

Coordinated reactive power control to achieve minimal operating costs



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ARTICLE INFO

Article history:

Received 7 August 2013

Received in revised form 18 June 2014

Accepted 23 June 2014

Available online 26 July 2014

Keywords:

Distributed generation

Minimization of losses

Reactive power flow

Smart grid

Voltage control

ABSTRACT

This paper deals with the influence of distributed generation (DG) on distribution losses in medium voltage (MV) distribution networks. The aim was to minimize the losses and operation costs with only DG reactive power compensation with respect to voltage constraints. Thus, the active power flows are not affected as any attempt of active power curtailment causes financial loss for DG owner. The advantage of technologies that build up new smart grids is the possibility of developing new approaches of network management. In this paper, a coordinated reactive power control is presented which takes advantage of real-time data measurements from the network. The load-flow algorithm is implemented into the coordinated control, which determines the optimal operating point using a modeled network for every generator separately. The aim of the algorithm is to minimize the reactive power flow. The solution is evaluated by means of computer simulations. The simulated network is a part of the Slovenian medium-voltage distribution network. The presented results illustrate that the algorithm results in fast, simple and efficient energy loss allocation with an acceptable level of accuracy.

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Introduction

When operating distribution networks, there is always reactive power present due to electrical loads and capacitances of the power lines and cables. A part of the loss is due to reactive power that travels back and forth in power lines, all the way from power sources to the load points [1]. The reactive power also has a profound effect on the security of power systems because it affects voltages throughout the system. However, loss minimization and voltage control are competing objectives and minimizing losses does not ensure voltage control, usually both objectives exclude each other [2].

To minimize losses and achieve maximal economic benefits, reactive power flow has to be controlled, which has been the topics of many papers and many different solutions are already implemented [3–13]. To compensate reactive power flow most common and spreaded solution in distribution networks are capacitor banks which act like source of reactive power. With a proper control voltages can be controlled and losses reduced. Different solutions to obtain optimal switching schemes are presented in papers such as [14–18]. DGs can decrease losses by providing local complementary reactive power [1]; they can be modeled as active power sources which are also capable of injecting and consuming reactive

power [19–21]. Their advantage is that they are scattered uniformly across the network and can be thus more efficient in minimizing the losses. Inverter-based technologies enable fast and reliable response to the network needs especially in the case of voltage rise [2]. In our previous work [22] it is also shown that the majority of the savings can be obtained by setting optimal reactive set-points of DG in compare to classical On-Load Tap Changer (OLTC) control.

DG usually work with a constant power factor ($\cos \varphi = 1$) and do not provide any ancillary services to the network. At present many countries already prescribe the usage of static $Q(U)$ characteristic for the contribution with local voltage control (example Slovenia [23] or European project MetaPV [24]). However, these solutions have limited control possibilities due to the lack of a communication infrastructure. Information and communication technologies (ICT) and smart meter implementation have enabled DG to take advantage of unused reactive power capabilities and to participate in emerging markets with reactive power. In today's competitive electricity market, the establishment of an adequate reactive power pricing methodology is becoming a key issue in providing the voltage control ancillary service [25]. However, there are many open questions in the literature related to dispatch of reactive power, many of them raised and discussed in [2,26].

The aim of presented research was to develop a control algorithm to minimize the operation costs, which is very simple in structure, but still effective, and thus suitable for implementing it into the SCADA as an application for controlling DG inverters. To

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solve non-linear objective functions, evolutionary algorithms came into existence [27]; many papers have started to use intelligent techniques such as genetic algorithm, particle swarm optimization, fuzzy logic, fuzzy wavelet network, and artificial neural networks [28] to obtain optimal operating points when dealing with a large number of DG. This paper shows that effective coordinated control solutions can be still achieved only by using well known load-flow calculation with the combination of simple step-by-step algorithm which minimizes the objective function. By allocating the reactive power of DG taking into account the reactive power dispatching costs, the point of minimal operation costs can be achieved. Furthermore, the issue of fair opportunity costs and oversizing of inverters [29] is also addressed.

The problem formulation and control system design is presented in Section ‘Control system design’. The simulated network and the simulation results are shown in Section ‘Study case’. Finally, conclusions are drawn in Section ‘Conclusion’.

Control system design

As the active and reactive power of the loads and generators in the network are constantly monitored and measured with smart meters, this data can be used to generate a coordinated control algorithm. The heart of the presented control system is a load-flow algorithm, which minimizes the losses in small steps using a modeled network. Possessing periodically power measurements, the simulations are carried out to minimize the reactive power flow. In a number of load-flow steps the optimal reactive power of the DG is determined and new set points sent to the generators to correlate their outputs. With the increasing processing power of computers, the number of necessary load-flows is not of crucial consideration, as long as the algorithm converges reliably which is of great importance when making industrial applications.

Fig. 1 presents a part of the distribution feeder and shows the direction of the power flow. The generators generate active power but their spare reactive power capabilities are unused. If DG could produce or consume a certain amount of reactive power, the reactive power that travels along the feeder could be minimized.

Let us assume that reactive power is flowing through the feeder from the main substation to the end of the feeder. The reactive power that reaches *Busbar 1* can be written as:

$$Q_{1j} = Q_{2i} + Q_{L1}. \quad (1)$$

If the generator G_1 produces reactive power equal to Q_{1j} , the reactive power flow from *Line 1* will be zero resulting in minimal losses in this line. Next, if the generator G_2 produces reactive power in the same way (equal to Q_{2j}) the reactive power through *Line 2* will also be minimal. Thus, if the reactive power capacity of all DG is unlimited, the reactive power flow through the feeder and losses will be minimal.

Unfortunately, the reactive power of DG is limited and in many cases the network operator cannot acquire reactive power from them. If DG owners are not financially stimulated to generate or consume reactive power they will not participate in the ancillary services. The problem is even more complex as the losses do not vary linearly; optimization of a generator influences losses

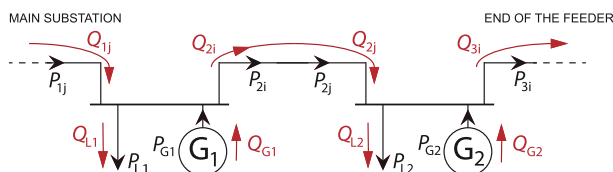


Fig. 1. Example of reactive power flow toward the end of the line.

throughout the entire system and the effect is also different for each generator separately. If a generator changes its current generation and injects more reactive power into the grid, the loss reduction will be different for each generator. Therefore, the algorithm has to determine the loss reduction due to reactive power change for each generator. The power losses in the line j can be determined by the following equation:

$$Losses_{ij} = \frac{P_j^2 + Q_j^2}{U_j^2} R_{LINE,j}, \quad (2)$$

where P_j and Q_j are active and reactive power receiving end busbar, $R_{LINE,j}$ is the line resistance and U_j is the voltage at the node j . Let us assume there are no reactive power losses and analyze reactive power distributed in Fig. 2. The feeder line is rather general, and due to compensation along the feeder and no DG penetration, the active power line is spread in indifferent directions along the feeder as observed in Fig. 2(a). If the generator tries to minimize the losses in the above described case, the reactive power flow changes from the generator to the beginning of the feeder where the beginning of the feeder (OLTC substation) presents slack bus. It can be seen from Fig. 2(b) that in lines where the reactive power flow has the same direction as the line touching the generator node, the losses were reduced and in the opposite cases the losses were increased.

The sum of losses for every line using (2) can determine the change in losses i.e. loss reduction. If the power change is $Q_{G,STEP}$ the losses change is:

$$Losses\ change \approx \sum_{j=1}^N \left(\frac{P_j^2 + Q_j^2}{U_j^2} R_{LINE,j} - \frac{P_j^2 + (Q_j - Q_{G,STEP})^2}{U_j^2} R_{LINE,j} \right). \quad (3)$$

$Q_{G,STEP}$ is negative, in the case it has the opposite direction. N represents the last line in which the change is made, as described in Fig. 2. Loss reductions are calculated for every generator separately. That generator, where losses i.e. losses costs are reduced for the largest share, changes its output for $Q_{G,STEP}$ in the current iteration. The load flow is then run once again (new voltages, consumption and generation data are obtained) and procedure repeated. The algorithm stops when the change in output of any generator does not anymore reduce but increases the losses or if the voltage limits are reached. Solving power flows with different reactive power injections introduces errors in (3) and power flow-input data for loss allocation process due to different bus voltages to consumers and DG [30]. However, since the step change is relatively small,

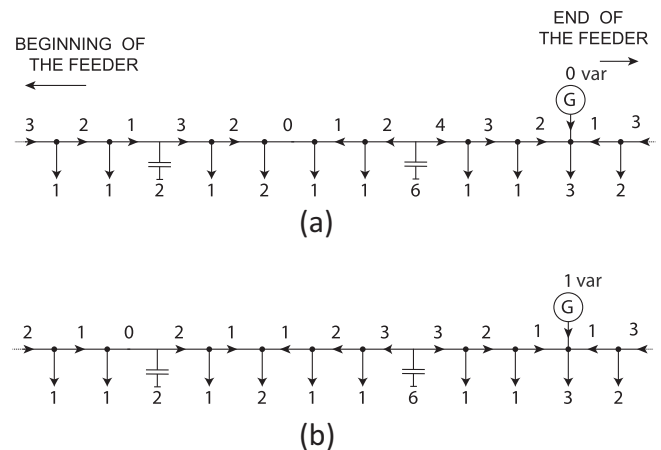


Fig. 2. Reactive power flow when DG is not participating in loss minimization (a) and when DG reduces the reactive power flow in the line coming from the substation (b).

simplifications can be made i.e. the voltages (U_j) and active power flow remain the same if a small step is made. Thus, power savings can be easily calculated for every step. The reactive power change is applied to the generator and the load flow is calculated once again and the voltages (which were presumed to be constant when calculating the expected loss reduction) and power flow correlated.

As mentioned, the ancillary services come at a price as the market participants utilize the network in different ways to maximize their profits [31]. Every generator (or a group of generators) in the network, which wants to participate in the ancillary services, has to offer a price for a certain amount of reactive power. An example is presented in Fig. 3.

For small amounts of reactive power the price is small and vice versa. The offer is cumulative of variable costs and opportunity costs, which rise practically exponentially [25]. This offer is actually the same as trading with active power [32]. The offer has to be composed of two parts: for consuming and for injecting reactive power. If a generator is operating at power factor $\cos \varphi = 1$, and its reactive power is zero, the payment for ancillary services is also zero. When calculating the loss reduction cost, the cost of reactive power compensation has to be taken into account. Thus, not only DG but also compensation devices can also participate with their offers.

The principled flow-chart algorithm is presented in Fig. 4.

By utilizing small reactive power change steps when reducing network losses i.e. operation costs, the problem of optimization can be linearized. There are only two possible values for generators to change its output; one step increase and one step decrease in generation from the current reactive power output. Thus, the algorithm calculates the savings for each generator in the feeder and determines which generator will change its output in the current step. After series of steps, the optimal operating set points for all DG are achieved. Using this approach, the optimization problem is divided into smaller parts, which are easier to solve than solving one large problem and thus, the final solution can be easily and quickly found. The outputs of the algorithm, which are given by the last suitable load-flow, are new DG reactive power set points, which are sent to the generators. The generators must then produce the reactive power they have sold to the operator.

The loss allocation problem has a pure economic nature but it has to be solved with mathematical algorithm [30]. This raises the question whether this solution is optimal. The fact that branch power losses are a nonlinear function of bus power injections makes it difficult for solving the optimization problem. Because of this, the issue of fairness will probably never be fully resolved by any optimization method. The final allocation always contains a certain proportion of arbitrariness, as concluded in [33,31]. Nevertheless, the result of the optimization algorithm always fulfills the following equation:

(losses costs) + (ancillary services costs)

$$\leq (\text{operation (losses) costs with constant power factor}). \quad (4)$$

The whole operation costs are always the same or smaller compared to constant power factor operation or by using a static $Q(U)$ characteristic. The algorithm cannot deteriorate the objective function as in the theoretical worst case, the algorithm does not do anything and DG maintains a $\cos \varphi = 1$ operation.

Study case

Simulated network description

To illustrate some practical implications of the proposed loss minimization algorithm, the operation is demonstrated on a part of a real 20 kV medium-voltage (MV) Slovenian distribution network model. The single-line diagram of the analyzed network is shown in Fig. 5. The network and optimization algorithm were modeled in Matpower 4.1 [34]. For load-flow the default solver is used, which is based on a standard Newton's method.

The 20 kV network is connected to the HV level at 110 kV through a 31.5 MVA transformer. There are many diverse feeders in the network; for the picture of algorithm functioning, four feeders were used and others were modeled as loads connected at the HV/MV substation. Loads and generators were modeled as R-X impedances at 20 kV voltage level that are also voltage dependent and were modeled as composite loads, consisting of 50% constant impedance and 50% constant power. For loads, a power factor $\cos \varphi \approx 0.95$ was presumed. Depending on the size of each settlement with an MV/LV transformer substation, represented as one load, an adequate size of the generation was determined.

The maximal peak consumption is approximately 26 MVA (at 19:15) and maximal peak generation from DG is approximately 29 MW (at 12:00). The maximum active power output of 68 DG was less than 0.1 MW, of 65 DG between 0.1 and 0.5 MW and of 16 DGs between 0.5 and 1 MW.

The OLTC operation was assumed to be upgraded to use multiple measurement points in real time in the critical areas around the network.

Control system performance evaluation

In this section the algorithm is validated by means of simulations. To demonstrate the functioning of the algorithm, the operation point during strong solar radiation, at 13:00, is presented for different scenarios. Firstly, the simulations were run such that the generators did not participate in either the voltage control or loss minimization and worked with a constant power factor ($\cos \varphi = 1$). The resulting active line loss is 2.45%. The DG active power participation for one operating point at 13:00, is presented in Fig. 6. Of clearness, the operating points of DG are presented only for Feeder 1 (see Fig. 5).

Next, the operation of the coordinated algorithm is presented in Fig. 7, which also represents results at 13:00. In this case the ancillary services costs were zero. DG reactive power capacities were limited only with inverters circular P-Q diagram. Thus, minimal losses were achieved with respect to the physical constraints of inverters. The red¹ columns in Fig. 7(a) represent active power and the blue columns indicate reactive power generation. A negative value implies that the generators are consuming the reactive power. In Feeder 1 several generators appear to be consuming reactive power. This is due to the presence of many cables with a high

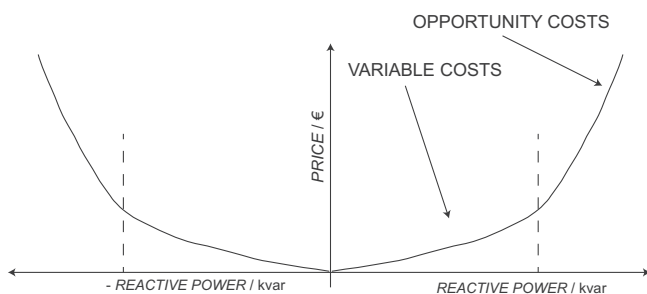


Fig. 3. Reactive power and its price that generators offer for a certain time frame (10-min or 15-min). In this case the generator can produce or consume the reactive power.

¹ For interpretation of color in Figs. 7 and 11, the reader is referred to the web version of this article.

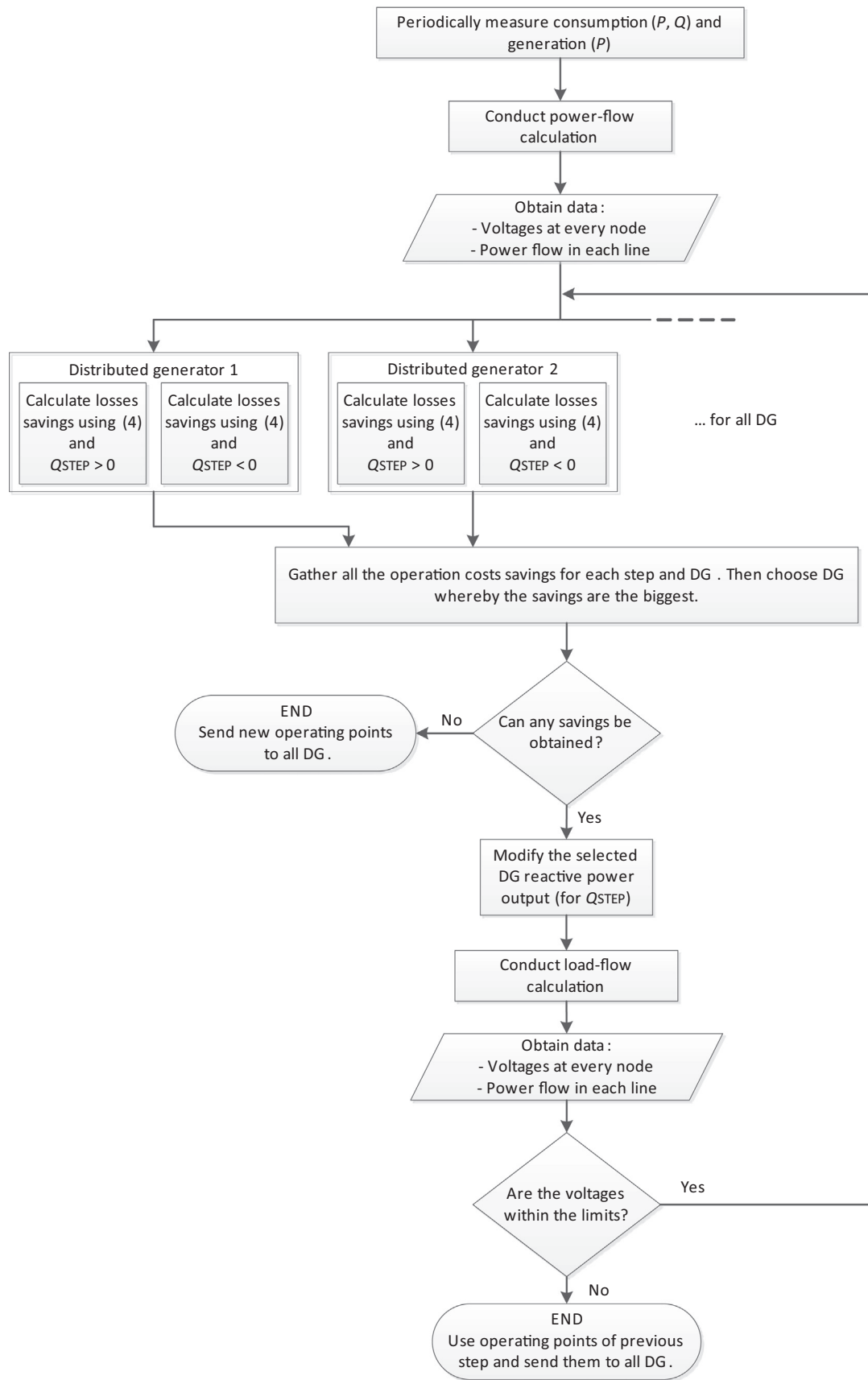


Fig. 4. Principled flow-chart diagram of the algorithm which is performed every period.

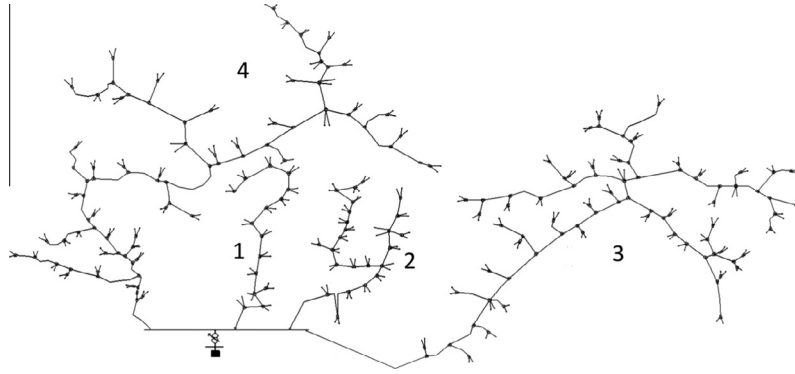


Fig. 5. MV distribution system under study with four feeders.

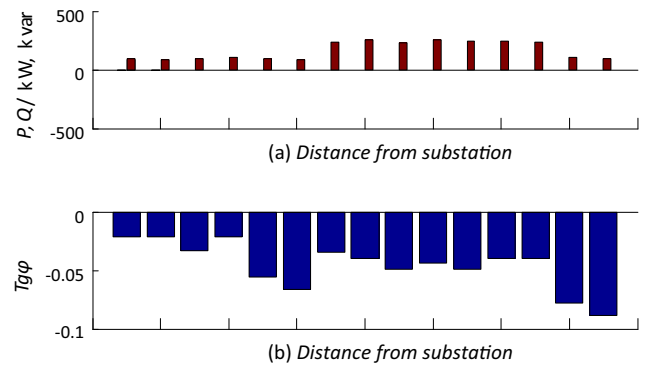
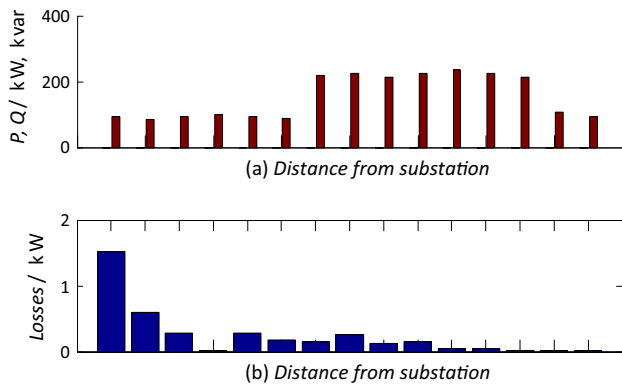


Fig. 6. Operation of the generators with constant power factor for feeder 1 – snapshot at 13:00. Red columns in Case a present DG active power generation and Case b presents feeder line losses. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

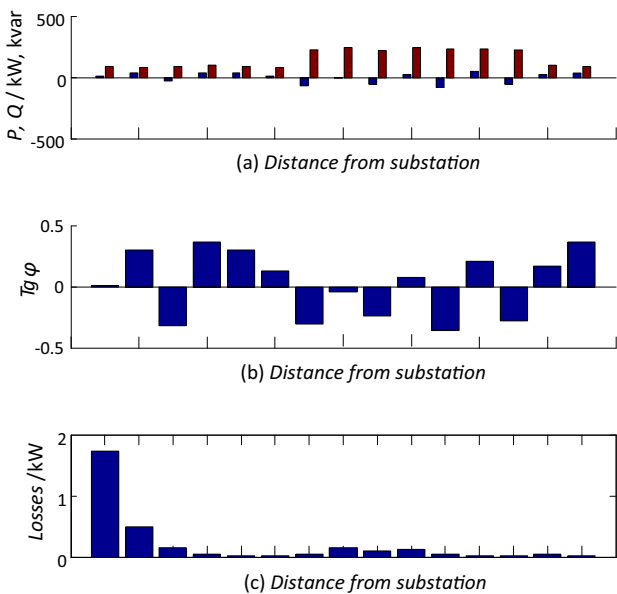


Fig. 7. Operation of the generators with variable power factor – snapshot at 13:00. Active and reactive powers are presented in Case a and corresponding $\tan \phi$ in Case b. Losses are presented in Case c.

capacitance in the feeder. With distribution of reactive power in this manner, the losses are minimal subject to presented optimization algorithm. Furthermore, Fig. 7(b) represents $\tan \phi$ for every

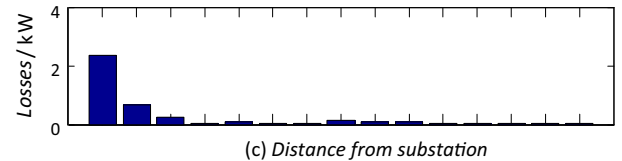


Fig. 8. Operation of Feeder 1 taking into account ancillary services costs (Snapshot at 13:00).

generator. $\tan \phi$ is the ratio between the reactive and active power of generators and can be interpreted as loading of the generator with reactive power. In [22] for example, coordinated control using uniform $\tan \phi$ is presented. To every feeder in the network a uniform $\tan \phi$ operating point is sent periodically. Thus, a more fair dispatch of reactive power is achieved.

In the next step, the price for reactive power dispatch of the generators is added to the coordinated optimization algorithm. As described in Section 2, the offer of the generators with ancillary services can be given for reactive power consumption or injection. For presentation of the algorithm functioning, the offer of all DG was modeled as quadratic function, which fairly good presents the variable and opportunity costs [25], but in principle, any function can be taken. The offer differs by a coefficient c in the equation:

$$\text{price} = c \cdot Q_G^2. \quad (5)$$

Fig. 8(a) shows operation at 13:00 of the Feeder 1, where the coefficients c are not zero but represent a specified value ($c = 0.01$ for all DGs). Price for the loss is assumed to be 1 €/MW h. It should be noted that this is a theoretical model, the true price of loss and price for ancillary services, will be built on the ground (supply and demand) and will be automatically adaptable. A closer look at the reactive power dispatch reveals that

reactive power from the generators is changed. Additionally, engagement of the generators is different and the losses, compared to the case with no ancillary services cost, are higher. On the other hand, the whole operation costs are still smaller compared to constant power factor operation or by using static $Q(U)$ characteristic.

Fig. 9(a) presents the sum of line losses during the day. Solid line represents operation with a constant power factor and the dashed line represents the proposed coordinated algorithm. Fig. 9(b) presents a one-day voltage profile of MV/LV substations measured at the critical areas around the distribution system when DG is operated with a constant power factor. Fig. 9(c) represents the voltage profile using the coordinated algorithm with no ancillary services costs. It is observed that while minimizing losses, the voltage conditions have deteriorated as OLTC operations have increased, which means that the network can accept less DG. As said in the beginning, loss minimization and voltage control are competing objectives and usually both exclude each other.

The speed of the algorithm convergence can be seen in Fig. 10, which presents the necessary load-flow iterations to obtain minimal losses. The step change is set to 1 kW. It is observed that the algorithm converges very quickly and reliably with approximately 1400 load-flows. The simulations were run with different $Q_{G,STEP}$ (0.1 kvar, 0.01 kvar and 0.001 kvar) and for all the cases the algorithm converged well and reduced the losses for the same amount, only the time to obtain the solution varied.

Additionally, Fig. 11 presents a loss reduction with respect to available reactive power (available maximal $|\tan \phi|$) and physical constraints of inverters for the case if ancillary services are zero

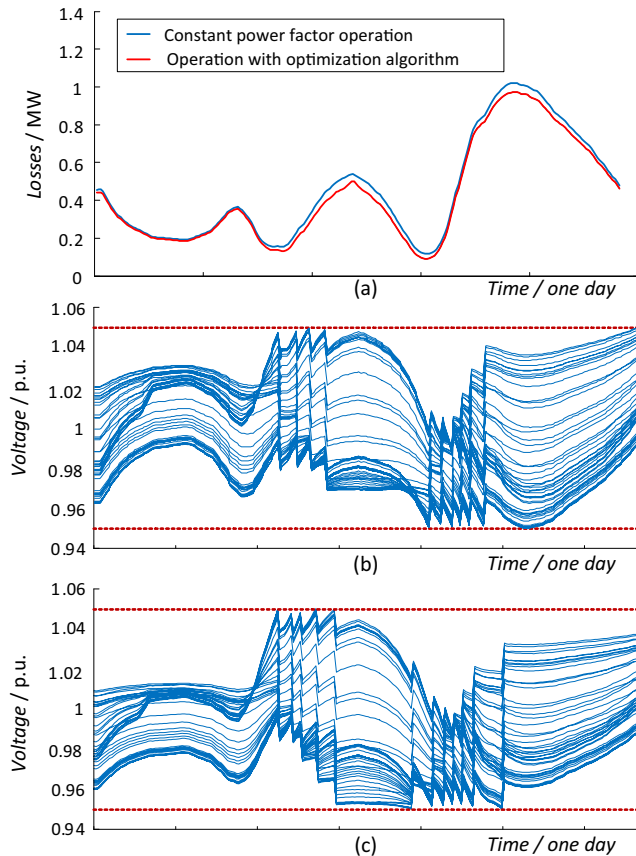


Fig. 9. Sum of the losses during the day (Case a). Blue line presents operation with constant power factor and red line, the presented coordinated algorithm. Case b presents one-day voltage profile of some MV/LV substations with DG constant power factor operation. Case c presents voltage profile with coordinated reactive power control used. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

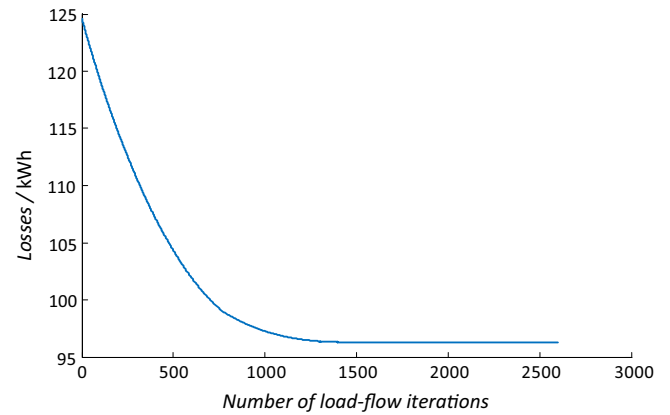


Fig. 10. Number of necessary load-flows to obtain minimal losses.

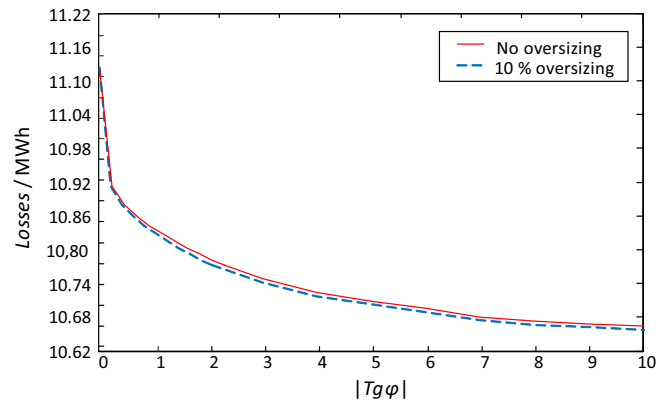


Fig. 11. Loss reduction due to optimal reactive power dispatch as a function of available maximal $|\tan \phi|$ in the presence of many photovoltaic (PV) sources in the network.

and thus the reactive power operating point adjustable by the operator freely over the available range. The red line in Fig. 11 represents current loss reduction and the blue line indicates loss reduction by oversizing inverters by 10%. It can be observed that oversizing of inverters has little effect on loss minimization. The small difference between the lines is due to the fact that during the peak hours inverters have little reactive power capabilities on reserve. The statutory requirement of oversizing of inverters appears meaningful only when reducing the increase in voltage. Furthermore, it can be seen that the majority of the saving can be obtained in the span of $|\tan \phi| < 0.5$. This fact poses the question if to some extent reactive power dispatch should be mandatory.

In [22] the issue of fairness is presented as DG at some locations have greater opportunity costs. To achieve more uniform reactive power distribution, all DG in one feeder operated with the same $\tan \phi$ and on this assumption the operating point of minimal losses is to be found. As in this paper $\tan \phi$ is different for each DG, the losses i.e. operating costs, are expected to be smaller, which is also verified in Table 1 and Fig. 12. Still, the issue of different opportunity costs is problematic as the customers cannot change their electrical location along the feeder. Furthermore, ancillary services should not be dependent upon the location of DG as this could result in placing new DG in the areas where the voltage deviations are already more frequent. For example, Fig. 13 presents uniform optimal $\tan \phi$ for all DG at one feeder to achieve optimal operating conditions. During the evening consumption increases and DG have to inject more reactive power in comparison to active power which is, in the case of PV, small, which results in very high $\tan \phi$.

Table 1
Simulation results for one day (constant current loads).

Control	Losses (%)	Losses reduction compared to $\cos \varphi = 1$ operation (%)
Without DG	17.88 MW h	/
Only centralized OLTC control with constant $\cos \varphi$ operation	11.13 MW h	/
Coordinated reactive power control with uniform $\tan \varphi$ operation	10.64 MW h	4.4
Proposed coordinated reactive power control	10.46 MW h	6.0

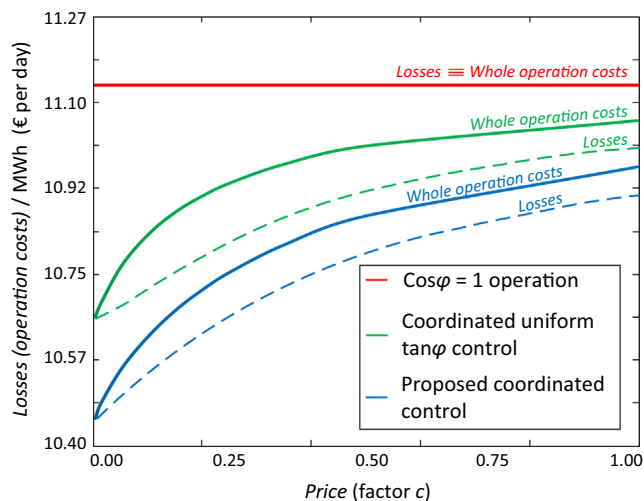


Fig. 12. Comparison of losses and whole operating costs as a function of ancillary services costs for different loss minimization control algorithms. To obtain these curves the offer of all DG has to be similar with the same coefficient c .

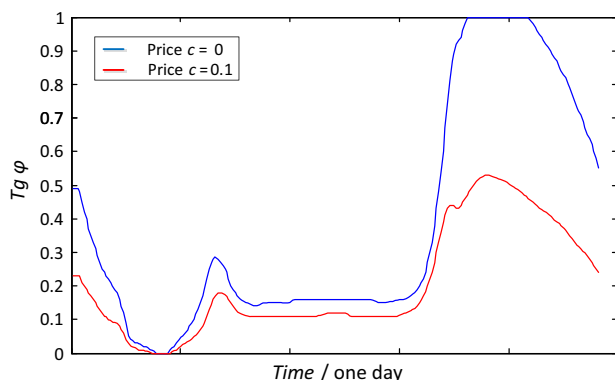


Fig. 13. Optimal $\tan \varphi$ trajectory during one day.

The blue line presents optimal $\tan \varphi$ in the case if ancillary services costs are zero and red line in the case factor c in (5) is 0.1. It can be seen that in the second case $\tan \varphi$ deviations are logically smaller.

To sum up, Table 1 presents a comparison of possible loss reduction by different controls and no ancillary services cost.

An effective operation of coordinated control requires an accurate estimation of the current network situation at each time instance, which could be non-trivial in many cases [24]. Despite this drawback, coordinated control has several advantages in contrast

to centralized and local control, such as easier establishment of reactive power market and more effective voltage control during emergency situations e.g. voltage rise, which usually presents the biggest risk in distribution networks. Local voltage controls such as static $Q(U)$ characteristics are only temporary solutions to these risks. With the implementation of smart meters in the majority of distribution networks, different coordinated voltage controls will become standard practice to mitigate voltage rise and minimize operation costs. An initial step toward this goal is an upgrade of the centralized tap-changer voltage step control by implementation of multiple voltage measurement points in the network.

However, it should be noted that the simulated network is of a relatively small size. Longer and more branched feeders incur higher losses, which is also dependent on the amount of DG in the network. Every scheme will face different technical and commercial issues and must be studied on a site-by-site basis [35]. This implies that increased savings can be made if a bigger network is simulated. The calculated savings are therefore specific for each network.

Conclusion

This paper deals with the problem of line loss and operation cost minimization in distribution networks with a high proportion of DG. With an appropriate reactive power control, DG can help minimize losses. Information and communication technologies and smart meter implementation will enable distribution operators to take advantage of unused DG reactive power capabilities and participate in emerging reactive power markets.

A coordinated control algorithm has been presented to determine new reactive power operating points for the generators on the basis of active and reactive power measurements from the smart meters in order to minimize reactive power flow through the network feeder. Due to a limited amount of reactive power from DG, the ancillary service costs have also been taken into account. The results show a reasonable loss reduction and reduction of operation costs. The solution was evaluated by means of computer simulations. The simulated network is a part of the Slovenian medium-voltage distribution network. The vision of presented research work was to develop a method which can represent a viable solution for cost-effective intelligent control of industrial electronic applications to distributed power generation systems. That is why the proposed method is simple in structure and can be easily implemented in automatic control devices. It obtains only one approximated linearized equation and load-flow step-by-step search algorithm.

Our future work will be focused on the most economical way to minimize the voltage rise, taking into account not to penalize only some retail customers as they cannot change their electrical location along the feeder. With this algorithm upgrade the system will be fully operational and will represent one of the alternative options to be used in future Smart Grids.

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