Turkish Journal of Electrical Engineering & Computer Sciences

http://journals.tubitak.gov.tr/elektrik/

Research Article

Turk J Elec Eng & Comp Sci
(2019) 27: 4624 – 4639
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doi:10.3906/elk-1901-54

The impact of demand response programs on UPFC placement

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Received: 07.01.2019 • **Accepted/Published Online:** 27.06.2019 • **Final Version:** 26.11.2019

Abstract: Demand response (DR) and flexible AC transmission system (FACTS) devices can be effectively used for congestion management in power transmission systems. However, demand response program (DRP) implementation can itself affect the optimum location of FACTS devices, which is one of the main issues in power system planning. This paper investigates the impact of DRPs on unified power flow controller (UPFC) placement. The harmony search algorithm is employed to determine the optimum locations and parameter setting of UPFC in a long-term framework. The optimization problem is solved with different objectives including generation and congestion cost reduction, as well as loss reduction. In this paper, the proposed approach is analyzed using 5 different cases, which are defined in such a way that they demonstrate the impact of DRPs on the UPFC placement problem. The IEEE reliability test system is used as an illustrative example to demonstrate the necessity of considering DRPs for UPFC placement.

Key words: FACTS devices, demand response programs, harmony search algorithm, congestion management, loss reduction

1. Introduction

Demand response programs (DRPs) are applied to consumers' activities to change their electricity utilization in response to fluctuations in electricity prices. These programs are developed in such a way that they are attractive in terms of utility requirements and customer demands. The most noticeable utility advantage of implementing DRPs is the reduction in peak load and it benefits customers by reducing their energy bills [1].

The unified power flow controller (UPFC), proposed by Gyugyi in 1991 [2], is one of the most brilliant types of FACTS devices capable of providing active and reactive power control independently. So far, many papers have been published in the area of FACTS device placement and different approaches have been proposed for this complicated optimization problem [3–21]. Among them, in recent years, researchers have also conducted extensive studies on the implementation of DRPs, with different purposes such as reducing the electricity price and enhancing the security of the power system.

The effects of DR on the cost reduction and improvement of the load curve's characteristics were explored in [22] and [23]. In [24–27] DR was considered as a tool for congestion management. In [28], an economic comparison between DRP implementation and using FACTS devises for the enhancement of available transfer capability (ATC) was presented. A brief review of the literature is outlined in Table 1.

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Table 1. Literature review.

Ref.	Tools		Objectives							Optimization	
	FACTS devices	DRPs	Cong. manag.	Gen. cost	ATC	Loss	Voltage profile	Voltage stability	Security	Heur istic	Anal ytical
[3]	✓		✓	✓							MIP
[4]	✓				✓		✓				MIP
[5]	✓			✓	✓	✓					MIP
[6]	✓			✓	✓	✓					NLP
[7]	✓		✓								LMPs
[8]	✓		✓			✓					LMPs
[9]	✓				✓	✓				GA	
[10]	✓				✓	✓				GA	
[11]	✓				✓					PSO	
[12]	✓					✓	✓	✓		PSO	
[13]	✓		✓					✓		PSO	
[14]	✓				✓					PSO	
[15]	✓			✓						DE	
[16]	✓								✓	DE	
[17]	✓			✓						IA	
[18]	✓				✓					NSGA	
[19]	✓			✓		✓	✓			CRO	
[20]	✓					✓	✓	✓		AAA	
[21]	✓								✓	FFA	
[22]		✓		✓						PSO	
[23]		✓		✓						ICA	
[24]		✓	✓								ED
[25]		✓	✓								MIP
[26]		✓	✓								MIP
[27]		✓	✓								SA
[28]	✓	✓			✓						SA

In previous studies on the issue of UPFC placement, the effect of DRPs was not seen. Since DRPs are important tools for managing congestion by changing the load pattern, they can affect the location of UPFCs. Therefore, the study of the effect of DRPs on UPFC placement is important. Thus, this paper proposes a new methodology to solve the complicated problem of finding the optimal location and proper sizing of a UPFC in the presence of DRPs on a long-term horizon. The optimization problem is solved in such a way that parameters including generation and congestion costs or loss are minimized.

The contributions of this paper are twofold. First, the impact of DRPs on UPFC implementation has not been considered in previous studies. However, in smart grids, the end-user customers' participation in the electricity market in the DR framework is encouraged and therefore should be taken into account in power system planning and operation decisions. Therefore, this study explores the impact of these programs on UPFC placement on a long-term horizon. Second, the long-term framework, which takes into account the load duration curve (LDC), enables the proposed method to consider the UPFC impact on generation and congestion costs and system losses in a more realistic fashion rather than just considering a one-hour time frame, which was mostly considered as the study horizon in the literature.

2. Demand response programs

DRPs can be classified based on how they encourage customers to change their demand. Accordingly, DRPs are divided into two main categories: time-based rate (TBR) programs and incentive-based programs (IBPs). These programs aim to encourage customers to reduce the use of electric power during peak load times. In order to evaluate the effect of DRPs on the UPFC placement problem, developing a price-responsive demand model is necessary. Different economic models of price-responsive loads to be used in DRP implementation have been introduced in previous studies [29–32].

The TBR program as a DRP is addressed in this paper. Therefore, there is neither penalty nor reward for customers to change their load profiles. The above models are developed to accommodate the changes on the demand side for customers based on the spot market price [32].

Taking into account different tariffs assigned for different periods, customers change their demand from initial value $D(t)$ to $D_{DR}(t)$, as expressed by the following equation:

$$\Delta D(t) = D_{DR}(t) - D(t), \tag{1}$$

where $D(t)$ and $D_{DR}(t)$ are initial load demand and load demand after implementing DR in hour t, respectively. Taking B(D(t)) as the revenue of the customer obtained from the consumption of electrical energy (D(t) in MWh) during hour t, the customer's benefit, denoted by S(D(t)), for hour t will be:

$$S(D(t)) = B(D(t)) - D(t)P(t), \tag{2}$$

where $P(t)$ is the electricity price. In order to maximize the customer's benefit, $\partial S/\partial D(t)$ should be zero. Therefore, after doing some mathematical calculations, the single-period and multiperiod models of the responsive load are obtained through (3) and (4), respectively:

$$D_{DR}(t) = D(t)\{1 + E(t,t)\frac{[P(t) - P_0(t)]}{P_0(t)}\}, \tag{3}$$

$$D_{DR}(t) = D(t)\{1 + \sum_{\substack{j=1 \\ t \neq j}}^{24} E(t,j)\frac{[P(j) - P_0(j)]}{P_0(j)}\}, \tag{4}$$

where $E(t,t)$ is the price elasticity in period t versus period t (self-elasticity), and $E(t,j)$ is the price elasticity of period t versus period j (cross-elasticity), respectively. Furthermore, $P_0(t)$ and $P_0(j)$ are the initial electricity prices at periods t and j, respectively.

2.1. Load economic model

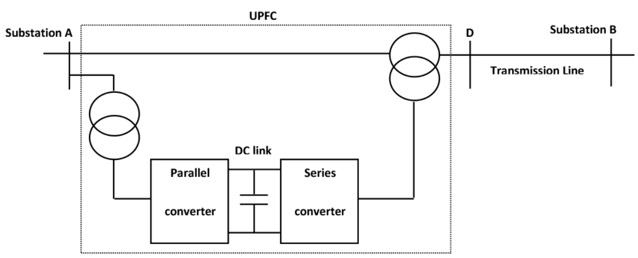
The responsive load economic model is obtaining by integrating (3) and (4) into (5):

$$D_{DR}(t) = ((1-\eta_D) \times D(t)) + \eta_D \times D(t)\{1 + E(t,t)\frac{[P(t) - P_0(t)]}{P_0(t)} + \sum_{\substack{j=1 \\ t \neq j}}^{24} E(t,j)\frac{[P(j) - P_0(j)]}{P_0(j)}\}, \tag{5}$$

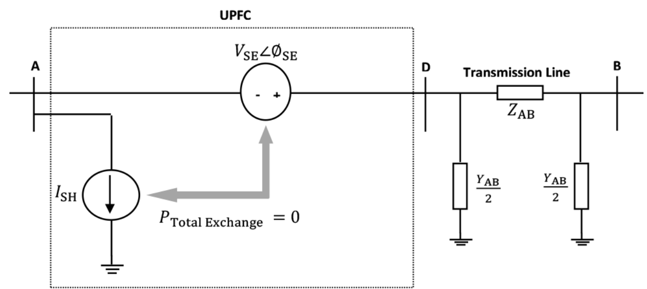
where η_D is defined as the percentage of load participating in the DRP.

3. UPFC modeling and formulations

The UPFC static model and its formulation to be used for the OPF problem are discussed in this section. AC transmission controllers can be used to control or optimize the power transfer over a transmission line in power systems. One such controller is the UPFC, presenting a perfect choice due to its control options. The basic structure of a UPFC is displayed in Figure 1a. As was stated earlier, automatic power flow control mode is



(a)



(b)

Figure 1. (a) Basic scheme of UPFC, (b) equivalent circuit of UPFC.

one of operation control modes existing for UPFCs and it is regarded as having great potential for power flow management. In fact, the UPFC is able to independently and directly control the desired active and reactive power flows in the line by providing sufficient rating and continuous and automatic estimation of magnitude and phase angle of the injected voltage vector [2]. Many studies in the literature on UPFC analysis and modeling and various models have incorporated UPFCs in optimal power flow (OPF) analysis formulation [33–35].

The injected power model [33] shown in Figure 1b, is employed in this paper to model the UPFC. There are only three controllable UPFC parameters [33]: the magnitude of the injected voltage of transformer (V_{SE}) in series with the transmission line, the phase angle of the injected voltage (ϕ_{SE}), and the shunt transformer reactive current (I_{SH}). The upper and lower boundaries of these control variables can be expressed as follows:

$$0 \leq V_{SE} \leq V_{SE}^{max}, 0 \leq \phi_{SE} \leq 2\pi, -I_{SH}^{max} \leq I_{SH} \leq I_{SH}^{max}. \tag{6}$$

Considering the boundaries defined in (6), this study aims to determine the optimal UPFC parameters (V_{SE}, ϕ_{SE}, and I_{SH}) in such a way that the objective function, which will be defined later, is minimized. Based on the equivalent circuit presented in Figure 1b, the active and reactive power injected in buses A (P_A^{inj}, Q_A^{inj}) and B (P_B^{inj}, Q_B^{inj}) can be calculated via (7) through (10) [33]:

$$P_A^{inj} = -V_B V_{SE}[Gcos(\delta_B - \phi_{SE}) - Bsin(\delta_B - \phi_{SE})] + G_F V_{SE}^2 + 2V_A V_{SE} G_F cos(\delta_A - \phi_{SE}), \tag{7}$$

$$Q_A^{inj} = V_A V_{SE}[G_F cos(\delta_A - \phi_{SE}) - B_F sin(\delta_A - \phi_{SE})] - V_A I_{SH}, \tag{8}$$

$$P_B^{inj} = -V_B V_{SE}[Gcos(\delta_B - \phi_{SE}) + Bsin(\delta_B - \phi_{SE})], \tag{9}$$

$$Q_B^{inj} = -V_B V_{SE}[Gcos(\delta_B - \phi_{SE}) - Bsin(\delta_B - \phi_{SE})], \tag{10}$$

where $G + jB = 1/Z_{AB}$, $G_F = Re(Y_{AB}) + G$, $B_F = Im(Y_{AB}) + B$, and $V_A\angle\delta_A$ and $V_B\angle\delta_B$ are the voltage phasors at buses A and B, respectively.

4. Long-term model

The peak load and growth of energy demand for each year are equal to the corresponding values obtained in the last year multiplied by the associated growth rates. In this study, the average growth rate is considered as the growth rate and is denoted by AGRP and AGRE for annual peak loads and total energy demands, respectively. Hence, the peak load and total energy demand in year yr, i.e. P_{yr} and E_{yr}, are calculated via (11) and (12):

$$P_{yr} = P_{(yr-1)} \times (1 + AGRP), \tag{11}$$

$$E_{yr} = E_{(yr-1)} \times (1 + AGRE). \tag{12}$$

The future load block in subperiod b and year yr, represented by $bl_{b,yr}$, is determined using a linear transformation of the load for subperiod b in the base year ($bl_{b,0}$) and is formulated as follows [36]:

$$bl_{b,yr} = a \times bl_{b,0} + b, \tag{13}$$

$$a = \frac{E_{yr} - 8760 \times P_{yr}}{E_0 - 8760 \times P_0}, \tag{14}$$

$$b = \frac{P_{yr} \times E_0 - P_0 \times E_{yr}}{E_0 - 8760 \times P_0}. \tag{15}$$

Furthermore, the load of bus z at each load block is determined by multiplying the load at each block and the load distribution factor of that specific bus as in (16):

$$PD_{z,b,yr} = D_{z,b,yr} \times bl_{b,yr}. \tag{16}$$

5. The proposed method

The objective of power system operation and planning in restructured electricity markets is to maximize the social welfare or, in other words, to minimize the operational costs. Given the high investment costs of a UPFC, using this device may cause considerable risk, showing the high importance of determining the UPFC's optimum location and parameter settings. Accordingly, this study seeks to minimize the losses or operation costs by implementing a UPFC on a long-term horizon.

A planning year is divided into multiple subperiods, each with fixed loads. The number of subperiods is determined based on the planning requirements and load patterns. In this study, a planning year is divided into 4 subperiods, each representing a seasonal load pattern, so there are 4 load blocks in a base year with the corresponding duration. Thus, there are load blocks over a three-year horizon, each block with corresponding probability of occurrence. In addition, Section 4 presents the linear transformation for calculating the load in each subperiod in the other two consecutive years. The bus load in the subperiod is calculated as the load distribution factor multiplied by the subperiod load. Furthermore, a proper commitment status of the generation unit for each load level is determined in this study by executing a unit commitment algorithm and the unit commitment output is used for the generator status at each load level.

5.1. The OPF subroutine

Assuming the proper commitment configuration for each of the 12 load blocks, an OPF is performed in the presence of the UPFC. The generation dispatch and load schedules are determined by running OPF in pool-based electricity markets. OPF is performed according to the bids proposed by market participants such as suppliers and customers by considering all network and participants' constraints. To this end, the OPF problem is solved in this paper using MATPOWER [37] as a package of MATLAB M-files for solving the power flow and OPF problems.

5.2. Locational marginal price and congestion cost

The locational marginal price (LMP) as a way of managing congestion in many deregulated electricity markets is defined as the lowest cost for providing an additional megawatt in a bus without violating the network constraints [7, 8]. The LMP contains three different components: 1) marginal energy, 2) marginal loss, and 3) congestion [7, 8]. The LMP for bus i can be defined as:

$$LMP_i = \lambda + \lambda \frac{\partial P_L}{\partial P_i} + \sum_{k=1}^{N_L} \mu_{L_k} \frac{\partial P_k}{\partial P_i}, \tag{17}$$

$$LMP_i = \lambda + \lambda_{L,i} + \lambda_{C,i}, \tag{18}$$

where λ is the marginal energy, $\lambda_{L,i} = \lambda \partial P_L / \partial P_i$ is the marginal loss, and $\lambda_{C,i} = \sum_{k=1}^{N_L} \mu_{L_k} \partial P_k / \partial P_i$ corresponds to the congestion. Thus, the LMP difference between the two ends of a specific line is associated with the extent of loss and congestion on that line. Similar to (18), the LMP for bus j can be written as:

$$LMP_j = \lambda + \lambda_{L,j} + \lambda_{C,j}. \tag{19}$$

By taking the difference between spot prices of buses i and j, we have:

$$\Delta LMP_{ij} = (\lambda_{L,i} - \lambda_{L,j}) + (\lambda_{C,i} - \lambda_{C,j}). \tag{20}$$

Equation (20) confirms that LMP differences of any two buses consist of two different parts, one of them corresponding to the marginal losses and the other to the congestion. The congestion cost at a specific time is calculated as follows:

$$CC = \sum_{k=1}^{N_L} \Delta LMP_{ij} P_{ij}. \tag{21}$$

The loss in the power system is then calculated using the following equation:

$$P_{Loss} = \sum_{ij=1}^{N_L} |P_{ij} + P_{ji}|, \tag{22}$$

where N_L is the number of lines and P_{ij} is the active power flowing from bus i to bus j.

5.3. The objective functions of the placement and sizing problem

UPFC optimal locating and parameter setting are determined by using two different objective functions. The first objective function employed to minimize the total operation cost, including generation cost and congestion cost, is presented as follows:

$$F_1 = \sum_{t=1}^{T} \sum_{b=1}^{N_{Lb}} Sh_{t,b} \times [F_{t,b} + CC_{t,b}], \tag{23}$$

where $F_{t,b}$ is the generation cost of load block b at year t, $CC_{t,b}$ is the congestion cost of load block b at year t, and $Sh_{t,b}$ is the probability of occurrence of load block b.

The second objective function, which seeks to minimize the loss, is defined as follows:

$$F_2 = \sum_{t=1}^{T} \sum_{b=1}^{N_{Lb}} Sh_{t,b} \times P_{Loss_{t,b}}, \tag{24}$$

where $P_{Loss_{t,b}}$ is the power loss of load block b at year t. Since this paper assumes that only one of these objective functions is considered in each situation, the best solution is the one having the minimum value of either of these objective functions (average cost or loss per hour).

5.4. Harmony search algorithm for solving the optimization problem

The harmony search algorithm (HSA) was proposed by Geem et al. [38] in an analogy with the music improvisation process, where music players obtain better harmony by improvising the pitches of their instruments. The HSA parameters are the harmony memory size (HMS), harmony memory considering rate (HMCR), pitch adjusting rate (PAR), and the termination criterion (the maximum number of searches). The number of solution vectors in the harmony memory matrix is the HMS, as is the case for the population in GAs, and it usually varies from 10 to 100. The parameter called HMCR, ranging from 0 to 1, is adopted by the HSA in order to use this memory effectively. The mentioned parameter is normally set in the range of 0.5 to 1. In addition, another option called PAR, ranging from 0.1 to 0.5, is usually adopted for improving the solutions and escaping local optima. Different steps are taken by the HSA to find the optimal solution for a problem [38]:

Step 1. Initialize the HSA parameters such as HMS, HMCR, PAR, and termination criterion.

Step 2. Initialize the harmony memory (HM) matrix with HMS randomly generated solution vectors. These harmony vectors are sorted by the objective function values as a result of the solution they represent.

Step 3. Improvising a new harmony from the HM: with probability HMCR, a value of one of the solutions in the harmony memory is used and also this value changes slightly with probability PAR; otherwise (with probability 1-HMCR), a random value is used for all decision variables.

Step 4. If the new solution is better than the worst solution in the harmony memory, the worst solution is replaced by the new one and the HM is updated.

Step 5. Steps 3 and 4 are repeated until the termination criterion (number of iterations) is met.

The general flowchart of the proposed methodology is given in Figure 2

6. Simulation results

The IEEE reliability test system [39] shown in Figure 3 is used to analyze the effectiveness of the proposed method in a 3-year time period. The HSA is used in this paper, since compared to traditional optimization

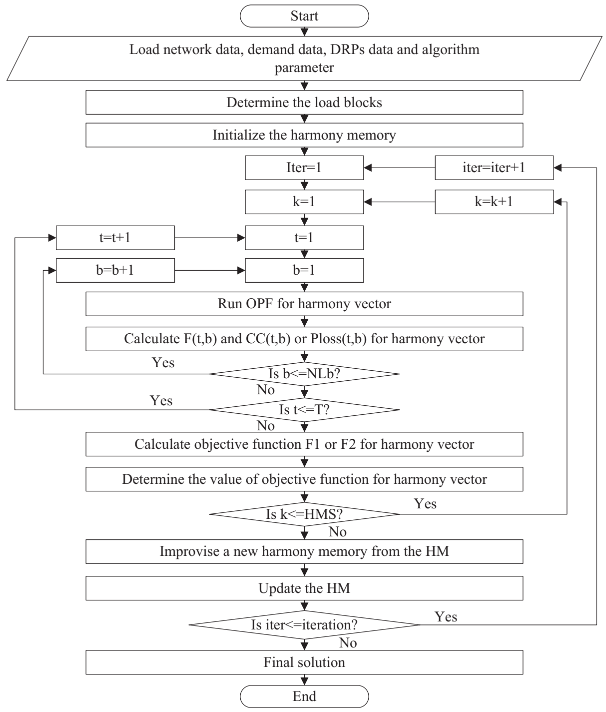


Figure 2. Flowchart of the proposed methodology.

techniques it is more effective in solving a wide variety of optimization problems in power system studies [40, 41]. The HSA has fewer mathematical requirements and does not need initial value settings of the decision variables. It also makes a new vector after taking into account all existing vectors rather than considering only two (parents) as in the genetic algorithm. These features increase the flexibility of HSA and enable it to find better solutions. The HSA parameters are presented in Table 2. The generators' data and the peak value

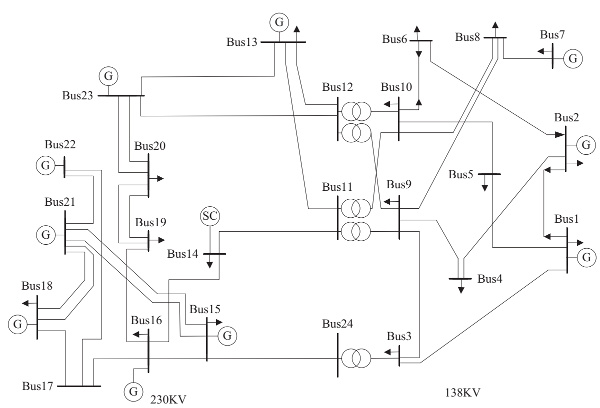


Figure 3. IEEE reliability test system.

of bus loads in the first year are available in [39]. It is assumed that the power factor of each load remains constant as the load grows. It is also assumed that a set of the existing units does not change in the period under study. The load blocks in the base year are presented in Table 3 and the mean values of the load and

Table 2. HSA parameters.

HMS	HMCR	PAR	Iteration
50	0.8	0.3	100

energy growth rates are considered to be 0.08. The price elasticity of demand is adopted from [32] and is as

Table 3. Load blocks in base year.

Subperiod	1	2	3	4
Load (MW)	2850	2280	2565	2280
Duration (weeks)	17	9	13	13

presented in Table 4. As shown in this table, different load levels are divided into three periods based on [42].

Table 4. Price elasticity of demand.

Hour	Peak	Off-peak	Low level
Peak	–0.1	0.016	0.012
Off-peak	0.016	–0.1	0.01
Low level	0.012	0.01	–0.1

In the proposed approach, five different cases are taken into account to thoroughly investigate the impact of DRPs on the UPFC placement problem. In the first and second cases, the UPFC placement problem is solved without considering DRPs and with the objectives of operation cost and loss minimization. In the third case, the power system is analyzed in the presence of DRPs and without UPFC. The UPFC placement problem is solved in the fourth case in the presence of DRPs to minimize the operational cost, while the last case deals with this problem with the objective of loss minimization. These cases, which are also detailed in Table 5, will be investigated in the following subsections. In order to find the UPFC optimum location and size, the total generation and congestion costs should be calculated for the base case. First, the generation and congestion costs along with the losses of the base case without DRPs and UPFC should be estimated for each load level. For the sake of brevity, only the average values of the study horizon are presented in Table 6. At some hours of the following years, the OPF does not converge and the operator has to employ load curtailment to supply the loads. Therefore, the generation and congestion costs are very high.

Table 5. Details of cases.

Case no.	UPFC	DRPs	Objective function
1	✓		Operation cost minimization
2	✓		Loss minimization
3		✓	×
4	✓	✓	Operation cost minimization
5	✓	✓	Loss minimization

Table 6. Summary of base case results.

Average generation cost (\$/h)	Average congestion cost (\$/h)	Average loss (MWh/h)
54327.0031	138391.6935	62.5293

6.1. Case 1: UPFC placement with the objective of operation costs minimization

In this case, the UPFC placement problem is solved without implementing DRPs. The objective function to be minimized is the operation cost, which includes payment to generation units and congestion costs of the transmission network. Table 7 summarizes the solutions of this case. The three best solutions leading to the lowest operation costs obtained through the proposed method are presented in this table. These solutions are sorted in descending order with respect to their operating costs. The sizes of parallel and series converters are also provided in this table. The AGC and ACC values for each rank are presented in Figures 4a and 4b, respectively. As can be seen in Figures 4a and 4b, the AGC and ACC values have been decreased by using the proposed method compared to the base case. Furthermore, the best solution corresponds to rank 1, in which the AGC and ACC values are minimum among all ranks.

Table 7. Best solution of UPFC placement for operation cost minimization.

Rank	Line	V_{SE} (p.u.)	ϕ_{SE} (Rad)	I_{SH} (p.u.)
1	3-9	0.1050	5.6913	-0.424
2	3-9	0.0892	5.8147	0.8209
3	13-23	0.1367	0.6724	0.7818

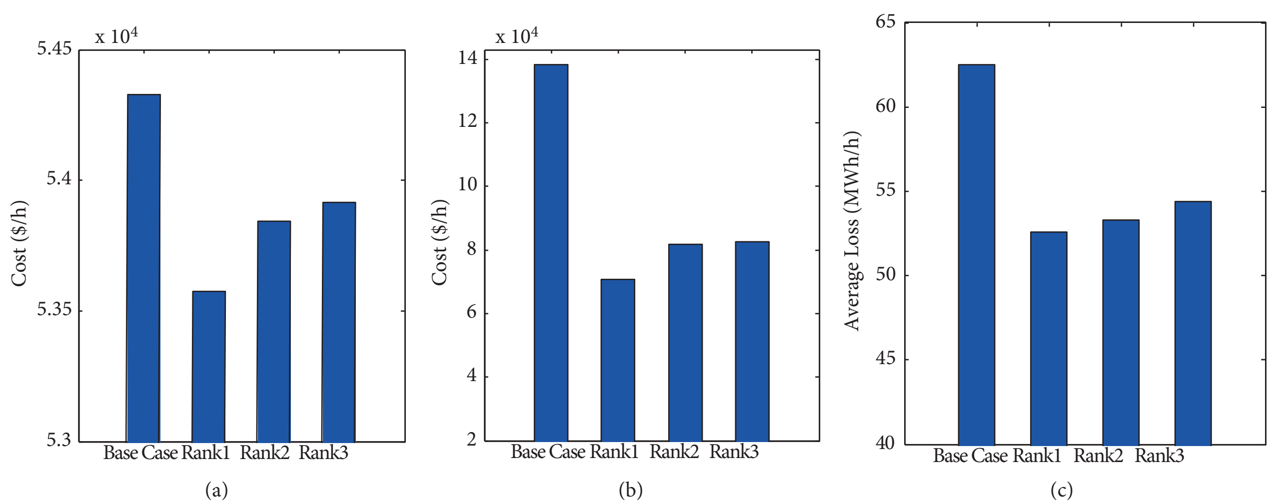


Figure 4. (a) Average generation cost (AGC), (b) average congestion cost (ACC), (c) network average loss.

6.2. Case 2: UPFC placement with the objective of loss minimization

Loss minimization is the objective function considered in this case. Also, the UPFC placement problem is solved without DRPs in this case. The results presented in Table 8 are the three best solutions of UPFC placement leading to the lowest loss obtained by the proposed approach. These solutions are sorted in descending order with respect to their loss. Loss reduction (LR) percentage is also provided in this table. The network losses associated with each rank are presented in Figure 4c. As shown in this figure and in comparison with the base case, the system losses are decreased significantly. Furthermore, the best solution corresponds to rank 1, in which the network loss values are minimum among all ranks.

Table 8. Best solutions of UPFC placement for loss minimization.

Rank	Line	V_{SE} (p.u.)	ϕ_{SE} (Rad)	I_{SH} (p.u.)	LR (%)
1	16-19	0.0886	0.1437	0.427	15.8
2	17-18	0.0260	0.2574	0.4121	14.6
3	17-22	0.2449	0.2400	–0.806	12.9

6.3. Case 3: Base case with DRPs and without UPFC

Table 9 shows the results of implementing DRPs in the base case. It also presents the average generation and congestion costs after employing DRPs plus the average network loss. Comparing these results with those of the base case shows a considerable reduction in all three values due to the impact of DRP implementation.

Table 9. Average system costs and loss after implementing DRPs.

Average generation cost ($/h)	Average congestion cost ($/h)	Average loss (MWh/h)
49383.4116	41572.6220	61.1471

6.4. Case 4: UPFC placement for operational costs minimization in the presence of DRPs

In this case, the impact of DRPs on UPFC placement on the operation cost minimization is investigated. Like in case 1, the objective is to minimize the payment to generation units and congestion cost of the transmission network. Table 10 provides the three best solutions leading to the lowest operation cost obtained by the HSA for this case. The UPFC parameters along with the AGC and ACC changes are presented in this table and Figures 5a and 5b, respectively.

Table 10. Best solutions of UPFC placement for operational cost minimization in the presence of DRPs.

Rank	Line	V_{SE} (p.u.)	ϕ_{SE} (Rad)	I_{SH} (p.u.)
1	12-13	0.1581	0.5707	–0.489
2	3-9	0.1576	5.7177	–0.443
3	3-9	0.1395	5.9058	0.5589

6.5. Case 5: UPFC placement with the objective of loss minimization in the presence of DRPs

In this case, the UPFC placement problem is solved for loss reduction while the DRPs are implemented in the power system. The three best solutions of UPFC placement leading to the lowest loss in the presence of DRPs are shown in Table 11. The network losses associated with each rank are presented in Figure 5c. A comparison of these results with those of the base case and case 2 suggests that implementing both DRPs and the UPFC can significantly decrease the loss of the network and improve the network performance.

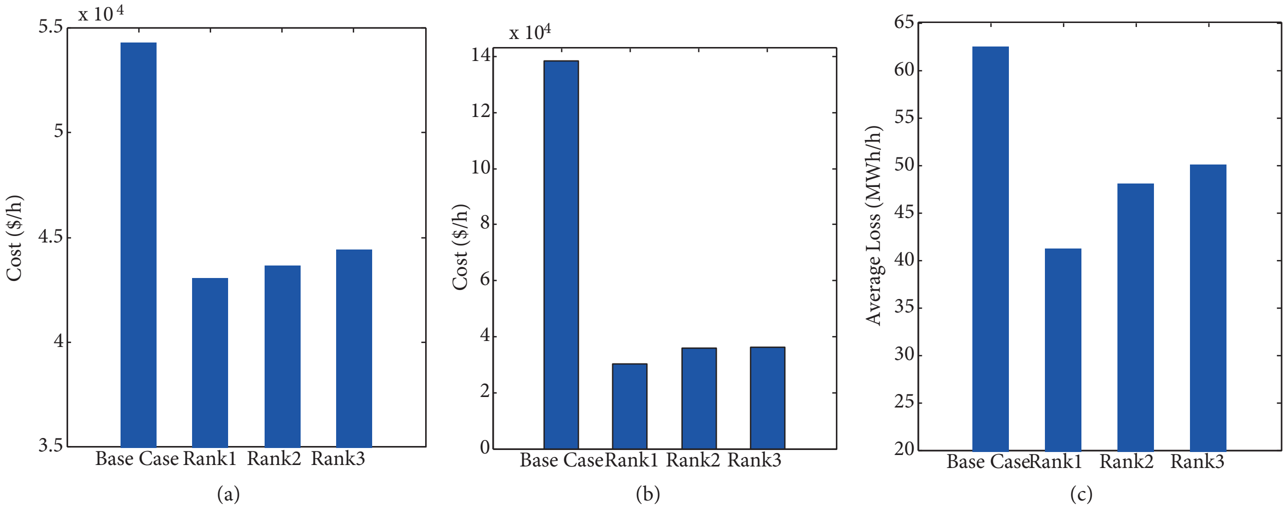


Figure 5. (a) Average generation cost (AGC), (b) average congestion cost (ACC), (c) network average loss.

Table 11. Best solutions of UPFC placement for loss minimization in the presence of DRPs.

Rank	Line	V_{SE} (p.u.)	ϕ_{SE} (Rad)	I_{SH} (p.u.)	LR (%)
1	18-21	0.1325	5.1270	–0.699	32.62
2	16-17	0.1372	5.9134	–0.746	21.31
3	18-21	0.0923	5.7537	0.6006	18.16

7. Discussion

First of all, note that in this paper, the proposed algorithm was run 10 times in each case as shown in Figure 6, in which the convergence result for case 2 is illustrated. As shown in Figure 6, with 10 executions of the algorithm, the objective value converged to an optimum value or near optimum value. In this paper we select the result from the one that is the best among ten runs and without taking means and standard deviations of the results.

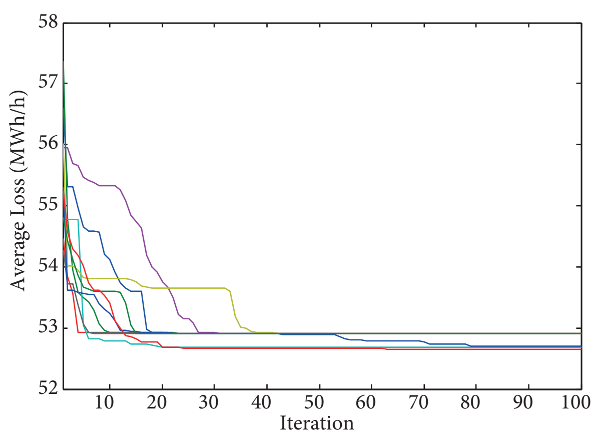


Figure 6. Convergence behavior of the proposed algorithm.

This paper analyzed the impact of DRPs on UPFC placement and parameter setting in a long-term framework. Results showed that the optimal UPFC placement significantly improved the network performance by alleviating the transmission congestion and decreasing the network losses. On the other hand, deploying

DRPs significantly reduced the network congestion and losses. When both UPFC and DRPs are properly implemented, the network has the best condition. However, these potentials can only be activated if the UPFC and DRPs are considered simultaneously and the effect of customer participation on UPFC placement is fully modeled and considered in the decision-making. As the results in Tables 7, 8, 10, and 11 show, the UPFC placement solution is different when DRPs are employed; thus, it is vital to consider the effect of these programs.

The AGC and ACC values for different cases are shown in Figures 7a and 7b respectively while the loss values are presented in Figure 7c. Note that in all cases rank 1 as the optimum solution for each case is selected to be compared with other cases as shown in these figures. Although the UPFC or DRPs alone have been able to reduce the AGC, ACC (cases 1 and 3 in Figures 7a and 7b), and loss (cases 2 and 3 in Figure 7c) compared to the base case, the effect of the DRPs alone on the AGC and ACC is greater than the UPFC effect (Figures 7a and 7b), while in terms of loss reduction the effect of the UPFC alone is greater than that of the DRPs (Figure 7c). However, the UPFC and DRPs simultaneously have the highest reduction in AGC and ACC values (case 4 in Figures 7a and 7b) and losses (case 5 in Figure 7c).

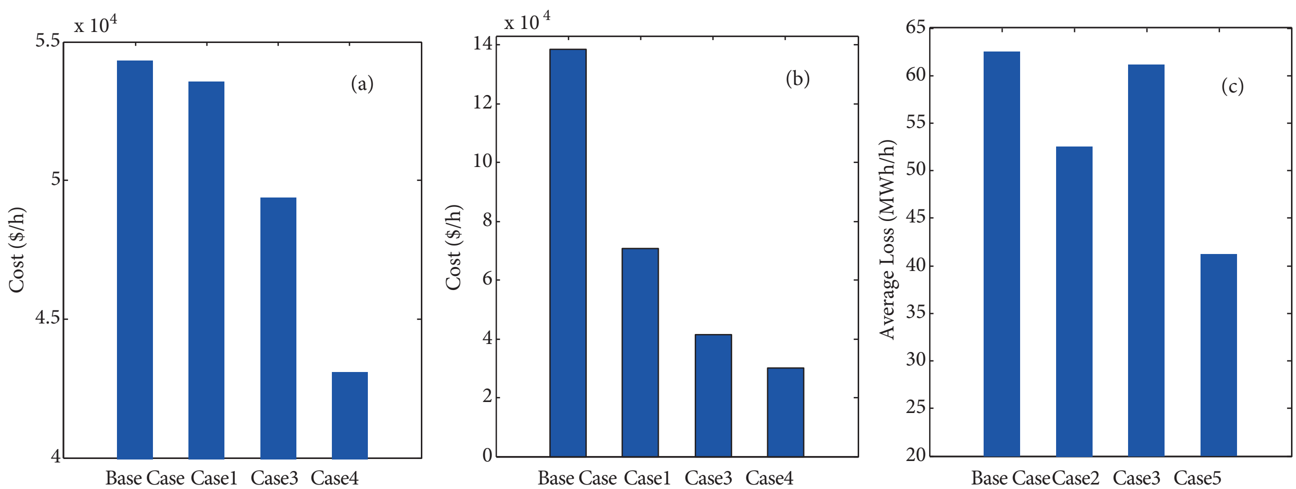


Figure 7. (a) Average generation cost (AGC), (b) average congestion cost (ACC), (c) network average loss.

In this study, two different objectives have been followed: congestion mitigation and loss reduction. The first one has been considered in cases 1 and 4, and the second one has been considered in cases 2 and 5. However, selecting a desired case is totally based on the operator's preference. In the results section, it was shown that applying DRPs when locating the UPFC can lead to solutions with lower costs and losses in cases 4 and 5, respectively. Therefore, if the operator's focus is on the costs, he can refer to case 4. On the other hand, if losses are more important for the operator, he can refer to case 5. The selection of the objective functions varies as the network characteristics and operators' preferences change. Additionally, these objectives can be considered simultaneously with different or equal coefficients to improve the performance of the power system.

8. Conclusion and future work

In this study, an HSA-based optimization method was proposed for the optimal UPFC placement and parameter setting in the presence of DRPs in a deterministic long-term framework. The optimization problem was solved with different objectives including generation and congestion cost reduction, as well as loss reduction. The

IEEE Reliability Test System was used as an illustrative example to identify the impact of DRPs on the UPFC locating problem. Results proved that DRP consideration highly affects the UPFC placement problem. It was shown that when DRPs are employed the UPFC placement solution is changed and that the highest reduction in AGC, ACC, and loss are obtained when the UPFC and DRPs are considered simultaneously. In the future, we are going to consider a more realistic load model along with considering cost-benefit analysis in the proposed method.

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