Engineering and Technology Journal
Journal homepage: https://etj.uotechnology.edu.iq

Impact of the UPFC on the optimal transmission switching for cutting down market power cost

Check for updates

Sunday Oladejo Adetona *, Makanjuola Yussuf Adetola , Frank Nwoye Okafor, Nwabueze Godfrey Ubakanwa

Department of Electrical and Electronics Engineering, Faculty of Engineering, University of Lagos, Lagos, Nigeria.
*Corresponding author Email: sadetona@unilag.edu.ng

HIGHLIGHTS

- WNE models strategic generation companies' (gencos) behavior in exercising market power on EPG
- The fast voltage stability index adjusts EPG parameters and identifies critical lines for OTS
- A forceful reduction in social cost occurs when the market is under WNE and OTS is implemented
- Social cost for scheduling gencos under WNE and OTS, with or without the UPFC, remains the same
- A strategic generator dispatches more power in the presence of UPFC compared to its absence in the EPG

ARTICLE INFO

Handling editor: Ivan A. Hashim

Keywords:
Market power, Strategic gencos, Optimal transmission switching, Fast voltage stability index, and UPFC.

ABSTRACT

The exercise of market power by the strategic generating companies (gencos) in the deregulated wholesale electricity market (WEM) should be mitigated, as it results in higher wholesale prices of electricity and a drop in competition in the WEM. Consequently, Optimal Transmission Switching (OTS) has been proposed as a means by which the System Operator in the WEM can use to mitigate it. It is also imperative that the effect of the Unified Power Flow Controller (UPFC) on reducing the cost due to the market power using OTS must be investigated. Therefore, this study used the Fast Voltage Stability Index (FVSI) to select the critical lines to be optimally switched and compensated. The compensation factor was used to size the UPFC. The modified IEEE 14-bus system was utilized as the test system. Worst Nash Equilibrium (WNE) was used to model the behavior of the strategic gencos in exercising market power on an EPG. The OTS under WNE was modeled and solved in the General Algebraic Modeling System (GAMS) studio with the aid of the Network Enabled Optimization System (NEOS) server. The results of the FVSI were used to modify the parameters of the EPG in the GAMS studio and identify critical lines for the OTS. The simulated results revealed that in using OTS under WNE, strategic gencos dispatch more power in the presence of the UPFC than in its absence, reducing the cost associated with the market power of the strategic gencos.

1. Introduction

The purpose of deregulating the electric power industry is to bring competition into the wholesale electricity markets (WEM), improve the system's efficiency, and lower the wholesale price of electricity. All these benefits can only be achieved if the System Operator (SO) ensures no power abuse by any market participants (MP). But this is usually not the case in deregulated WEM as generating companies (gencos) easily exercise and abuse their market powers [1] by withholding some of their available generating capacity, leading to a lower level of competition in the market, poorer efficiency, higher wholesale price of electricity, and a negative impact on the global welfare of other MP [2]. Optimal Transmission Switching (OTS), which is the switching in and out of lines to achieve optimal power flow (OPF), has been explored in many studies. For instance, in [3], using a deterministic and genetic algorithm, OTS was used as a control method for correcting over- and under-voltage situations and line overloading. The authors of [4] used OTS to address the challenge of line loss and cost reduction on the electric power grid (EPG), and the results obtained were good. In [5], the authors took their study a step further to study how OTS affects the efficiency of the EPG; the result showed an improvement in EPG's efficiency with OTS. In [6], the use of OTS to address a combination of the above-stated problems was studied. Alas, none of these aforementioned studies address

http://doi.org/10.30684/etj.2024.144807.1645
Received 21 November 2023; Received in revised form 23 January 2024; Accepted 29 January 2024; Available online 21 February 2024
2412-0758/University of Technology-Iraq, Baghdad, Iraq

the problem of reducing the generating cost associated with the market power using OTS. In fact, only [7] and [8] have been found to address this problem directly.

In Noriega [7], OTS was used with a Worst-Nash Equilibrium (WNE) linear optimization formulation adopting a modified IEEE 14-bus system. A model was created to determine the generation cost due to the exercising of the market power by some generators. The proposed Nash equilibrium formulation includes gencos that might withhold some of their capacities, called strategic generators, and gencos that release their maximum generation capacities to the WEM, called non-strategic generators. The results showed that the market power of the strategic generators was reduced due to the release of more amounts of their available generation capacities when OTS was adopted compared to when OTS was not adopted. In [8], OTS was proposed to reduce market power costs caused by some strategic gencos and eventually improve the global welfare of all the scheduling generators in the deregulated WEM. The Cournot game theory and Nash Equilibrium were also used to model the gencos' behavior and the market power exercise. The simulation result showed that changing the configuration of the EPG by the SO will reduce the cost associated with the market power. Furthermore, it was discovered that the set of Nash Equilibria changes under different network topologies. Therefore, the SO can choose the network configuration that gives the Nash equilibrium with the least market power cost in the WEM.

With the rise in the number of actual installations of Flexible Alternating Current Transmission System (FACTS) controllers in the EPG as listed in the work of [9]; and studies carried out on them where they have yielded positive results in available transfer capacity (ATC) enhancement [10, 11], transmission line loss reduction [12], voltage regulation improvement [13], optimal generation [14], reduction of severity of overloading [15], and power flow control [9] to name but a few, it is likely that their presence in the EPG will have an effect when OTS is used in the mitigation of market power of gencos by the SO. One study that related FACTS devices with market power is [16]; where a thyristor-controlled series capacitor (TCSC) and a thyristor-controlled phase angle regulator (TCPAR) were used in steady-state operation. The market power was determined using the Nodal Must Run Share index on the standard IEEE 14-bus system with and without the aforementioned FACTS, and the results obtained were compared. With respect to market power, the study sees the use of FACTS as a threat that gencos can use to increase their market power, and the authors indirectly emphasize the consideration of market power in the placement of FACTS. Regrettably, the study did not show the effects of the FACTS on the EPG when OTS is used to mitigate market power exercised by the strategic gencos. Then, the question is, what is the effect of the presence of FACTS when OTS is used to mitigate market power, and the amount of reduction/increase of the cost, if any, associated with the market power? There is yet to be a study that investigates this effect. This is the focus of this study. The UPFC, which has the capability of controlling power flow by controlling the real and reactive power and which provides fast reactive compensation [17], is chosen for this study and modeled as a combination of a Static Var Compensator (SVC) and a TCSC [15] and [21].

Due to the cost of UPFC and other economic considerations in utilizing them on the EPG, it is necessary to know where the lines and buses will give the best results and their optimal sizing. FACTS placement on the EPG is usually carried out using two major approaches. One is the evolution programming optimization algorithm approach, and the other uses the Line Stability Indices (LSI) method. In this study, the LSI approach is adopted. In [18], the Reactive Power Reduction Index and Real Power Flow Performance Index were used to identify lines for compensation to improve transmission congestion. If different lines were selected, the more economical line was chosen by minimizing the total cost of installation of the FACTS. Sensitivity analysis was adopted for optimal TCSC and Static Synchronous Compensator (STATCOM) placement for power system security and reduction of transmission congestion [19]. In that study, the sensitivity analyses are Total System Reactive Power Loss Sensitivity Index, Line Loss Sensitivity Index, and Total System Loss Sensitivity Index. Genetic Algorithm (GA) was used in optimal sizing of the controllers. In [20], a comparative study of the use of the Power Stability Index (PSI) and Fast Voltage Stability Index (FVSI) in the optimal placement of SVC on the IEEE 14-bus System for voltage profile improvement, power loss reduction and enhancement of ATC was carried out. The indices' values were determined from the results of load flow calculations using the Newton-Raphson method. In [21], the FVSI was used to identify the line for the placement of the UPFC, while the Artificial Bee Colony optimization algorithm was employed in parameter sizing. In [22], a study was carried out on improving power system voltage stability using the dynamic model of UPFC employing two L, the FVSI, and the Voltage Collapse Point Indicator index. The results found the LSI to be accurate in locating the line to place the UPFC. In this study, therefore, the FVSI is adopted as the LSI of choice in determining the critical line (s) for the OTS, the placement of the UPFC, and the compensation factor for determining the parameter sizing of the UPFC.

2. Mathematical formulations

This work aims to study the effect of the UPFC on the OTS for cutting down abusive market power of the strategic gencos and the cost that is due to it in the deregulated WEM. To achieve the study's goal effectively, it is imperative to develop the mathematical formulation of the UPFC, OTS, market power, and associated costs. The developments of these mathematical formulations are presented in this section of the paper.

2.1 Mathematical formulation of the UPFC

The UPFC concept was proposed by Gyugyi in 1991 [23]. The controller can selectively and simultaneously control all the parameters affecting power flow in the transmission line (i.e., voltage, impedance, and phase angle). Furthermore, it can independently control both the active and reactive power flow in the line [23]; therefore, it was employed in this study. To that effect, the UPFC is modeled as a unification of an SVC at a bus and a TCSC tied to the same bus, as revealed in [23, 24].

Figure 1 shows the structure of the UPFC inserted in a 2-bus EPG, whereas Figure 2 depicts the mathematical model of the same 2-bus EPG with the UPFC connected. In Figure 2, the TCSC is modeled as a variable reactance (X_{TCSC}) injected in the line, while SVC is modeled as a reactance source (X_{SVC}) inserted at one end of the line [24]. The SVC is represented by B_{SVC}; which is a shunt variable susceptance connected at bus j.

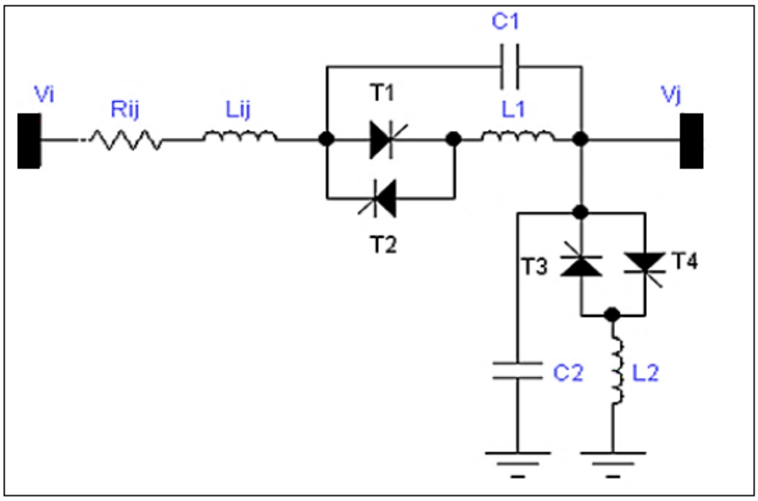

Figure 1: UPFC structure inserted in 2-bus EPG

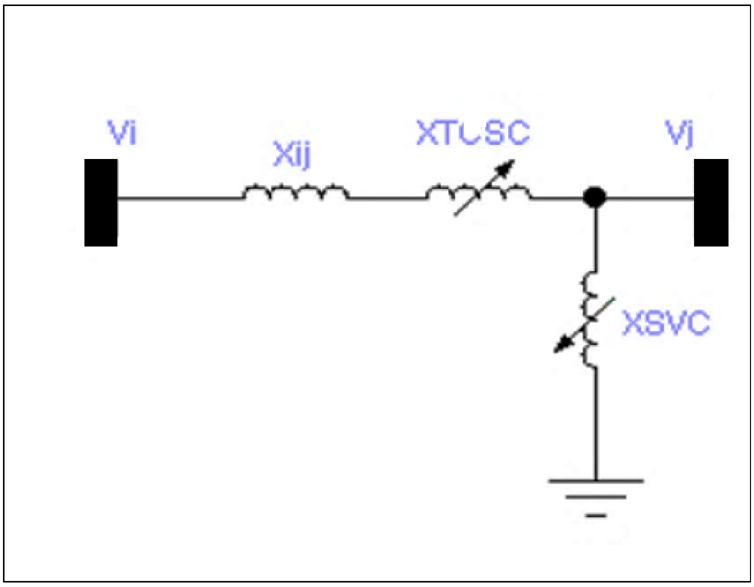

Figure 2: The model of the Figure 1[15],[21]

In Figure 1, $Z_{ij} = R_{ij} + X_{ij} = |Z_{ij}|\angle\theta_{ij} \cong X_{ij} \cong |X_{ij}|\angle 90^0$ denotes the impedance of the transmission line connecting bus i to bus j. The C_1 and L_1 are TCSC's capacitor and reactor, respectively, for controlling both the active and reactive power flow in the line, whereas the C_2 and L_2 are SVC's capacitor and reactor, respectively, for injecting or absorbing Q_{SVC} based on the voltage at bus j (V_j). In the figure, T_1 and T_2 are thyristors for the switching activities in the TCSC based on the firing angle, whereas, T_3 and T_4 are thyristors for the switching activities in the SVC based on the firing angle.

As revealed in the study of [25], the reactive power Q_{SVC} is injected or absorbed by the SVC based on the V_j. Thus:

$$Q_{SVC} = \frac{V_j^2}{X_{SVC}} = V_j^2 B_{SVC} \tag{1}$$

In Equation (1), $B_{SVC(min)} \leq B_{SVC} \leq B_{SVC(max)}$. The TCSC adjusts the line reactance. X_{ij} in which it is inserted [23] with the help of the coefficient of TCSC, k:

$$X_{TCSC} = \pm kX_{ij} \tag{2}$$

Then, the adjusted line reactance X'_{IJ} becomes:

$$X'_{ij} = X_{TCSC} + X_{ij} = X_{ij} \pm kX_{ij} = X_{ij}(1 \pm k) \tag{3}$$

It has been revealed in [26] that upon neglecting the line resistance in the 2-bus EPG, the real and reactive power supplied to bus j from line l, that is, the line linking bus i to j are now given respectively as:

$$P'_{ij} = P'_l = \frac{V_i^2}{|Z'_{ij}|} cos\theta'_{ij} - \frac{V_i V_j}{|Z'_{ij}|} \quad (4)$$

$$Q'_{ij} = Q'_l = \frac{V_i^2}{|Z'_{ij}|} sin\theta'_{ij} - \frac{V_i V_j}{|Z'_{ij}|} \sin(\theta'_{ij} + \delta_i - \delta_j) = \frac{V_i^2}{|X'_{ij}|} sin(90^0) - \frac{V_i V_j}{|X'_{ij}|} \sin(90^0 + \delta_i - \delta_j) = \frac{V_i^2}{|X'_{ij}|} - \frac{V_i V_j}{|X'_{ij}|} \cos(\delta_i - \delta_j) \quad (5)$$

Upon invoking linear approximation on (4) and (5), that is, making V_i and V_j to be 1.00 pu, and δ_i and δ_j to be small, we have:

$$P'_{ij} = P'_l = \frac{1}{|X'_{ij}|}(\delta_i - \delta_j) = |B'_{ij}|(\delta_i - \delta_j) \quad (6)$$

$$Q'_{ij} = Q'_l = \frac{1}{|X'_{ij}|} - \frac{1}{|X'_{ij}|} = 0 \quad (7)$$

The linear approximation model of the active power flow on transmission asset l presented in (6) was employed in [7]. To validate this study's results with that of [7], we also employed the model in this work.

The model for the computation of the cost of UPFC installation revealed in [24] is:

$$C = 0.0003(|Q_{ij}| - |Q'_{ij}|)^2 - 0.2691(|Q_{ij}| - |Q'_{ij}|) - 188.22 \quad \$ \quad (8)$$

In Equation (8), Q'_{ij} $(MVars)$ is the reactive power that flows through the line ij after the injection of the UPFC on it. The settlement of this cost is taken care of by the Market Operator (MO) in the WEM through the congestion cost.

2.2 Placement and sizing of the UPFC

In this study, the approach uses an LSI, the FVSI, to identify the bus and line in which the shunt and series components of UPFC must be placed in the EPG. It is a system of network ranking lines developed by Musirin and Abdul Rahman [27]. According to them, an FVSI less than 1.00 suggests that the grid is in a stable operating condition, whereas an FVSI greater than 1.00 shows that the system is unstable. At the initial stage, before compensation with the UPFC, the voltages at buses i and j are $V_i = |V_i|\angle\delta_i$ and $V_j = |V_j|\angle\delta_j$ respectively; the apparent power at the bus j is represented by $S_j = P_j + jQ_j$ and $Z_{ij} = R_{ij} + jX_{ij}$ is the impedance of the transmission line [15]. With this information, the study in [15] has been able to show that

$$FVSI_{ij} = \left| \frac{4|Z_{ij}|^2 Q_j X_{ij}}{|V_i|^2 (R_{ij} sin(\delta i - \delta j) - Xij cos(\delta i - \delta j))^2} \right| \leq 1 \quad (9)$$

And when $\delta_i = \delta_j$ or if the load angle $(\delta_i - \delta_j)$ is assumed to be very small, it has been established in [27] that

$$FVSI_{ij} = \frac{4|Z_{ij}|^2 Q_j}{|V_i|^2 \, Xij} \leq 1 \quad (10)$$

With the aid of (9) or (10), the critical line in the network can be identified.

2.2.1 Criteria for placing UPFC using FVSI

After evaluating and ranking FVSI for all lines of the EPG, the line with the largest value of FVSI is regarded as the most critical/sensitive line and chosen for the compensation.

2.2.2 Setting of parameters of UPFC:

After selecting the best position in the network to place the UPFC, its sizing needs to be set to minimize the FVSI. In calculating the sizing, in this case, the reactance of the controller can be found keeping in mind that:

1) The series component of the UPFC can be controlled to work either in the capacitive or the inductive modes while avoiding steady-state resonance.
2) In the study of [7], which this study is building upon, the shunt susceptance was neglected, so in this study, there is no need to size the SVC.

In this application, it will be assumed that UPFC provides variable capacitive reactance into the line. In [28], it is stated that the percent series compensation in line should be within 25% and 70% of the line reactance, which is expressed as:

$$k = \frac{X_C}{X_L} \quad (11)$$

In (11), k, X_C, and X_L are the compensation factor, capacitive reactance, and reactance of the transmission line, respectively. Upon using values of k within the range of 25% to 70%, the effect of the UPFC on the EPG can be investigated

2.3 Mathematical formulation of the OTS

The OTS is basically the switching in and out of a set of lines in the EPG to achieve optimal power flow (OPF); as such, it reduces the operating costs of the scheduling generating units. This study modeled the OTS using Direct Current OPF (DCOPF) optimization to make the problem linear and reduce the computation time.

2.3.1 Mathematical formulation of the OTS without the presence of the UPFC

The objective function of the OTS is to minimize the total operating cost (TC) conditional on the noticeable restraints and Kirchhoff's laws controlling the load flow in the EPG [29-31]. If the operating cost of generating power (P_g) from g^{th} generating unit is c_g; then, the total operating costs (TC_g) for a set of all generating units Ω_g in an EPG would, therefore, be:

$$TC_g = \sum_{g=1}^{\Omega_g} c_g P_g \tag{12}$$

The operating limits of the g^{th} generating unit are $P_g^{min} \leq P_g \leq P_g^{max}$; where $P_g^{min} and\ P_g^{max}$ are minimum and maximum power outputs of the g^{th} generating unit. And, if the operating cost of transmitting power through a transmission line l that connects bus i to bus j is c_l; then, the total operating costs (TC_l) for a set of all transmission lines Ω_l in an EPG would, therefore, be:

$$TC_l = \sum_{l=1}^{\Omega_l} c_l (1 - \zeta_l) \tag{13}$$

In Equation (13), ζ_l is a binary variable which describes the status of each l in the EPG viz:

$$\zeta_{ij} = \zeta_l = \begin{cases} 1; when\ l\ is\ connected \\ 0; when\ l\ is\ not\ connected \end{cases} \tag{14}$$

The OTS problem involving the cost of switching a line without the UPFC connected in EPG is therefore formulated as a mixed integer problem mathematically modeled [30] as:

$$minimize\ TC = TC_g + TC_l = \sum_{g=1}^{\Omega_g} c_g P_g + \sum_{l=1}^{\Omega_l} c_l (1 - \zeta_l) \tag{15}$$

Subject to

The constraint that takes care of the generation limit of each unit:

$$P_g^{min} \leq P_g \leq P_g^{max} \qquad \forall\ g\ \in \Omega_g \tag{16}$$

The transmission constraints:

$$-\zeta_{ij} P_{ij}^{max} \leq P_{ij} \leq \zeta_{ij} P_{ij}^{max} \qquad \forall\ ij\ \in \Omega_l \tag{17}$$

The constraint that handles power flow on line l that connects bus i to bus j [29],[31]:

$$P_{ij} - B_{ij}(\delta_i - \delta_j) \leq (1 - \zeta_{ij})\, M \qquad \forall\ ij\ \in \Omega_l \tag{18}$$

$$P_{ij} - B_{ij}(\delta_i - \delta_j) \geq (1 - \zeta_{ij})\, M \qquad \forall\ ij\ \in \Omega_l \tag{19}$$

In Equations (18),(19), $M =$ a large integer $[29, 30, 31] = max_{ij}\ B_{ij}(\delta_i - \delta_j)$, and $\sum_l^{\Omega_l}(1 - \zeta_{ij}) \leq N_{sw}$; where N_{sw} is the number of permissible switching actions in EPG.

The constraint that handles power balance among (P_g), load demand (d_i) and line flow (P_{ij}) [29],[31]:

$$\sum_{g=1}^{\Omega_g} P_g + d_i = \sum_{l=1}^{\Omega_l} C_l\, P_l = 0 \qquad \forall\ i \in \Omega_B, \forall\ l \in \Omega_l \tag{20}$$

In Equation (20), Ω_B = set of buses in the EPG and C_l = incidence matrix

The formulation presented in (12) through (20) are applicable to find minimum TC in EPG that is not under OTS and UPFC. To use the formulation in this situation, $N_{sw} = 0$

2.3.2 Mathematical formulation of the OTS in the presence of the UPFC

The OTS problem involving the cost of switching a line when the UPFC is injected in an optimal location of the EPG is formulated as a mixed integer problem mathematically modeled as:

$$minimize\ TC = TC_g + TC_l = \sum_{g=1}^{\Omega_g} c_g P_g + \sum_{l=1}^{\Omega_l} c_l(1-\zeta_l) \tag{21}$$

Subject to

The constraint that takes care of the generation limit of each unit:

$$P_g^{min} \leq P_g \leq P_g^{max} \qquad \forall\, g \in \Omega_g \tag{22}$$

The transmission constraints:

$$-\zeta_{ij} P_{ij}^{max} \leq P'_{ij} \leq \zeta_{ij} P_{ij}^{max} \qquad \forall\, ij \in \Omega_l \tag{23}$$

The constraint that handles power flow on line l that connects bus i to bus j:

$$P'_{ij} - B'_{ij}(\delta'_i - \delta'_j) \leq (1-\zeta_{ij})\, M' \qquad \forall\, ij \in \Omega_l \tag{24}$$

$$P'_{ij} - B'_{ij}(\delta'_i - \delta'_j) \geq (1-\zeta_{ij})\, M' \qquad \forall\, ij \in \Omega_l \tag{25}$$

In Equations (24),(25), M' = a new large integer $= max_{ij}\, B'_{ij}(\delta'_i - \delta'_j)$, and $\sum_l^{\Omega_l}(1-\zeta_{ij}) \leq N_{sw}$; where N_{sw} is the number of permissible switching actions in EPG.

The constraint that handles power balance among (P_g), load demand (d_i) and line flow (P'_{ij}):

$$\sum_{g=1}^{\Omega_g} P_g + d_i = \sum_{l=1}^{\Omega_l} C_l P'_l = 0 \qquad \forall\, g \in \Omega_g,\ \forall\, i \in \Omega_B, \forall\, l \in \Omega_l \tag{26}$$

In Equation (26), Ω_B = set of buses in the EPG and C_l = incidence matrix.

The formulation presented in (21) through (26) are still applicable to find minimum TC in EPG that is not under OTS but under UPFC. To use the formulation in this situation, $N_{sw} = 0$.

2.4 Mathematical formulation of the market power

As done by [7,8], and to validate the results that would be obtained in this study, the Cournot competition and Nash equilibrium concepts were used to model the behaviors of the gencos in this study. The Cournot competition concept involves a few gencos and several schemes; the schemes are the amount of power each genco generates, and the goal of the gencos is to maximize their net surplus [7].

For a genco, Nash equilibrium is arrived at whenever its deportment (scheme) is the best reaction to the schemes (deportments) of other gencos in the deregulated WEM. Figure 3 presents the characteristic reactions of two gencos R_1 and R_2. The $BR_1(R_2)$ in the figure manifests the best reactions of genco R_1 in agreement with the reactions of genco R_2; similarly for the $BR_2(R_1)$. The point of intersection of the schemes elected by the gencos ($R_1{}^*$ and $R_2{}^*$) is the Nash equilibrium reaction for each of them.

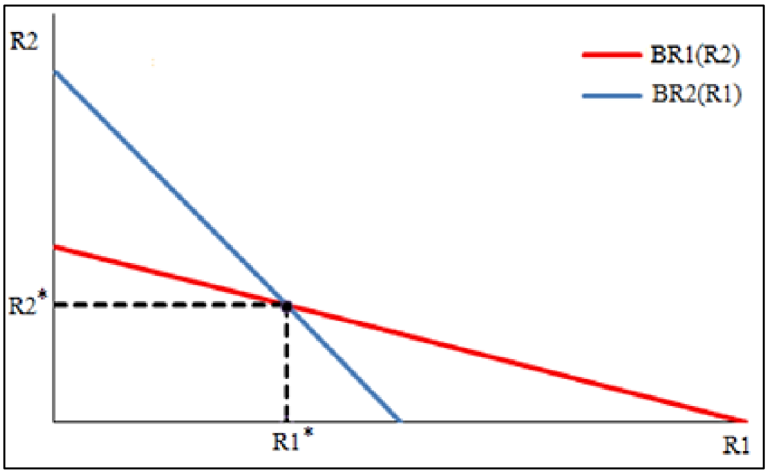

Figure 3: Nash equilibrium is found by two gencos [7]

It should be noted that at the Nash equilibrium, there is no bonus for any genco that alters its deportment (scheme) if all activities of all other gencos are sustained. To attain the equilibrium point, all MP play their particular part according to the market rules. Also, there can be many Nash equilibriums for a problem [7]. Problems can converge to a bad equilibrium for gencos based on reducing the profits or a good equilibrium for the gencos based on increasing profits.

In this study, strategic gencos would try to find the Nash equilibrium to maximize their net surplus when there is no contingency. Market power in the WEM is modeled as the Worst-Nash Equilibrium (WNE), defined as the Nash Equilibrium that maximizes the generation cost [7]. In this situation, non-strategic gencos will release all their capacity to the grid; however, they can choose what amount they will offer to the WEM. Consequently, the net surplus of a strategic genco under WNE is higher than that of the strategic genco when not under WNE for its dispatch.

The foregoing reveals that, if the set of all generating units Ω_g that consists of both strategic and non-strategic units that have a variable cost of production c_g and the amount of electricity generated under Nash equilibrium is P_g^{rld}, then the strategic gencos market power under the OTS problem can be formulated as:

$$Maximize \quad -\sum_{g=1}^{\Omega_g} c_g P_g^{rld} + \sum_{l=1}^{\Omega_l} c_l(1-\zeta_l) \quad \forall\, g \in \Omega_g, \forall\, l \in \Omega_l \tag{27}$$

Subject to

The constraint that handles the released capacity P_g^{rld} of a set of all strategic generating units Ω_k:

$$P_g^{rld} = P_g^{max} \sum_{k=1}^{\Omega_k} x_{gk} w_k + w_o P_g^{max} \quad \forall\, k \in \Omega_k, \forall\, g \in \Omega_g \tag{28}$$

In Equation (28), the binary variable x_{gk} denotes whether the unit will exercise market power or not; and it is expressed as:

$$x_{gk} = \begin{cases} 1; \textit{strategic genco exercises no market power} \\ 0; \textit{strategic genco exercises market power} \end{cases} \tag{29}$$

In (28), the variable w_o represents the percentage of the P_g^{rld} supplied to the WEM, whereas the variable w_k denotes the percentage of the P_g^{rld} held back from the WEM, therefore:

$$\sum_{k=1}^{\Omega_k} w_k = 1 - w_o \tag{30}$$

Equation (30) reveals that when the unit is non-strategic $\sum_{k=1}^{\Omega_k} w_k = 0$; consequently, the unit offers its maximum capacity to the WEM.

The constraint that takes care of the generation limit of each unit:

$$P_g^{min} \le P_g^{rld} \le P_g^{max} \qquad \forall\, g \in \Omega_g \tag{31}$$

The transmission constraints:

$$-\zeta_{ij} P_{ij}^{max} \le P_g^{rld} \le \zeta_{ij} P_{ij}^{max} \qquad \forall\, ij \in \Omega_l \tag{32}$$

The constraint that handles power flow on line l that connects bus i to bus j [29],[31]:

$$P_g^{rld} - B_{ij}(\delta_i - \delta_j) \le (1-\zeta_{ij})\, M \qquad \forall\, ij \in \Omega_l \tag{33}$$

$$P_g^{rld} - B_{ij}(\delta_i - \delta_j) \ge (1-\zeta_{ij})\, M \qquad \forall\, ij \in \Omega_l \tag{34}$$

In Equation (33) and (34), M = a large integer [29][30][31] $= max_{ij}\, B_{ij}(\delta_i - \delta_j)$, and $\sum_l^{\Omega_l}(1-\zeta_{ij}) \le N_{sw}$; where N_{sw} is the number of permissible switching actions in EPG.

The constraint that handles power balance among (P_g^{rld}), load demand (d_i) and line flow (P_{ij}) [29],[31]:

$$\sum_{g=1}^{\Omega_g} P_g^{rld} + d_i = \sum_{l=1}^{\Omega_l} C_l\, P_l = 0 \qquad \forall\, i \in \Omega_B, \forall\, l \in \Omega_l \tag{35}$$

In Equation (35), Ω_B = set of buses in the EPG and C_l = incidence matrix.

The formulation presented in (27) through (35) still applies to find the maximum TC in EPG that is not under OTS and UPFC. To use the formulation in this situation, $N_{sw} = 0$. Also, the formulation presented in (27) through (35) is still applicable to find the maximum TC in EPG under OTS and UPFC. To use the formulation in this situation, $B_{ij}(\delta_i - \delta_j) = B'_{ij}(\delta'_i - \delta'_j)$.

3. Modeling, simulated results and discussion

The mathematical formulations obtained in section 2 of this paper were implemented on a modified test system, modeled, and simulated in the GAMS studio via the NEOS server. This section of the paper presents the test system we adopted in this study and the modeling and simulations carried out upon applying the mathematical formulations obtained in section 2.

3.1 Test system

The modified version of the IEEE 14-bus system, Figure 4, was adopted by [7]; and, therefore, used for the sake of validation of the results that would be obtained in this study. Both OTS under market power conditions without and with the presence of UPFC were applied to the test bed to investigate the effects of UPFC in cutting down the social costs associated with the market power in the WEM. The generators, loads, and transmission lines data of the modified version of the test bed are presented in Tables 1, 2, and 3, respectively.

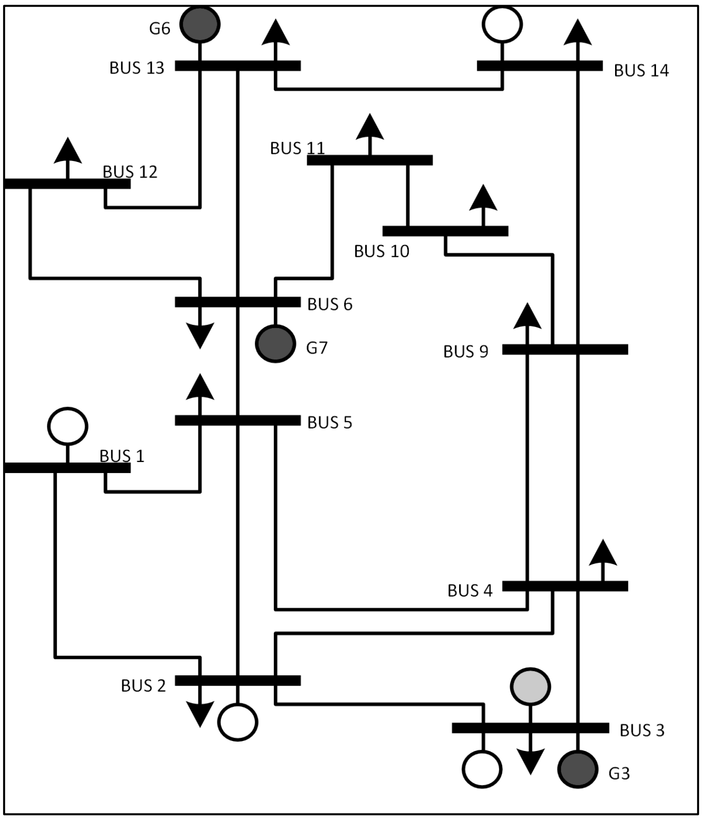

Figure 4: IEEE 14-bus System [7]

Table 1 presents the identity, bus number, generation capacity, and marginal cost of generating 1 MWh of electricity for each EPG bus. In Table 2, the bus identity and load demand by each bus of the test bed are depicted. Table 3 presents the line identity and reactance of each line of the test bed. It is evident from Tables 1 and 2 that the net load demand from the test bed is 259 MW, whereas the total generating capacity offered to the deregulated WEM by the gencos is 880 MW. This information reveals that this WEM allows competition among the gencos in the EPG; some of the gencos would be extra-marginal producers after the MO does what is needed. Table 1 also reveals that the prices offered by u4, u5, and u7 are highly exorbitant; as such, some of them would be extra-marginal producers.

Table 1: Generation of data

ID	Bus	Unit Size MW	Cost generation $/MWh
U1	1	30	30
U2	2	200	20
U3	3	150	100
U4	3	100	10000
U5	13	100	5000
U6	6	100	150
U7	3	100	150
U8	14	100	100
total		**880**	

Table 2: Load data

Bus	Demand MW
2	217
3	94.2
4	47.8
5	7.6
6	11.2
9	29.5
10	9.0
11	3.5
12	6.1
13	13.5
14	14.9
	259.0

In line with [7], the modified test system is divided into three areas based on generator units. Generators u1, u2, and u3 belong to Area 1, Generators u4, u5, and u6 belong to Area 2, while Generators u7 and u8 belong to Area 3. This study chooses a strategic generator from an area; therefore, u3, u6, and u7 are strategic generators from Areas 1, 2, and 3, respectively.

Table 3: Line data

ID	L1	L2	L3	L4	L5	L6	L7	L8	L9	L10
From Bus-To Bus	1-2	1-5	2-3	2-4	2-5	3-4	4-5	4-7	4-9	5-6
Reatance(ohms)	0.05917	0.22304	0.19797	0.17632	0.17388	0.17103	0.04211	0.209012	0.55618	0.25202
ID	L11	L12	L13	L14	L15	L16	L17	L18	L19	L20
From Bus-To Bus	6-11	6-12	6-13	7-8	7-9	9-10	9-14	10-11	12-13	13-14
Reatance(ohms)	0.19890	0.25581	0.13027	0.17615	0.11001	0.08450	0.27038	0.19207	0.19988	0.34802

3.2 Modeling and simulations

An FVSI MATLAB script was developed and run in the MATLAB environment to get the FVSI of all the lines of the modified version of the test bed, and the results obtained were used to select the line to be compensated. The FVSI results were also employed to predict lines likely to be optimally switched in the General Algebraic Modeling System (GAMS) studio version 43.4.1 so as not to inject UPFC into them. The incidence matrix of the modified EPG was created in the MATLAB environment, converted into Comma-Separated Values (CSV) files, and then imported to the GAMS studio.

The DCOPF model was employed to get the optimal operating schedules of gencos, considering the transmission line restraints. The objective function is defined as Gencos's total operating costs. The model type for finding the social cost of the scheduling gencos under perfect competition was Linear Program (LP). At the same time, we employed a stage Mixed Integer Linear Program (MILP) for getting the social cost of the scheduling gencos under WNE, OTS, and (or) injection of the UPFC in an optimal location of the modified test bed. The optimization problems under WNE were obtained with the help of the NEOS server in the GAMS studio.

3.3 Simulation results and discussion

3.3.1 Social cost of scheduling gencos under perfect competition

The EPG was not under WNE, OTS was not used, and UPFC was not injected under conventional perfect competition. Table 4 presents the simulated results of the optimal power dispatched (OPD) and social cost (SC) for all the scheduling gencos under normal competition in the deregulated WEM in the GAMS studio.

Table 4: OPD and Social Cost of the scheduling gencos under perfect competition

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	19.932	30	579.96
U2	2	51.430	20	1,028.60
U3	3	113.666	100	11,366.60
U4	3	0.000	10000	0.00
U5	13	0.000	5000	0.00
U6	6	29.745	100	2,974.50
U7	3	0.000	150	0.00
U8	14	44.227	100	4,422.70
total		259.000		20,390.36

It is evident from Table 4 that the sum of the OPD and SC of all scheduling units are 259 MW and $20,390.36, respectively. The SC result obtained is almost the same as the SC result ($20,689.00) obtained in [7]. Therefore, the results obtained in this study reveal that the total OPD equals the total load demand in the EPG, and the total SC equals the optimal solution (objective function) found in the GAMS studio.

3.3.2 The SC of the scheduling gencos under imperfect competition

Under frail competition, some strategic gencos purposely hold back some percentage of their capacity in the WEM. This premise and this study assumed that u3 held back 26.15% of its available capacity.

It is evident from Table 5 that the sum of the OPD and SC of all scheduling units are 259 MW and $62,752.54, respectively. The SC result obtained is almost the same as the SC result ($60,811.00) obtained in [7]. The results obtained in this work reveal that the total OPD equals the total load demand in the EPG, and the total SC equals the optimal solution (objective function) found in the GAMS studio under imperfect competition. The result reveals that when a strategic genco purposely holds back 26.15% of its actual capacity, there is a forceful growth in social cost from $20,390.36 to $62,752.54, representing a 207.76% increment.

Table 5: OPD and Social Cost of the scheduling gencos under imperfect competition

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	30.000	30	900.00
U2	2	75.252	20	1,505.04
U3	3	5.975	100	579.50
U4	3	0.000	10000	0.00
U5	13	8.571	5000	42,855.00
U6	6	37.122	100	3,712.20
U7	3	59.496	150	8,924.40
U8	14	42.584	100	4,258.40
total		259.000		62,752.54

3.3.3 Social cost when EPG was under WNE using OTS in the absence of UPFC

Table 6 presents the OPD and SC simulated results obtained in the GAMS studio for each scheduling gencos in the WEM under WNE using OTS without UPFC. It is evident from Table 6 that the sum of the OPD and SC of all scheduling units are 259 MW and $17,764.01, respectively. The SC result obtained is the same as the SC result obtained in [7]. The results reveal that the total OPD equals the total load demand in the EPG; and the total SC equals the optimal solution (objective function) found in the GAMS studio. The result reveals a forceful reduction in the SC from $20,390.36 to $17,764.01, representing a 12.88% reduction.

Table 6: OPD and Social Cost when EPG was under WNE using OTS in the absence UPFC

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	0.001	30	0.03
U2	2	101.699	20	2,033.98
U3	3	94.200	100	9,420.00
U4	3	0.000	10000	0.00
U5	13	0.00	5000	0.00
U6	6	16.688	100	1,668.80
U7	3	0.00	150	0.00
U8	14	46.512	100	4,641.20
total		259.000		17,764.01

3.3.4 The SC when EPG was under WNE using OTS with UPFC in an optimal location

3.3.4.1 FVSI ranking of lines

To investigate the effects of UPFC in cutting down the market power costs of the intra-marginal gencos in the deregulated WEM, there is a need to find an optimal location for the injection of the compensator in the EPG. In this study, therefore, FVSI was used to locate the critical lines in the EPG where the UPFC can be injected. The FVSI results of the lines are presented in Figure 5.

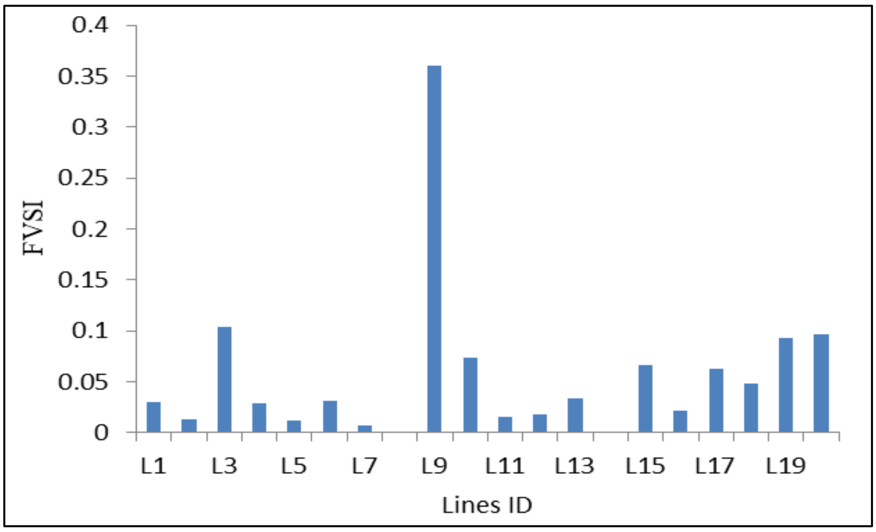

Figure 5: The plot of FVSI against Lines ID

The figure reveals that the line with the highest value of the FVSI is L9, followed by L3, L20, L19, and L10. In this study, some of the aforementioned lines are assumed to be potential candidates that can be the optimally switched lines in the GAMS studio; therefore, they should not be considered for the injection of the UPFC. The possible nominee for the injection of the compensator is either L15 or L17, and the chosen line for the optimal placement of the UPFC is L17, because its reactance is greater than that of L15.

3.3.4.2 Parameter Sizing

To get the parameter sizing, the compensator connected in series with the L17 is assumed to be injecting series capacitive reactance X_C into the line. The line reactance of the L17 is 0.27038 pu; therefore, upon using the values of k that range from 0.25 through 0.65 at the step of 0.10 and Equation (9), we obtained various values of the X_C that were injected into the line L17 sequentially.

Table 7: OPD and SC of the schenduing gencos under WNE,OTS, and UPFC when K=0.25

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	0.001	30	0.03
U2	2	101.699	20	2,033.98
U3	3	94.200	100	9,420.00
U4	3	0.000	10000	0.00
U5	13	0.000	5000	0.00
U6	6	24.510	100	2,451.00
U7	3	0.000	150	0.00
U8	14	38.590	100	3,859.00
total		259.000		17,764.01

Table 8: OPD and SC of the schenduing gencos under WNE, OTS, and UPFC when K=0.35

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	0.001	30	0.03
U2	2	101.699	20	2,033.98
U3	3	94.200	100	9,420.00
U4	3	0.000	10000	0.00
U5	13	0.000	5000	0.00
U6	6	23.307	100	2,330.70
U7	3	0.000	150	0.00
U8	14	39.793	100	3,979.30
total		259.000		17,764.01

Table 9: OPD and SC of the schenduing gencos under WNE, OTS, and UPFC when K=0.45

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	0.001	30	0.03
U2	2	101.699	20	2,033.98
U3	3	94.200	100	9,420.00
U4	3	0.000	10000	0.00
U5	13	0.000	5000	0.00
U6	6	22.103	100	2,210.30
U7	3	0.000	150	0.00
U8	14	40.997	100	4,099.70
total		259.000		17,764.01

Table 10: OPD and SC of the schenduing gencos under WNE, OTS, and UPFC when K=0.55

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	0.001	30	0.03
U2	2	101.699	20	2,033.98
U3	3	94.200	100	9,420.00
U4	3	0.000	10000	0.00
U5	13	0.000	5000	0.00
U6	6	20.900	100	2,090.00
U7	3	0.000	150	0.00
U8	14	42.200	100	4,220.00
total		259.000		17,764.01

Table 11: OPD and SC of the schenduing gencos under WNE,OTS, and UPFC when K=0.65

ID	Bus	OPD MW	Maeginal cost $/MWh	Social cost $
U1	1	0.001	30	0.03
U2	2	101.699	20	2,033.98
U3	3	94.200	100	9,420.00
U4	3	0.000	10000	0.00
U5	13	0.000	5000	0.00
U6	6	19.696	100	1.969.60
U7	3	0.000	150	0.00
U8	14	43.404	100	4,340.40
total		259.000		17,764.01

Presented in Tables 7 through 11 are the OPD and SC simulated results obtained in the GAMS studio for each of the scheduling gencos in the WEM when the EPG was under WNE, OTS, and, with the injection of the UPFC in line L17 of the EPG; when k varied from 0.25 to 0.65 in steps 0.10 respectively.

It is evident from Tables 7 through 11 that the sum of the OPD and SC of all scheduling units at different degrees of k are 259 MW and $17,764.01, respectively. The results reveal that the total OPD equals the total load demand in the EPG; and the total SC equals the optimal solution (objective function) found in the GAMS studio. The results reveal that the social cost would not be increased when strategic gencos hold back a certain percentage of their actual capacity, and OTS is used in the presence of UPFC in an optimal location with the grid under WNE.

4. Discussion

Figure 6 summarizes the analysis of the total social cost for all the scheduling gencos in the WEM under different situations. In the figure, states 1, 2, 3, and 4 depict the WEM under perfect competition, imperfect competition, WNE using OTS without UPFC, and WNE using OTS with UPFC, respectively.

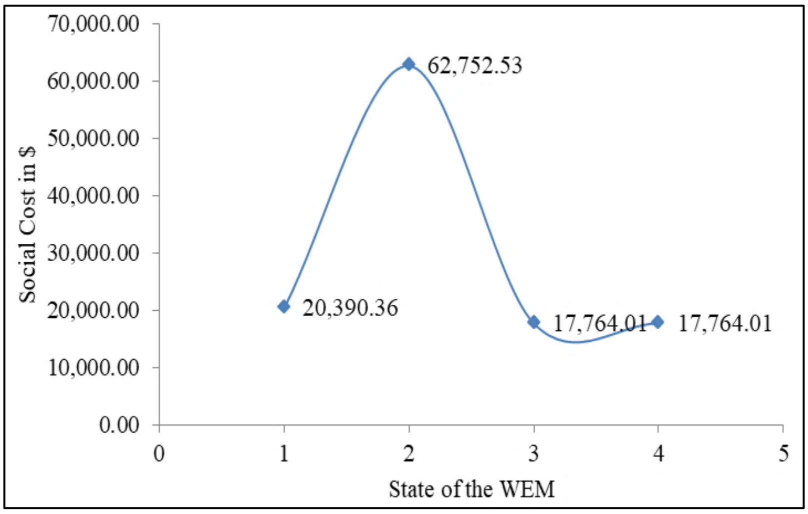

Figure 6: The total social cost for all the scheduling gencos in the WEM under different situations

The social costs for all scheduling gencos under perfect competition and imperfect competition in the WEM without OTS are $20,390.36 and $62,752.53, respectively. The results reveal that when some strategic gencos purposely hold back some percentage of their available capacity in an imperfect WEM without necessary arrangement on the ground, there will be a forceful growth in the social cost. When the market is under WNE and OTS was used for mitigation of market power, the social cost for all scheduling gencos was $17,764.01, which reveals that there is a forceful reduction in social cost from $20,390.36 to $17,764.01. The social cost shown in the figure still gives $17,764.01 with the injection of the UPFC in an optimal location of the EPG when using OTS under WNE.

Table 12 summarizes the OPD of each scheduling gencos in MW under different situations in the WEM. Though the social cost for scheduling gencos under WNE and OTS without and with UPFC is the same, the optimal generation dispatch of the units does not remain the same, as shown in Table 12. It can be seen that the optimal generation dispatch without and with the UPFC differs for u6 (a strategic generator) and u8 (a non-strategic generator) while meeting the total load demand of 259 MW on the network at all times. The table shows that the generation dispatch of u6 under OTS and WNE without UPFC is 16.688 MW; under the same condition, but with UPFC in the network, the generation dispatch of the unit increased from 19.696 MW at a compensation factor of 0.25 to 24.511 MW at a compensation factor of 0.65. The generation dispatch of u8, a non-strategic generator, under OTS and WNE but without UPFC is 46.412 MW, but with UPFC, it reduced from 43.404 MW to 38.589 MW over the same range of the compensation factor. For the other two strategic units, u3 maintained the same generation dispatch of 94.2 MW without and with the UPFC, while u7 dispatched no power with and without UPFC in the network. The generation dispatch of all other generating units remained the same with and without UPFC compensation.

Table 12: The summary of the OPD of each schenduling gencos in the WEM under different situations

Unit	Maeginal cost $/MWh	OPD under traditional competition (MW)	OPD under frail competition (MW)	OPD under WNE&OTS only (MW)	OPD under WNE,OTS&UPFC instented in an optinal location of the EPG (MWh)				
					K=0.25	K=0.35	K=0.45	K=0.55	0.65
U1	30	19.932	30.000	0.001	0.001	0.001	0.001	0.001	0.001
U2	20	51.430	75.252	101.699	101.699	101.699	101.699	101.699	101.699
U3	100	113.666	5.975	94.200	94.200	94.200	94.200	94.200	94.200
U4	10000	0.000	0.000	0.00	0.000	0.000	0.000	0.000	0.000
U5	5000	0.000	8.571	0.00	0.000	0.000	0.000	0.000	0.000
U6	100	29.745	37.122	16.688	19.696	20.900	22103	23.307	24.511
U7	150	0.000	59.496	0.00	0.000	0.000	0.000	0.000	0.000
U8	100	44.237	42.584	46.412	43.404	42.200	40.997	39.793	38.589
Total		259.000	259.000	259.000	259.000	259.000	259.000	259.000	259.000

For power balancing, as strategic unit u6 increases its generations dispatch, non-strategic unit u8 decreases its generations dispatch. The results also show that no strategic generator dispatched less in the presence of UPFC than in the absence of UPFC. It can be deduced that the presence of UPFC on the network when using OTS to mitigate the market power of gencos will cause strategic generators to dispatch more than they would in the absence of UPFC, and those that do not increase their dispatch will maintain the amount of their generation dispatch as at without UPFC. Table 13 displays the amount of capacity offered to the WEM by each unit without and with UPFC at different compensation levels from k = 0.25 to k = 0.65. It can be seen that all non-strategic units offered their total capacity, and u3 (strategic) offered 94.20 MW under Optimal Transmission Switching with and without the presence of UPFC.

Table 13: The summary of the amount of capacity offered to the WEM by all participating gencos in the WEM under different situations

Unit	Maeginal cost $/MWh	MW offerd under traditional competition	MW offerd under frail competition	MW under WNE&OTS only	Offerd MW under WNE,OTS & UPFC instented in an optinal location of the EPG (MWh)				
					K=0.25	K=0.35	K=0.45	K=0.55	0.65
U1	30	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000
U2	20	200.000	200.000	200.000	200.000	200.000	200.000	200.000	200.000
U3	100	150.000	7.000	94.200	94.200	94.200	94.200	94.200	94.200
U4	10000	100.000	100.000	100.00	100.000	100.000	100.000	100.000	100.000
U5	5000	100.000	100.000	100.00	100.000	100.000	100.000	100.000	100.000
U6	100	100.000	100.000	52.894	41.891	54.352	56.250	50.993	47.014
U7	150	100.000	100.000	56.250	6.250	6.250	6.250	6.250	50.477
U8	100	100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000
Total		880.000	737.000	733.344	672.341	684.802	686.700	681.443	721.691

The table shows that the total capacity offered to the WEM without UPFC ranges from 733.344 MW to 880.000 MW. In contrast, the total capacity offered to the WEM in the presence of UPFC ranges from 672.341 MW to 721.691 MW at the different compensation factor values. This reveals that energy would be efficiently utilized when UPFC is injected in an optimal location under optimal transmission switching.

5. Conclusion

In this study, the Fast Voltage Stability Index was adopted to identify the most critical line in the modified IEEE 14-bus system for the placement of the UPFC. The compensation factor was adopted in determining the sizing/amount of reactive capacitance to be injected into the identified line and the bounds/limits of varying the reactance. Optimal Transmission Switching under the Worst Nash Equilibrium was formulated in GAMS, and an investigation into the effect of the presence of UPFC when OTS is used in reducing the social cost under market power was carried out. The results of this study showed that with the presence of UPFC in the network, though the total amount of generation capacity offered to the market by the generators will be lesser than in the absence of UPFC:

1) There would be a forceful reduction in social costs when the market is under WNE, and OTS is carried out. Though the social cost for scheduling gencos under WNE and OTS without and with the UPFC is the same, the optimal generation dispatch of the units remains unchanged.
2) A strategic generator will likely dispatch more in the presence of UPFC than in the absence of UPFC in the network.
3) A strategic generator that did not dispatch more in the presence of UPFC will not dispatch less than it did in the absence of UPFC. If there is no increase in generation dispatch with the UPFC, the strategic generator will dispatch the same amount as it did without UPFC.
4) For generation not to exceed load demand, a non-strategic generator may dispatch less in the presence of UPFC than in the absence of UPFC.

Author contributions

Conceptualization, S. Adetona; methodology, S.Adetona and M. Adetola; software, M. Adetola, and F. Okafor; validation, F. Okafor and N. Ubakanwa; formal analysis, M. Adetola; investigation, M. Adetola and N. Ubakanwa; resources, S. Adetona and M. Adetola; data curation, M. Adetola; writing—original draft preparation, S. Adetona, M. Adetola, and N. Ubakanwa; writing—review and editing, S. Adetona and F. Okafor; visualization, S. Adetona; supervision, S. Adetona; project administration, S. Adetona and F. Okafor. All authors have read and agreed to the published version of the manuscript.

Funding

This research received no specific grant from any funding agency in the public, commercial, or not-for-profit sectors.

Data availability statement

The data that support the findings of this study are available on request from the corresponding author.

Conflicts of interest

The authors declare that there is no conflict of interest.

Reference

[1] F. Wolak, Managing Unilateral Marlket Power in Electricity, World Bank Policy Research, September 2005. https://doi.org/10.1596/1813-9450-3691

[2] A. F. Rahimi and A. Y. Sheffrin, Effective market monitoring in deregulated electricity market, IEEE Trans. Power Syst., 18 (2003) 486-496. https://doi.org/10.1109/TPWRS.2003.810680

[3] M. Granelli, M. Montagna, F. Zanellini, P. Bresesti, R. Vailati and M. Innorta, Optimal network reconfiguration for congestion management by deterministic and genetic algorithms, Electr. Power Res., 76 (2006) 549-556. https://doi.org/10.1016/j.epsr.2005.09.014

[4] G. Schnyder and H. Glatvitsch, Security enhancement using an optimal switching power flow, IEEE Trans. Power Syst., 5 (1990) 674-681. https://doi.org/10.1109/59.54580

[5] E. Fisher, R. P. O'Neill and M. C. Ferris, Optimal Transmission Switching, IEEE Trans. Power Syst., 23 (2008) 1346-1355. https://doi.org/10.1109/TPWRS.2008.926411

[6] S. Wei and V. Vijay, Corrective switching algoritm for relieving overloads and voltage violations, IEEE Trans. Power Syst., 20 (2005) 1877-1885. https://doi.org/10.1109/TPWRS.2005.857931

[7] M. A. Noriega Odor, Optimal Transmission Switching for Reducing Market Power Cost, Stockholm, MSc Thesis, KTH Royal Institute of Technology, 2012.

[8] T. Yaser, M. Hesamzadeh, R. Baldick and D. Biggar, Transmission network switching for reducing market cost in generation sector: A Nash-equilibrum approach, Electr. Power Syst. Res., 146 (2017) 71- 79. https://doi.org/10.1016/j.epsr.2016.12.031

[9] N. Acharya, A. S. Yome and N. Mithulananthan, Facts about flexible AC transmission systems (FACTS) controllers: Practical installations and benefits, Australian Universities Power Engineering Conference (AUPEC), Hobart, Tasmania, Australia, September 25-28, 2005. Tasmania, Australia: School of Engineering, University of Tasmania.

[10] K. Gupta , B. Khan and S. E. Mubeen, Available transfer capablity enhancement by Unified Power Flow Controller., IEEE International Conf. Signal Process. Inf. Commun. Energy Syst., (SPICES), Kozhikode, 2015. https://doi.org/10.1109/SPICES.2015.7091428

[11] Y. Xiao, Y. H. Song and Y. Z. Sun, Application of stochastic srogramming for available transfer capablity enhancements using FACTS devices, IEEE Power Engineering Soceity Summer Meeting, Seattle, WA, 2000. https://doi.org/10.1109/PESS.2000.867638

[12] Y. S. Sunday, O. P. Ubeh and B. Jimoh, Efficient utilization of transmission line via optimal location of UPFC considering loadability analysis., Zaria J. Electr. Eng. Technol., Ahmadu Bello University, Zaria, Nigeria, 10, 2021. http://dx.doi.org/10.13140/RG.2.2.28808.90885

[13] K. B. Vijay and V. Ramaiah, Enhancement of dynamic stability by optimal location and capacity of UPFC: A hybrid approach, Energy, 2019.

[14] I. G. Adebayo, M. A. Bhaskhar, A. A. Yusuff and A. A. Jimoh, Optimal location identification of FACTS devices through Genetic Algorithm and Network Structural Characteristics Techniques, 2016 IEEE International Conference on Renewable Energy Research and Applications, 778-782, 2016. http://dx.doi.org/10.1109/ICRERA.2016.7884442

[15] S. O. Adetona, E. B. Olaboyin, R. I. Salawu and F. N. Okafor, Upshot of unified power flow controller on the minimization of the severity of overloading on electric power grid, J. King Saud Univ. Eng. Sci., 2021. https://doi.org/10.1016/j.jksues.2021.10.010

[16] P. Karthikeyan, S. K. Sahoo, R. Roopesh, S. Mathur, I. J. Raglend and D. P. Kothari, Utilizing FACTS devices in enhancements of market power under congestion- A threat to a deregulated market., in Annual IEEE Indian Conference (INDICON), 2012. https://doi.org/10.1109/INDCON.2012.6420632

[17] S. Gupta and K. Sarbjeet, Importance of FACTS devices in Power Systems, Int. J. Sci. Res., 10 (2021) 529-533.

[18] S. A. Taher and H. Besharat, Transmission Congestion Management by Determining Optimal Location of FACTS in Deregulated Power Systems, Am. J. Appl. Sci., 5 (2008) 242-247. https://doi.org/10.3844/AJASSP.2008.242.247

[19] A. Samimi and M. A. Golkar, A Novel method for optimal placement of FACTS based on sensitivity analysis for enhancement of power system static security, Asian J. Appl. Sci., 5 (2012) 1-19. http://dx.doi.org/10.3923/ajaps.2012.1.19

[20] R. Roshan, P. Samal and P. Sinha, Optimal placement of FACTS devices in power transmission network using power stablity index and fast voltage stability index, IEEE 2020 Int. Conf. Electr. Electron. Eng., 246 - 251, 2020. https://doi.org/10.1109/ICE348803.2020.9122975

[21] S. Adetona, R. Salawu, F. Okafor and J. Adeyemi, The impact of Unified Power Flow Controller on the loadability of the Electric Power Grid., J. Eng. Studies and Res., 26 (2020). https://doi.org/10.29081/jesr.v26i4.231

[22] S. Ahmad, S. Mekhilef and F. Albatsh, Voltage Stability Improvement by Placing Unified Power Flow Controller at suitable location in Power System Network, 2014.

[23] Hingorani N. G. and Gyugyi L., Understanding FACTS, New York: IEEE Press, 2000.

[24] M. Saravanan, S. Mary Raja Slochanal, P. Venkatesh and J. Prince Stephen Abraham, Application of particle swarm optimization technique for optimal location of FACTS devices considering cost of installation and system loadability, Electr. Power Sys. Res., 77 (2007) 276-283. https://doi.org/10.1016/j.epsr.2006.03.006

[25] M. A. Khan, U. Khalil, H. Khan, A. Uddin and S. Ahmed, Power Flow Control by Unified Power Flow Controller, Eng. Technol. Appl. Sci. Res., 9 (2019) 3900-3904. https://doi.org/10.48084/etasr.2587

[26] Grainger, J. J. and Stevenson, W. D., Jr. Power System Analysis, McGraw-Hill, Inc., Singapore, 1994.

[27] I. Musirin and T. K. Abdul Rahman, Novel fast voltage stability index (FVSI) for voltage stability analysis in power system, Student Conference on Research and Development, SCORED, 265-268, 2002. https://doi.org/10.1109/SCORED.2002.1033108

[28] Saadat, H., Power System Analysis, New York: Mc Graw Hill, 1999.

[29] K. W. Hedman, S. S. Oren and R. P. O'Neill, Flexible Transmission in the Smart Grid: Optimal Transmission Switching, in A. Sorokin et al. (eds.), Handbook of Networks in Power Systems I, Energy Systems, 523 – 554, 2012.

[30] K. W. Hedman, R. P. O'Neill, E. B. Fisher and S. S. Oren, Optimal Transmission Switching With Contingency Analysis, IEEE Trans. Power Sys., 24 (2009) 1577 – 1586. https://doi.org/10.1109/TPWRS.2009.2020530

[31] Z. Yang, H. Zhong, Q. Xia and C. Kang, Optimal Transmission Switching With Short-Circuit Current Limitation Constraints, IEEE Trans. Power Sys., 31 (2016) 1278 – 1288. https://doi.org/10.1109/TPWRS.2015.2434961