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Coordinated Voltage and Reactive Power Control Strategy with Distributed Generator for Improving the Operational Efficiency

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Abstract – This study proposes a voltage and reactive coordinative control strategy with distributed generator (DG) in a distribution power system. The aim is to determine the optimum dispatch schedules for an on-load tap changer (OLTC), distributed generator settings and all shunt capacitor switching on the load and DG generation profile in a day. The proposed method minimizes the real power losses and improves the voltage profile using squared deviations of bus voltages. The results indicate that the proposed method reduces the real losses and voltage fluctuations and improve receiving power factor. This paper proposes coordinated voltage and reactive power control methods that adjust optimal control values of capacitor banks, OLTC, and the AVR of DGs by using a voltage sensitivity factor (VSF) and dynamic programming (DP) with branch-and-bound (B&B) method. To avoid the computational burden, we try to limit the possible states to 24 stages by using a flexible searching space at each stage. Finally, we will show the effectiveness of the proposed method by using operational cost of real power losses and voltage deviation factor as evaluation index for a whole day in a power system with distributed generators.

Keywords: Coordinated reactive power control, Voltage sensitivity factor, Voltage regulation, Loss minimization, Receiving power factor, OLTC transformer, Distributed generator, Capacitor

1. Introduction

Modem power systems are often affected by an inadequate reactive power supply and a reduction of voltage stability margin. Those could be negative effects on voltage profiles, active and reactive power losses [1]. The operator can improve this situation by reallocating reactive power generations in the system, by adjusting transformer taps, by changing generator voltages, and by switching VAR sources. The system losses can also possibly be minimized [2].

A voltage and reactive power control strategy in conventional distribution systems is normally achieved by incorporating on-load tap changers (OLTC) and shunt capacitors [3]. The transformer with OLTC changes its tap position to control the lower side voltage magnitude directly, whereas the capacitor banks affect the higher side voltage magnitude indirectly by changing the amount of reactive power demand at the bus [4].

The introduction of distributed generation (DG) affects the power flows, which in turn alters some bus voltage profiles and influences the control strategy with voltage and reactive power controllers [5]. As the penetration of DG units increases in the distribution system, all players would be best served by allocating them in an optimal way so as to increase reliability, reduce system losses, and improve the voltage profile while serving the primary goal of energy injection. [6]. In order to meet the objective function such as active power losses, voltage regulation, and receiving power factor, there has to be coordination control between DG and conventional voltage and reactive power control equipment.

Many researchers have addressed the problem of voltage and reactive power control in distribution systems. Recently, most of them have focused on an automated remote dispatch either by using one-day-ahead daily dispatch schedules or real-time control [7]. The two method mentioned above can be applied to a smart grid which is a future power system combined with IT technology. A future distribution network is a smart grid that will be integrated with advance communication facilities, linking all voltage and reactive power controllers such as shunt capacitors, OLTC and DG to sensors and actuators with the network control center [8].

When dynamic programming is employed to determine the optimal dispatch of some controllers in the distribution system, the computational burden is acceptable because of the relatively small searching space. However, to find the optimal schedule of more controllers requires a very large search space that is computationally time-consuming [7]. To reduce the computational burden, some techniques should be applied to the algorithm.

In this paper, coordinated voltage and reactive power control methods are proposed that adjust the optimal

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control values of capacitor banks, OLTC and the AVR of DGs by using voltage sensitivity factor (VSF) and dynamic programming (DP) with the branch-and-bound (B&B) method.

The coordination control algorithm is implemented by a Python script and the result is used to apply for PSS/E. The PSS/E allows the user to access the system by using a Python script [9].

2. Problem Formulation

A voltage and reactive power control strategy involves coordination among all shunt capacitors, the OLTC, and the DG in the distribution system to minimize active power losses and to improve the voltage profile according to the load demand and DG output power based on a time series. Conventionally, voltages at the primary bus of a substation change slightly over a day and are therefore assumed to have a constant value. The OLTC setting is based on the change of load [7]. With the hourly load and generation data for the next day advancing, the determination of an optimal dispatch is desirable in the next 24 hours [10]. In other words, the on/off status of shunt capacitors, the tap position of OLTC, and the voltage set point of the distributed generator must be determined for each hour of the following so that total system loss can be minimized.

The optimal dispatch schedules for the settings of OLTC, DG and all shunt capacitor switching can be formulated mathematically as an optimization problem.

The following objective function is set to minimize the real power losses and keep all the voltages within the limits as much as possible:

$$\begin{aligned} &\boldsymbol{Min} \\ &\boldsymbol{F(x)} = \sum_{i=1}^{N}\left[\sum_{j=1}^{N_l} \boldsymbol{P_{Loss,i,j}} + \boldsymbol{R}\cdot\sum_{k=1}^{N_b}(\boldsymbol{V_{i,k}} - \boldsymbol{V_{i,k}^{ref}})^2\right] \\ &\quad = \boldsymbol{J_1} + \boldsymbol{J_2} \end{aligned} \tag{1}$$

where

x	controllable variables
N	number of stages in a day, which is 24 for a 1 hour interval between *i* and *i*+1
N_l	number of branches including transformer
$P_{Loss,i,j}$	real power loss of each branch *j* at time *i*
R	a penalty factor
N_b	number of buses
$V_{i,k}$	voltage at bus-*k* at time *i*
$V_{i,k}^{ref}$	reference bus voltage at bus-*k* at time *i*

The objective function is subject to standard power balancing equality constraints as well as the following additional inequality constraints including control variables limits and state variables limits.

$$V_{G,k}^{min} \le V_{G,k} \le V_{G,k}^{max} \quad \forall k \in N_{DG} \tag{2}$$

$$T_m^{min} \le T_m \le T_m^{max} \quad \forall m \in N_T \tag{3}$$

$$C_n^{min} \le C_n \le C_n^{max} \quad \forall n \in N_C \tag{4}$$

$$V_{i,k}^{min} \le V_{i,k} \le V_{i,k}^{max} \quad \forall k \in N_b \tag{5}$$

where

$V_{G,k}$	voltage set point of distributed generators at bus-*k*
$V_{G,k}^{min}$	minimum allowed voltage of DGs (i.e., 0.95 p.u.)
$V_{G,k}^{max}$	maximum allowed voltage of DGs (i.e., 1.05 p.u.)
N_{DG}	number of distributed generators
T_m	OLTC tap position at mth transformers
T_m^{min}	lower limit of tap position (i.e., -8)
T_m^{max}	upper limit of tap position (i.e., +8)
N_T	number of transformers with OLTC
C_n	status of nth shunt capacitors including fixed capacitor and switched capacitor.
C_n^{min}	lower limit of status of capacitor (i.e., 0)
C_n^{max}	upper limit of status of capacitor
N_C	number of shunt capacitors
$V_{i,k}$	bus voltage at bus-k at time i
$V_{i,k}^{min}$	minimum allowed voltage (i.e., 0.99 p.u.)
$V_{i,k}^{max}$	maximum allowed voltage (i.e., 1.04 p.u.)

3. Solution Algorithm

Using the mathematical model for the optimal dispatch problem described in the last section, we will proceed to solve this problem and determine an optimal dispatch by using voltage sensitivity factor and dynamic programming with the branch-and-bound (B&B) method. Finally, we will show the effectiveness of the proposed method by using system operation costs as an evaluation index.

Based on the proposed method, an analytical software tool has been developed in a PSS/E environment with Python to run the load flow, calculate voltage sensitivity factor, power losses, and eventually to trace the optimal dispatch schedules.

3.1 Voltage sensitivity factor

Using VSF can reduce the computational effort. This process is performed each bus in control area which is described in next section.

The linearized steady state system power voltage equations are the following

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_{P\theta} & J_{PV} \\ J_{Q\theta} & J_{QV} \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} \tag{6}$$

At each operation point, we keep P constant and evaluate voltage sensitivity by considering the incremental relationship between Q and V. To reduce (6), letting $\Delta P = 0$,

$$\Delta V = J_R^{-1} \Delta Q \tag{7}$$

where

$$J_R = \left[J_{QV} - J_{Q\theta} J_{P\theta}^{-1} J_{PV} \right]$$

J_R is called the reduced Jacobian matrix of the system. This is the matrix which directly relates the bus voltage magnitude and bus reactive power injection [11].

The diagonal elements of are the voltage sensitivity factors, $\Delta V/\Delta Q$, at each bus k [12]. That is,

$$VSF_k = \Delta V_k / \Delta Q_k \tag{8}$$

From (7), we can obtain the matrix of the voltage sensitivity factors each time i.

3.2 Dynamic programming with the b&B method

The optimal dispatch of OLTC tap position, voltage set point of DG and status of shunt capacitors can be determined by using dynamic programming. However, to find the optimal dispatch schedule for control variables across the whole distribution system one day in advance by dynamic programming requires a very large search space that is computationally time-consuming [7]. Therefore, we need to calculate the computational burden which means the total length of possible states or search paths through the system state at 24 stages. In this study, since there are two or more possible values for each capacitor and there are 17 possible positions for OLTC and 11 possible voltage set point of DG are described in Table 1, the maximum length of each stage is following

$$L_i^{max} = \prod_{n=1}^{N_C} C_n^{max} \times 17 \times 11 \tag{9}$$

From (9) and Table 1 in next section, we can obtain $(144 \times 17 \times 11)^{24}$ states at 24 stages as the size of the whole searching space. If we try to solve the problem using total length described in (9), it will be entailed with a heavy computational burden.

Therefore, we propose several techniques to reduce the size of the searching space. First, possible states of shunt capacitors at each stage can be reduced by checking the initial status of shunt banks and the initial voltage profiles. That is, if the initial voltage is lower than the reference voltage, the states which have a status lower than the initial values could be excluded from counting the possible states.

Second, the branch-and-bound method is applied [10]. Branch and Bound is a general purpose method to solve discrete optimization problems, and is useful to solve small instances of hard problems. However, using the B&B may take exponential time in the worst-case. In this study, we try to find out some ranges based on saved control values at the previous stage by using B&B with specific upper and lower bounds.

This will be limited to the OLTC tap position and the voltage set point within ±2 steps based on their setting values at i-1 stage. In this way, the computational burden can be greatly reduced. However, the searching space at each stage will be created with flexible length $L(i)$. If the initial values of each shunt capacitor in this study have zero, the size of the searching space at initial stage would be $L(0) = (144 \times 5 \times 5)$ as a length of feasible states.

3.3 Selection of evaluation index

The evaluation index includes costs of system losses and receiving power factor [13] at the point of common coupling (PCC) as a means of improving economic efficiency. We also consider voltage deviation factor (VDF) as an indication for improving voltage profile across whole network.

To perform this process, we assume that the following parameters with the electric service agreement including electric charges. Electricity price per unit is 65 KRW/kWh. And the standing charge per unit is 7.111 KRW/kWh [14].

The system operational costs are determined by considering two parts is described in Fig. 1. First, we use the cost of loss penalty per hour which is calculated from active power losses (kW) and electricity price. Second, the cost of receiving power factor penalty or incentive which is calculated from the standing charge and power factor rate can be considered. The operating time of one day is 24 hours based on load demand and DG output power profiles, which are introduced in next section.

3.4 Computational procedure

The flowchart of the solution algorithm is represented in

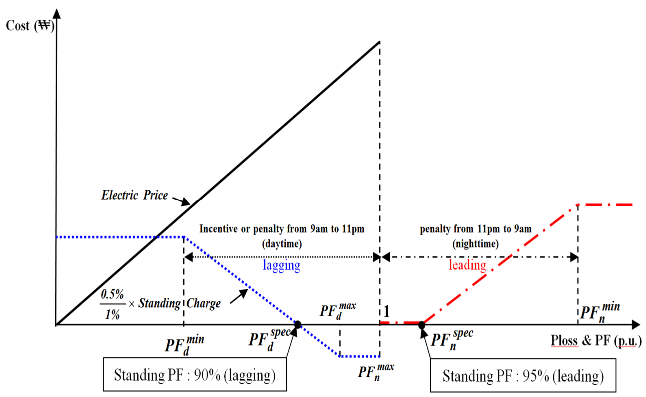


Fig. 1. Illustration of the system operational costs including losses and receiving power factor

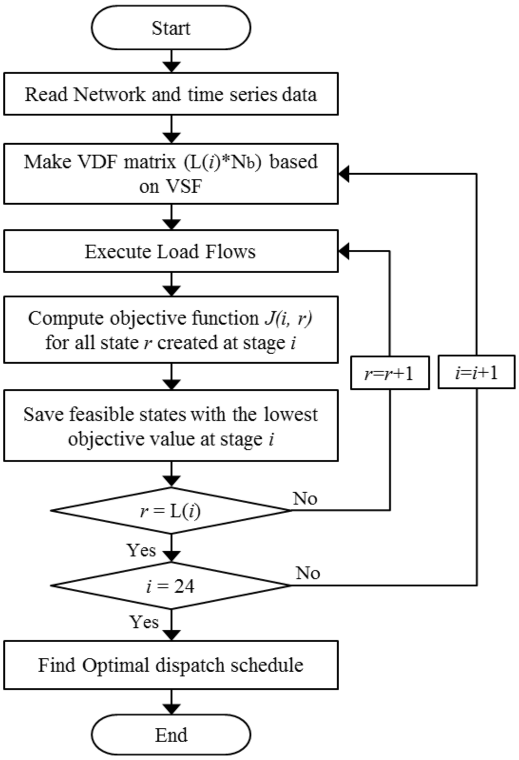


Fig. 2. Flowchart of optimal dispatch schedule algorithm using VSF and DP with B&B method

Fig. 2. The VSF and dynamic programming with some techniques, including the B&B method are applied to an optimal dispatch strategy. In computational procedure of the outer loop, we create the VDF matrix based on VSF to minimize the computational effort during the whole proposed control using initial load flow results each time *i*. This block also defines the feasible states with length *L*(*i*) at each time *i*. This process is repeated until the final stage is reached.

The inner loop is employed to execute the load flow, compute *J*(*i, r*) and save the feasible states with the minimum objective value at stage *i*.

Finally, we can find the optimal dispatch schedule backtracking saved data.

In the next section, the case study with modified IEEE 14 bus test system will be indicated the simulation results using this computational procedure.

4. Case Study

4.1 Test system

The modified IEEE 14bus test system in Fig. 3 is used to demonstrate the effectiveness of the proposed method. For research purposes, the connection between node 7 and 9 is closed and load is added at node 7. Five fixed or switched capacitors are added as shown in Fig. 3. This paper assumes

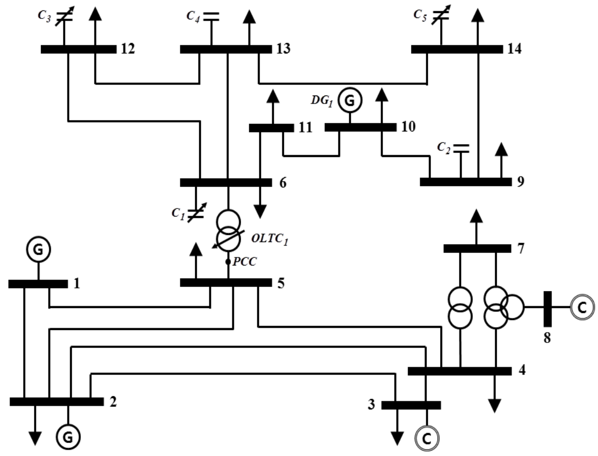


Fig. 3. Modified IEEE 14bus system

Table 1. The detailed data of the OLTC and DG

OLTC [p.u.]			DG [p.u.]			
Ntap	VTmax	VTmin	VGmax	VGmin	Qmax	Qmin
17	1.10	0.90	1.04	0.99	0.6	-0.6

Table 2. Ranges of control variables in proposed method

Variable name	Type	Range
Shunt1	Integer	[0,1,2,3] p.u.
Shunt2	Integer	[0,1] p.u.
Shunt3	Integer	[0,1,2] p.u.
Shunt4	Integer	[0,1] p.u.
Shunt5	Integer	[0,1,2] p.u.
OLTC1	Discrete	[0.90,0.91,...,1.09,1.10]
DG1	Discrete	[0.99,0.995,...,1.035,1.04]

that the transformer between node 5 and 6 is changed from a fixed tap OLTC and distributed generator is connected to node 10. Table 1 presents the detailed data of the OLTC and DG. Table 2 shows a summary of the control variables including five shunt capacitors, OLTC and DG for proposed method. In this study, the load model for load flow studies is adopted constant MVA which means bus loads are not a function of voltage magnitude.

The total load of control area which includes node 6, 9, 10, 11, 12, 13, 14 is 77.7 MW and 38.5 MVAr for normal load condition. The control area of test system is based on the 154 kV distribution systems.

4.2 Load and generation profile based on time series

In a day, assuming the network is scanned every hour, for twenty-four hours operation, the network is scanned for 24 times. We assume the following as shown in Fig. 4: First, load level varies from 40% to 100% for heavy load condition which is 86.33MW. Second DG output power varies from 45% to 80% for the rated capacity which is 50MW.

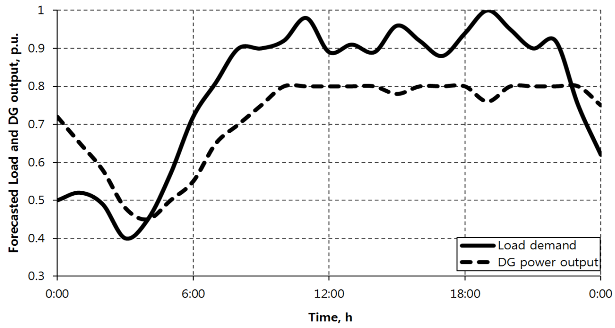
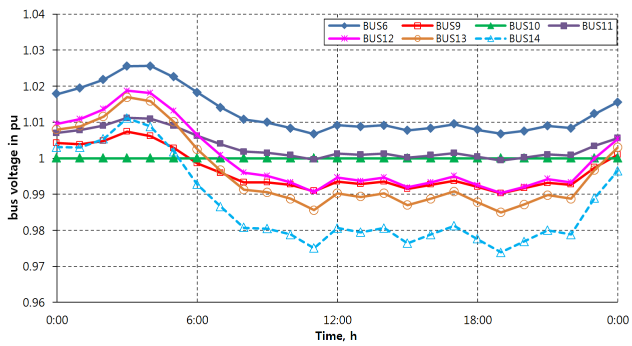


Fig. 4. Typical load demand and DG power output curve

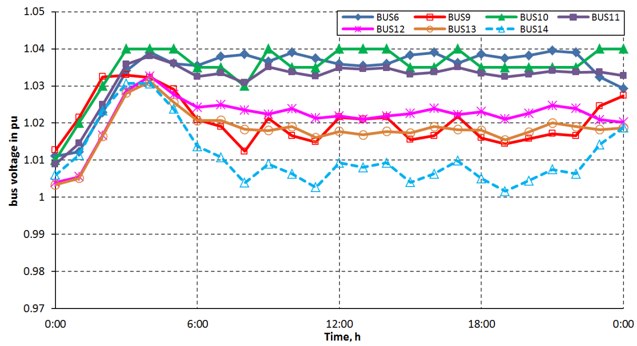
4.3 Simulation results

Fig. 5 shows the voltage profiles of before control and the proposed method. The results of bus voltage of before control as shown in Fig. 5(a) tend to depend on the load demand and DG power output are plotted shown in Fig. 4. All of the customer's voltages should be kept within the permissible voltage limits (1.015±0.025 p.u.) [15]. However, in Fig. 5(a), bus voltages at some nodes from 5:00 to 24:00 exceed the minimum allowed voltage. The bus voltage at node 14 is the lowest in the control area as shown in Fig. 5(a). On the other hand, all of the bus voltages are kept within the permissible voltage limits. The voltage profile at node 14 is greatly improved.

Fig. 6 shows the comparison of voltage deviation factors from the voltage profile results as shown in Fig. 5. The VDF is considered as an evaluation index to valid the effectiveness of proposed method. In Fig. 6, one can see that proposed method at each hour is more effective with regard to improving the voltage profiles.



(a)



(b)

Fig. 5. Voltage profiles of control area for the whole day : (a) before control, (b) proposed method

System active power losses (MW) in the control area at each hour with and without control are represented in Fig. 7.

At each stage i, we can compute objective and save the feasible states with the lowest objective value which is system losses. These saved values at each stage i are less than the simulation results from before control, respectively.

Receiving power factors (%) at the PCC at each hour with and without control are shown in Fig. 8. as a means of improving economic efficiency. In this study, the receiving power factor is considered as evaluation index for calculating system operational costs. The proposed method can be seen to have contributed to improving the receiving

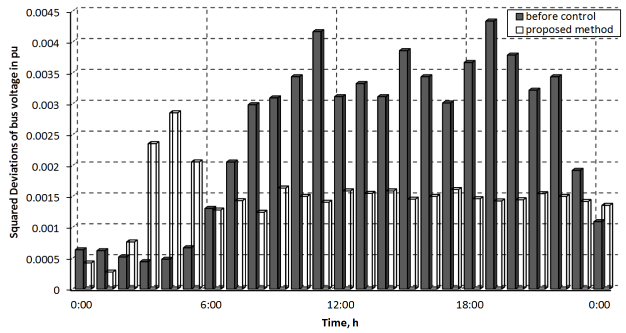


Fig. 6. Comparison of voltage deviation factors

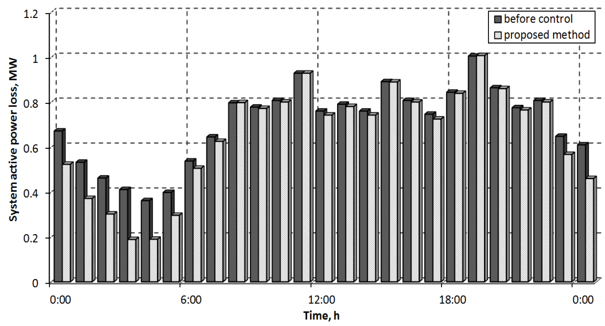


Fig. 7. System loss without and with control

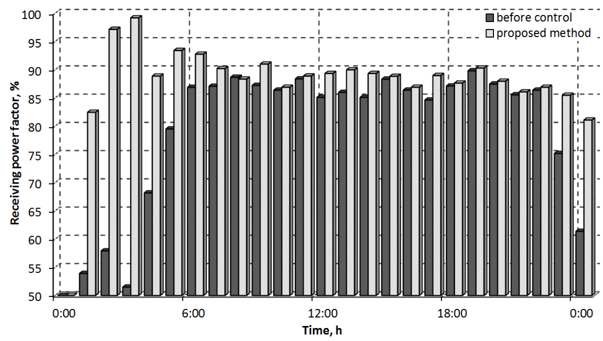


Fig. 8. Receiving power factor without and with control

power factor.

Table 3 shows the optimal dispatch schedule of OLTC, DG and five shunt capacitor switching based on the time series data as shown in Fig. 4. The initial tap position of OLTC is -2, the initial set point of DG is 1 p.u., and the initial status of the two fixed capacitor (C_2 and C_4) is on (1). And the initial status of three fixed or switched capacitor (C_1, C_3 and C_5) is off (0). To keep the voltage fluctuation in the the permissible voltage limit at node 14 in the whole day, the status of the shunt capacitor C_5 is on (1) at all stages.

Table 3. Optimal dispatch schedules from proposed method.

Hour	C_1	C_2	C_3	C_4	C_5	TAP1	VG1
0	0	1	0	0	1	0	1.010
1	0	1	0	0	1	+1	1.020
2	2	1	0	0	1	+3	1.030
3	1	0	0	0	1	+1	1.040
4	0	0	0	0	1	-1	1.040
5	0	0	0	0	1	-1	1.040
6	0	0	0	0	1	-2	1.035
7	0	0	0	0	1	-3	1.035
8	0	0	0	0	1	-4	1.030
9	0	0	0	0	1	-3	1.040
10	0	0	0	0	1	-4	1.035
11	0	0	0	0	1	-4	1.035
12	0	0	0	0	1	-3	1.040
13	0	0	0	0	1	-3	1.040
14	0	0	0	0	1	-3	1.040
15	0	0	0	0	1	-4	1.035
16	0	0	0	0	1	-4	1.035
17	0	0	0	0	1	-3	1.040
18	0	0	0	0	1	-4	1.035
19	0	0	0	0	1	-4	1.035
20	0	0	0	0	1	-4	1.035
21	0	0	0	0	1	-4	1.035
22	0	0	0	0	1	-4	1.035
23	0	0	0	0	1	-2	1.040

Table 4. Comparison of the results from several cases concerning the reduced computational burden

	Before control	Not reduced burden	Reduced burden
Maximum length of 24 stages, L^{max}	-	26928	3600
Objective value of J (MW)	17.025	15.706	15.815
Execution time (sec)	0.6	575	206

Table 5. The summary of simulation results

	Before control	Proposed method
Losses (kW)	17,025.4	15,815.0
Power factor (%)	79.05	87.70
VDFimp%	100	58.21
Cost of Losses (KRW/day)	1,106,650	1,028,006
Cost of PF (KRW/day)	411,451	111,120

VDFimp%=[VDF(before control)- VDF(proposed method)]/ VDF(before control)

Cost of Losses=Losses (kW)·electricity price(KRW/kWh)

The proposed method has been implemented using the Python in PSS/E environment. The total objective values and execution time of the optimal dispatch schedules by several techniques with and without flexible searching space at each stage are summarized in Table 4.

The total real power losses, power factor and their cost based values (KRW/day) are summarized in Table 5.

Based on the simulation results summarized in Table 5 and assumed conditions described in 3.3, total operating cost (TOC) of one year can be obtained the following results.

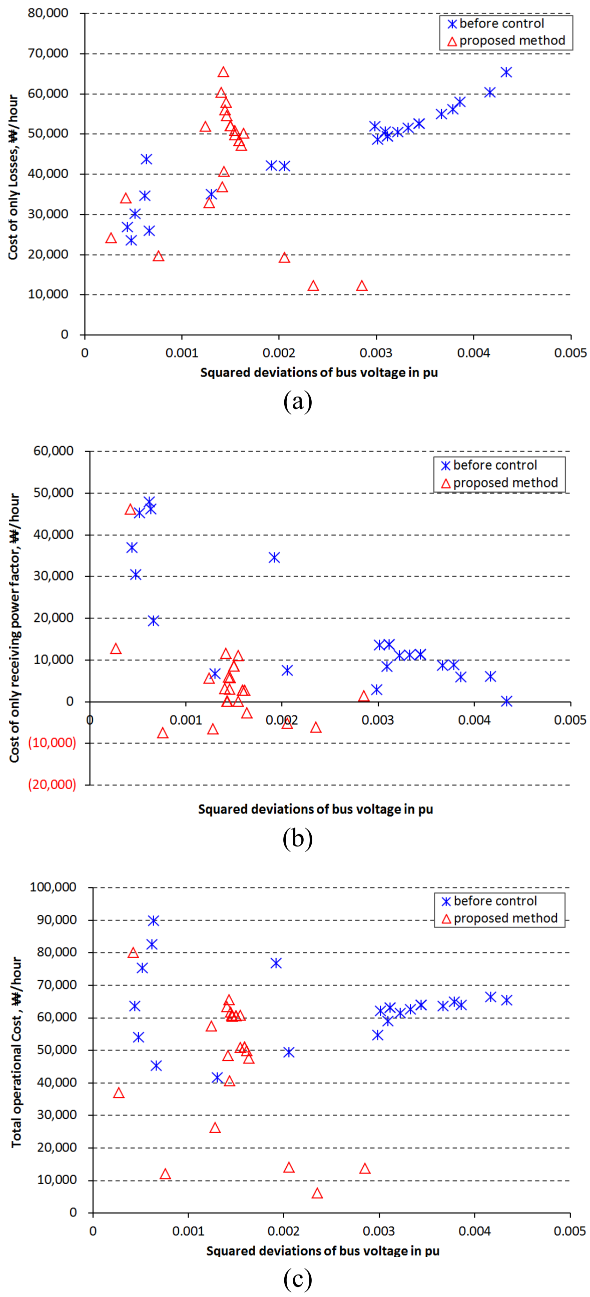


Fig. 9. Scatter plots between VDF and Total operation cost: (a) only losses, (b) only PF, and (c) both losses and PF

Table 6. Operating expenses and Annual Saving (in million won)

Case		Before control	Proposed method
TOC	only losses	403.9272	375.2223
	only PF	150.1796	40.5588
	losses and PF	554.1068	415.7812
Annual Saving (%)	only losses	0	7.11
	only PF	0	72.99
	losses and PF	0	24.96

Annual Saving = [TOC(before control)- TOC(proposed method)] ·100/ TOC(before control)

Fig. 9 shows the correlation between two variables which are VDF and total operational cost using scatter plots. From three sub plots in Fig. 9, we have the following observations. First, total system costs and VDF are shows relatively reduced. Second, considering both losses and VDF is greatly reduced after control as shown in Fig. 9(c).

Table 5 shows a summary of the total annual operating cost and benefit of proposed method according to three cases. Cleary the proposed method reduces the system operational costs and improve the voltage profiles from Fig. 9 and Table 6.

5. Conclusion

A new coordinated voltage and reactive power control strategy is proposed in this paper. The control variables include switched or fixed shunt capacitor bank, tap position of on-load tap changer and voltage set point of distributed generator. The proposed method is implemented by a Python script and the result is used to apply for PSS/E. Optimal dispatch schedules are obtained by using voltage sensitivity factor and dynamic programming with branch-and-bound method. To avoid the computational burden, voltage deviation matrix based sensitivity factor are applied and the searching space is reduced with flexible size. The evaluation index includes costs of system losses and receiving power factor at the point of common coupling as a means of improving economic efficiency. Simulation results indicate that the proposed method is effective in handing the system operational cost saving and voltage regulation. This control strategy makes it possible to minimize the total operational costs with system losses and receiving power factor and improve the voltage profile for a whole day in power system with distributed generators. The combined objective function including receiving power factor and loss minimization needs to be studied in the future.

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