Z}_H + \overline{Z}_{line}$. For relatively slow variations, the AVR acting on the tap changer moves the voltage controlled point to the MV busbars of the HV/MV substation transformer, and the equivalent impedance includes only the line impedance $\overline{Z}_{line}$.

In order to get a significant voltage variation, the reactance X_{eq} has to be relatively high, that is, the grid should be relatively weak to get the grid voltage affected by the voltage control of the local generator. Conversely, low X_{eq} values require high reactive generation capability by the DG unit in order to provide adequate voltage control, otherwise the generator operates at its reactive power limits (see Section 2.3.2) and under these conditions loses the possibility of playing a role in voltage control.

The external system seen from the local generator terminals can be represented by its *external characteristic* on a plane with axis given by the reactive power generation Q_G and the voltage at the generator terminals V_G, for a generator producing a specified value of active power P_G and current $\bar{I}_G$, taking into account the impedance $\overline{Z}_T = R_T + jX_T$ of the transformer connecting the local generator to the grid. The network side is represented by the voltage $\overline{V}_S$ and by the current $\bar{I}_S$ injected into the grid. The transformation ratio is $a_T = I_G / I_S$. The basic equations to be considered are the active and reactive power balances

$$P_S = P_G - R_T I_G^2 \tag{1}$$

$$Q_S = Q_G - X_T I_G^2 \tag{2}$$

and the expressions related to the definition of the apparent power

$$V_G^2 I_G^2 = P_G^2 + Q_G^2 \tag{3}$$

$$V_S^2 I_S^2 = P_S^2 + Q_S^2 \tag{4}$$

By elaborating these expressions, the external characteristic on the $V_G(Q_G)$ plane is represented as a family of curves depending on the voltage magnitude V_S at the grid side. The general formulation of the external characteristic is

$$Q_G = \frac{X_T V_G^2}{Z_T^2} - \sqrt{\frac{V_G^2 V_S^2}{a_T^2 Z_T^2} - P_G^2 + 2\frac{R_T V_G^2}{Z_T^2} P_G - \frac{R_T^2 V_G^4}{Z_T^4}} \quad (5)$$

For a generation systems with given parameters, the shape of the curves depends on the active power generation P_G. Typically, the curves exhibit a nearly-linear shape. Fig. 2 shows the family of curves obtained for a 500 kVA transformer by assuming 1 MVA as base power, with R_T = 0.024 p.u., X_T = 0.1176 p.u., a_T = 1.0 and P_G = 0.4 p.u., for a set of values of the curve parameter V_S. For instance, considering null reactive power generation the voltage magnitude V_G to be imposed at the generator terminals to get a given voltage magnitude V_S is higher than V_S, because of the needed compensation of the voltage drop occurring on the transformer series impedance in the generation of the active power P_G.

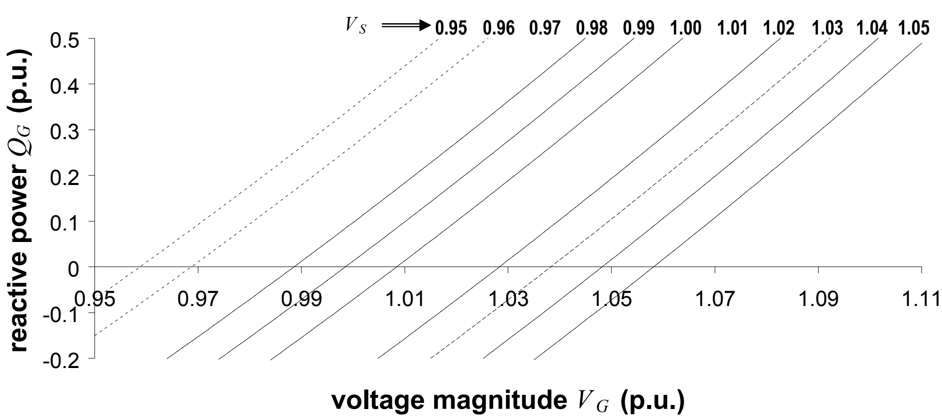


Fig. 2. Family of curves representing the external characteristic seen from the local generator terminals.

Equation (5) can also be used to update the reactive power Q_G (and the voltage V_G, if the reactive power limits are violated) during the iterative process of the backward-forward sweep algorithm (Carpaneto et al., 2008b).

2.3. Connection of synchronous generators to the grid

2.3.1. Transformer-based network connection

Local synchronous generators are used in applications like hydro power units. The traditional solution used in the VIU system to connect the local generators to the grid adopts a single transformer with fixed transformation ratio a_T. The value of the transformation ratio a_T depends on the transformer short-circuit impedance X_T and on the nominal power factor of the generator, in order to make it possible the injection in the grid of the nominal reactive power at nominal voltage. From the circuit in Fig. 1, the link among voltages and reactive power generation is expressed in an approximated form as

$$V_G = \frac{V_S}{a_T} + a_T X_T \frac{Q_G}{V_S} \tag{6}$$

The expression (6) clearly shows the strong coupling between the reactive power Q_G and the generator voltage magnitude V_G. Decoupling between Q_G and V_G can be enhanced by making the transformation ratio a_T variable, by means of a tap changer-under load (TCUL). The TCUL provides better operational flexibility at the expense of increased investment and operational costs.

2.3.2. Voltage controllers and reactive power limits

Different types of *voltage controllers* can be used to act on the local generator:

1. A *standard* voltage controller operating in *voltage-support* mode. The voltage magnitude at the generator terminals can be maintained at the predefined value until the excitation limits of the synchronous machine are reached. The excitation limits depend on the excitation current, but at first approximation it is possible to consider constant reactive power generation limits, with minimum value $Q_G^{\min}$ and maximum value $Q_G^{\max}$. The reactive power limit $Q_G^{\min}$ is usually time-independent (stability limit), while the limit $Q_G^{\max}$ is time-inverse (rotor thermal limit). When the local generator operates at its reactive power limits, the generator voltage is imposed by the network, taking into account the transformation ratio and impedance of the local transformer. The local generator at its terminals is modelled as a classical PV generator with reactive power limits. Fig. 3 shows the PV controller characteristic for a 500 kVA generator with reactive power generation limits $Q_G^{\min}$ = -0.125 p.u., $Q_G^{\max}$ = 0.3 p.u., and a voltage control range extended from 0.98 p.u. to 1.02 p.u., with reference value V_R = 1 p.u..

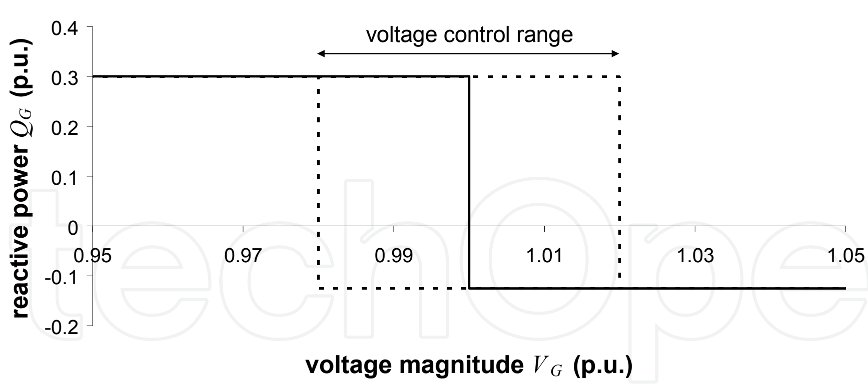


Fig. 3. PV voltage controller with reactive power generation limits.

2. A *combined voltage and reactive power controller* (CVQC, Carpaneto et al., 2004). The static characteristic of this type of controller differs with respect to the voltage-support type controller, as the CVQC introduces an additional *voltage-following* band. The local generator with CVQC can operate in the voltage-following mode at given (e.g., unity) power factor when the voltage at its terminals falls within the range from $V_G^{\min}$ to $V_G^{\max}$. In this voltage range, operation of the local generator and of its transformer can

be enhanced by keeping the control at null reactive power, with the effect of reducing the power losses in the local generator-transformer unit. In the other parts of the characteristic, the excitation control holds the generator voltage at the corresponding voltage value, until the reactive power limits are reached. Exploiting the CVQC guarantees then a good compromise between the needs of fixed reactive power/voltage control and the system generator requirements for limiting the internal losses. Fig. 4 shows an example of the CVQC characteristic for a 500 kVA generator with reactive power generation limits $Q_G^{\min}$ = -0.125 p.u., $Q_G^{\max}$ = 0.3 p.u., and two voltage control ranges extended from 0.96 p.u. to 1.0 p.u. (regulated at V_R^{low} = 0.99 p.u.) and from 1.0 p.u. to 1.04 p.u. (regulated at V_R^{high} = 1.02 p.u.), respectively.

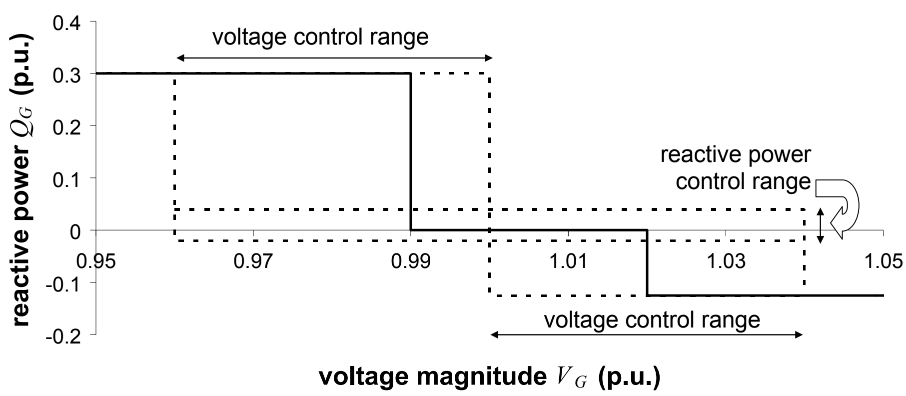


Fig. 4. CVQC voltage controller with limits and external characteristics.

In the CVQC case, the *transition* from the voltage-following to the voltage-support control mode is practically driven by the network-side voltage, by properly choosing the regulated values V_R^{low} and V_R^{high} and of the tap position of the local transformer. When the local generator operates at *unity power factor*, the generator output current and the voltage drop on the transformer connecting the local generator to the network are relatively low, at the benefit of the local system. The proposed regulator automatically guarantees its *participation* to the system voltage control only when the network voltage tends to move out of the prescribed voltage range. For a predefined the range of network-side voltages (from V_S^{low} to V_S^{high}) at which operation is required in the internal voltage-following band, the voltage limits are approximated by calculating $V_R = V_R^{\text{high}}$ with $V_S = V_S^{\text{low}}$ (and $V_R = V_R^{\text{low}}$ with $V_S = V_S^{\text{high}}$) from the equation

$$V_R - \frac{V_S}{a_T} - R_T \frac{P_G}{V_G} - X_T \frac{Q_G}{V_G} = 0 \tag{7}$$

where a_T corresponds to one of the available tap positions of the off-line tap changer of the local transformer.

2.3.3. Operating points

The operating point at a voltage-controllable node is given by the intersection of the $Q_G(V_G)$ characteristic of the external system (like in Fig. 2) and of the local voltage controller, including the reactive power limits (Fig. 3 or Fig. 4). The analysis of the intersection points (as shown in Fig. 5 in the case with CVQC voltage controller) provides interesting hints on the voltage controllability of the distribution system. In particular:

1. It is possible to control the voltage V_S at the network side by means of the local generator only for a limited range of values of the voltage V_S. For local generators of relatively small size with respect to the HV/MV substation, the voltage control range is thus very limited.
2. Conceptually, the voltage control band of the local generator should be chosen in such a way to make voltage control effective, taking into account that the voltage V_S changes during the day. Thus, generators with the same characteristics but located in different network nodes could need different settings of the voltage controller.
3. In the presence of multiple voltage-controllable local generators, the settings should be defined by some coordinated control. However, if the local generators are owned and managed by different entities, there is no such coordination. Coordinated control can be attempted within a micro-grid (Nikkhajoei & Lasseter, 2009).

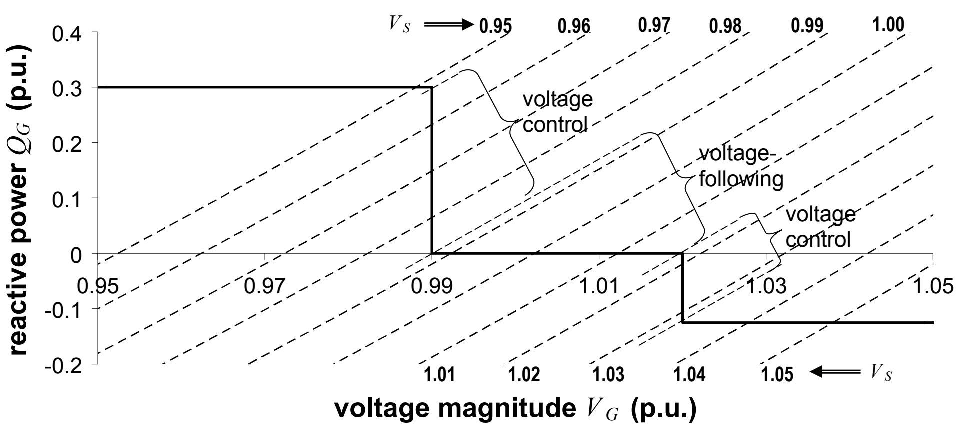


Fig. 5. Operating points obtained from the intersection of the characteristics of external system and CVQC voltage controller for a given DG active power generation.

A detailed analysis of the voltage controller operation with variable daily load patterns is presented in Carpaneto et al., 2004. The periods of time in which the controllers operate in voltage-support mode, voltage-following mode or at the maximum/minimum reactive power generation limits are identified for different setting of the controllers and transformation ratio, with the aim of endeavouring to find the most promising control settings. An approximated $V_R(a_T)$ representation is found as a straight line of the type

$$V_R = k_a\, a_T + V_0 \tag{8}$$

in which the parameters k_a and V_0 depend on the type of voltage controller and on the location of the generator in the distribution system. In particular, from the results found in Carpaneto et al., 2004, it emerges that the best conditions generally occur for k_a = -1. Hence, for a given generation unit it is possible to choose the tap setting a_T among the available ones, thus obtaining from Equation (8) the value of V_R for which the time of voltage-controlled operation is maximum. For the CVQC, a similar representation can be considered by using V_R as the central value of the two voltage controlled bands and taking into account the width of the voltage control band as additional variable.

2.3.4. Capability curves

Considering the nominal apparent power S_N and the nominal power factor $\cos(\varphi_N)$ of the synchronous machine, the maximum reactive power can be approximated as $Q_G^{\max} \approx S_N \sin(\varphi_N)$.

For a local generation unit composed of the generator and the interconnection transformer, the significant notion to represent the boundaries of the active and reactive power that can be injected into the grid interconnection point is the *capability chart* (Losi et al., 1998), that is, the capability curve referred to the grid connection point, including the effects of all components in the local system generation unit and their specific settings.

2.4. Other generators and network interfaces

Besides synchronous machines, the basic types of connection of local generation units to the distribution network are:

- *Induction generators* (without converters), used in very small hydro power plants and in some types of wind systems.
- *Power electronic inverter-based* grid interface, with different types of inverters. Blaabjerg et al., 2006 present the basic control structures of the inverters, the control strategies adopted in case of faults in the grid and the methods for DG synchronization with the grid. In many cases, the inverters are controlled to inject power into the grid at unity conventional power factor (calculated with the waveform components at fundamental frequency). The inverter control can also be adapted for to provide enhanced power conditioning, with various objectives such as injecting/absorbing reactive power, providing harmonic filtering, three-phase system balancing, mitigating the effects of voltage dips or short interruptions, eliminating zero-sequence components. Voltage-source inverter (VSI), that can be voltage-controlled or current-controlled (Ko et al., 2006). Voltage control can be aimed at reproducing reactive power control characteristics similar to a synchronous generator. In this case, additional functions of the inverter control include local voltage stabilization, reactive power support/power factor correction, improvement of local voltage quality at low-order harmonics, uninterruptible power supply (UPS), and active power support by using a bi-directional VSI to control the active power flow between the DC bus and the grid. However, current is not controlled, and since a VSI inverter has a short-time overload capacity much lower than a synchronous machine, the inverter rating has to be augmented (with increased cost) to provide the extra current. With current control, it is possible to obtain currents with nearly sinusoidal waveform, also with benefits to protection system operation, but with no contribution to improve the local voltage quality. Finally, Z-source inverters (ZSI), are a different category, whose applications to DG are described in Gajanayake et al., 2009.
- *Doubly-Fed Induction Generators* (DFIG), widely used in wind systems, as a particular case in which the rotor-side converters are added to the wound-rotor induction machine (Baroudi et al., 2007). One of the advantages of the DFIG structure is that the size of the

rotor-side converter is relatively low with respect to the rated power of the induction machine. However, this leads to a relatively small impact of the converter on voltage and reactive power control.

2.5. Basics of the voltage control with DG

In the traditional systems without DG, it was generally possible to set up a suitable value of supply voltage V_{MV} at the MV busbars in order to obtain all voltage magnitudes at the distribution system network nodes within the acceptable range around the rated voltage of the system. Possible cases with excessive voltage drops could be solved through appropriate location of power factor correction capacitors at some nodes of the distribution system.
The presence of DG units makes it necessary to reformulate the voltage control problem. In particular, the general idea of finding a value of the supply voltage V_{MV} at the MV busbars could lead to the impossibility of obtaining all voltage magnitudes at the distribution system network nodes within the acceptable range. In order to illustrate this point with a simple qualitative example, let us consider the two-feeder "fork" system (Fig. 6), composed of a passive feeder, represented by an equivalent load at the end of the feeder, and another feeder with uncontrollable DG (negative PQ load) at its end, With respect to the voltage profiles, the passive feeder experiences a voltage drop, while the DG feeder experiences a voltage rise. The amounts of the voltage variations depend on the load and local generation power, respectively, and change in time. Practically, it may happen that the voltage profiles exceed both the voltage limit on the passive feeder and the upper voltage limits in the DG feeder. In this case, no solution can be found by only varying the voltage V_{MV} from centralised voltage control. This explains the need for adding further voltage controllers in the distribution systems. Local voltage controllers embedded in the DG interface with the grid can fit this need.

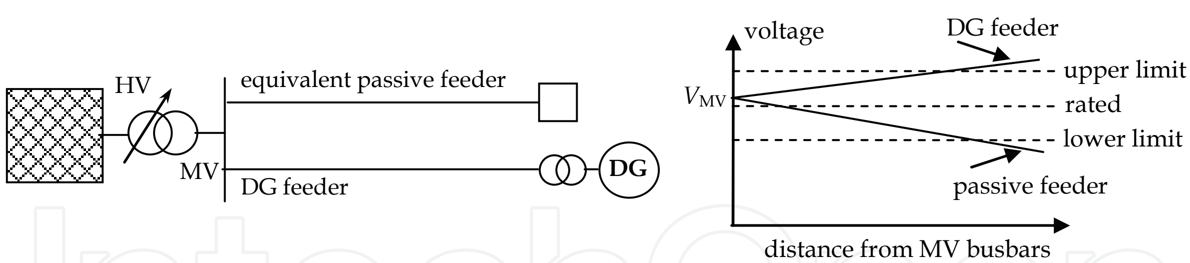


Fig. 6. The two-feeder "fork" system and the voltage profiles along the feeders.

However, the interaction among different voltage-controlled DG units operated independently of each other could create confusion and be ineffective. Suitable solutions can be found looking for coordinated voltage control strategies involving both the DNO and the operators of the DG units, based on agreed objectives and reliable communications (Baran & El-Markabi, 2007). In order to avoid the complexity of coordination, alternative solutions have been proposed to provide local solutions by making the DG unit injecting in the network, in addition to active power, independently-controlled reactive power (Bollen & Sannino, 2005; Carvalho et al., 2008) to compensate for the voltage difference between the voltages at the generator terminal and at the network terminal. For this purpose, imposing $V_G = V_S$ in Equation (5) yields the reactive power Q_G that the generator should provide for a given active power production P_G to compensate for the local voltage variation. These solutions require on the one hand sufficiently high reactive power capability in the DG unit, and on the other hand the control is time-dependent (with time-variable tap changing at the local transformer), in order to follow the voltage variations at the network side. In particular, the reactive power capability of the local generator decreases when the active power production is relatively high.

2.6. General formulation of the voltage control problem

The voltage control problem in the distribution systems with DG can be formulated with the objective of maintaining the voltage close to a reference value at any node of the system. This objective can be used either individually, to set up the voltage controls for a given system structure, or as part of a multi-objective optimization problem together with other objectives such as losses, operational costs, reliability indicators, energy efficiency indicators, environmental impact indicators, duration of the voltage-controlled operation through local DG groups, and others.

Voltage control optimisation can be considered as an operational planning problem, in which all the system components are already located in the network and the focus is set on their operational strategy. The period of analysis can be of the order of one day, or one week. Within this period, the time evolution of typical generation and load profiles at each node is assumed to be known. The input data include the reference values of the control systems to be considered. The constraints are given by the power flow equations, the minimum and maximum voltage limits, the thermal limits of the branches and of the MV/LV transformers, the reactive power limits of the local generators, where applicable, and other operational limits of the equipment.

Besides the modelling of the different types of voltage controllers, the key aspect to be considered in voltage control optimisation is the dependence on time of the electrical variables and controls. In this respect, the possible solutions also depend on the economic aspects linked to the acquisition of the control systems. With reference to relatively large public distribution networks, the controllers can be adjusted on-load (such as the centralised control at the HV/MV substation, driving the ULTC), or off-load (such as the tap positions of the MV/LV transformers). For cost reasons, off-load tap changers can be considered also at the local transformers connecting the DG units to the grid. According to these concepts, the following classification can be used for the voltage controls (Carpaneto et al., 2004):

- *time-independent*: tap positions of the transformers located at each MV/LV node and of the transformers connected to the local generation groups, voltage set points of the voltage-controllable local generators, and width of the internal voltage-following band for each CVQC;
- *time-dependent*: voltage reference of the centralised voltage control (the “control law”).

A general mathematical formulation of the voltage control objective function, based on combining various literature results, is presented here for a voltage control optimization refers to the MV distribution system. A radial system is considered, with each branch numbered according to its ending node. Let us denote as a_k the transformation ratio deriving from the transformer tap positions of the MV/LV transformers. The explicit model of all the MV/LV transformers at the load or local generation nodes is provided, in order to set the target voltage magnitude $\hat{V}_{k,LV}$ at each node belonging to the set $\boldsymbol{K}_{LV} = \{k = 1,\dots K_{LV}\}$ of the

distribution system. The set $\boldsymbol{K}_{LV}$ also includes voltage-uncontrollable generation nodes. The upper voltage limits at the generation nodes cannot be exceeded, as the voltage control settings of the voltage-controllable generation units are constrained to avoid exceeding these limits.
The time domain is represented by a set of discrete points j = 1,.., J. The variable of interest is the voltage magnitude V_{kj} at each MV node corresponding to a LV node $k \in \boldsymbol{K}_{LV}$, for each point in time j = 1,.., J. In order to be compared to the target voltage $\hat{V}_{k,LV}$, the MV node voltage is first subject to the transformation ratio a_k, then the voltage drop in the transformer windings is modelled, in terms of the loading condition, as a fraction of the short-circuit voltage Δv_k given by the ratio between the current I_{kj} circulating in the transformer and the corresponding thermal limit $I_k^{\max}$. Other terms appearing in the objective function are the consumer energy E_{kj} introduced as a weighting factor to give more importance to the nodes $k \in \boldsymbol{K}_{LV}$ and to the time intervals j = 1, ..., J in which the energy consumption is higher, and the consumer damage constant C_k (Strezoski et al., 2001). The final form of the objective function is:

$$f = \sum_{j=1}^{J} \sum_{k \in \boldsymbol{K}_{LV}} \left(C_k E_{kj} \left(\frac{V_{kj}}{a_k} - \frac{I_{kj}}{I_k^{\max}} \Delta v_k - \hat{V}_{k,LV} \right)^2 \right) \tag{9}$$

The formulation can be easily adapted to take into account the MV consumers ($\Delta v_k = 0$). The objective function (9) has to be minimized, and the related constraints have to be met at any time interval.
A further variant consists of defining a "customer voltage quality" index (Choi & Kim, 2000) in which the maximum deviation with respect to the voltage reference is over-penalised any time it exceeds the limits of the acceptable voltage range. On the structural point of view, in some cases step voltage regulators could be installed into the distribution system feeders (Roytelman & Ganesan, 2000), further increasing the number of control variables.
In practical systems, the number of time-independent and time-dependent control variables to be determined is significantly high, so that performing exhaustive search on the discrete variables would be prohibitive, and the shape of the objective function is unknown. Hence, heuristic techniques are typically used for the solution of the optimization problem (Carpaneto et al., 2004; Senjyu et al., 2008).

3. Evaluation and allocation of distribution system losses

3.1. Generalities on distribution system losses

In a VIU structure, the cost of losses was included into the overall electricity production costs, and there was no need for determining it specifically. In the restructured electricity business, the specific costs associated to any individual aspect of the business need to be identified. In particular, the system losses are an additional component with respect to the actual energy consumption (for loads) or energy generation (for local generators) indicated in the economic transactions between the distribution system operator and the consumer/producer located at a specific node in the network. Evaluation and allocation of the system losses to suppliers and consumers are key issues to be addressed, in order to set up appropriate economic penalties or rewards for suppliers and consumers.

In general terms, for a distribution system the total energy losses are determined as the difference between the measured energy output from the HV/MV substation and the measured energy input to the load points (distributed generation can be treated as a negative load). The quantification of the total losses is affected by uncertainty, because the measuring instruments are characterised by their intrinsic accuracy, the synchronization of the remote meters is not guaranteed, and the measured data could be affected by errors in the communication system.

The total losses include technical and non-technical losses (NTL) (Taleski & Rajicic, 1996). The technical losses occur in the circuits in their normal operation, have a non-linear dependence on currents and powers, and cannot be easily assessed, especially in situations with scarcity of data on the electrical network parameters and on the system operation.

The concept of NTL encompasses various components typically referred to frauds (e.g., from meter tampering, meter by-passing or illegal connections), billing and measurement errors (e.g., human errors during meter readings, meter or data communication failures, and metering equipment deterioration or ageing). Other causes, such as imperfect electrical contacts and current tappings due to local isolation failures, can be attributed to NTL as well. For billing purposes, the NTL are typically allocated to the rate classes in proportion to their energy consumption.

This section deals with the *technical losses*, whose value is determined by running a power flow under the hypothesis that the parameters of the distribution system, the local generations and the loads are known without uncertainty. Specific aspects concerning loss evaluation and loss allocation in balanced and unbalanced distribution systems with distributed generation are addressed. Loss evaluation is dealt with in the general case of unbalanced systems, highlighting specific loss partitioning aspects. Loss allocation refers to assign to each supplier and consumer in the distribution system a portion of the system losses, to be taken into account in the payments in addition to the components of the electricity tariff (such as a fixed component, a component related to the contract power, a component related to the energy consumption, and further components for exceeding specific thresholds set on maximum power or reactive energy).

3.2. Loss evaluation in three-phase systems

Loss analysis in general three-phase systems is useful to point out the basic aspects of loss allocation, and is relevant to distribution systems with single-phase lines and loads.

The network branch modelling in unbalanced multi-wire distribution systems is typically done by using the Carson's equations to calculate the self and mutual impedances for an arbitrary number of conductors, and by applying the Kron reduction to determine the 3x3 reduced impedance matrix $\mathbf{Z}_{abc}$ of each branch, referred to the phases *a*, *b* and *c* (Kersting, 2001). This reduced branch representation is particularly useful to carry out three-phase power flow calculations without introducing a detailed model of the return path (composed of the neutral conductor and the ground).

In Kersting, 2001, it is indicated to calculate the real power losses of a line segment as the difference (by phase) of the input power in the line segment minus the output power of the line segment. This classical technique is used for computing the total losses in a branch represented by its reduced 3x3 matrix, as the difference between the input (node *m*) and output (node h) power of the branch (Fig. 7), corresponding to write, considering $\mathbf{v}_m = \left[\overline{V}_{m,a}, \overline{V}_{m,b}, \overline{V}_{m,c}\right]^{\mathrm{T}}$, $\mathbf{v}_h = \left[\overline{V}_{h,a}, \overline{V}_{h,b}, \overline{V}_{h,c}\right]^{\mathrm{T}}$ and $\mathbf{i} = \left[\bar{I}_a, \bar{I}_b, \bar{I}_c\right]^{\mathrm{T}}$ (the superscript T indicates transposition):

$$\Delta P_{tot} = \Re e\left\{(\mathbf{v}_m - \mathbf{v}_h)^{\mathrm{T}}\, \mathbf{i}^*\right\} = \Re e\left\{\mathbf{i}^{\mathrm{T}} \mathbf{Z}_{abc}\, \mathbf{i}^*\right\} \tag{11}$$

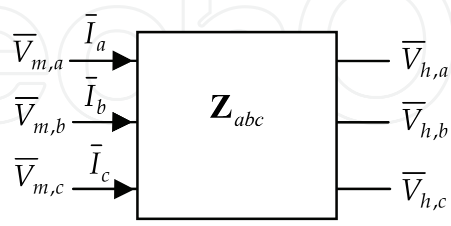


Fig. 7. Representation of a branch reduced to the three-phase branch impedance matrix.

An alternative way for computing the total losses can be defined by taking into account the real part of the branch impedance matrix, $\mathbf{R}_{abc} = \Re e\{\mathbf{Z}_{abc}\}$. In fact, as demonstrated in Appendix B of Carpaneto et al., 2008a, the following equivalence holds:

$$\Re e\left\{\mathbf{i}^{\mathrm{T}} \mathbf{Z}_{abc}\, \mathbf{i}^*\right\} = \mathbf{i}^{\mathrm{T}} \Re e\{\mathbf{Z}_{abc}\}\, \mathbf{i}^* \tag{12}$$

so that the expression of the total losses becomes

$$\Delta P_{tot} = \mathbf{i}^{\mathrm{T}} \mathbf{R}_{abc} \mathbf{i}^* \tag{13}$$

However, as remarked in Carpaneto et al., 2008a, the formulations (12) and (13) are not generally equivalent for the purpose of partitioning the total losses among the three phases. Differences in loss partitioning occur in branches with non-zero current in the return path. In these cases, only the Resistive Component-based Loss Partitioning (RCLP) method, defined in Carpaneto et al., 2008a, by using the matrix $\mathbf{R}_{abc}$, provides the correct decomposition of the currents in the neutral conductor and in the ground into various components to be associated with the phase currents. The RCLP method provides a meaningful representation of the Joule losses in each physical conductor (phases and neutral) and in the ground.

Considering the vector $\Delta\mathbf{p} = \left[\Delta P_a\ \Delta P_b\ \Delta P_c\right]^{\mathrm{T}}$ containing the losses associated to the phase currents, the RCLP method provides the partition of the total losses as

$$\Delta\mathbf{p} = \Re e\left\{\mathbf{i} \otimes \left(\mathbf{R}_{abc}\, \mathbf{i}^*\right)\right\} \tag{14}$$

where $\otimes$ denotes the component-by-component vector product. In this way, for each component the associated losses are proportional to the projection of the phasor representing that current component onto the phasor representing the specified current (Carpaneto et al., 2008a).

Application of (14) with the matrix $\mathbf{Z}_{abc}$ instead of $\mathbf{R}_{abc}$ with non-zero current in the return path would result in the loss partitioning paradox identified and explained in Carpaneto et al., 2008a. Occurrence of this paradox leads to partition the total losses in uneven way, for instance with heavily loaded phases associated to losses even higher than the total losses, or with negative losses that can be associated to lightly as well as to heavily loaded phases. The correct partitioning obtained by using the RCLP method still admits negative losses to occur as a result of the decomposition of the return path currents into the components associated with the phase currents, but is able to fully explain the individual terms of such decomposition.

3.3. Loss allocation concepts and principles

The main difficulty of setting up loss allocation techniques in distribution networks depends on the fact that the branch losses are expressed as non-linear (nearly quadratic) functions of the current or power generations and loads. Furthermore, cross-terms appear, due to the interaction between power injections in different nodes.

The loss allocation concepts have become much more important because of the growing presence of distributed generation and resources in the distribution systems. In fact, the presence of a relatively significant amount of distributed generation may reverse the power flows in some branches of the distribution systems. Thus, a local generator operating at a specific location in the distribution network and with a given output may provide benefits to the network depending on the system structure and on the location and amount of every generator and load. The need for taking into account the full power flow solution also indicates that it is not correct to use the substitution method that considers the difference of the total losses in the presence or absence of a single unit (local generator or load) for determining the effects of that unit on loss allocation (for further details, see Section 8.4 of Jenkins et al., 2000). In addition, the diffusion of distributed generation has made it inappropriate to use methods based on uniform or demand-squared loss allocation formulated by taking into account only the demand side.

The loss allocation results should reflect the contribution of each supplier/consumer to the system losses, taking into account the active power and reactive power sides, as well as incorporating the effects of voltage controls. Variation during time of generation, load patterns, system structure and control settings has to be appropriately taken into account.

The possible benefits of loss allocation are determined on the basis of the concept of *marginal losses*. Conceptually, for a local generator (or load) the marginal losses, determined for a certain shapshot in time, are defined by checking whether a small (theoretically infinitesimal) increase of the amount of active or reactive generation (or load) increases or reduces the system losses P_L. In general, the distribution system losses depend on the net power (i.e., generation minus load) connected to a node. At a generic node k, considering the net active power P_k and the net reactive power Q_k, the effects of marginal losses can be expressed by introducing the marginal loss coefficients $\rho_{Pk} = \partial P_L / \partial P_k$ and $\rho_{Qk} = \partial P_L / \partial Q_k$, acting as sensitivity factors. Considering for instance the net active power and using the superscript 0 to denote the reference conditions (i.e., the present power flow solution), it is possible to write, for small deviations:

$$P_L - P_L^{(0)} = \rho_{Pk}\left(P_k - P_k^{(0)}\right) \tag{15}$$

On these bases, loss reduction benefits for the system occur when $\rho_{Pk} > 0$ and the net power is decreased, as well when $\rho_{Pk} < 0$ and the net power is increased.

These concepts can be taken into account by the regulation in order to set up a system of incentives and penalties. As such, the owner of a local unit could incur an incentive if the unit exploitation determines marginal loss reduction, or a penalty if the unit exploitation causes a marginal loss increase. If each node of the system contains either a load or a generator, on the basis of the above concepts, penalties would occur for load nodes with negative marginal loss coefficients or generation nodes with positive marginal loss coefficients, while incentives would occur for load nodes with positive marginal loss coefficients or generators with negative marginal loss coefficients (Mutale et al, 2000). This conceptual structure, in which loss allocation reflects the contribution of each supplier/consumer to active and reactive losses, provides correct signals to the electricity business, as it stimulates the introduction of new local generation only in the locations and with the amounts for which a benefit on network efficiency could occur.

In addition, an effective loss allocation method should be formulated according to easily understandable principles, based on the real data of the networks, and should recover the total amount of losses. The loss allocation results should be economically efficient, avoiding discrimination and cross-subsidization among users (Jenkins et al., 2000).

After calculating the loss allocation terms for all network components (generators, loads, compensation devices, and shunt parameters of the network), these terms have to be attributed to specific entities in order to clear the loss allocation economic issues. For this purpose, the losses allocated to each load or compensation device (such as power factor correction capacitor) are attributed to the specific owner, whereas the losses allocated to the shunt parameters of the branch model are attributed to the DNO.

3.4. Network-related aspects impacting on the formulation of loss allocation techniques

In principle, the loss allocation problem has a different formulation for transmission systems or for radial distribution systems.

In transmission systems, a (large) generator is connected to the slack node of the power flow equations, then part of the losses are allocated also to the slack node. Furthermore, a transmission network with K nodes is represented by using the full KxK bus impedance matrix $\mathbf{Z}_{bus}$, or the full KxK bus admittance matrix $\mathbf{Y}_{bus}$.

In distribution systems, the supply node is uniquely determined by the connection to a higher voltage network through the power substation and corresponds to the slack node of the system. The supply side, managed by the DNO, typically supplies the largest part of the power, but it does not correspond to a physical generator. As such, the loss allocation methods have to be carefully designed to take into account the specific characteristics of the slack node. Furthermore, in distribution systems local loads or generators are owned and managed by different entities, and operated within specific regulatory frameworks.

In order to allocate the distribution system losses, the DNO is considered as the subject undertaking bilateral contracts for loss allocation with the distribution system entities (Carpaneto et al., 2006a). The distribution system losses are allocated to the local generators and loads connected to the distribution system nodes, *excluding* the slack node. For this reason, a distribution network with K nodes is represented by using the reduced (K-1)x(K-1) bus impedance matrix $\mathbf{Z}_{bus}$, or the reduced (K-1)x(K-1) bus admittance matrix $\mathbf{Y}_{bus}$.

As a consequence of the conceptual differences indicated above, it is possible to apply the loss allocation methods formulated for transmission systems to the distribution systems, provided that the losses allocated to the slack node are redistributed among the other nodes (Carpaneto et al., 2006a). A simple way to avoid allocating losses to the slack node is to connect the slack node to the reference node with a null impedance, that is, to impose the slack voltage magnitude to zero in the network used for determining the loss allocation; in this case, it is possible to use the loss allocation methods defined for transmission systems for allocating losses in distribution systems, as shown in the examples presented in Carpaneto et al., 2006b.

A significant case in the formulation of loss allocation methods is the one in which the distribution network has negligible shunt parameters in the branch model, such as for most aerial distribution networks and for low voltage cables. In this case, if no generation nor load is modelled as impedance or admittance component, the network has no connection to the system reference node (*floating* network). This causes the impossibility of constructing the full KxK bus impedance matrix and to use the loss allocation methods based on this matrix. However, the technique of connecting the slack node to the reference node for distribution systems in this case enables obtaining meaningful loss allocation also for a floating network. Strictly speaking, for a floating network correct results would be obtained also with non-null impedance for the slack node connection to the reference node (Carpaneto et al., 2006b).

3.5. Loss allocation techniques

The most appropriate loss allocation techniques start from the power flow results and exploit the concept of marginal losses to formulate suitable indicators to express the positive or negative contribution of generators and loads to reduce the system losses. These techniques can generally be partitioned into *derivative-based* and *circuit-based*. The correctness in the formulation of the computational techniques depends on avoiding the occurrence of the loss allocation paradox identified in Carpaneto et al., 2006a.

3.5.1. Derivative-based methods

A general expression for the derivative-based methods can be built by approximating the total losses L in function of the net node power vector $\mathbf{p}$ in quadratic form (Carpaneto et al., 2008b)

$$L = L_0 + \mathbf{b}^{\mathrm{T}}\mathbf{p} + \frac{1}{2}\mathbf{p}^{\mathrm{T}}\mathbf{A}\,\mathbf{p} \tag{16}$$

where $L_0 = L\big|_{\mathbf{p}=0}$ represents the no-load losses, the column vector $\mathbf{b} = \left.\frac{\partial L}{\partial \mathbf{p}}\right|_{\mathbf{p}=0}$, and $\mathbf{A}$ is a symmetric matrix. Higher-order terms are neglected. The terms L_0 and $\mathbf{b}$ are null in the absence of shunt circuit components (e.g., shunt line or transformer parameters) and of circulating currents depending on different voltage settings at different PV nodes (as the ones introduced by local generators operating in the voltage control range).

By indicating the derivative of the total losses with respect to the vector $\mathbf{p}$ as $L_{\mathbf{p}} = \frac{\partial L}{\partial \mathbf{p}}$, from analytical elaborations it is possible to obtain

$$2L = \left(L_{\mathbf{p}}^{\mathrm{T}} + \mathbf{b}^{\mathrm{T}}\right)\mathbf{p} \tag{17}$$

from which the vector $\boldsymbol{\psi}$ containing the loss allocation coefficients is defined in such a way to represent the total losses as $L = \boldsymbol{\psi}^{\mathrm{T}}\,\mathbf{p}$:

$$\boldsymbol{\psi} = \frac{L_{\mathbf{p}} + \mathbf{b}}{2} \tag{18}$$

The expression (18) indicates how the loss allocation vector depends on the derivative of the total losses with respect to the load vector. In particular, the derivative $L_{\mathbf{p}}$ alone is unable to provide a loss allocation vector, and reconciliation to the total losses is needed by dividing by 2 even in the case in which $\mathbf{b} = \mathbf{0}$.
From another point of view, the exact variation of the losses defined in the quadratic form (16) with respect to load power variations can be expressed by considering two generic net power vectors $\mathbf{p}_1$ and $\mathbf{p}_2$, leading to the total losses $L^{(1)}$ and $L^{(2)}$, respectively, by using the average value of the derivatives calculated in the two configurations (Carpaneto et al., 2008b):

$$L^{(2)} - L^{(1)} = \left(\frac{L_{\mathbf{p}}\big|_{\mathbf{p}_1} + L_{\mathbf{p}}\big|_{\mathbf{p}_2}}{2}\right)^{\mathrm{T}} \left(\mathbf{p}_2 - \mathbf{p}_1\right) = \left[\mathbf{b} + \frac{1}{2}\mathbf{A}\left(\mathbf{p}_1 + \mathbf{p}_2\right)\right]^{\mathrm{T}} \left(\mathbf{p}_2 - \mathbf{p}_1\right) \tag{19}$$

The expression (19) is independent of L_0. If $\mathbf{p}_1 = \mathbf{0}$ and $\mathbf{p}_2 = \mathbf{p}$, the equation providing the total losses $L = L^{(2)}$ becomes

$$L = \left[\mathbf{b} + \frac{1}{2}\mathbf{A}\mathbf{p}\right]^{\mathrm{T}} \mathbf{p} \tag{20}$$

If $\mathbf{b} = \mathbf{0}$, the loss coefficient vector $\boldsymbol{\psi} = \tfrac{1}{2}\mathbf{A}\,\mathbf{p}$ can be directly used to represent the total losses as $L = \boldsymbol{\psi}^{\mathrm{T}}\,\mathbf{p}$, with no need of reconciliation. If $\mathbf{b} \neq \mathbf{0}$, the product $\boldsymbol{\psi}^{\mathrm{T}}\,\mathbf{p}$ gives an approximation of the total losses.
The above illustration of the properties of the total losses is useful to discuss the formulation of some derivative-based methods proposed in the literature. In general, the matrix $\mathbf{A}$ and the vector $\mathbf{b}$ are not known. The methods are then elaborated by using the power flow state variables $\mathbf{x}$ (voltage magnitudes at the PQ nodes and voltage phase angles at all nodes, slack node excluded), and the Jacobian matrix $\mathbf{J}_{\mathbf{x}}$ containing the derivatives of the power flow equations with respect to the vector $\mathbf{x}$. Two methods based on expressing the total losses in quadratic form have been presented in Mutale et al., 2000:

1) the Marginal Loss Coefficients (MLC) method, in which an auxiliary vector $\boldsymbol{\sigma}$ is calculated by solving the linear system

$$\mathbf{J}_{\mathbf{x}}^{\mathrm{T}}\boldsymbol{\sigma} = \frac{\partial L}{\partial \mathbf{x}} \tag{21}$$

and reconciliation is needed to get $L = \boldsymbol{\psi}^{\mathrm{T}}\mathbf{p}$, since the product $\boldsymbol{\sigma}^{\mathrm{T}}\mathbf{p}$ in real systems approximately represents half of the total losses, on the basis of the same concepts discussed in (18), obtaining the loss allocation vector

$$\boldsymbol{\psi} = \boldsymbol{\sigma}\frac{L}{\boldsymbol{\sigma}^{\mathrm{T}}\mathbf{p}} \approx \frac{\boldsymbol{\sigma}}{2} \tag{22}$$

2) the Direct Loss Coefficients (DLC) method, using the Taylor series expansion of the total loss equation around the no-load conditions, in which an auxiliary vector $\boldsymbol{\gamma}$ is calculated by solving the linear system

$$\bar{\mathbf{J}}_{\mathbf{x}}^{\mathrm{T}}\boldsymbol{\gamma} = \frac{1}{2}\mathbf{H}\,\Delta\mathbf{x} \tag{23}$$

in which the rationale of using the average Jacobian matrix $\bar{\mathbf{J}}_{\mathbf{x}}$ calculated from the Jacobian matrices in two configurations (the current operating point and no-load) is based on the same concepts discussed in (19), and the Hessian matrix $\mathbf{H}$ of the loss equation is calculated at the current operating point. If the conditions corresponding to $\mathbf{b} = 0$ are satisfied, there is no need for reconciliation ($\boldsymbol{\psi} = \boldsymbol{\gamma}$), otherwise the product $\boldsymbol{\gamma}^{\mathrm{T}}\mathbf{p}$ gives an approximation of the total losses.

In distribution systems with voltage-controllable distributed generation, the definition of the MLC and DLC methods is affected by the fact that the voltage magnitude of a PV node is not a state variable in the power flow equations, thus the loss allocation coefficients are undefined for PV nodes. However, as remarked in Section 2.3.3 for synchronous generators, the local generators could operate in voltage control mode only for a portion of the total time interval of operation, being constrained to the reactive power limit in other time periods. These aspects may cause a discontinuity in the time evolution of the MLC and DLC coefficients. However, a voltage-controllable local generation unit is typically connected to the grid through a local transformer, that can be considered as integral part of the local system. As such, it is possible to adopt a two-step technique of analysis (Carpaneto et al., 2008b). In the first step, the power flow is solved by taking into account the detailed characteristics of the local generator (including its voltage control system) and of the local transformer. In the second step, each generation unit (generator and transformer) is replaced by the net power injected into the distribution network calculated from the power flow, thus constructing a *reduced network* in which no PV node appears. The losses in the local transformer are part of the local system and are correctly excluded from the loss allocation. Any possible reactive power limit enforced or other specific modelling details are implicitly embedded in the net power representation. The loss allocation is then calculated for the reduced network by using derivative-based or other methods. For the derivative-based methods, the Jacobian matrix to be used for loss allocation purposes has to be recalculated also when the power flow solution has already used a method requiring the construction of a Jacobian matrix, since the number of nodes in the reduced network is different with respect to the one of the original network. One critical aspect is the calculation of the no-load configuration to be used in equation (23) when one or more local generator operate as a PV nodes. In this case, being the loss allocation calculated on the reduced network, the effect of the voltage setting at PV nodes cannot be taken into account.

3.5.2. Circuit-based methods

The derivative-based methods illustrated in the previous subsection require the calculation of the Jacobian matrix (and in one case of the Hessian matrix) of the power flow equations. Indeed, the power flow for radial distribution networks is typically solved by methods like the backward/forward sweep, that exploit the network structure and circuit equations and do not require the construction of the Jacobian nor Hessian matrices. This fact leads to the definition of circuit-based loss allocation methods, in which no information on the derivatives is needed. One aspect to be verified for a circuit based-method is the possibility of reproducing the sensitivity information needed for representing the marginal losses, in order to ensure that the method effectively provides the correct signals, as discussed in Section 3.3. In the methods indicated in this section, this sensitivity information is implicitly provided by verifying that, for variable loads and in comparable cases (concerning the presence of voltage controls), the allocated losses computed with the circuit-based methods exhibit the same behaviour as those obtained by using derivative-based methods.

The formulation of the circuit-based methods could be affected by a conceptual paradox (Carpaneto et al., 2006a), based on concepts similar to those discussed in Section 3.2 for phase loss partitioning. In particular, the total active power losses on a branch can be calculated in two alternative ways, for a given branch current $\bar{I}$:

a) considering the branch impedance $\bar{Z}$ (the asterisk denotes conjugation):

$$L = \Re e\left(\bar{I}^* \bar{Z}\,\bar{I}\right) \tag{24}$$

b) considering the real part R of the branch impedance:

$$L = \bar{I}^* R\,\bar{I} \tag{25}$$

However, using the above formulations leads to different loss partitioning results between the active and reactive power flows in the branch. In particular, if the characteristic angle of the branch impedance $\bar{Z}$ is higher than the characteristic angle of the load, the loss allocation carried out by using (25) fails to provide meaningful results. This fact can be easily highlighted by considering the presence in the same node of two loads with the same active power but different reactive powers, resulting in allocation of more losses to the load

with lower reactive power (Carpaneto et al. 2006a). This paradox never occurs by using (25) for loss allocation purposes.
The rationale for interpreting the direct use of the sole resistive components in (25) rather than the real part of the terms in (25) containing the complex impedance can be shown by considering a branch with series impedance $\overline{Z} = R + \mathrm{j}X$, supplying a load with complex power $\overline{S} = P + \mathrm{j}Q$, with voltage magnitude V at the load terminal. The total losses are

$$L = \left(\frac{RP + XQ}{V^2}\right)P + \left(\frac{RQ - XP}{V^2}\right)Q \tag{26}$$

The interdependence between active and reactive flows can be eliminated by simplifying the terms depending on the product of the active and reactive power, obtaining:

$$L = \left(\frac{RP}{V^2}\right)P + \left(\frac{RQ}{V^2}\right)Q \tag{27}$$

The multipliers of P and Q are the loss allocation coefficients applied to the active and reactive load, respectively. The use of the coefficients determined from (26) leads to the loss allocation paradox mentioned above. The coefficients defined in (27) with reference to the sole resistive parameter of the branch allow obtaining meaningful and paradox-free loss allocation.
In order to show the formulations of some efficient circuit-based loss allocation methods proposed in the literature to be used in distribution networks with DG, let us consider a distribution system with K+1 nodes and B branches. The slack node is denoted as node 0. For any node k = 0,…, K, the power flow data and results include the complex node voltage $\overline{V}_k$, the net input complex power $\overline{S}_k = P_k + \mathrm{j}Q_k$ and the net input current $\overline{I}_k$.
On the basis of these definitions, four circuit-based methods are presented below.

1. *Z-bus loss allocation* (Conejo et al., 2000). The application of this method in its classical form requires the construction, for a non-floating system, of the matrix $\mathbf{Z}_{\text{bus}}$ with dimensions (K+1)x(K+1), slack node included. The elements of the $\mathbf{Z}_{\text{bus}}$ matrix of the distribution system are indicated as $\overline{z}_{km} = r_{km} + \mathrm{j}x_{km}$. The expression of the losses L_k allocated to each node k = 0,…, K is:

$$L_k = \Re e\left(\overline{I}_k^* \sum_{m=0}^{K} r_{km}\overline{I}_m\right) \tag{28}$$

   In order to get meaningful results for distribution systems in which the slack node does not participate to the loss allocation, the losses allocated to the slack node in (28) are redistributed among the other nodes. For this purpose, the technique of connecting the slack node to the reference node is used, as discussed in Section 3.4. This connection has a similar effect to partitioning the slack node losses among the other nodes and extends the application of the method to floating systems (Carpaneto et al., 2006b).

2. *Loss allocation through a modified* $\mathbf{Y}_{\text{bus}}$ *matrix* (Daniel et al. 2005). The original method described in the paper is formulated to be applied to transmission systems, in which loss allocation is carried out separately for generation nodes (sources) or load nodes (sinks), by decomposing the system currents. In the application to distribution systems, a modified matrix $\mathbf{Y}_{\text{bus}}$ with dimensions $(K+1)\text{x}(K+1)$, included the slack indicated at node $k = 0$ for the sake of representation, is constructed by including the equivalent admittances at the generation nodes, and the loads are treated as current injections. For the load node $k = 1,\ldots, K$, the losses L_k are allocated on the basis of the load current $\bar{I}_k$ by taking into account the resistance $R^{(b)}$ of a branch $b = 1,\ldots,B$ of the network, the column vector $\mathbf{i}$ containing all the load node currents and the column vector $\mathbf{c}^{(b)}$ containing the b-th column of the incidence matrix containing the relations among node current injections to branch currents:

$$L_k = \Re e\left(\bar{I}_k \sum_{b=1}^{B} \mathbf{i}^{*\mathrm{T}} \left(\mathbf{c}^{(b)^{*\mathrm{T}}} R^{(b)} \mathbf{c}^{(b)}\right)\right) \tag{29}$$

This method is applicable to any type of distribution system, considering the distributed generation as a negative load, also in floating cases, being it possible to construct the bus admittance matrix in any case.

3. *Branch Current Decomposition Loss Allocation* (BCDLA, Carpaneto et al., 2006a). This method is defined for a radial distribution system. Let us consider the set $\boldsymbol{K}^{(b)}$ of the downward nodes supplied from branch b, the set $\boldsymbol{B}_k$ of the branches belonging to the unique path from node k to the slack node, and the net input current $\bar{I}_k$ at node k (including the contribution of the loads and of the shunt elements connected to node k). The current $\bar{I}^{(b)}$ passing in the series element of the π–model of branch $b = 1,\ldots, B$ with branch resistance $R^{(b)}$, is

$$\bar{I}^{(b)} = \sum_{k\in\boldsymbol{K}^{(b)}} \bar{I}_k \tag{30}$$

The losses allocated to node k are calculated as

$$L_k = \Re e\left(\bar{I}_k^{*} \sum_{b\in\boldsymbol{B}_k} R^{(b)} \bar{I}^{(b)}\right) \tag{31}$$

The BCDLA method has been extended to perform loss allocation in three-phase unbalanced systems (Carpaneto et al., 2008a), exploiting the effective loss partitioning determined by the application of the RCLP method discussed in Section 3.2. The three-phase net input current at node k is represented by the column vector $\mathbf{i}_k = \left[\bar{I}_{k,a}, \bar{I}_{k,b}, \bar{I}_{k,c}\right]^{\mathrm{T}}$, and the losses allocated to the three phases of the load connected to node k are denoted as $\boldsymbol{\lambda}_k = \left[L_{k,a}\, L_{k,b}\, L_{k,c}\right]^{\mathrm{T}}$. The current flowing in the series elements of branch $b = 1,\ldots, B$ is

$$\mathbf{i}^{(b)} = \sum_{k \in \boldsymbol{K}^{(b)}} \mathbf{i}_k \tag{32}$$

and the losses allocated to the three phases of node k are

$$\boldsymbol{\lambda}_k = \Re e\left[\mathbf{i}_k \otimes \sum_{b \in \boldsymbol{B}_k} \left(\mathbf{R}_{abc}^{(b)} \left(\mathbf{i}^{(b)}\right)^*\right)\right] \tag{33}$$

The BCDLA method is particularly effective for various reasons. First, it is paradox-free and uses directly the power flow results, with no approximation required. In particular, it can be conveniently used in association to efficient implementations of the backward/forward sweep algorithm for solving the power flow in which there is no need of storing the bus impedance matrix or bus admittance matrix coefficients. Furthermore, it is applicable to any kind of radial system, either with non-negligible shunt parameters or floating. Then, it defines the loss allocation factors for all active and reactive power components at any node. In particular, all shunt components (such as shunt branch parameters and power factor correction devices) are treated in a consistent way, making it possible to identify their specific contribution depending on their location in the distribution system. Finally, the sum of the allocated losses equals the total losses, with no need of reconciliation.

4. *"Succinct" method for loss allocation* (Fang & Ngan, 2002). The original formulation of the "succinct" method assumes that the losses associated to the shunt admittance branches can be allocated in average terms to all users, and focuses on the allocation of the losses due to the series branch impedance, thus being affected by the paradox discussed above. A revisited paradox-free version of the method has been formulated in (Carpaneto et al. 2006a), expressing the losses allocated to node $k = 1,\ldots,K$ as

$$L_k = \Re e\left\{\bar{I}_k^* \sum_{b=1}^{B} \left[\left(r_{ik} - r_{qk}\right)\bar{I}^{(b)}\right]\right\} \tag{34}$$

where i and q are the sending and ending node of branch b, respectively, whereas r_{ik} and r_{qk} are resistances taken from the real part of the bus impedance matrix.
In the application of the method to distribution systems, also in this case the slack node is connected to the reference node, also enabling the application of the method for floating systems, as discussed in Section 3.4.

3.5.3. Other methods

A multi-stage loss allocation scheme has been formulated by Costa & Matos, 2004. Within this scheme, the first stage consists of loss allocation to the consumers or to their providers,

the second stage to loss allocation to the distributed generators, and the third stage to allocation of the remaining loss variations referred to voltage profile variations.
Further methods rely upon the concept of tracing the electricity flow, attributing the flows in the network branches to the nodal injections. Application of these method could be complicated in meshed networks, but in radial distribution systems each branch flow is given by the sum of the shunt contributions in the downward portion of the network. In this case, the electricity flow tracing is uniquely defined, and loss allocation procedures such as the one presented in Bialek and Kattuman, 2004, can be directly used.

4. Conclusions

This chapter has recalled the basic aspects and some specific details of the steady-state assessment of topics like voltage control, reactive power support and loss allocation in distribution networks with distributed generation. Voltage control is one of the issues that needs to be addressed in a dedicated way in the presence of distributed generation. One of the open fields of research in this area is the promotion of a coordinated voltage control (Viawan & Karlsson, 2007; Nikkhajoei & Lasseter, 2009; Madureira & Peças Lopes, 2009) in the distribution network, or in specific portions of the network that could be managed as micro-grids. Coordinated voltage control could provide benefits for the interaction of multiple local generators scattered in the distribution network. Within a micro-grid, the impedance between the local generators is relatively small. If multiple local generator are connected to the micro-grid, trying to perform voltage control, inaccurate setting of the voltage set points of the local generators can cause the presence of circulating currents in the network. In order to prevent this effect, voltage versus reactive power droop control can be exploited (Nikkhajoei & Lasseter, 2009). Additional possibilities may come from the adoption of secondary voltage control, fast with respect to the TCUL and slow with respect to the local controllers. The control strategies have generally to be evaluated in conditions of time-dependent variation of generation and load. Variability in time of the local controls requires additional investments, justifiable when sufficient benefits can be guaranteed. Indeed, the effects of applying any type of voltage control have to be checked against their impact on other objectives such as loss or operating costs reduction.
Concerning loss allocation, the circuit-based techniques presented in this chapter have been shown to be effective for radial systems. The presence of micro-grids and more generally the perspective of increased diffusion of distributed generation may suggest the adoption of non-radial network structures. Further analyses have to be carried out to extend the circuit-based loss allocation methods to operation of non-radial structures.

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In the recent years the electrical power utilities have undergone rapid restructuring process worldwide. Indeed, with deregulation, advancement in technologies and concern about the environmental impacts, competition is particularly fostered in the generation side, thus allowing increased interconnection of generating units to the utility networks. These generating sources are called distributed generators (DG) and defined as the plant which is directly connected to distribution network and is not centrally planned and dispatched. These are also called embedded or dispersed generation units. The rating of the DG systems can vary between few kW to as high as 100 MW. Various new types of distributed generator systems, such as microturbines and fuel cells in addition to the more traditional solar and wind power are creating significant new opportunities for the integration of diverse DG systems to the utility. Interconnection of these generators will offer a number of benefits such as improved reliability, power quality, efficiency, alleviation of system constraints along with the environmental benefits. Unlike centralized power plants, the DG units are directly connected to the distribution system; most often at the customer end. The existing distribution networks are designed and operated in radial configuration with unidirectional power flow from centralized generating station to customers. The increase in interconnection of DG to utility networks can lead to reverse power flow violating fundamental assumption in their design. This creates complexity in operation and control of existing distribution networks and offers many technical challenges for successful introduction of DG systems. Some of the technical issues are islanding of DG, voltage regulation, protection and stability of the network. Some of the solutions to these problems include designing standard interface control for individual DG systems by taking care of their diverse characteristics, finding new ways to/or install and control these DG systems and finding new design for distribution system. DG has much potential to improve distribution system performance. The use of DG strongly contributes to a clean, reliable and cost effective energy for future. This book deals with several aspects of the DG systems such as benefits, issues, technology interconnected operation, performance studies, planning and design. Several authors have contributed to this book aiming to benefit students, researchers, academics, policy makers and professionals. We are indebted to all the people who either directly or indirectly contributed towards the publication of this book.

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