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Short-Term Scheduling of Active Distribution Systems

A. Borghetti, M. Bosetti, S. Grillo, M. Paolone, F. Silvestro

Abstract-- **The latest distribution management systems tend to incorporate optimization functions for the short-term scheduling of the various energy and control resources available in the network (e.g., embedded generators, reactive power compensators and transformers equipped with on-load tap changers). The short-term scheduling procedure adopted in the paper is composed by two stages: a day-ahead scheduler for the optimization of distributed resources production during the following day, an intra-day scheduler that every 15 minutes adjusts the scheduling in order to take into account the operation requirements and constraints of the distribution network. The intra-day scheduler solves a non-linear multi-objective optimization problem by iteratively applying a mixed-integer linear programming (MILP) algorithm. The linearization of the optimization function and the constraints is achieved by the use of sensitivity coefficients obtained from the results of a three-phase power flow calculation. The paper shows the application of the proposed approach to a medium-voltage 120 buses network with 10 dispatchable generators and 2 transformers equipped with on-load tap changers.**

Index Terms—**Distributed generation, operation of distribution networks, MILP.**

I. Introduction

THE increasing penetration of distributed energy resources (DERs) in medium voltage (MV) networks involves a substantial evolution in their operational practice [1].

The idea of the active distribution network foreseen a high DERs penetration scenario in which, overcoming the usual "connect and forget" approach, DERs are involved in the network management. Each DER becomes, within its specific capability limits, an active subject of network regulations and an important control mean for the network operation. The final purpose is to take advantage of dispatchable DERs for both the exploitation of the available energy resources and for an improved level of service quality.

For an active operation of distribution networks, the improvement of the distribution management systems (DMS) appears to be needed in order to allow the coordinate scheduling of both dispatchable DERs and regulation resources, such as on-load tap changers (OLTC).

In the literature, various approaches have been presented for active distribution networks DMS (e.g., [2-6]). In [7,8] a two-stages procedure has been proposed: a day-ahead economic scheduler that calculates the DERs active power set points during the following day in order to minimize the overall costs, and an intra-day scheduler that, every 15 minutes, updates DERs and OLTCs set points.

This paper briefly reviews the two stages approach and presents a new implementation of the intra-day scheduler based on the use of a mixed-integer linear programming (MILP) algorithm that allows the detailed representation of OLTCs positions. As the optimization problem is non-linear, the MILP algorithm is included in an iterative procedure by means of the linearization of both the objective function and constraints. The sensitivity coefficients needed for the linearization are obtained from the results of a detailed three-phase power flow calculation.

The proposed procedure is applied to a MV 120 buses network with 10 dispatchable generators, renewable recourses (wind and photovoltaic units), and 2 transformers equipped with on-load tap changers.

The paper is structured as follows. Section II briefly reviews the two stage approach and, then, presents the MILP formulation of the linearized optimization problem and the calculation of the sensitivity coefficients. Section III presents the results of the application of the two-stage scheduler to typical urban and rural distribution feeders. Section IV concludes the paper.

II. The two stage approach and MILP formulation of the intra-day scheduler

A. Day-ahead scheduler

The day-ahead scheduler aims at better exploiting the generation units on the basis of their availability, production costs and constraints. The procedure considers both thermal and electric DERs and both dispatchable and not-dispatchable DERs. As described in [8], the scheduler defines the DERs set point in terms of required energy production (power for the assigned time interval), by using the day-ahead forecasts of both thermal and electrical loads, as well as of renewable productions.

The inputs are: (a) electrical and thermal load forecasts, (b) forecast of energy supplied by renewable source, (c) costs for production units, (d) constraints (upper and lower limits)

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relevant to the generating units.

The optimization problem is defined as the minimization of the sum of the variable costs of each generation units (both electric and thermal) for all the time intervals, taking into account both electrical and thermal load balances, as well as upper and lower production limits.

Thermal load balance constraint assumes particular importance for the case of combined heat and power (CHP) units that usually follow the thermal load requests.

B. Intra-day scheduler

Fig. 1 shows the scheme of the optimization procedure, whose multi-objective function consists in the minimization of the voltage deviations with respect the rated value, of the DERs production deviations with respect the set points calculated by the day-ahead scheduler and of the network losses.

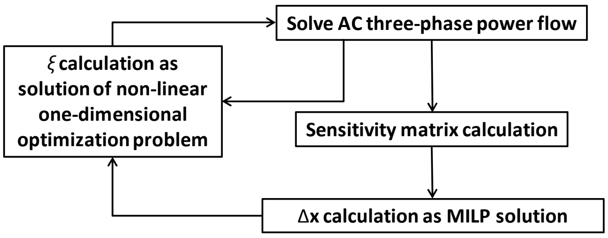


Fig. 1. Scheme of the scheduling procedure.

At the beginning of each iteration, sensitivity coefficients are needed for the problem linearization. The coefficients are obtained from the results of a three-phase power flow calculation.

The linearized optimization problem is then solved by means of a MILP algorithm in order to find the improvement direction $\Delta\mathbf{x}$ of control variables vector $\mathbf{x} = [\mathbf{P}_{\mathrm{DER}}\ \mathbf{Q}_{\mathrm{DER}}\ \mathbf{n}_{\mathrm{OLTC}}]$, being $\mathbf{P}_{\mathrm{DER}}$ and $\mathbf{Q}_{\mathrm{DER}}$ the DERs active and reactive power operation set-points and $\mathbf{n}_{\mathrm{OLTC}}$ the OLTCs operating tap positions.

The initial values of the DERs control variables and OLTCs positions are modified by $\xi\Delta\mathbf{x}$, where $\Delta\mathbf{x}$ is the solution of the MILP and coefficient ξ is calculated so to minimize the value of objective function as the solution of a non-linear one-dimensional optimization problem, by means of the golden section method.

The iterative procedure stops when the objective function or control variables do not change significantly between two consecutive iterations or a maximum number of iterations is reached.

The following two paragraphs are devoted to the formulation of the MILP problem and to the calculation of the sensitivity coefficients.

C. *MILP formulation for the intra-day scheduler*

The objective of the linear optimization problem relevant to the intra-day scheduler is:

$$\min_{\mathbf{s}_{\mathrm{P}},\mathbf{s}_{\mathrm{Q}},\mathbf{s}_{\mathrm{n}}} \left\{ \sum_{j=1}^{N_{\mathrm{DER}}} \alpha \mathbf{s}_P + \beta P_{loss} + \sum_{i=1}^{N} \gamma \mathbf{s}_V \right\} \tag{1}$$

where N_{DER} is the number of dispatchable DERs, N is the bus number, $\boldsymbol{s}_{\mathrm{P}}$ is the vector of the artificial variables that represent the absolute values of the differences of DERs power outputs P_j with respect to their references values $\overline{P}_j$ calculated by the day-ahead scheduler (i.e. $\left|P_j - \overline{P}_j\right|$ for each DER j); $\boldsymbol{s}_{\mathrm{V}}$ is the vector of the artificial variables that represent the absolute values of the differences of bus voltages V_i with respect to their rated value $\overline{V}$ (i.e. $\left|V_i - \overline{V}\right|$ for each bus i); P_{loss} is the value of the network losses.

Coefficients α, β, and γ are the weights of each component of the objective function.

The non-linear relationships that links bus voltages and losses to control variables $\mathbf{x}$ are linearized as follows

$$\begin{aligned} \left|\Delta V_i\right| &= \mathbf{K}_{i\mathbf{P}}\Delta\mathbf{P}_{\mathrm{DER}} + \mathbf{K}_{i\mathbf{Q}}\Delta\mathbf{Q}_{\mathrm{DER}} + \mathbf{K}_{i\mathbf{n}}\Delta\mathbf{n}_{\mathrm{OLTC}} \qquad \forall i \\ \Delta P_{loss} &= \mathbf{L}_{P_{\mathrm{loss}}\mathbf{P}}\Delta\mathbf{P}_{\mathrm{DER}} + \mathbf{L}_{P_{\mathrm{loss}}\mathbf{Q}}\Delta\mathbf{Q}_{\mathrm{DER}} + \mathbf{L}_{P_{\mathrm{loss}}\mathbf{n}}\Delta\mathbf{n}_{\mathrm{OLTC}} \end{aligned} \tag{2}$$

$\mathbf{K}_{i\mathbf{P}}$, $\mathbf{K}_{i\mathbf{Q}}$, and $\mathbf{K}_{i\mathbf{n}}$ are the vectors of sensitivity coefficients of voltage deviations at bus i to control variables variations $\Delta\mathbf{x}$,. Similarly, $\mathbf{L}_{P_{\mathrm{loss}}\mathbf{P}}$, $\mathbf{L}_{P_{\mathrm{loss}}\mathbf{Q}}$, and $\mathbf{L}_{P_{\mathrm{loss}}\mathbf{n}}$ are the vectors of the sensitivity coefficients of active network losses.

The set of the problem constraints include the typical capability limits of each DER. OLTCs tap positions $\mathbf{n}_{\mathrm{OLTC}}$ can assume only discrete values between a minimum and a maximum value with respect to the neutral position, corresponding to the rated transformer ratio.

The ampacity limit of each line or cable b is taken into account by including specific upper bounds to the current amplitude variation

$$\left|\Delta I_b\right| = \mathbf{H}_{b\mathbf{P}}\Delta\mathbf{P}_{\mathrm{DER}} + \mathbf{H}_{b\mathbf{Q}}\Delta\mathbf{Q}_{\mathrm{DER}} + \mathbf{H}_{b\mathbf{n}}\Delta\mathbf{n}_{\mathrm{OLTC}} \quad \forall b \tag{3}$$

where $\mathbf{H}_{b\mathbf{P}}$, $\mathbf{H}_{b\mathbf{Q}}$, and $\mathbf{H}_{b\mathbf{n}}$ are the sensitivity coefficient vectors of the current amplitude variation at branch b.

D. *Calculation of the sensitivity coefficients*

The sensitivity coefficients may be estimated by several power flow calculations, each obtained by a small perturbation to one control variable. However, the computation time significantly increases at the increasing of the number of dispatchable DERs.

On the other hand, the same sensitivity coefficients may be obtained from the results of the initial power flow calculation (e.g., [9]). In particular, voltage sensitivity coefficients $\mathbf{K}_{i\mathbf{P}}$, $\mathbf{K}_{i\mathbf{Q}}$ in Cartesian coordinates are evaluated by the inverse of the square Jacobian matrix:

$$J = \begin{bmatrix} \dfrac{\partial \boldsymbol{P}}{\partial \mathbf{V}_R} & \dfrac{\partial \boldsymbol{P}}{\partial \mathbf{V}_X} \\ \dfrac{\partial \boldsymbol{Q}}{\partial \mathbf{V}_R} & \dfrac{\partial \boldsymbol{Q}}{\partial \mathbf{V}_X} \end{bmatrix} \tag{4}$$

where $\mathbf{P}$, $\mathbf{Q}$ and $\mathbf{V}$ are the active powers, reactive powers and voltages at each bus, except at the slack bus. Sensitivity coefficients $\mathbf{K}_{i\mathbf{n}}$ can be obtained by the summation of the products between the sensitivity coefficient of active and reactive powers at the busses to each OLTC variation and the appropriated coefficients $\mathbf{K}_{i\mathbf{P}}$, $\mathbf{K}_{i\mathbf{Q}}$, already calculated.

Assuming a PI equivalent circuit, the sensitivity coefficients relevant to branch current variations are directly obtained from the voltage sensitivity coefficients of two terminal busses.

III. APPLICATION EXAMPLE

Both the day-ahead scheduler and the intra-day scheduler have been implemented in Matlab and the `lp_solve` routine is used for the solution of the MILP optimization problems. The three-phase power flow calculations required by the intra-day scheduler are carried out in the EMTP-RV environment. The link between Matlab and EMTP-RV is provided by specifically developed JavaScript functions.

The procedure is applied to a 120-bus MV distribution network which configuration is detailed described in [10]. The network is composed by four feeders, all fed by the same bus of the sub-transmission network by means of two 150/20 kV transformers equipped with OLTCs (T1 and T2). Two of the feeders (called urban 1 and urban 2) are fed through transformer T1 and are characterized by a typical urban configuration. The other two (called rural 1 and rural 2) are fed through transformer T2 and are characterized by a typical rural configuration. Both OLTCs have 17 positions (±8 and the neutral) each corresponding to 1.5% of the rated voltage value.

A. Day-ahead scheduler

In what follows, the main characteristics of the load, of wind and photovoltaic generation, as well as of available dispatchable DERs are described. Then 24-hours results of the day-ahead scheduling are presented.

1) Loads characteristics

A total number of 118 loads are assumed. As shown in Fig. 2, the whole set is made up of 5 different types of active and reactive power profiles (agricultural, commercial, industrial, residential, illumination). For the case of residential and illumination profiles the data are available at 15-min intervals, whilst for the others at one-hour intervals.

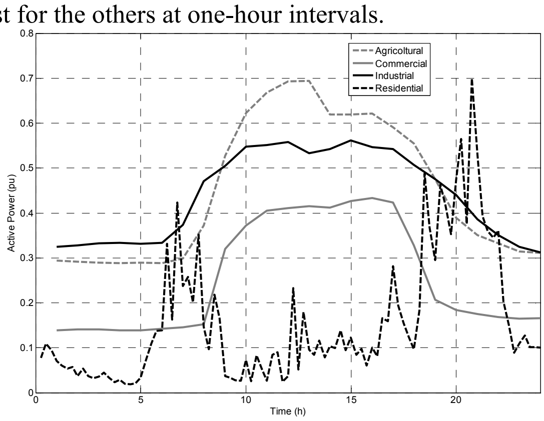


Fig. 2. Assumed daily profiles for the various load types.

2) Wind and photovoltaic generation

In the network are present 13 wind turbines, each of 850 kW rated power, installed in 5 wind plants. 2 wind plants, each composed by 2 turbines, are connected to rural feeder 1 (namely, DER_58 and DER_63), and 3 wind plants, each composed by 3 turbines, are connected to rural feeder 2 (namely, DER _109, DER _116 and DER _119).

In order to characterize the power output of each wind turbine, the 13 wind profiles have been generated, with a certain degree of correlation, by using the 10-min detail master profile shown in Fig. 3, by adding a zero mean and 1.4 m/s standard deviation Gaussian noise.

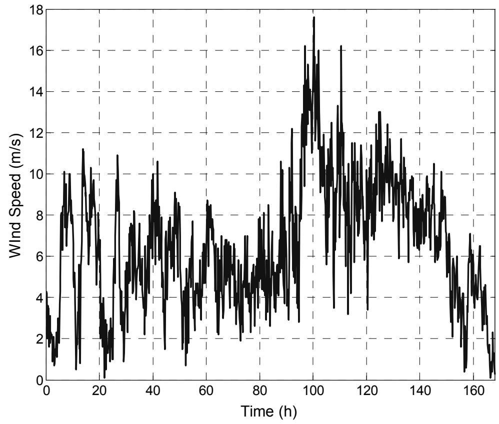


Fig. 3. One week of wind speed data of the master profile.

Moreover, one photovoltaic field, 1 MW peak, is connected to rural feeder 2 (DER_95). The photovoltaic output is described by a profile of sun irradiance with a 30-min detail.

3) Dispatchable DERs

10 dispatchable DERS are connected to the network: 4 to urban feeder 1 (DER _04, DER_18, DER_19, and DER_20), 3 to urban feeder 2 (DER_21, DER_23, DER_31), 3 to rural feeder 1 (DER_40, DER_49, DER_54). For each dispatchable DER, Table I reports type, variable production cost, and both the electrical and thermal rated power outputs.

TABLE I.
DERS MAIN CHARACTERISTICS
GT: GAS TURBINE; ICE: INTERNAL COMBUSTION ENGINE; B: BIOMASS

Name	Type	Feeder	Rated el. output MW	Rated th. output MW	Cost €/MWh
DER_04	GT	Urban 1	3.5	–	115
DER_18	ICE	Urban 1	0.5	–	130
DER_19	GT	Urban 1	3.0	–	95
DER_20	GT	Urban 1	5.5	–	85
DER_21	GT	Urban 2	5.0	–	94
DER_23	ICE	Urban 2	1.0	–	140
DER_31	GT	Urban 2	5.0	–	111
DER_40	B	Rural 1	1.5	1.65	150
DER_49	B	Rural 1	3.0	3.30	150
DER_54	B	Rural 1	3.0	3.30	150

4) Scheduling results

The implemented algorithm aims at better exploiting the generation units on the basis of their availability, production costs and constraints. Grid costs are assumed those of a typical day-ahead Italian market session, increased by a 5.1% factor representing the standard MV losses (Fig. 4).

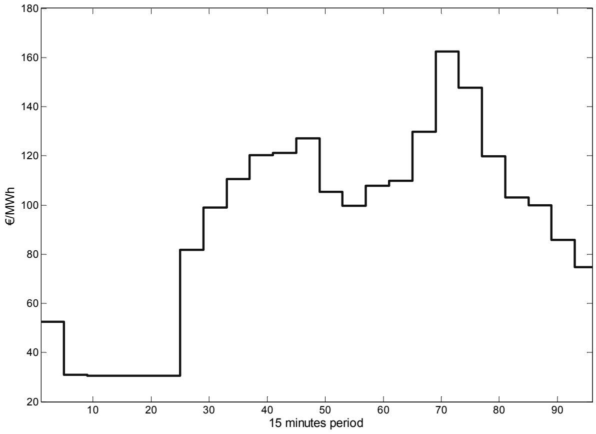


Fig. 4. Grid costs.

The results for an optimization period of 96 15-min intervals (one day) are shown in Fig. 5 – Fig. 7. Fig. 5 shows the electrical power output schedules. Due to the high production costs, DERs that produce only electrical energy are scheduled at their upper limit only when grid costs are high.

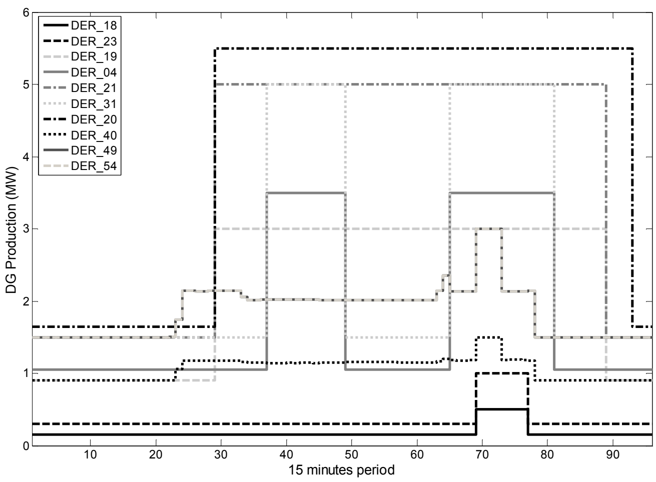


Fig. 5. Day-ahead scheduling results: electrical power outputs.

Fig. 6 shows the different behavior of CHP (combined heat and power) biomass units (DER_40, DER_49 and DER_54), which are bound to follow their thermal load.

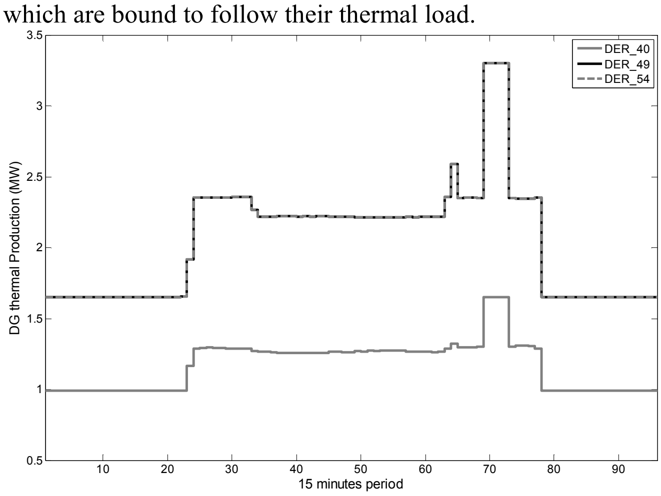


Fig. 6. Day-ahead scheduling results: thermal production of CHP generating units.

The power exchange through the interface with the sub-transmission network illustrated in Fig. 7, shows that during several periods the distribution system is able to export power to the grid (negative values in Fig. 7).

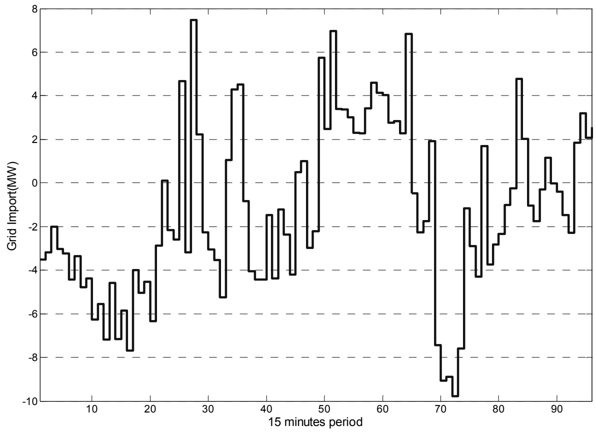


Fig. 7. Power exchange through grid interface.

B. *Intra-day scheduler*

In order to illustrate the intra-day scheduler, we present here the results relevant to two of the 15-min periods already considered by the day-ahead scheduler optimization. The two periods are characterized by the minimum and maximum total load requests, namely period no. 17 (4 am) and period no 77 (7 pm), respectively. As shown in Fig. 7, in both periods the distribution network is exporting power to the grid.

The initial DERs set-points are shown in Table II. The first 10 DERs are those assumed to be dispatchable, so their active and reactive power outputs may be adjusted by the intra-day scheduler, as well as the set points of the two OLTCs, assumed initially at the neutral position.

TABLE II.
DERS INITIAL SET-POINT FOR BOTH THE NETWORK CONFIGURATION CHARACTERIZED BY MINIMUM AND MAXIMUM LOAD.

Connection feeder	N	DER	Initial condition Minimum load		Initial condition Maximum load	
			P (kW)	Q (kW)	P (kW)	Q (kW)
Urban 1	1	DER_04	1050	788	3500	2625
	2	DER_18	150	113	150	113
	3	DER_19	900	675	3000	2250
	4	DER_20	1650	1238	5500	4125
Urban 2	5	DER_21	1500	1125	5000	3750
	6	DER_23	300	225	300	225
	7	DER_31	1500	1125	5000	3750
Rural 1	8	DER_40	900	675	1172	879
	9	DER_49	1500	1125	2141	1606
	10	DER_54	1500	1125	2141	1606
	11	DER _58	739	0	261	0
	12	DER _63	538	0	200	0
Rural 2	13	DER _95	0	0	0	0
	14	DER _109	1326	0	469	0
	15	DER _116	1063	0	528	0
	16	DER _119	950	0	677	0

For both periods, the intra-day scheduler is applied with 3 different sets of the α,β,γ values:

opt1) α=0, β=0, γ=1

opt2) α=1, β=0, γ=1

opt3) α=50, β=0, γ=1.

For the case of opt1 parameters, the scheduler takes into account only the objective of voltage deviation minimization, multiplied by γ in (1). The non-null value of α parameter in opt2 and opt3 permits to take also into account the minimization of the DERs active output deviations, being the value α=50 sufficient to fix each DERs active output to its reference value calculated by the day-ahead scheduler. β is always set to zero so that the minimization of the losses is not explicitly included in the objective function.

1) Time period of minimum load

The calculated set-points of each DER are reported in Table III and those of the OLTCs in Table IV. Table V summarizes the network losses values and voltage-deviation mean absolute values for each set of α,β,γ values.

TABLE III

DERS ACTIVE AND REACTIVE POWER IN THE PERIOD OF MINIMUM LOAD

DER	Opt1		Opt2		Opt3	
	P (kW)	Q (kvar)	P (kW)	Q (kvar)	P (kW)	Q (kvar)
DER_54	28	200	1024	-2248	1500	-2249
DER_49	681	43	1500	565	1500	202
DER_40	1313	990	900	1125	900	-141
DER_18	499	374	150	375	150	375
DER_19	2	1127	900	196	900	474
DER_20	975	-2793	1650	-4124	1650	-4124
DER_23	0.6	473	300	750	300	750
DER_21	3	14	1500	-3095	1500	-2295
DER_31	2189	2295	1500	3749	1500	3749
DER_04	1873	-2164	1050	1364	1050	2625

TABLE IV

OLTCS TAP POSITIONS IN THE PERIOD OF MINIMUM LOAD

Transformer	Initial condition	Opt1	Opt2	Opt3
T1	0	+1	+1	0
T2	0	-1	0	+1

TABLE V

LOSSES AND VOLTAGE DEVIATIONS IN THE PERIOD OF MINIMUM LOAD

	Initial condition	Opt1	Opt2	Opt3
Losses (kW)	339	205	379	425
Mean Absolute Voltage Deviation (V)	568	132.3	132.6	136.4

As expected, a large α value constraints DERs active power set-points to be similar to the day-ahead scheduler results. Such a condition led to a slightly less accurate voltage regulation. The opt1 values allow the reduction of DERs active power outputs in order to minimize bus overvoltages, resulting in a significant reduction of network losses. As shown in Table V, the adoption of opt2 and opt3 set of values allows the decrease of overvoltages, but not the active power flows reduction, which results in an increase of network losses.

Fig. 8 shows the voltage profiles for each of the feeders, as obtained by adopting the opt1 and opt3 sets of α,β,γ values. For each feeder, the obtained voltage profiles are very similar. For the case of rural feeder 1, the action of the scheduler limits the voltage of all the nodes into the ±5% range around the rated value (1 p.u.), whilst for the rural feeder 2, where dispatchable DERs are not connected, this aim is not completely achieved.

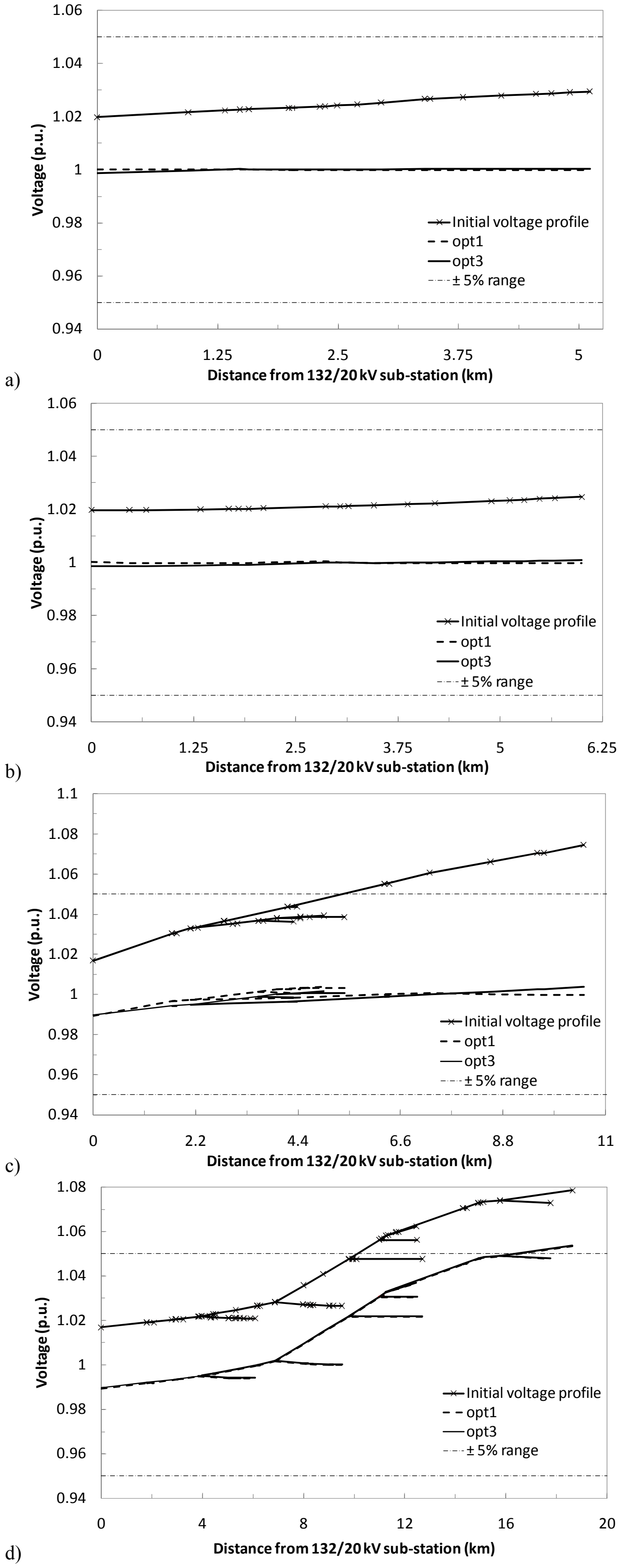


Fig. 8. Intra-day scheduling in the time period of minimum load: comparison between the initial voltage profile and the opt1 - opt3 results: a) urban feeder 1, b) urban feeder 2, c) rural feeder 1, and d) rural feeder 2.

2) *Time period of maximum load*

The calculated set-points of each DER are reported in Table VI and those of the OLTCs in Table VII. Table VIII summarizes the network losses and voltage-deviation mean absolute values for each set of α,β,γ values.

TABLE VI
DERS ACTIVE AND REACTIVE POWER IN THE PERIOD OF MAXIMUM LOAD

DER	Opt1		Opt2		Opt3	
	P (kW)	Q (kvar)	P (kW)	Q (kvar)	P (kW)	Q (kvar)
DER_54	2234	-1865	2141	-2250	2141	-2250
DER_49	0.2	-2243	318	-1880	2141	-2250
DER_40	0.2	-1117	0.3	-1116	1172	-716
DER_18	500	375	150	375	150	375
DER_19	3000	2250	3000	2250	3000	2250
DER_20	1573	2396	5500	-547	5500	-1888
DER_23	999	750	300	750	300	750
DER_21	2021	-925	5000	-1354	5000	-2539
DER_31	5000	3749	5000	3750	5000	3750
DER_04	3500	2625	3500	2625	3500	2625

TABLE VII
OLTCS TAP POSITIONS IN THE PERIOD OF MAXIMUM LOAD.

Component	Initial condition	Opt1	Opt2	Opt3
T1	0	-3	-2	-1
T2	0	+6	+6	+6

TABLE VIII
LOSSES AND VOLTAGE DEVIATIONS IN THE PERIOD OF MAXIMUM LOAD

	Initial condition	Opt1	Opt2	Opt3
Losses (kW)	630	534	652	740
Mean Absolute Voltage Deviation (V)	640	87	96	125

With respect to the period of minimum load, in the period of maximum load the OLTCs coordinated action is more important in order to contemporary reduce bus voltages along the urban feeders, whilst sustaining the voltages at rural feeder 2 that is not supplied by dispatchable DERs.

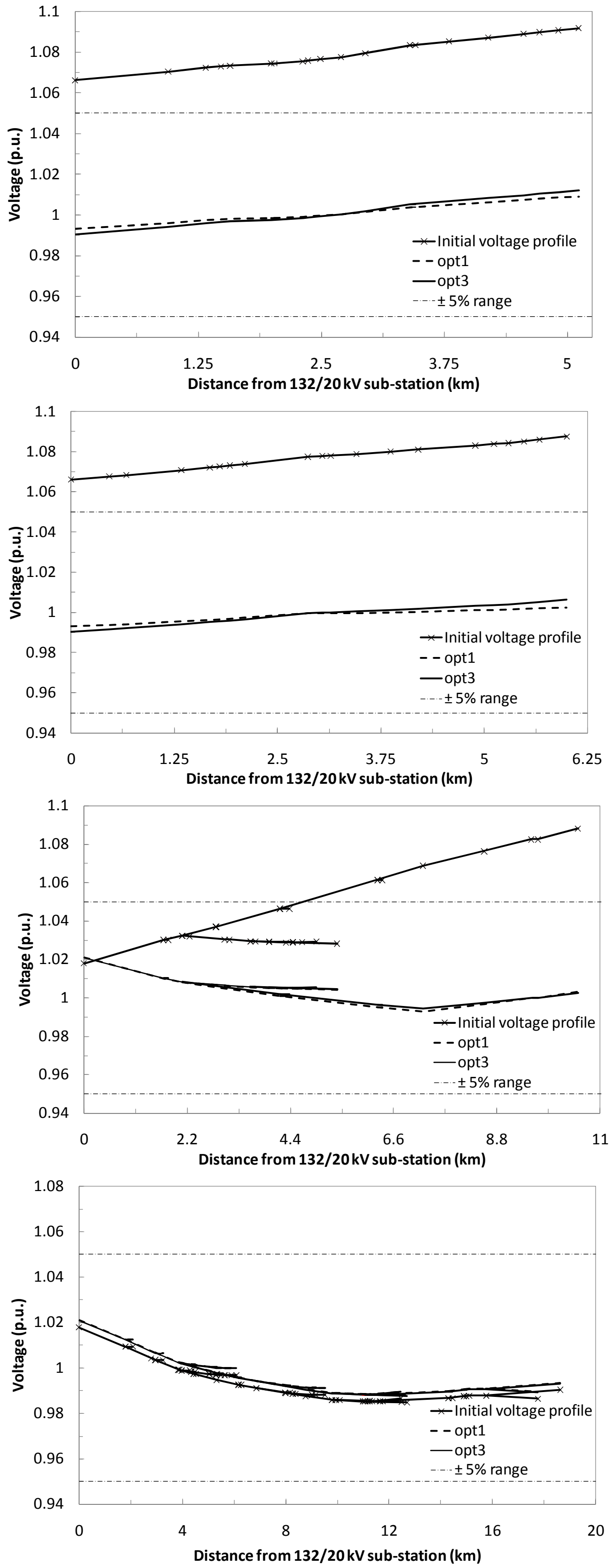
Fig. 9 shows the voltage profiles before and after the action of the intra-day scheduler for the case of both opt1 and opt3 sets. In this period, before the intra-day optimization, all the node voltages of the two urban feeders are above the +5% range. As shown in Fig. 9a and Fig. 9b, the action of the intra-day scheduler achieves a substantially flat voltage profile for all the feeders, also when the active power output of dispatchable DERs is fixed to the reference value calculated by the day-ahead scheduler. Also in this period, however, the limitation in the reduction of the DERs active power output result in an increased value of the network losses.

IV. CONCLUSIONS

This paper has shown that the proposed scheduler can be successfully applied to a distribution network with numerous busses and a large presence of various types of DERs.

The intra-day scheduler based on the iterative solution of a MILP problem allows a detailed representation of discrete OLTCs tap positions and the incorporation of the line ampacity constraints.

An interesting feature of the proposed approach is that, at each iteration, the linearization of the optimization problem is achieved by means of sensitivity coefficients that can be directly obtained from the results of a single power flow calculation.



a) b) c) d)

Fig. 9. Intra-day scheduling in the time period of maximum load: comparison between the initial voltage profile and the opt1 - opt3 results: a) urban feeder 1, b) urban feeder 2, c) rural feeder 1, and d) rural feeder 2.

V. Acknowledgment

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