A Smart Strategy for Voltage Control Ancillary Service in Distribution Networks

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***Abstract*—The expected impact of distributed generation (DG) into Smart Grid represents a great challenge of the future for power systems. In particular, the integration of DG based on renewable energy sources (RESs) in distribution networks, without compromising the integrity of the grid, requires the development of proper control techniques to allow power delivery to customers in compliance with power quality and reliability standards. This paper proposes a coordinated local control approach that allows distribution system operator (DSO) and independent power producers (IPPs) to obtain benefits offering the voltage regulation ancillary service to DSO and maximizing allowable active power production for each RES unit belonging to the same IPP. The control is based on a cooperation of data transfer between DSO and IPPs. In order to realize such cooperation, a nonlinear constrained optimization problem is formulated and solved by sequential quadratic programming (SQP) method. The validation of the proposed control technique has been conducted through several time series simulations on a real MV Italian distribution system.**

***Index Terms*—Ancillary services, distribution networks, reactive power control, renewable distributed resources, smart grid, voltage control.**

I. INTRODUCTION

IN the last years the penetration of renewable energy sources (RESs) is growing worldwide encouraged by national and international policies, which aim to increase the share of sustainable sources and highly efficient power units to reduce greenhouse gas emissions and alleviate global warming [1]. However, power quality in existing power systems could worsen because of the high penetration of RESs, which could cause unexpected voltage rises on the distribution lines.

In the context of Smart Grid, based on active/autonomous distribution networks and/or multiple microgrids, many technologies and control strategies, such as smart inverters and intelligent distribution transformers, can be implemented on distribution systems providing ancillary services for voltage control [2].

In the past, reactive power regulation has been proposed for voltage control at the connection bus by using decentralized approaches, often without any coordination of distributed generation (DG) units [3]–[9]. Lately, however, thanks to advances in information and communication technologies (ICTs), which address power systems toward Smart Grids, centralized approaches are spreading more, although both approaches can be applied to yield good performances. Nonetheless, it is reasonable to assume that centralized control will typically give more robust and overall better results [10]. Refs. [11]–[14] have dealt with the voltage control problem considering a centralized approach. In particular, in [11] an optimal control voltage method with coordination of distributed installations, such as on load tap changer (OLTC), step voltage regulator (SVR), shunt capacitor (SC), shunt reactor (ShR), and static var compensator (SVC), was proposed. Casavola *et al.* presented a control strategy based on a predictive control idea for online reconfiguration of OLTC voltage set-point in medium voltage (MV) power grids with DG [12]. In [13] a centralized approach to reduce voltage rises in distribution grid in the presence of high DG penetration was discussed. The same approach was used in [14] to provide ancillary services in distribution systems: a centralized control system in real time produces the reference signals to all converters of the DG units in order to control the reactive power injections. Furthermore, it allows partial compensation or elimination of waveform distortions and voltage unbalances either at all system buses or in particular areas with more sensitive loads. Other interesting works focused on ancillary services are described in [15]–[18]. In particular, Authors in [15] and [16] deal with new procedures for reactive/voltage ancillary services market: the first proposes a minimization of the reactive power payments by distribution system operator (DSO) to independent power producers (IPPs), power losses, and voltage profile index; the second one addresses voltage control in multi-microgrid systems. The minimization of the losses is also the goal of [17], where an optimal management of the reactive power, supplied by photovoltaic unit inverters, was proposed. A good discussion on the use of operating charts for describing resources availability in ancillary services is reported in [18].

Many presented approaches allow DSO to take advantage of ancillary services without consideration of the potential benefits for IPPs. For this reason, we present a smart strategy that offers the mandatory voltage control ancillary service, based on a coordinated control method, able to obtain the maximum allowable active power production for each RES unit owned by the same IPP. It allows avoiding, as much as possible, the DG units disconnections due to the infringement of voltage regulatory limits. This control strategy operates controlling the DGs' reactive/active power exchange with the distribution network

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and it is based on the cooperation of data transfer between DSO and IPPs. Specifically, DSO communicates power system state to IPP that solves an optimization problem to provide references to RESs in order to avoid voltage constraint violations. The proposed control, thus, reaps the benefits of both approaches: the control strategy is global because involves DSO and IPPs, therefore intrinsically more reliable and comprehensive, but the resolution of the regulation problem to achieve the overall optimum control input is local. Thus, the IPPs, often constrained to offer the ancillary service of voltage regulation to DSO [19], can maximize, at the same time, the active power production.

Its main contributions compared to the literature can be summarized as follows: 1) the approach discussed in this paper takes into account not only the power converter capability curves, but also the limits imposed by national standards; 2) the optimization technique increases the active power production of IPPs compared to other local controls [7], [8]; 3) in the presence of several DG-RES units the proposed algorithm calculates the set points for each one in order to control the voltage profiles without the necessity of a complete sensitivity analysis; 4) the control proposes a smart strategy that tries to enhance the classical ancillary service related to voltage regulation; 5) the proposed method allows obtaining more benefits in terms of active power maximization compared to other voltage controls reported in literature also in the presence of high DG penetration.

The remainder of this paper is organized as follows. Section II contains the control method structure with a focus on the voltage control, the problem formulation and the definition of capability curves proposed and used in this work. Section III describes, in detail, the optimization approach showing the different steps of the control algorithm. Section IV presents the simulation results obtained by the application of the coordinated control to a real Italian distribution system. Finally, Section V contains remarks and conclusion.

II. VOLTAGE CONTROL AND PROBLEM FORMULATION

The proposed voltage control is based on a local regulation performed by an IPP, owner of some DG units connected to different bulk supply points (BSPs) of the distribution network (DN). In particular, the control is implemented through two different steps: in the first one IPP regulates the voltage profiles by means of reactive power using the sensitivity coefficients evaluated for each RES unit connected to BSP as shown in [6]–[8] and [13]. In the second one IPP performs a coordinated regulation of the reactive powers among the DG units.

In particular, the previous cited references present control methods based on an a-priori sensitivity analysis of the DN buses in order to calculate the sensitivity coefficients of the DG units that allow changing voltage values on the BSP by means of reactive (or active) power. This result is achieved by applying a decentralized voltage control up to capability curves limits by means of the reactive power provided by power inverters or through a reduction of the active power (backup solution). On the contrary, in the proposed control, if the local reactive power compensation based on the sensitivity analysis fails (the reactive power reaches the availability limits) then IPP performs a coordinated regulation of the reactive powers among the RES units. The aim is to avoid their disconnections due to voltage limit violation increasing the total power fed into the grid. It is worthy to highlight that only in this second case the proposed coordinated approach involves also the DSO during the control, which provides the power system state in order to develop the coordinated control.

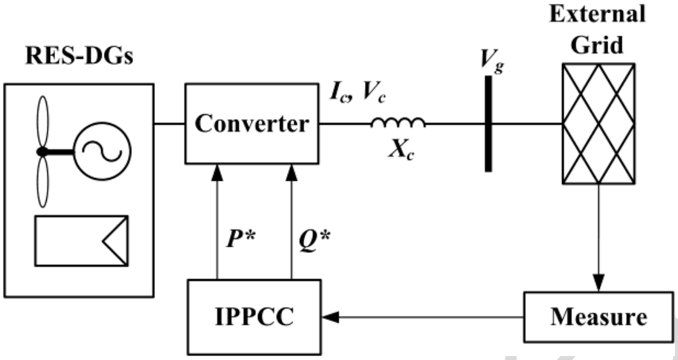


Fig. 1. Proposed control structure.

In detail, from an operational point of view, the *coordinated regulation of the reactive power* can be divided in three steps:

1) DSO sends data of DN state to IPP;
2) IPP Control Centre (IPPCC) processes data estimating the power set points (active and reactive power) of each RES unit in order to control the voltage profiles within the limits taken into account;
3) each generator changes the actual power set point with the new one received by IPPCC.

Therefore, the core of the control described so far is carried out by IPPCC that has to solve a constrained optimization problem to have the regulation set point.

A. Voltage Control

Typically, DG-RESs are connected to the DN by means of electronic power converters. Using power converters it is possible to control the voltage at the BSP varying the P/Q ratio. In order to implement a proper voltage control strategy, it is necessary to include in the control algorithm the capability curves of the power converter [20]. Fig. 1 depicts the structure of the proposed voltage control through a generic diagram of inverter based RES-DG, where P^* and Q^* are the active and reactive power set points, respectively, elaborated by the IPPCC by solving an optimization problem; I_c and V_c are the inverter outgoing current and voltage; X_c is the reactance, which takes into account the DG transformer and the grid filters used for DG connection to DN. Finally, V_g is the voltage connection bus value.

B. Problem Formulation

The coordinated voltage control action takes place only if the first regulation strategy, based on the sensitivity analysis analytically described in [6]–[8], fails. The solution of an optimization problem with nonlinear constraints allows obtaining the set points that IPP must use to regulate voltage profiles. The objective function $f(\mathbf{Q}_{\mathrm{DG}})$ to minimize through the control variable is the sum of the DG-RESs reactive powers owned by IPP:

$$\min_{\mathbf{Q_{DG}}} \{f(\mathbf{Q_{DG}})\} = \min_{\mathbf{Q_{DG}}} \left\{ \sum_{i=1}^{N_{DG}} Q_{DG_i} \right\} \tag{1}$$

TABLE I
POWER FACTOR CONSTRAINTS IMPOSED BY GRID CODE
IN DENMARK, GERMANY, ITALY, AND UNITED KINGDOM

Symbol	Denmark	Germany	Italy	United Kingdom
PF_{min}	0.975*	0.95	0.95	0.95

*for power plants with a rated power of 1.5÷25 MW

subject to the following constraints:

$$\begin{cases} V_{\min} \le V_{DG_i} \le V_{\max} \\ PF_{\min} \le PF_{DG_i} \le PF_{\max} \\ Q_{\min} \le Q_{DG_i} \le Q_{\max} \end{cases} \tag{2}$$

where N_{DG} is the number of DG units, $\mathbf{Q}_{\mathrm{DG}}$ is the vector of the reactive powers injected/absorbed by DG units, $V_{\min}$ and $V_{\max}$ are, respectively, the minimum and maximum values of the voltage imposed by the standard [21], $PF_{\min}$ and $PF_{\max}$ are the power factor constraints, $Q_{\min}$ and $Q_{\max}$ are the limits imposed by the physical capability of the converter, as described in the next subsection. V_{DG_i}, PF_{DG_i}, and Q_{DG_i} are the voltage, power factor, and reactive power values of DG-RES, respectively. Furthermore, we need to consider the power flow equations as equality constraints of the optimization problem.

The nonlinear relationships between the constraints in (2) and the control variable Q_{DG_i} for the bus i are

$$\begin{cases} Q_{DG_i} = V_i \sum\limits_{h \in Ni} V_h [G_{ih} \sin(\vartheta_i - \vartheta_h) - B_{ih} \cos(\vartheta_i - \vartheta_h)] \\ PF_i = \cos\left(\tan^{-1}\left(\frac{Q_{DG_i}}{P_{DG_i}}\right)\right) \\ Q_{cap_i} = \min\left(Q^c_{DG_i}, Q^v_{DG_i}\right) \end{cases} \tag{3}$$

where V_i and V_h are the voltage values at bus i and h; G_{ih} and B_{ih} are the real and the imaginary part, respectively, of the element in the bus admittance matrix corresponding to the ith row and the hth column; ϑ_i and ϑ_h are the voltage angles at the ith and hth bus; N_i is the number of bus directly connected to the ith bus and P_{DG_i} is the active power of the DG unit connected to the ith bus. $Q^c_{DG_i}$ and $Q^v_{DG_i}$ are the boundaries of the converter capability curves limited by current and voltage constraints, respectively.

It is worth to note that the minimization of the global reactive power (1) needed to control voltage allows reducing conductor losses, inverter losses, transformer losses and opportunity costs as described in detail in [22] and [23].

C. Power Converter Capability Curves

The converter output power (active and reactive) is limited by the capability curves of the grid-side inverter connection depicted in Fig. 1. Here, without loss of generality, RES units based on distributed wind turbines (DWTs) with synchronous generators and photovoltaic (PV) systems are considered. Set the maximum available active power, the capability curves can be calculated as described in [8] and [20].

The maximum available reactive power of a generator is

$$Q_{cap} = \min\{Q^c_{DG}, Q^v_{DG}\} \tag{4}$$

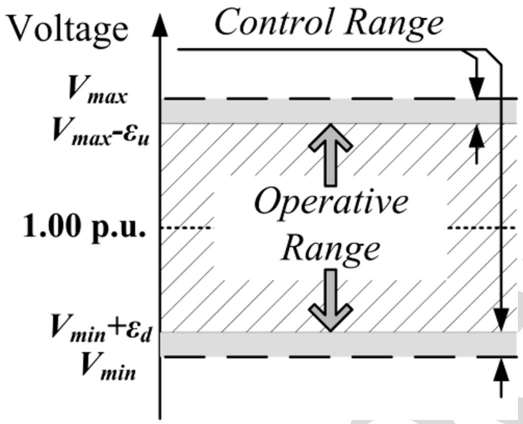


Fig. 2. Allowed, Operative and Control Ranges used in the proposed control method.

where Q^c_{DG} and Q^v_{DG} are

$$\begin{cases} Q^c_{DG} = \sqrt{(V_{\mathrm{g}} I_{c_{\max}})^2 - P^2_{DG}} \\ Q^v_{DG} = \sqrt{\left(\frac{V_{\mathrm{g}} V_{c_{\max}}}{X_c}\right)^2 - P^2_{DG}} - \frac{V^2_{\mathrm{g}}}{X_c} \end{cases} \tag{5}$$

with $I_{c_{\max}}$ maximum current output and $V_{c_{\max}}$ maximum voltage output of inverter. The latter constraints can be formulated as follows:

$$\begin{cases} I_{c_{\max}} = \frac{\sqrt{P^2_R + Q^2_R}}{V_{\mathrm{g}\max}} \\ V_{c_{\max}} = \frac{f_{\max} X_c}{V_{\mathrm{g}\max}} \sqrt{1 + \left(\tan\theta_R + \frac{V^2_{\mathrm{g}\max}}{f_{\max} X_c}\right)^2} \end{cases} \tag{6}$$

where P_R and Q_R are the rated active and reactive power and θ_R is the rated power factor angle. Besides, $f_{\max}$ and $V_{\mathrm{g}_{\max}}$ are the maximum frequency and voltage of the electrical grid. Furthermore, the constraints, imposed by Grid Code on the power factor, are taken into account in this study to better simulate reality conditions. The values shown in Table I are referred to four European countries with a high penetration of RES plants on the DN. $PF_{\min}$ indicates the minimum value of power factor (leading and lagging) at the BSP.

III. METHOD OF SOLUTION

The proposed control method realizes a voltage regulation absorbing/injecting reactive power and, only if necessary, cutting active power taking into account the capability curves limits. The range delimited by standard limits [$V_{\min}$,$V_{\max}$] is defined as *Allowed Voltage Range*, as depicted in Fig. 2. It is divided in three zones where the proposed control algorithm operates applying the following rules: no control actions are carried out within the *Operative Range*; an amount of reactive (active) power is absorbed/injected into the grid to satisfy the voltage constraints if the voltage variation is positive/negative within the *Control Ranges*, delimited by two threshold levels (ε_u, ε_d). In Fig. 3 the control algorithm flow chart related to a single RES unit is shown considering the above case violation (voltage rise). The IPPCC, after a power flow simulation, calculates the existing difference between the actual (at step k) and the previous (at step k-1) voltage value at BSP. If the

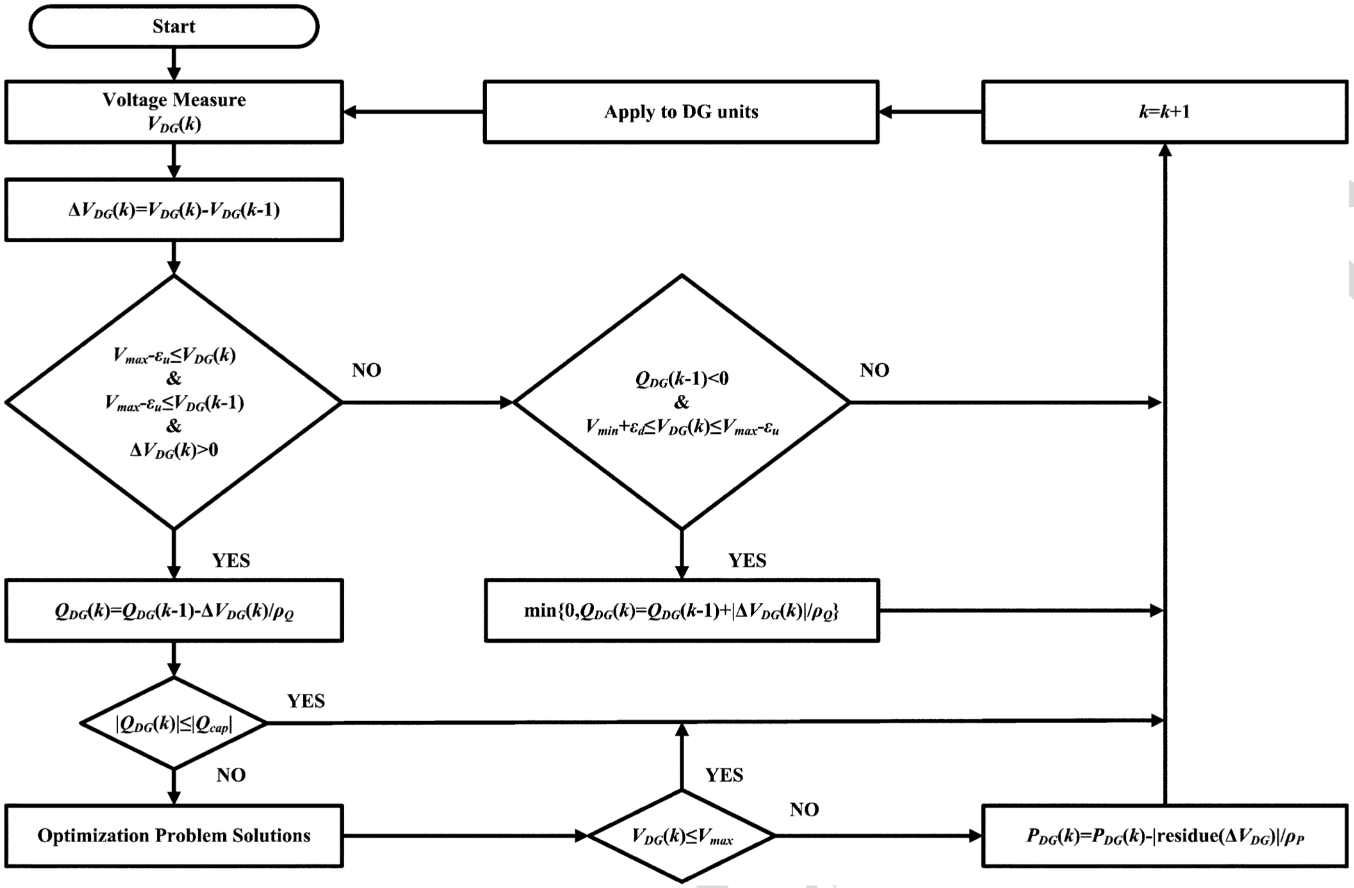


Fig. 3. Flow chart of the control algorithm.

calculated voltage value $V_{DG}(k)$ exceeds $[V_{\max} - \varepsilon_u]$ and the voltage variation $\Delta V_{DG}(k)$ is positive, than the reactive power on the controlled bus is reduced according to

$$Q_{DG}(k) = Q_{DG}(k-1) - \frac{\Delta V_{DG}(k)}{\rho_Q} \tag{7}$$

where ρ_Q is the reactive power sensitivity coefficient calculated as described in [13].

If the amount of reactive power is within the capability curves the cycle ends, otherwise the optimization problem, illustrated in the previous section, is solved. At the end, another voltage check on the controlled bus is carried out, and, if it fails, the active power is reduced proportionally to the uncompensated residue voltage variation by using the reactive power control. In this case, it is possible to calculate the active power necessary to satisfy the voltage constraints by means of the RES unit sensitivity coefficient, ρ_P.

On the other hand, if the voltage is within the *Operative Range* and the reactive power is different from zero, the algorithm reduces the reactive power absorption proportionally to the voltage variation.

It is important to remark that the proposed procedure allows also maximizing the overall active power production because the active power curtailment is only a backup solution that occurs when it is impossible to control the voltage profiles within the mandatory limits by means of coordination between DG units.

The optimization problem is solved by means of an SQP method considering a quadratic approximation of the Lagrangian function as follows:

$$L(x, \lambda, \mu) = f(x) + \sum_{j=1}^{n} \mu_j h_j(x) + \sum_{i=1}^{m} \lambda_i \mathrm{g}_i(x) \tag{8}$$

where $f(x)$ is the objective function described in (1), $h_j(x)$ are the equality constraints of the power flow equations and $g_i(x)$ are the inequality constraints as in (2); n and m are the number of equality and inequality constraints included in the optimization problem, respectively. Finally, μ and λ are the Lagrangian multipliers. Starting from the solution x_r defined in the previous iteration $(r-1)$, at each new step the SQP algorithm provides an appropriate search direction d_r towards the solution of the following quadratic programming subproblem:

$$\begin{cases} \min\limits_{d} f(x_r) + \nabla f(x_r)^T d + \frac{1}{2} d^T \nabla^2_{rr} L(x_r, \lambda_r, \mu_r) d \\ \nabla h_j(x_r)^T d + h_j(x_r) = 0 \qquad j = 1, \ldots, n \\ \nabla \mathrm{g}_i(x_r)^T d + \mathrm{g}_i(x_r) = 0 \qquad i = 1, \ldots, m. \end{cases} \tag{9}$$

The contribute d_r is used to create a starting solution for the next iteration as follows:

$$x_{r+1} = x_r + \alpha_r d_r \tag{10}$$

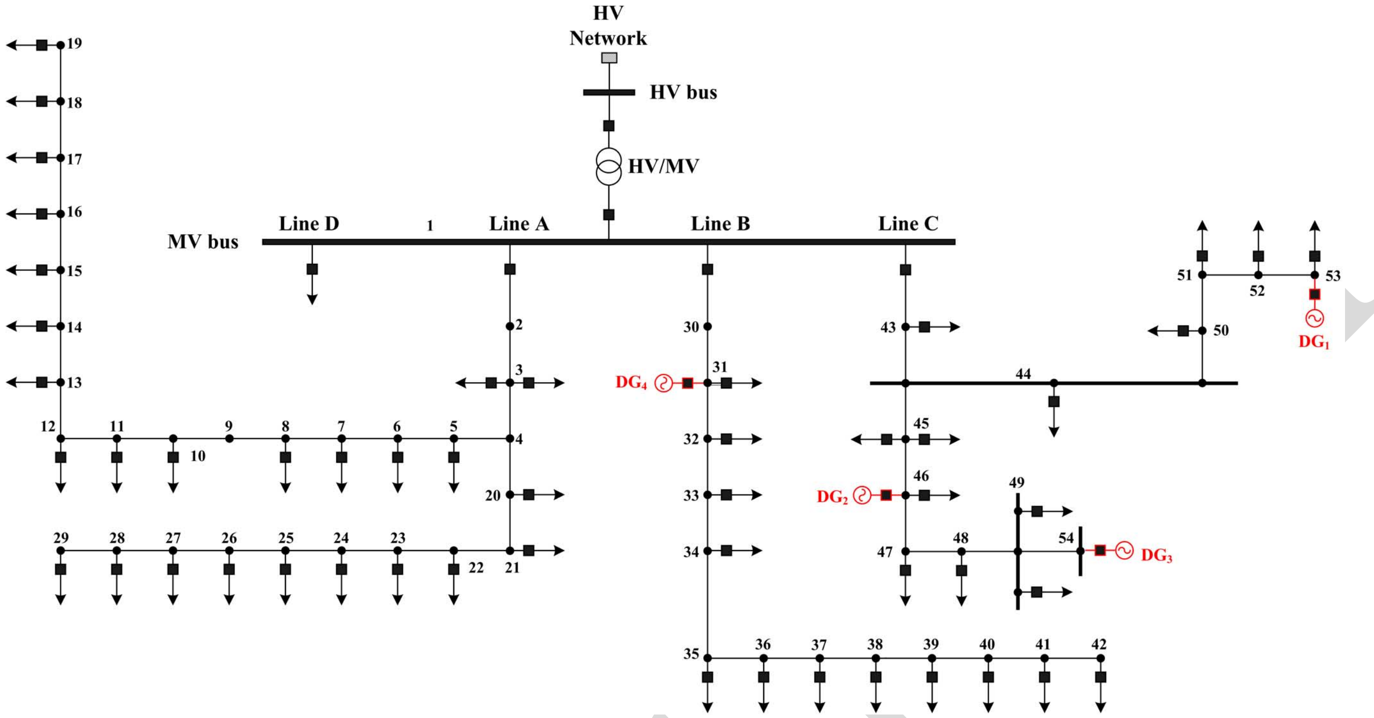
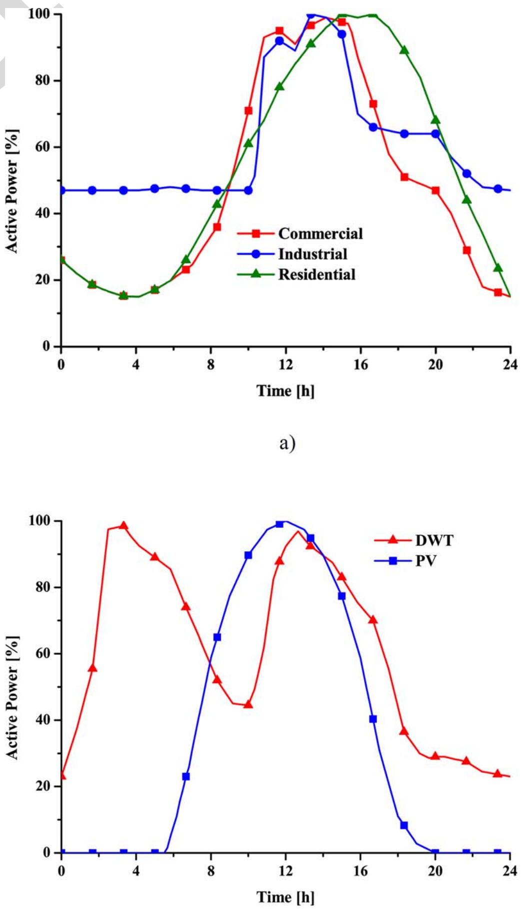


Fig. 4. Single diagram of the distribution network under test.

where α_r is the step length parameter determined by using an appropriated line search procedure, so that a sufficient decrease in a merit function is obtained [24]. The notable point of SQP is that it is a classical robust solution method in optimization theory that can deal with inequality constraints effectively. It has good performances in solving nonlinear constrained problems, which makes it a quite effective approach among the normal line search methods and widely considered as one of the most prominent algorithms in nonlinear programming. Furthermore, SQP allows obtaining a global optimization if a merit function is properly chosen extending the part convergence to global convergence [25].

IV. CASE STUDY: SIMULATIONS AND RESULTS

In order to show the effectiveness of the proposed control method a real Italian MV distribution network has been considered. The network, depicted in Fig. 4, is a 54-bus 20-kV distribution system with 4 feeders fed by a 132-kV, 50-Hz subtransmission system with short circuit level of 750 MVA through a 150/20 kV Δ/Y_{g} transformer with rated power of 25 MVA and $X/R = 0.1$. The tap was set to 1.006 p.u., according to one of two classical Italian control strategies for distribution systems [7]. Two DWTs, each with a rated power of 5 MVA, are connected to the buses 46 and 54 and two PV units with the same rated power are connected to the buses 31 and 53. Fig. 5 depicts the normalized profiles used for the different load categories (residential, commercial and industrial) and for the PV units and DWTs. These profiles are multiplied for the rated power of each load or generator in order to have the power daily profile of each bus. The rated powers of the loads are reported in the Appendix together with network data. The capability curves, imposed by Italian national standards, limit the power factor between 0.95



a)

b)

Fig. 5. Active power normalized profiles. a) Load demands. b) Generation profiles.

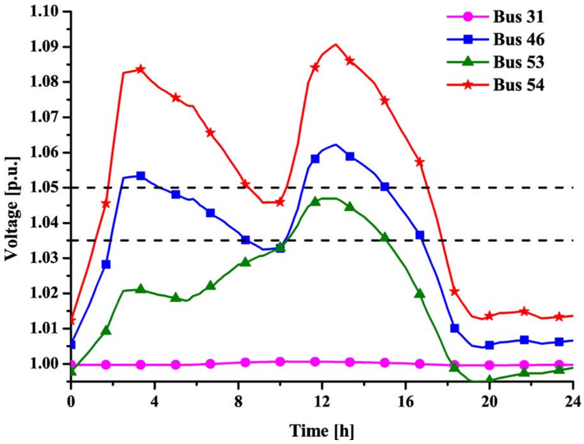


Fig. 6. Voltage profiles of RES unit connections without control.

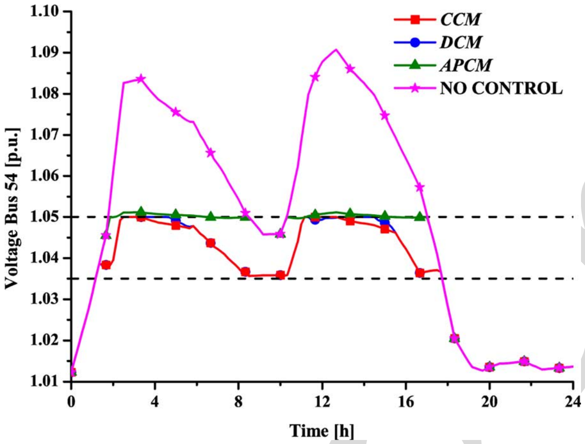


Fig. 7. Voltage profiles of the RES units connected to the bus 54 using different voltage control strategies.

lagging and 0.95 leading [19]. Furthermore, the threshold values are set to $\varepsilon_u = \varepsilon_d = 0.015$.

Time series simulations have been carried out with computed state of 10 minutes in order to illustrate the potential benefits introduced by the proposed *Coordinated Control Method (CCM)* compared to two types of regulation common in literature. The first one, named *Active Power Control Method (APCM)*, consists in a simple active power curtailment proportional to the voltage violation. The second one is a *Decentralized Control Method (DCM)* that uses the sensitivity coefficients proposed in [6] and [13] for absorbing/injecting reactive power in order to control voltage profiles. The average simulation time to perform the *CCM* has been estimated around 21 s by using a workstation with an Intel Xeon E3-1230 V2 (3.30 GHz, 64 bit) processor, 16 GB of RAM and MATLAB™ R2013a. In any case, it is worth to note that the simulation times for all steps have been less than a minute, which are compatibles with the considered control step time of 10 minutes. However, the convergence times depend on the case study taken into account. The SQP has been implemented in MATLAB™ setting the maximum number of iterations to 1000, considering a tolerance of 1e-3 for the step size, 1e-6 for the objective function and 1e-20 for the magnitude of any constraint function. In Fig. 6, it is possible to see the voltage profiles when no control actions have been applied. The dashed lines specify the band of the *Control Range*, where the greater one also indicates the maximum limit allowable for the voltage (1.05 p.u.) [21]. In these conditions the voltages at the buses 46 and 54 exceed the maximum value limit of 1.05 p.u. On the contrary, by using one of the three described control methods it is possible to achieve a correct voltage regulation. Indeed, as illustrated in Fig. 7 for the bus 54, the voltage rise, due to the DG connected at the bus, is correctly regulated within the standard limits. Furthermore, it is possible to note how these results could be achieved using indistinctly the *APCM, DCM,* and *CCM*. Nevertheless, these strategies are characterized by significant differences in terms of active and reactive power usage. In Figs. 8 and 9 the active and reactive power injections/absorptions for these three methods are illustrated. In detail, the *DCM* compared with the *APCM* allows reducing active power curtailments absorbing reactive power up to the limits imposed by the capability curves. As matter of fact, the simulation results highlighted an increment of 81.5% in the active power production on a whole day using the *DCM* instead of the *APCM*. However, as depicted in Fig. 8, the *CCM* allows injecting all the available active power increasing the active power production of 18.5% compared to the *DCM*. Fig. 9 shows that this result

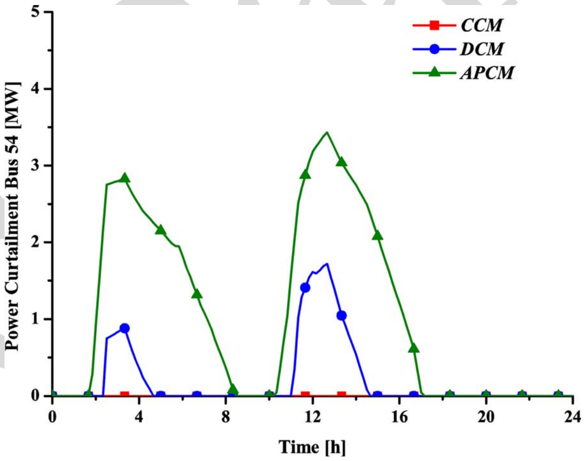


Fig. 8. Active power curtailment of the RES units connected to the bus 54 using different voltage control strategies.

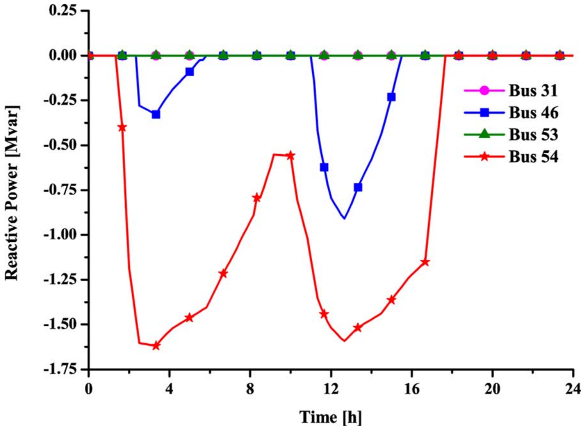


Fig. 9. Reactive power of RES unit connections using CCM.

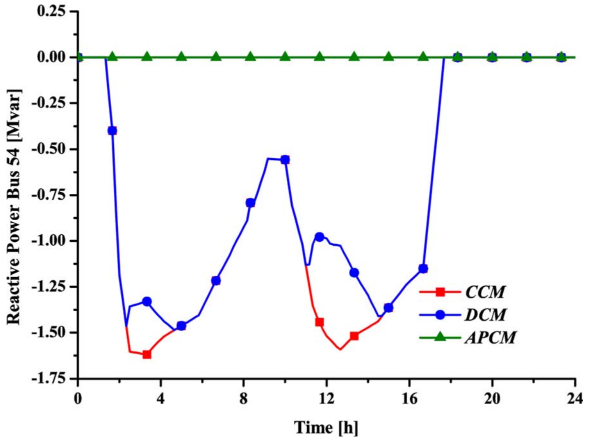


Fig. 10. Reactive power absorption of the RES units connected to the bus 54 using different voltage control strategies.

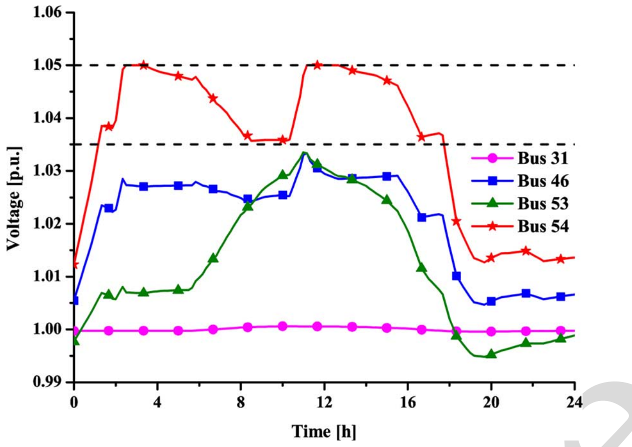


Fig. 11. Voltage profiles of RES unit connections using CCM.

TABLE II
COMPARISON BETWEEN THE CONTROL METHODS AT BUS 54

Control Method	Active Power Curtailment during a day [MWh]	Reactive Power Absorption during a day [Mvarh]
APCM	25.89	0.00 (ind.)*
DCM	5.04	17.73 (ind.)
CCM	0.00	19.38 (ind.)

*ind.: inductive reactive power

has been obtained increasing the reactive power absorption at the bus 46, which has not already reached the capability curves limits. Nonetheless, the *CCM* requires a daily reactive power absorption of 19.38 Mvarh that is slightly greater than 17.73 Mvarh needed to apply the *DCM* approach, as it is possible to observe from Table II. Furthermore, comparing Figs. 9 and 11, it is possible to understand that the solution given by the optimization process is correct because the bus 46 absorbs reactive power, supporting the bus 54 in voltage regulation, even though the voltage at BSP is within the mandatory limits (Fig. 11).

Finally, a further check has been carried out on the capability curves. Indeed, Fig. 12 shows the set points elaborated by the IPPCC solving the constrained optimization problem. Also in this case the control works properly, in fact, all the set points are within the standard imposed by national code (dashed lines) and physical limits (continuous lines).

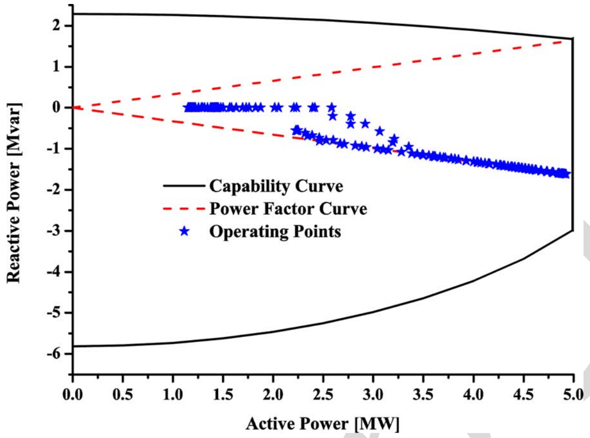


Fig. 12. Capability curves of the RES units connected to the bus 54.

V. CONCLUSIONS

In this paper a smart strategy to offer the mandatory voltage control ancillary service is developed. It is based on a coordinated approach able to obtain the maximum allowable active power production for each RES unit owned by an IPP. This strategy can be divided in two subsequent steps. Initially, a decentralized voltage control is carried out through a sensitivity analysis. If it fails, a nonlinear constrained optimization problem is solved in order to maximize the active power production within mandatory limits. In this second step, DSO is involved sharing the set points of the distribution network with IPP, which offers an ancillary service bringing benefits for both.

The optimization problem is solved using an SQP method taking into account the limits imposed by physical (i.e., power converter capability curves) and Grid Code constraints. In order to prove the validity of the proposed method several time series simulation analysis are run on a real Italian distribution network test grid with distributed wind turbines and photovoltaic units. The new method, named *Coordinated Control Method*, is compared with other two voltage control methods presented in literature highlighting the advantages in terms of active power curtailments needed to avoid voltage problems. The simulation results point out an increase of 18.5% in the active power production during daily time series simulations, compared to a traditional decentralized voltage control. It is interesting to note that, in the presence of several DG units owned by an IPP and connected to the same distribution network, the control calculates automatically the set points for each DG unit in each condition. The proposed control allows reducing the whole reactive power injection/absorption, maximizing, at the same time, the active power production.

Additionally, significant results could be obtained in the presence of high DG penetration when, usually, a traditional control method it is forced to reduce the active power in order to avoid voltage problems. In contrast, as this method requires a cooperation of data transfer between DSO and IPPs, in order to determine the status of the grid, a monitoring and acquisition system is necessary.

TABLE III
LINE PARAMETERS

N° of bus from	to	Length [km]	r [Ω/km]	x [Ω/km]
1	2	5.000	0.253	0.359
2	3	1.600	0.206	0.344
3	4	3.000	0.206	0.344
4	5	0.900	0.320	0.126
5	6	0.190	0.320	0.126
6	7	0.200	0.320	0.126
7	8	0.700	0.443	0.132
8	9	0.700	0.443	0.132
9	10	0.001	0.387	0.138
10	11	0.300	0.443	0.132
11	12	0.600	0.320	0.126
12	13	0.505	0.641	0.138
13	14	0.250	0.443	0.132
14	15	0.370	0.320	0.126
15	16	0.750	0.320	0.126
16	17	0.300	0.387	0.138
17	18	0.320	0.387	0.138
18	19	0.320	0.387	0.138
4	20	0.932	0.320	0.126
20	21	0.747	0.320	0.126
21	22	1.250	0.320	0.126
22	23	0.390	0.320	0.126
23	24	0.400	0.320	0.126
24	25	0.550	0.320	0.126
25	26	0.350	0.320	0.126
26	27	1.550	0.320	0.126
27	28	0.890	0.320	0.126
28	29	0.750	0.320	0.126
1	30	0.200	0.320	0.126
30	31	0.143	0.164	0.113
31	32	0.410	0.320	0.126
32	33	0.568	0.320	0.126
33	34	0.520	0.320	0.126
34	35	0.390	0.320	0.126
35	36	0.278	0.320	0.126
36	37	0.251	0.320	0.126
37	38	0.343	0.320	0.126
38	39	0.200	0.320	0.126
39	40	0.639	0.320	0.126
40	41	0.010	0.320	0.126
41	42	0.350	0.320	0.126
1	43	5.343	0.206	0.344
50	51	0.060	0.524	0.390
51	52	0.876	0.524	0.390
52	53	0.400	0.524	0.390
43	44	2.564	0.206	0.344
44	45	3.000	0.206	0.344
45	46	4.480	0.206	0.344
46	47	1.400	0.524	0.390
47	48	2.580	0.524	0.390
48	49	0.500	0.524	0.390
49	54	0.750	0.524	0.390
44	50	1.370	0.524	0.390

Projecting in the near future and considering the increasing of smart meters installations, PMU and the improvement of Smart Grid interoperability, the *Coordinated Control Method* could represent a good solution to apply to a distribution network for voltage control purposes.

TABLE IV
LOAD CHARACTERISTICS

Bus	Active Power [MW]	Reactive Power [Mvar]	Profile*
1	4.752	2.301	I
2	0.000	0.000	0
3	2.698	1.307	I
4	0.000	0.000	0
5	0.124	0.060	R
6	0.025	0.012	C
7	0.124	0.060	R
8	0.124	0.060	R
9	0.000	0.000	0
10	0.174	0.084	I
11	0.198	0.096	I
12	0.124	0.060	R
13	0.124	0.060	R
14	0.124	0.060	R
15	0.124	0.060	R
16	0.124	0.060	R
17	0.124	0.060	R
18	0.198	0.096	I
19	0.050	0.024	R
20	0.124	0.060	C
21	0.124	0.060	C
22	0.124	0.060	R
23	0.124	0.060	R
24	0.124	0.060	R
25	0.124	0.060	R
26	0.124	0.060	R
27	0.124	0.060	R
28	0.124	0.060	R
29	0.124	0.060	R
30	0.000	0.000	0
31	0.158	0.076	C
32	0.038	0.018	C
33	0.158	0.076	R
34	0.252	0.122	I
35	0.158	0.076	R
36	0.252	0.122	I
37	0.158	0.076	R
38	0.104	0.050	C
39	0.252	0.122	I
40	0.158	0.076	R
41	0.268	0.130	I
42	0.158	0.076	R
43	0.270	0.131	R
44	0.383	0.185	R
45	0.324	0.157	R
46	0.090	0.044	R
47	0.054	0.026	R
48	0.036	0.017	C
49	0.216	0.105	R
50	0.036	0.017	R
51	0.774	0.375	R
52	0.036	0.017	R
53	0.144	0.070	R
54	0.000	0.000	0

* R: Residential, I:Industrial, C:Commercial, 0: No Load

APPENDIX

Table III lists the line parameters. Table IV lists the load characteristics.

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