

Article

Transmission-State-Dependent Carbon-Trading Settlement in UPFC-Assisted Preventive Optimal Power Flow

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Abstract

Low-carbon OPF studies usually include carbon cost or emission limits in generation-side dispatch, while carbon-accounting studies often evaluate emissions after dispatch. The link between transmission-side flow control and carbon settlement has received less attention. In particular, it remains unclear how UPFC-driven changes in branch flows and losses should affect allowance balance, trading volume, and settlement cost in preventive OPF. This paper therefore proposes a transmission-state-dependent carbon-trading settlement method for UPFC-assisted preventive OPF. Different from post-dispatch carbon accounting, the proposed method calculates carbon-trading quantities from the same network-feasible dispatch solution that determines UPFC-regulated flows, network losses, thermal generation, and contingency feasibility. The model is written in equivalent current injection form. A social-learning artificial bee colony algorithm with feasibility repair is used to solve the constrained problem, with infeasible trial solutions repaired according to power-balance, operating-limit, and carbon-trading constraints. The Taipower 345 kV transmission system is used for testing. Under the annual average daily load condition, line losses are reduced from 27,126.55 MWh to 21,281.92 MWh, while carbon emissions decrease from 300,988.72 tCO₂ to 279,527.70 tCO₂, corresponding to reductions of 21.55% and 7.13%. The generator-side profit remains positive at TWD 11,000,763. The combined UPFC-PCOPF case also satisfies the screened post-contingency line-loading and voltage constraints. The full-year cases show a similar reduction pattern. These results suggest that carbon-trading settlement is not a fixed post-dispatch accounting item. In UPFC-assisted dispatch, it is linked to transmission losses and thermal generation.

Keywords: carbon-trading settlement; carbon allowance balance; UPFC; FACTS control; preventive optimal power flow; low-carbon dispatch; equivalent current injection; feasibility repair



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1. Introduction

The low-carbon transition of power systems is no longer determined by generation scheduling alone. Renewable intermittency, transmission congestion, operating security, and carbon-related regulation now act on the same dispatch process. The Taiwan grid is used in this study as a real transmission-network case, but the modeling issue is broader: how carbon management can be embedded into dispatch decisions under realistic network conditions without weakening system security or delivery efficiency [1–5].

Recent work on optimal power flow (OPF) has improved the treatment of renewable uncertainty and environmentally constrained dispatch. Once wind and solar output become stochastic, the dispatch problem grows more nonlinear and more sensitive to constraint handling and search quality [6,7]. Even so, most of this literature still concentrates on generation-side scheduling. The transmission network is usually represented through operating limits rather than treated as an active source of change in carbon-related outcomes.

A similar pattern appears in the security literature. Robust $N - k$ security-constrained optimal power flow (SCOPF) and sequential SCOPF models have shown that post-contingency feasibility should be incorporated directly into the scheduling stage [8,9]. Related studies on alternating-current security-constrained optimal power flow (AC SCOPF) have further strengthened the treatment of uncertainty [10], while broader OPF formulations that consider high-voltage direct current (HVDC) interconnections show that network dynamics also matter in secure operation [11]. These studies improve reliability, but they say much less about how preventive security scheduling changes carbon-related settlement and the resulting economic outcome.

Low-carbon dispatch research has approached the same issue from another direction. The institutional basis of carbon regulation has already been established through the European Union Emissions Trading System (EU ETS), and later assessments indicate that such mechanisms can alter both emissions and firm performance [12,13]. Research on renewable generation under carbon-trading conditions points in the same direction, suggesting that market-based carbon regulation can affect generation-side decisions more directly than conventional environmental penalties [14]. More recent dispatch studies move closer to carbon-aware operation. Dynamic carbon-emission measurement and carbon-emission-flow-based models make it possible to trace how dispatch reshapes emission responsibility [15,16]. Work on stepped carbon-trading mechanisms further shows that carbon settlement cannot be treated as a simple penalty appended after dispatch is obtained [17]. Carbon-accounted auction-based dispatch leads to a similar conclusion [18]. Yet the main analytical weight still falls on generation output and carbon accounting, while the network side remains secondary.

The market literature adds another dimension. Joint modeling of generator company (GenCo) behavior in electricity and carbon markets shows that carbon settlement can directly reshape dispatch incentives and market outcomes [19]. Similar interactions also appear in deregulated systems with distributed generation [20]. Coupled electricity-carbon scheduling and local carbon-trading coordination lead to the same conclusion, namely that carbon settlement is no longer external to system operation [21,22]. Related game-theoretic analysis further confirms that carbon-market rules can reshape the strategic behavior of market participants [23]. However, this body of work still says relatively little about how the physical transmission state feeds back into the same market result. Once losses, congestion, and post-contingency stress change, the carbon burden associated with dispatch also changes.

This point becomes more important when a Unified Power Flow Controller (UPFC) is introduced. A UPFC can regulate branch flows, reduce losses, relieve congestion, and support voltage profiles [24,25]. Most UPFC-OPF studies therefore focus on these technical effects and the resulting operating cost. Carbon accounting is usually treated in a different line of research, starting from generator-side emissions or the final dispatch result [26,27]. This separation is partly due to the difference between transmission-side investment and generator-side carbon trading. UPFC installation belongs to the transmission side, while carbon trading is mainly linked to generation-side emissions. Without a settlement link, the carbon-related value created by UPFC-based loss reduction is difficult to reflect. This paper addresses this missing link by tracing how UPFC-driven changes in branch flows

and losses affect thermal dispatch, emissions, allowance balance, trading volume, and settlement cost.

Coupling carbon settlement with network-feasible dispatch also increases the need for constraint handling, because infeasibility may arise from power-balance errors, line-limit violations, allowance imbalance, or excessive trading volume [28–30]. Before fitness evaluation, each candidate is repaired to keep the dispatch variables and carbon-settlement quantities consistent.

Existing studies approach this topic from different sides. Carbon-aware OPF usually adds emission cost or carbon limits to the dispatch model, whereas carbon-emission-flow studies trace carbon responsibility after the operating state has been obtained. FACTS/UPFC-assisted OPF mainly examines flow regulation, loss reduction, voltage support, and congestion relief. SCOPF and PCOPF focus on whether the dispatch remains feasible under credible contingencies. These approaches are therefore not direct numerical benchmarks for one another. What is still missing is a formulation that connects UPFC-induced changes in branch flows and losses with preventive OPF and carbon-trading settlement in the same network-feasible operating state.

These gaps lead to the proposed UPFC-assisted PCOPF framework. In this framework, allowance balance, trading volume, and settlement cost are calculated from the same ECI-based dispatch state used for branch flows, losses, thermal generation, and contingency checks.

The contributions are as follows

1. This study formulates a transmission-state-dependent carbon-trading settlement method for UPFC-assisted PCOPF. The carbon allowance balance, trading volume, and settlement cost are evaluated from the same feasible OPF state that determines UPFC-regulated branch flows, network losses, thermal generation, and contingency-feasible operation.
2. The study traces the transmission-to-settlement path under preventive security constraints. UPFC flow regulation changes network losses and thermal dispatch, and these changes enter the carbon-settlement result instead of being added later as post-dispatch accounting.

2. ECI-Based Optimal Power Flow with UPFC Modeling

2.1. ECI-Based Load Flow Model

The transmission-network load flow is expressed in the equivalent current injection (ECI) form [31], with the mismatch equations solved by Newton–Raphson iteration. Since the principal Jacobian terms of PQ buses remain unchanged during the iteration, this formulation is used here as a convenient load-flow basis for the later OPF calculation.

Figure 1 presents the π -equivalent circuit of a transmission line between buses a and b . In this model, R_{ab} and L_{ab} denote the series resistance and inductance of the line. The corresponding series admittance is written as $G_{ab} + jB_{ab}$, where G_{ab} is the conductance and B_{ab} is the susceptance. The shunt capacitance is represented by the shunt susceptance jB_c . On this basis, the equivalent current injection at bus a is written as

$$I_{a,eq}(k) = \frac{-S_a}{(U_a(k))^*} = I_{a,eq}^{(R)}(k) + jI_{b,eq}^{(I)}(k) \quad (1)$$

where $S_a = P_a + jQ_a$ is the complex power injection at bus a , $U_a(k)$ is the corresponding bus voltage at the k -th iteration, and $(\cdot)^*$ denotes complex conjugation. The superscripts R and I indicate the real and imaginary parts.

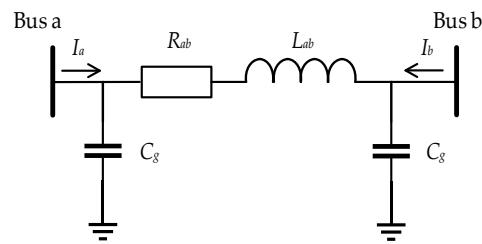


Figure 1. π -equivalent model of transmission line.

Following the branch structure shown in Figure 1, the terminal currents are defined as currents injected from each terminal bus into the line. Thus, I_{ab} is positive from bus a to the branch, and I_{ba} is positive from bus b to the branch. With the local shunt term included at each terminal, the currents can be written in rectangular form as

$$I_a = \left[G_{ab} \left(U_a^{(R)} - U_b^{(R)} \right) - B_{ab} \left(U_a^{(I)} - U_b^{(I)} \right) - B_c U_a^{(I)} \right] + j \left[G_{ab} \left(U_a^{(I)} - U_b^{(I)} \right) - B_{ab} \left(U_a^{(R)} - U_b^{(R)} \right) + B_c U_a^{(R)} \right] \quad (2)$$

$$I_b = \left[G_{ab} \left(U_b^{(R)} - U_a^{(R)} \right) - B_{ab} \left(U_b^{(I)} - U_a^{(I)} \right) - B_c U_b^{(I)} \right] + j \left[G_{ab} \left(U_b^{(I)} - U_a^{(I)} \right) - B_{ab} \left(U_b^{(R)} - U_a^{(R)} \right) + B_c U_b^{(R)} \right] \quad (3)$$

where $U_a^{(R)}$ and $U_a^{(I)}$ are the real and imaginary components of the voltage at bus a , and $U_b^{(R)}$ and $U_b^{(I)}$ are those at bus b . The current mismatches are then formed from the difference between the specified equivalent injections and the network currents obtained from the branch model.

After linearization, the correction step takes the form

$$\Delta \mathbf{I}_{ab}(k) = \mathbf{J}_{ab} \Delta \mathbf{U}_{ab}(k) \quad (4)$$

in which

$$\Delta \mathbf{I}_{ab}(k) = \left[\Delta I_a^{(R)} \Delta I_b^{(R)} \Delta I_a^{(I)} \Delta I_b^{(I)} \right]^T, \quad \Delta \mathbf{U}_{ab}(k) = \left[\Delta U_a^{(R)} \Delta U_b^{(R)} \Delta U_a^{(I)} \Delta U_b^{(I)} \right]^T \quad (5)$$

The associated Jacobian matrix is

$$\mathbf{J}_{ab} = \begin{bmatrix} G_{ab} & -G_{ab} & -(B_{ab} + B_c) & B_{ab} \\ -G_{ab} & G_{ab} & B_{ab} & -(B_{ab} + B_c) \\ (B_{ab} + B_c) & -B_{ab} & G_{ab} & -G_{ab} \\ -B_{ab} & (B_{ab} + B_c) & -G_{ab} & G_{ab} \end{bmatrix} \quad (6)$$

Equation (6) follows directly from the π -equivalent branch in Figure 1. For PQ buses, the entries of $\mathbf{J}_{ab}$ depend only on the line parameters and do not vary with the operating state. The Jacobian therefore remains constant during iteration.

PV buses are treated differently. The same applies to buses connected to wind generators. Their specified variables are not the same as those of PQ buses, so the operating conditions are introduced in the form of constraint functions. For bus a , the active-power condition is expressed as

$$g_{P,a}(\mathbf{X}) = P_a - P_a^{sp} = 0 \quad (7)$$

while the voltage-magnitude condition is written as

$$g_{V,a}(\mathbf{X}) = U_a - U_a^{sp} = 0 \quad (8)$$

where P_a^{sp} is the specified active-power injection, U_a^{sp} is the specified voltage magnitude of the PV bus, and $\mathbf{X}$ denotes the state vector of the load-flow problem.

After first-order linearization, the PQ-bus current mismatches and the PV-bus constraints are assembled into the following system equation

$$\Delta \mathbf{F}(k) = \mathbf{J}(k) \Delta \mathbf{X}(k) \quad (9)$$

To incorporate the PV-bus conditions into the ECI correction step, the active-power and voltage-magnitude constraints in (7) and (8) are linearized around the current operating point. The resulting correction equation for bus a can be written as

$$\begin{bmatrix} \Delta P_a \\ \Delta |U_a|^2 \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta U_a^{(R)} \\ \Delta U_a^{(I)} \\ \Delta U_b^{(R)} \\ \Delta U_b^{(I)} \end{bmatrix} \quad (10)$$

where

$$\begin{aligned} J_1 &= \begin{bmatrix} (U_a^{(R)} G_{ab} + U_a^{(I)} B'_{ab} + I_a^{(R)}) & (-U_a^{(R)} G_{ab} - U_a^{(I)} B_{ab}) \end{bmatrix} \\ J_2 &= \begin{bmatrix} (-U_a^{(R)} B'_{ab} + U_a^{(I)} G_{ab} + I_a^{(I)}) & (U_a^{(R)} B_{ab} - U_a^{(I)} G_{ab}) \end{bmatrix} \\ J_3 &= [2U_a^{(R)} \ 0] \quad J_4 = [2U_a^{(I)} \ 0] \end{aligned}$$

and

$$B'_{ab} = B_{ab} + B_c$$

After the PV-bus correction terms are embedded into the ECI formulation, the complete load-flow error equation of the j -bus system is obtained as

$$\begin{bmatrix} \Delta \mathbf{I}_{PQ}^{(R)} \\ \Delta \mathbf{P}_{PV} \\ \Delta \mathbf{I}_{PQ}^{(I)} \\ \Delta |\mathbf{U}_{PV}|^2 \end{bmatrix} = \begin{bmatrix} \mathbf{J}_{11} & \mathbf{J}_{12} \\ \mathbf{J}_{21} & \mathbf{J}_{22} \end{bmatrix} \begin{bmatrix} \Delta \mathbf{U}^{(R)} \\ \Delta \mathbf{U}^{(I)} \end{bmatrix} \quad (11)$$

where $\mathbf{J}_{11}$ and $\mathbf{J}_{12}$ correspond to the submatrices of the real-part mismatch equations, whereas $\mathbf{J}_{21}$ and $\mathbf{J}_{22}$ correspond to those of the imaginary-part and voltage-control mismatch equations. These submatrices are formed jointly by the constant branch terms of PQ buses and the linearized PV-bus power-voltage constraints.

In a j -bus system containing voltage-controlled buses, the global Jacobian matrix is no longer fully constant. However, only the entries associated with PV buses need to be updated during iteration. The amount of recalculation is therefore smaller than that required in the conventional Newton–Raphson formulation. This does not mean that the ECI formulation is proposed as a new load-flow method in this paper. It is adopted because the rectangular current-injection form allows PQ-bus equations, PV-bus power–voltage constraints, and UPFC-equivalent injections to be assembled in a consistent correction framework [31]. Compared with a polar formulation, this avoids repeatedly reforming trigonometric power-balance equations for all buses when PV-bus corrections and UPFC injection terms are updated.

2.2. UPFC Steady-State Model and ECI Integration

Figure 2 presents the steady-state structure of the UPFC [32]. The device consists of a shunt converter and a series converter sharing a common DC capacitor C_{dc} . The shunt branch is connected to bus i through the reactance X_{sh} , whereas the series branch is inserted into the transmission line through X_{se} . In the figure, $U_i \angle \varphi_i$ denotes the voltages at the

two terminal buses, and $I_L \angle \theta_L$ denotes the line current. The shunt injected current is represented by $I_{sh} \angle \theta_{sh}$, while the injected series voltage is denoted by $U_{inj} \angle \varphi_{inj}$. The active-power exchange of the shunt and series converters is expressed by P_{sh} and P_{se} , respectively. The DC-link condition is described by U_{dc} , together with the capacitor currents I_{dc1} and I_{dc2} . Under this arrangement, the shunt converter primarily acts on the connected bus and sustains the DC-link power balance, whereas the series converter acts on the transmission path and modifies the power-transfer condition.

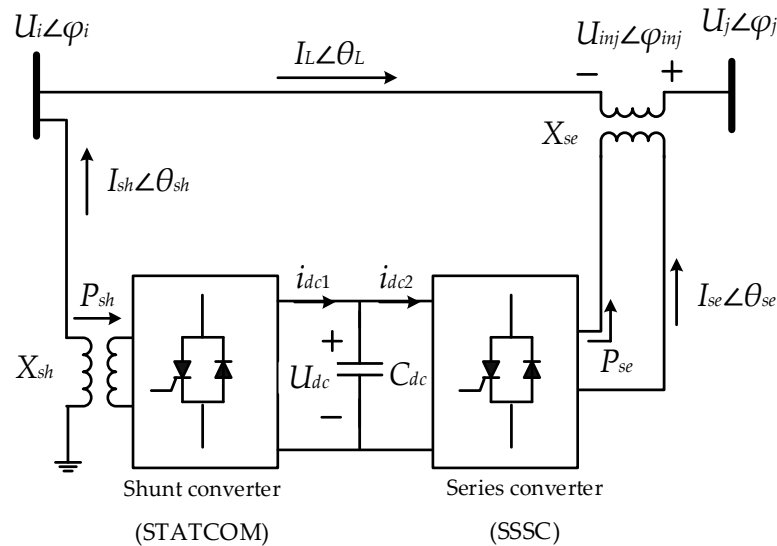


Figure 2. Steady-state configuration of the UPFC.

Figure 3 presents the steady-state equivalent circuit of the UPFC. The shunt branch is connected to the sending-end side through the coupling impedance Z_{sh} . The series branch injects a controllable voltage U_{pq} through Z_{se} . A virtual bus U_a' is placed between the converter branch and the original line. This arrangement is used to separate the converter action from the line section. It also makes the controlled power transfer at the connection point explicit. The line between U_a' and U_b is represented by the series elements R_{ab} and L_{ab} , together with the shunt capacitances C_s at both ends. The complex power through the virtual bus is denoted by S^{set} , and the corresponding line current is I_L .

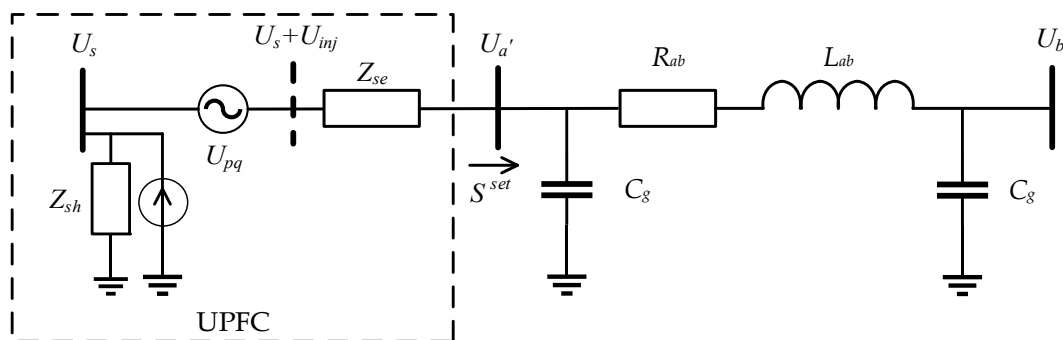


Figure 3. Equivalent circuit of the UPFC integrated with the transmission line.

The injected series voltage is written as

$$U_{pq} = |U_{pq}| e^{j\theta_{pq}} \quad (12)$$

with the operating limits

$$U_{pq,min} \leq |U_{pq}| \leq U_{pq,max}, \quad 0 \leq \theta_{pq} \leq 2\pi \quad (13)$$

At the virtual bus, the controlled complex power is written as $S^{set} = P^{set} + jQ^{set} = U_a^* I_L^*$, and the associated current term is $I^{set} = (S^{set}/U_{at})^*$. For the series branch, the Norton equivalent admittance is $y_{se} = 1/Z_{se} = g_{se} + jb_{se}$, so the corresponding injected current is $I_{N,se} = y_{se}U_{pq}$. The shunt admittance is $y_{sh} = 1/Z_{sh}$. The term jB_s denotes the shunt susceptance associated with the line capacitance.

With these quantities, the local current–voltage relation of Figure 3 is written as

$$\begin{bmatrix} \vdots \\ I_s \\ \vdots \\ I_{at} \\ \vdots \\ I_{s,at} \end{bmatrix} = \begin{bmatrix} \dots & \dots & \dots & \dots & \dots & \dots & \dots \\ \dots & \dots & \dots & \dots & \dots & g_{se} + jb_{se} & \dots \\ \dots & \dots & \dots & \dots & \dots & \vdots & \dots \\ \dots & \dots & \dots & \dots & \dots & -g_{se} - jb_{se} & \dots \\ \dots & \dots & \dots & \dots & \dots & \vdots & \dots \\ 0 & g_{se} + jb_{se} & 0 & g_{se} + jb_{se} & 0 & g_{se} + jb_{se} & 0 \end{bmatrix} \begin{bmatrix} \vdots \\ U_s \\ \vdots \\ U_{at} \\ \vdots \\ U_{pq} \end{bmatrix} \quad (14)$$

Equation (14) shows the role of the UPFC directly. The fourth column is introduced by the injected series voltage U_{pq} . The vector on the right-hand side contains the shunt injected current and the current associated with the controlled power at the virtual bus. In this form, the converter branch is merged into the local network equation.

To maintain the same solution structure as that used in Section 2.1, the augmented admittance matrix in Equation (14) is decomposed into its real and imaginary parts, namely $\mathbf{Y}_{aug} = \mathbf{G}_{aug} + j\mathbf{B}_{aug}$. The corresponding correction equation becomes

$$\begin{bmatrix} \Delta \mathbf{I}_{aug}^{(R)} \\ \Delta \mathbf{I}_{aug}^{(I)} \end{bmatrix} = \begin{bmatrix} \mathbf{G}_{aug} & -\mathbf{B}_{aug} \\ \mathbf{B}_{aug} & \mathbf{G}_{aug} \end{bmatrix} \begin{bmatrix} \Delta \mathbf{U}_{aug}^{(R)} \\ \Delta \mathbf{U}_{aug}^{(I)} \end{bmatrix} + \begin{bmatrix} \Delta \mathbf{I}_{inj}^{(R)} \\ \Delta \mathbf{I}_{inj}^{(I)} \end{bmatrix} \quad (15)$$

Here the shunt-side exchanged complex power is $S_{sh} = P_{sh} + jQ_{sh}$, and the corresponding equivalent injected current is $I_{sh} = (S_{sh}/U_s)^*$. The series branch enters the model through U_{pq} and its Norton equivalent current. The shunt branch appears as an injected current at bus U_s . After the virtual bus is introduced, the converter branch and the original line model are handled within the same ECI iterative framework.

2.3. UPFC Installation Principles and Candidate-Location Selection

A UPFC is not placed simply on the most heavily loaded line. That choice can be misleading. Some corridors look critical in the base case but become less important once power is redistributed. Others are the opposite. Voltage weakness and post-contingency behavior must therefore be considered together with line loading.

On this basis, the candidate locations are screened as follows:

- (1) One transmission corridor, one UPFC.

More than one device on the same line section seldom delivers a proportional control benefit. The added investment is easier to identify than the added operational gain.

- (2) Persistent heavy transfer is given priority.

A corridor that remains highly loaded across several operating states is more meaningful than one that appears stressed only in a single snapshot. In these locations, the effect of series voltage injection is usually more evident.

- (3) Very low-impedance lines are not preferred.

Their natural transfer capability is already strong. In most cases, the margin for further improvement is limited.

- (4) Voltage margin is checked at the same time.

Congestion alone is not enough. If the terminal buses also show weak voltage support, the value of UPFC installation becomes more apparent because both the series and shunt branches can contribute.

- (5) Strong local regulating sources reduce installation priority.

When nearby generators or synchronous compensators already provide effective voltage control, the extra support from the shunt branch may be less significant. Such locations are not removed entirely, but they are not treated as leading candidates.

- (6) Post-contingency redistribution is used as an additional filter.

Some lines are not dominant in the base case. They still deserve attention. After a severe outage, they may become the main path for redirected power and turn into the actual control bottleneck.

The screening is carried out under the base operating condition and the selected severe scenarios. It is used only to retain technically reasonable corridors; it is not a weighted security–economic placement index. Security is handled later by the PCOPF constraints and the contingency-screening process. Among the retained corridors, the final UPFC location is selected by the average generator-side net benefit reported in Table 1. This choice reflects the market-coupled purpose of this study: the UPFC should create measurable settlement value through loss reduction, emission reduction, and carbon-cost improvement while satisfying preventive security constraints.

Table 1. Economic performance comparison of the top five retained candidate lines for UPFC installation.

Candidate Line	Min. Net Benefit (TWD)	Avg. Net Benefit (TWD)	Max. Net Benefit (TWD)
No. 59	9,886,522	11,000,763	12,118,504
No. 3	10,088,530	10,758,665	11,900,763
No. 6	10,256,011	10,702,899	13,008,204
No. 58	9,976,302	10,615,801	11,185,025
No. 15	9,985,236	10,588,960	12,559,210

3. Carbon-Settlement-Coupled PCOPF Formulation

3.1. Electricity-Market and Carbon-Trading Mechanism

In a market-oriented power system, dispatch is no longer driven by fuel cost and operating limits alone. Network conditions also shape the final schedule. Carbon-related payments also affect the final schedule. For that reason, electricity dispatch and carbon settlement should be evaluated from the same OPF-based dispatch result. This is not a strategic market model with bidding or equilibrium constraints. Instead, it is an OPF-based dispatch setting in which market-cleared energy, carbon allowance balance, trading volume, and network-support settlement are obtained from the same feasible dispatch solution.

In the model used here, the generators bear the direct production cost. This includes fuel expenditure and the cost associated with carbon emissions. The transmission side does not produce electricity, yet it still affects the dispatch outcome through the condition of the network. When congestion becomes serious, or when transmission losses increase, the system needs more generation to supply the same demand. The carbon burden then rises with that additional output.

After a UPFC is introduced, the interaction between network operation and carbon settlement becomes more direct. By modifying the line-flow pattern and reducing active-power losses, the UPFC affects both the physical operating state of the transmission network and the carbon-related settlement results. In this paper, the electricity-market and carbon-trading terms are represented through a scenario-based settlement setting. The generation quantities used for settlement are interpreted as market-cleared energy, whereas transmission losses are calculated from the ECI-based network solution for each operating case. On this basis, the settlement quantities are evaluated from the same network-feasible OPF solution that produces the loss variation and thermal-generation changes.

3.2. Objective Function and Profit Model of Generators and Transmission Operator

The PCOPF is solved over the full network, but its economic objective is defined from the generator-side settlement. The load demand is treated as fixed, and demand-side utility is not modeled; therefore, the problem is not formulated as full social-welfare maximization. The carbon-price effect is still included through carbon-trading expenditure and allowance-settlement terms, so higher emissions reduce the generator-side net benefit. Generator output, transmission loss, and UPFC effects are taken from the feasible ECI-based operating point.

The objective over the scheduling horizon is written as

$$\max G = \sum_{t=1}^T \Pi_t^G \quad (16)$$

where Π_t^G denotes the net benefit of the generators in period t .

For each period, the generator-side net benefit is expressed as

$$\Pi_t^G = \lambda_t P_t^m + \pi_t (A_t^{\text{sell}} - A_t^{\text{buy}}) - \sum_{i=1}^{N_g} C_i(P_{i,t}) - D_t - R_t \quad (17)$$

Here, λ_t denotes the electricity-market clearing price, and π_t is taken as the clearing price of a single carbon market. The present model does not describe carbon-price fluctuation or buy–sell spreads; these can be added by replacing π_t with time-varying purchase and sale prices. P_t^m is the load-side cleared electricity sold to demand, which is fixed across the compared cases under the same load level. A_t^{sell} and A_t^{buy} represent the sold and purchased carbon allowances. D_t is the dispatch fee charged by the transmission side. R_t is the settlement associated with emission reduction created by network support.

In this paper, R_t is defined as a transmission-side settlement term rather than the profit of the transmission operator. The transmission operator is not modeled as a direct carbon trader. Instead, R_t reflects the network-side value associated with the emission-reduction effect of UPFC-supported loss reduction. Through branch-flow regulation and loss reduction, the UPFC indirectly reduces generator-side carbon emissions and carbon-trading expenditure.

The production cost of generator i is modeled as

$$C_i(P_{i,t}) = a_i + b_i P_{i,t} + c_i P_{i,t}^2 \quad (18)$$

where $P_{i,t}$ is the real-power output of generator i in period t , and a_i , b_i , and c_i are the corresponding cost coefficients.

The transmission-side effect enters the model through loss reduction. Let $P_t^{loss,0}$ and $P_t^{loss,u}$ denote the active-power losses without and with UPFC control, respectively. The loss reduction is then written as

$$\Delta P_t^{loss} = P_t^{loss,0} - P_t^{loss,u} \quad (19)$$

Reduced transmission loss changes the carbon burden of network delivery. The following term is used to describe the UPFC-related network-support effect. It belongs to the transmission-side settlement and does not directly revise generator emissions.

$$\Delta E_t = \zeta_t \Delta P_t^{loss} \quad (20)$$

Here, ζ_t is the equivalent emission coefficient in period t . In the present framework, the transmission operator does not enter the carbon-trading market as a direct trading participant. Its economic return is linked to carbon settlement through the loss-reduction effect created by UPFC control.

The related settlement term is therefore written as

$$R_t = \eta_t \pi_t \Delta E_t \quad (21)$$

where η_t is an exogenous allocation coefficient used to share the loss-reduction-related carbon benefit between the generation side and the transmission side. In the numerical cases, $\eta_t = 0.5$ is used as a neutral equal-sharing setting because no jurisdiction-specific sharing rule is imposed. Since R_t is linear in η_t , changing η_t proportionally changes the allocated transmission-side settlement and the generator-side net benefit, but it does not change the carbon-emission calculation, allowance-balance definition, or ECI-based network constraints. The resulting term R_t denotes the transmission-side settlement associated with UPFC-supported loss reduction.

In Equation (17), R_t is deducted from the generator-side net benefit because it represents the settlement paid to the transmission operator for the emission-reduction effect created by UPFC-supported loss reduction. It should not be interpreted as a carbon refund received by generators. Instead, R_t denotes a network-support settlement allocated to the transmission side, while the generator-side refund related to carbon-allowance settlement is represented separately by the carbon-trading terms.

Under this structure, the generators receive the direct income from electricity trading and carbon-allowance settlement, while bearing production cost, dispatch charges, and the emission-reduction settlement. The transmission operator is evaluated separately through the settlement result associated with network support and loss reduction. The model thus remains generator-oriented in its objective, while the economic effect of transmission-side control is still retained in the market-dispatch setting.

3.3. PCOPF Power Balance and Operational Constraints

The objective function in Section 3.2 is solved subject to network balance and operating limits. In the proposed PCOPF model, the economic decision and the network-feasible operating point are obtained simultaneously. The state variables are the real and imaginary parts of the bus voltages, while the control variables include the real-power outputs of dispatchable thermal units, the specified voltage magnitudes of PV buses, and the UPFC control variables on the selected corridor.

For each time interval t , the active-power balance of the system is written as

$$\sum_{i=1}^{N_g} P_{i,t}^G + P_{i,t}^{fix} = P_t^D + P_t^{loss} \quad (22)$$

where $P_{i,t}^G$ is the real-power output of dispatchable thermal unit i , $P_{i,t}^{fix}$ denotes the aggregated fixed scheduled injection, P_t^D is the total demand, and P_t^{loss} is the transmission loss.

The network equality conditions are enforced through the ECI mismatch equations. For each PQ bus k , the real and imaginary current mismatches are expressed as

$$\Delta I_{k,t}^{(R)} = I_{k,t}^{sp,(R)} - I_{k,t}^{cal,(R)} = 0 \quad (23)$$

$$\Delta I_{k,t}^{(I)} = I_{k,t}^{sp,(I)} - I_{k,t}^{cal,(I)} = 0 \quad (24)$$

For each PV bus m , the active-power and voltage-magnitude conditions are written as

$$\Delta P_{m,t} = P_{m,t}^{sp} - P_{m,t}^L - P_{m,t}^{cal} = 0 \quad (25)$$

$$\Delta V_{m,t}^2 = \left| U_{m,t}^{sp} \right|^2 - \left[\left(U_{m,t}^{(R)} \right)^2 + \left(U_{m,t}^{(I)} \right)^2 \right] = 0 \quad (26)$$

where $I_{k,t}^{sp,(R)}$ and $I_{k,t}^{sp,(I)}$ are the specified real and imaginary equivalent current injections, $I_{k,t}^{cal,(R)}$ and $I_{k,t}^{cal,(I)}$ are the corresponding calculated values, $P_{m,t}^{sp}$ is the specified active-power injection at PV bus m , and $P_{m,t}^L$ is the real-power demand at that bus.

The above conditions are assembled into the compact mismatch form

$$\Delta \mathbf{F}_t = \begin{bmatrix} \Delta \mathbf{I}_{PQ,t}^{(R)} \\ \Delta \mathbf{P}_{PV,t}^{(R)} \\ \Delta \mathbf{I}_{PQ,t}^{(I)} \\ \Delta \mathbf{V}_{PV,t}^2 \end{bmatrix} = 0 \quad (27)$$

which preserves the same rectangular-coordinate structure adopted in Section 2.

The real-power output of each dispatchable thermal unit is bounded by

$$P_i^{G,\min} \leq P_{i,t}^G \leq P_i^{G,\max}, \quad i = 1, N_g \quad (28)$$

Because the dispatch is time-coupled, the ramping capability of each thermal unit is also imposed:

$$-RD_i \leq P_{i,t}^G - P_{i,t-1}^G \leq RU_i \quad (29)$$

where RU_i and RD_i are the ramp-up and ramp-down limits of generator i .

The bus-voltage magnitude constraint is written in rectangular form as

$$\left(V_k^{\min} \right)^2 \leq \left(U_{k,t}^{(R)} \right)^2 + \left(U_{k,t}^{(I)} \right)^2 \leq \left(V_k^{\max} \right)^2, \quad k = 1, N_b \quad (30)$$

where N_b is the total number of buses.

For a general transmission line ℓ , the apparent-power flow is restricted by its thermal limit:

$$|S_{l,t}| \leq S_l^{\max}, \quad l = 1, N_l \quad (31)$$

where N_l denotes the total number of transmission lines.

For the selected UPFC corridor shown in Figure 3, the device is installed on the transmission path between buses a and b , and the virtual bus a' is introduced in the

equivalent model. The UPFC is modeled by its steady-state equivalent circuit. The OPF model limits the series-injected voltage and the shunt current within their operating ranges. Converter losses are ignored in this formulation. Therefore, the active power exchanged by the shunt and series converters is assumed to be balanced, and the DC-link power balance is written as

$$P_{sh,t} + P_{se,t} = 0 \quad (32)$$

where $P_{sh,t}$ and $P_{se,t}$ denote the shunt-side and series-side active-power terms of the UPFC.

The injected series voltage is represented by its real and imaginary parts. Its admissible range is constrained by

$$\left(U_{pq}^{\min}\right)^2 \leq \left(U_{pq,t}^{(R)}\right)^2 + \left(U_{pq,t}^{(I)}\right)^2 \leq \left(U_{pq}^{\max}\right)^2 \quad (33)$$

The shunt converter is further limited by its current capability, namely,

$$\left(I_{sh,t}^{(R)}\right)^2 + \left(I_{sh,t}^{(I)}\right)^2 \leq \left(I_{sh}^{\max}\right)^2 \quad (34)$$

In addition, the apparent power on the UPFC-controlled corridor must satisfy

$$|S_{ab,t}| \leq S_{ab}^{\max} \quad (35)$$

where $S_{ab,t}$ denotes the apparent power on the controlled corridor between buses a and b .

The UPFC is treated as a lossless steady-state device, and its control effect is represented by the ECI-compatible constraints in Equations (32)–(35) rather than by a separate control-mode variable. Taken together, these constraints define the feasible operating region of the proposed PCOPF model. The dispatch variables are restricted by system power balance, ECI mismatch equations, generator output limits, voltage security, line thermal limits, ramping constraints, and the operating range of the UPFC on the selected corridor. These variables are the main factors linking transmission losses, thermal generation, and carbon-settlement results in this study. Generator reactive-power limits, transformer tap adjustment, reserve constraints, and load-shedding variables are not included in the present formulation.

3.4. Contingency Severity Analysis and Contingency Selection

Base-case feasibility is not sufficient for the dispatch problem considered here. Before the final PCOPF schedule is fixed, the network is evaluated under a set of credible post-incident conditions. The screening procedure identifies the contingency associated with the most stressed post-contingency operating state and incorporates it into the preventive scheduling stage. This screening step is referred to as contingency severity screening (CSS). The same ECI framework developed in Section 2 is used throughout, so only the incident-related part of the original model needs to be corrected.

(1) Generator outage correction model

A generator trip removes its scheduled active-power injection from the pre-contingency operating point. The corresponding bus is no longer maintained as a PV bus in the post-contingency calculation. The correction is written as

$$P_{g,t}^{out} = P_{g,t}^0 + \Delta P_{g,t} \quad (36)$$

$$\Delta P_{g,t} = -P_{g,t}^0 \quad (37)$$

where $P_{g,t}^0$ is the generator output before the outage, $P_{g,t}^{out}$ is the remaining output after the trip, and $\Delta P_{g,t}$ is the active-power correction caused by the outage.

The lost injection is therefore removed directly from the original operating point. The post-contingency state is then solved in the same rectangular-coordinate ECI form.

(2) Transmission-line outage correction model

A line outage changes the network through the removal of the associated branch admittance. For the line model adopted in Section 2, the branch contribution is written as

$$\mathbf{Y}_{mn}^{br} = \begin{bmatrix} G_{mn} + j(B_{mn} - B_c) & -(G_{mn} + jB_{mn}) \\ -(G_{mn} + jB_{mn}) & G_{mn} + j(B_{mn} - B_c) \end{bmatrix} \quad (38)$$

The post-contingency admittance matrix is then expressed as

$$\mathbf{Y}_t^{(c)} = \mathbf{Y}_t^0 + \Delta \mathbf{Y}_{mn} \quad (39)$$

where $\mathbf{Y}_t^0$ is the original admittance matrix, and $\Delta \mathbf{Y}_{mn}$ is the sparse correction associated with the disconnected line. Only the entries related to buses m and n are revised:

$$\Delta \mathbf{F}_t^{(c)}(\mathbf{x}_t^{(c)}, \mathbf{u}_t) = 0 \quad (40)$$

where $\mathbf{x}_t^{(c)}$ is the post-contingency state vector and $\mathbf{u}_t$ is the dispatch vector determined by the preventive scheduling model.

(3) Severity ranking and contingency selection

The CSS stage is used to rank the network stress created by each contingency. In the present work, the first screening is based on the post-contingency line-overload result. This keeps the rule direct. It also avoids mixing too many indicators at the initial selection stage. The severity index of contingency c is defined as

$$\Gamma_c = \max_{\ell \in \mathcal{L}} \left\{ \max \left(0, \left| S_{\ell,t}^{(c)} \right| - S_{\ell}^{\max} \right) \right\} \quad (41)$$

where $\left| S_{\ell,t}^{(c)} \right|$ is the apparent power on line ℓ under contingency c , and $S_{\ell}^{\max}$ is the corresponding thermal limit. If no overload appears after the disturbance, the contribution of that line is taken as zero.

All candidate contingencies in the set C are then ranked in descending order according to Γ_c . The most severe contingency is selected by

$$c^* = \operatorname{argmax}_{c \in C} \Gamma_c \quad (42)$$

That contingency is carried into the subsequent preventive dispatch model. The final PCOPF solution is therefore checked against two states: the base operating condition and the most critical screened contingency. The resulting formulation is therefore a critical-contingency-constrained PCOPF, rather than a full $N-1$ SCOPF model.

3.5. Carbon-Emission and Carbon-Trading Constraints

In the proposed PCOPF model, carbon trading is tied directly to thermal dispatch. Once the output of each thermal unit is fixed, the corresponding emission level is fixed as well. Market trading then determines how the remaining allowance deficit or surplus is settled. The allowance term in this study is a dispatch-based benchmark calculated from the cleared generation profile and the adopted allowance coefficients. It may therefore change across operating cases when the generation mix changes.

For each dispatchable thermal unit i , the carbon emission in period t is represented by

$$E_{i,t} = \alpha_i^c (P_{i,t}^G)^3 + \beta_i^c P_{i,t}^G + \gamma_i^c \quad (43)$$

where $E_{i,t}$ is the carbon emission of unit i in period t , and α_i^c , β_i^c , and γ_i^c are the corresponding emission coefficients.

The total emission of the generator side in period t is

$$E_t^{tot} = \sum_{i=1}^{N_g} E_{i,t} \quad (44)$$

and the cumulative emission over the scheduling horizon becomes

$$E^{sum} = \sum_{t=1}^T E_t^{tot} \quad (45)$$

Let $\bar{E}$ denote the available carbon allowance over the scheduling horizon.

The cumulative emission in Equation (45) is used in the allowance-balance calculation. The network-support settlement in Equations (20) and (21) is calculated outside this emission account, so the loss-reduction effect is not counted again in the generator-side carbon-trading result. After carbon purchasing and selling are accounted for, the allowance balance is written as

$$E^{sum} \leq \bar{E} + \sum_{t=1}^T A_t^{buy} - \sum_{t=1}^T A_t^{sell} \quad (46)$$

where A_t^{buy} and A_t^{sell} denote the purchased and sold carbon allowances in period t , respectively.

A higher thermal output raises E^{sum} . The trading terms then absorb the remaining gap through purchased permits or released surplus allowance.

The carbon-trading settlement in period t is written as

$$C_t^{car} = \pi_t (A_t^b - A_t^s) \quad (47)$$

where π_t is the carbon-trading price in period t . This term is consistent with the generator-side net-benefit formulation in Section 3.2.

The admissible trading volume and settlement are imposed, the corresponding expenditure constraints are written as

$$\begin{cases} 0 \leq A_t^{buy} \leq \overline{A_t^{buy}} \\ 0 \leq A_t^{sell} \leq \overline{A_t^{sell}} \\ 0 \leq \pi_t A_t^{buy} \leq \overline{C_t^{buy}} \\ 0 \leq \pi_t A_t^{sell} \leq \overline{C_t^{sell}} \end{cases} \quad (48)$$

where $\overline{A_t^{buy}}$ and $\overline{A_t^{sell}}$ are the upper limits of carbon purchasing and selling in period t . $\overline{C_t^{buy}}$ and $\overline{C_t^{sell}}$ denote the maximum admissible purchasing and selling settlement in period t , respectively.

Equations (43)–(48) define the carbon-settlement calculation in the proposed market-dispatch model. UPFC-controlled loss variation changes the required thermal dispatch, and the updated dispatch result is then reflected in emissions, allowance balance, trading volume, and settlement cost. The overall solution procedure, including base-case calculation, outage-case initialization, PCOPF optimization, and carbon-settlement evaluation, is summarized in Figure 4.

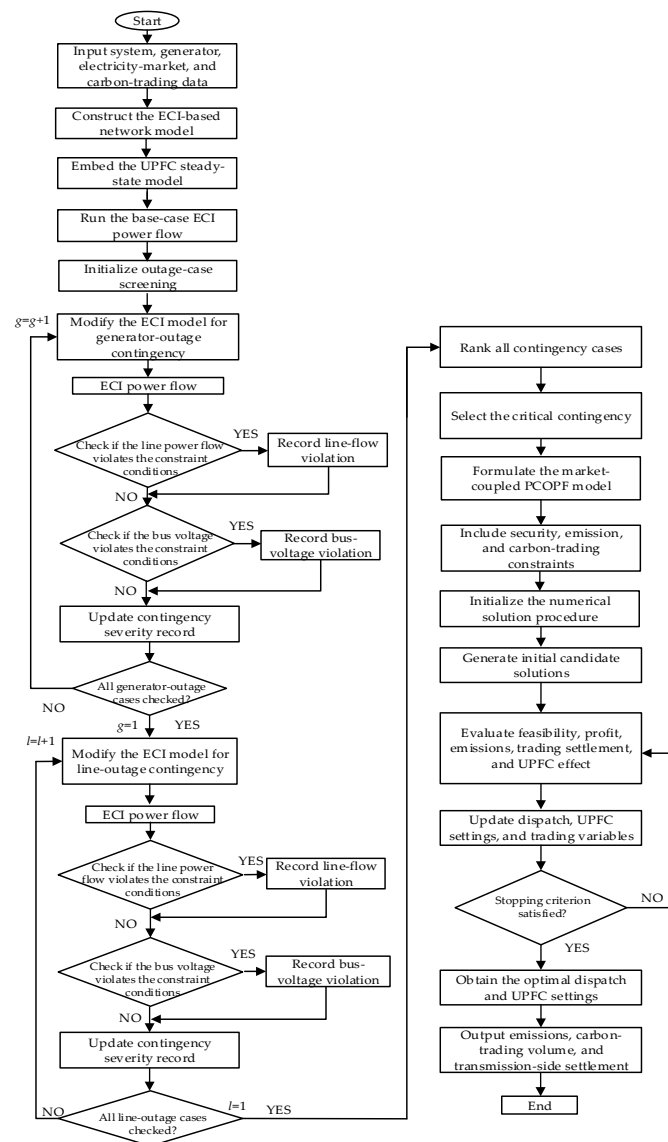


Figure 4. Overall solution procedure of the proposed PCOPF model.

4. Social-Learning Artificial Bee Colony with Feasibility Repair (SLABC-FR)

4.1. Artificial Bee Colony Framework and the Proposed Modification

The proposed PCOPF problem is constrained by ECI-based power balance, UPFC and network operating limits, and carbon-trading feasibility. A candidate schedule with a high economic value may still violate one of these constraints. SLABC-FR repairs bound violations, active-power imbalance, and carbon-trading infeasibility before fitness evaluation.

The proposed method is still built on the artificial bee colony (ABC) framework [30]. Each food source represents one candidate schedule. The colony contains employed bees, onlooker bees, and scout bees. Employed bees search around the current sources. Onlooker bees choose promising sources according to their quality. Scout bees replace stagnant sources when no further improvement is found.

In the standard ABC search, the candidate generated from source i on dimension j is written as

$$v_{i,j}^k = x_{i,j}^k + \phi_{i,j}^k (x_{m,j}^k - x_{i,j}^k) \quad (49)$$

where $m \neq i$ is a randomly selected source, and $\phi_{i,j}^k \in [-1, 1]$ is the perturbation factor.

The onlooker bee chooses source i according to

$$p_i^k = \frac{fit_i^k}{\sum_{n=1}^N fit_n^k} \quad (50)$$

where fit_i^k is the fitness-derived quality of source i , and N is the number of food sources.

If a source cannot be improved within a prescribed number of trials, it is abandoned and regenerated by

$$x_{i,j}^{k+1} = x_j^{\min} + rand(x_j^{\max} - x_j^{\min}) \quad (51)$$

The present method keeps this three-phase structure. The change is made in the search step itself. A learning term is added, and infeasible candidates are repaired before evaluation.

Each food source in the proposed SLABC-FR is written as

$$\mathbf{x}_i^k = [\mathbf{P}_G, \mathbf{U}_{PV}^{sp}, U_{PQ}^{(R)}, U_{PQ}^{(I)}, \mathbf{A}^{buy}, \mathbf{A}^{sell}] \quad (52)$$

where $\mathbf{P}_G$ denotes the dispatchable thermal outputs, $\mathbf{U}_{PV}^{sp}$ denotes the PV-bus voltage setpoints, $U_{PQ}^{(R)}$ and $U_{PQ}^{(I)}$ are the real and imaginary parts of the injected UPFC series voltage, and $\mathbf{A}^b$ and $\mathbf{A}^s$ denote the carbon-purchasing and carbon-selling variables.

The employed-bee update is modified as

$$v_{i,j}^k = x_{i,j}^k + \phi_{i,j}^k (x_{m,j}^k - x_{i,j}^k) + \alpha_k r_{1,i,j}^k (pbest_{i,j}^k - x_{i,j}^k) + \beta_k r_{2,i,j}^k (gbest_j^k - x_{i,j}^k) \quad (53)$$

where $pbest_{i,j}^k$ is the best source previously visited by bee i , $gbest_j^k$ is the best source in the current population, and $r_{1,i,j}^k, r_{2,i,j}^k \in [0, 1]$ are random numbers.

The learning coefficients vary with the iteration count:

$$\alpha_k = \alpha_i + (\alpha_f - \alpha_i) \frac{k}{k_{\max}} \quad (54)$$

$$\beta_k = \beta_i + (\beta_f - \beta_i) \frac{k}{k_{\max}} \quad (55)$$

The employed-bee, onlooker-bee, and scout-bee phases are kept in SLABC-FR. When a new source is produced, the bee refers to its own historical best source and the current best source of the colony. The source is then tested by the greedy replacement rule, and abandoned sources are regenerated in the scout-bee phase. Before the fitness value is calculated, the repair step adjusts infeasible candidates so that the power-balance and carbon-settlement constraints are satisfied.

Greedy replacement is then applied:

$$\mathbf{x}_i^{k+1} = \begin{cases} \mathbf{v}_i^k, & \text{if } F(\mathbf{v}_i^k) < F(\mathbf{x}_i^k) \\ \mathbf{x}_i^k, & \text{otherwise} \end{cases} \quad (56)$$

4.2. Feasibility Repair and Fitness Evaluation

Infeasible food sources appear frequently in the proposed PCOPF search. A repair step is therefore applied before fitness evaluation.

The penalized fitness is written as

$$F(\mathbf{x}) = -\Pi(\mathbf{x}) + \rho_{eq} \|\mathbf{g}(\mathbf{x})\|_2^2 + \rho_{in} \|\max(0, \mathbf{h}(\mathbf{x}))\|_2^2 \quad (57)$$

where $\Pi(\mathbf{x})$ is the generator-side net benefit, $\mathbf{g}(\mathbf{x})$ and $\mathbf{h}(\mathbf{x})$ denote the equality and inequality constraint sets, and ρ_{eq} and ρ_{in} are the corresponding penalty coefficients. Repair and penalty

are applied to different types of constraint violations. The repair step first adjusts directly correctable violations, such as variable bounds, active-power imbalance, and carbon-trading infeasibility. The repaired source is then evaluated by the ECI-based PCOPF model. Remaining violations in voltage limits, line-flow limits, UPFC limits, or post-contingency constraints are handled through the penalty term.

The repair begins with bound projection:

$$x_j \leftarrow \Pi_{[x_j^{\min}, x_j^{\max}]}(x_j) \quad (58)$$

where $x_j^{\min}$ and $x_j^{\max}$ are the lower and upper bounds of the j -th decision variable.

For period t , the active-power mismatch is

$$\Delta P_t = P_t^D + P_{loss} - P_t^{fix} - \sum_{i=1}^{N_g} P_{i,t}^G \quad (59)$$

where P_t^D is the load demand, P_{loss} is the network loss, P_t^{fix} is the aggregated fixed injection, and $P_{i,t}^G$ is the thermal-unit output.

The mismatch is redistributed over the participating thermal units as

$$P_{i,t}^G \leftarrow \Pi_{[P_{i,t}^{G,\min}, P_{i,t}^{G,\max}]}(P_{i,t}^G + \omega_{i,t} \Delta P_t) \quad (60)$$

where $\omega_{i,t}$ is the redistribution factor. The mismatch is not assigned to a single slack generator. It is distributed among the participating thermal units according to their available upward or downward regulation margins; if a unit reaches its limit, the remaining mismatch is redistributed to the other available units.

The carbon-trading variables are repaired by

$$A_t^{buy} \leftarrow \Pi_{[0, \overline{A_t^{buy}}]}(A_t^{buy}), A_t^{sell} \leftarrow \Pi_{[0, \overline{A_t^{sell}}]}(A_t^{sell}) \quad (61)$$

If the allowance balance is still violated after clipping, the repair continues until

$$E^{sum} \leq \overline{E} + \sum_{t=1}^T A_t^{buy} - \sum_{t=1}^T A_t^{sell} \quad (62)$$

is satisfied, where E^{sum} is the cumulative emission and $\overline{E}$ is the available allowance before trading.

The repair is applied to the candidate source generated by the colony, not to the analytical PCOPF model itself.

4.3. SLABC-FR for Solving the Proposed PCOPF

In the proposed SLABC-FR, each food source $\mathbf{X}_i^k$ represents the candidate schedule defined in Equation (52). For every generated source, the repair procedure in Equations (58)–(62) is applied first. The repaired source is then evaluated by the ECI-based PCOPF model in Section 3. The evaluation includes the base operating state under Equations (22)–(35), the selected critical contingency c^* determined by Equation (42), the generator-side net benefit in Equations (16)–(21), and the carbon-emission and carbon-trading relations in Equations (43)–(48). On this basis, the penalized fitness $F(\mathbf{X}_i^k)$ is computed by Equation (57). The colony update is then carried out through the employed-bee, onlooker-bee, and scout-bee phases defined in Equations (49)–(56). The final g_{best}^k is taken as the optimal solution of the proposed PCOPF. The procedure is summarized in Algorithm 1.

Algorithm 1 Pseudocode of the SLABC-FR algorithm for the proposed PCOPF

```

1.    $k = 0$ , initialize  $\mathbf{X}_i^k$ ,  $i = 1, 2, \dots, N$ ,
      within the admissible bounds of the decision variables.
2.   Repair each  $\mathbf{X}_i^0$  by (58)–(62), and evaluate  $F(\mathbf{X}_i^k)$  by (57).
3.    $pbest_i^0 = \mathbf{X}_i^0$ ,  $gbest_i^0 = \arg \min_{1 \leq i \leq N} F(\mathbf{X}_i^k)$ 
4.   while  $(k < k_{max})$  and (stopping criterion is not satisfied) do
5.     for  $i = 1, 2, \dots, N$  do
6.        $\mathbf{V}_i^k \leftarrow$  generate from  $\mathbf{X}_i^k$  by (53),
7.       repair  $\mathbf{V}_i^k$  by (58)–(62), and evaluate  $F(\mathbf{V}_i^k)$ ,
8.        $\mathbf{X}_i^k \leftarrow \begin{cases} \mathbf{V}_i^k, & \text{if } F(\mathbf{V}_i^k) < F(\mathbf{X}_i^k), \\ \mathbf{X}_i^k, & \text{otherwise,} \end{cases}$ 
9.        $pbest_i^{k+1} \leftarrow \begin{cases} \mathbf{X}_i^{k+1}, & \text{if } F(\mathbf{X}_i^{k+1}) < F(pbest_i^k), \\ pbest_i^k, & \text{otherwise,} \end{cases}$ 
10.    end for
11.    Compute  $p_i^k$  by (50).
12.    for each onlooker bee do
13.      select a food source according to  $p_i^k$ ,
14.      generate a new candidate  $\mathbf{V}_i^k$  around the selected source,
15.      repair  $\mathbf{V}_i^k$  by (58)–(62), and evaluate  $F(\mathbf{V}_i^k)$ 
16.      update the selected source and the corresponding  $pbest_i^{k+1}$  by (56).
17.    end for
18.    for  $i = 1, 2, \dots, N$  do
19.      if  $\mathbf{X}_i^{k+1}$  is not improved for  $L$  successive updates,
20.         $\mathbf{X}_i^k \leftarrow$  regenerate by (51),
21.        repair  $\mathbf{X}_i^{k+1}$  by (58)–(62), and evaluate  $F(\mathbf{X}_i^{k+1})$ .
22.      end if
23.    end for
24.     $gbest^{k+1} = \arg \min_{1 \leq i \leq N} F(pbest_i^{k+1})$ ,
25.     $k = k + 1$ .
26.  end while
27.  return  $gbest^k$ .

```

5. Numerical Results and Discussion

The Taipower 345 kV transmission system [33] shown in Figure 5 is used as the test network. It contains 40 buses and 85 transmission lines. The generation portfolio includes coal-fired, gas-fired, oil-fired, nuclear, hydroelectric, and IPP units. Generation limits, ramp-rate constraints, and other unit data were compiled from Taipower publications and related official sources. Appendix A lists the main economic, carbon-settlement, load, and UPFC settings. All simulations were performed in MATLAB 2016b on a personal computer with a 2.9 GHz Intel processor and 16 GB of memory.

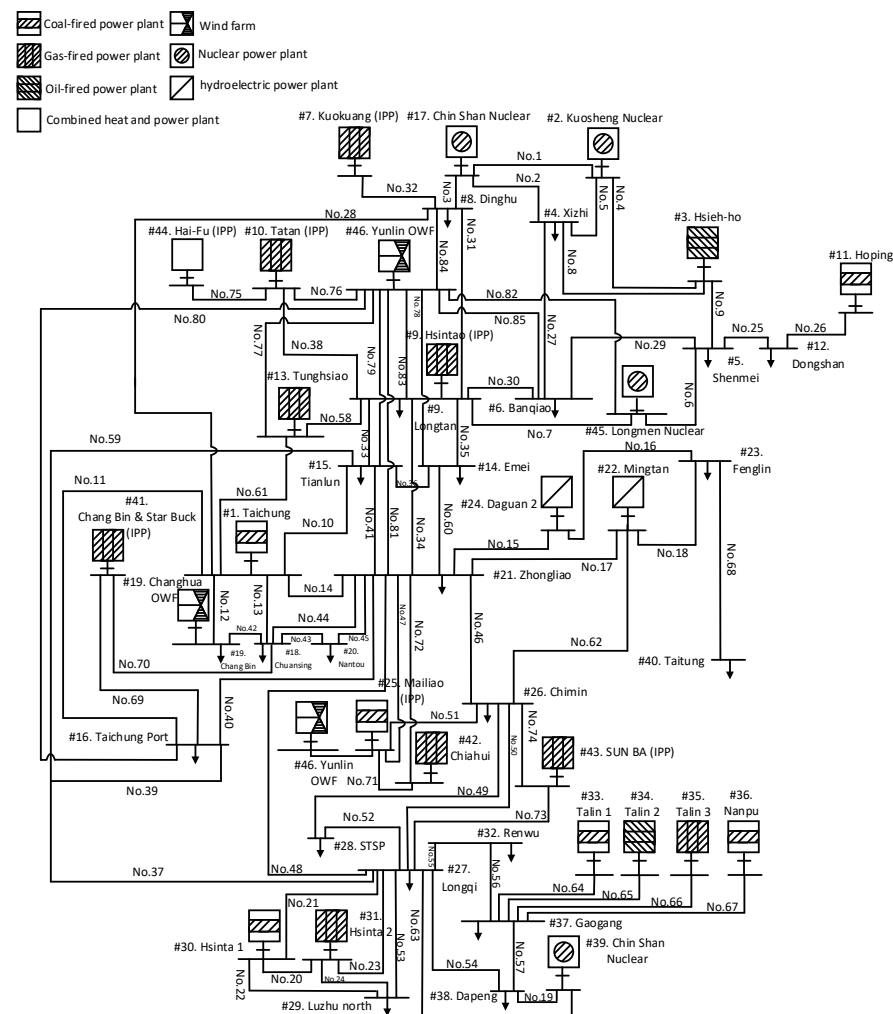


Figure 5. Structure of the Taipower 345 kV transmission system.

To distinguish the roles of UPFC control and contingency-constrained scheduling, four study cases are defined:

Case 1: No UPFC, no contingency-constrained PCOPF.

Case 2: With UPFC, without contingency-constrained PCOPF.

Case 3: Without UPFC, with critical-contingency-constrained PCOPF.

Case 4: With both UPFC and critical-contingency-constrained PCOPF.

Carbon-trading settlement is retained in all four cases. The comparisons that follow focus on algorithm convergence, annual daily average load operation, and full-year operation.

5.1. Convergence Testing of the SLABC-FR Algorithm

For the annual daily average load case, GA [34], PSO [29], ABC [30], and SLABC-FR are tested with the same population size, iteration limit, and stopping rule. SLABC-FR reaches a stable feasible result and gives the highest generator-side net benefit in this test; it is therefore used for the following case studies. The common settings and algorithm-specific parameters are listed in Appendix A (Table A1).

Figure 6 gives the 30-run average convergence history of the minimum operating cost. GA decreases slowly, while PSO and ABC reduce the cost faster but still need a visible settling stage. SLABC-FR reaches the low-cost range earlier and has the shortest settling process. The four algorithms use the same stopping rule, population size, initialization

range, constraint-handling rule, and maximum iteration number. The final statistics of the 30 runs are listed in Appendix A.

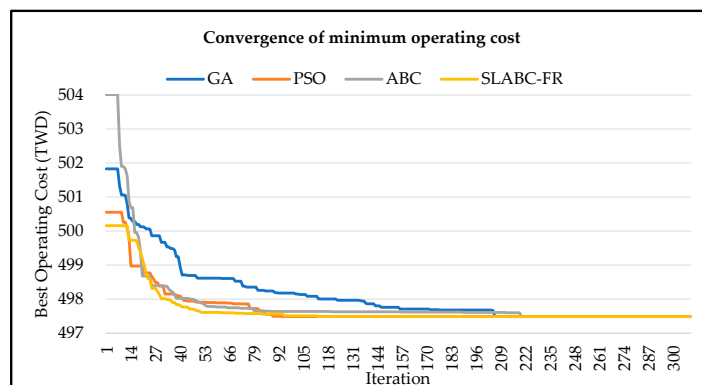


Figure 6. Convergence of minimum operating cost for different algorithms.

Figure 6 reports the average convergence history from 30 independent runs for each algorithm. All algorithms use the same stopping criterion, population size, initialization range, constraint-handling rule, and maximum iteration number. The corresponding final-run statistics are given in Appendix A.

Figure 7 gives the same comparison for generator-side net benefit. GA stays at the lowest level after convergence. PSO and ABC improve the benefit, but both settle below SLABC-FR. SLABC-FR reaches the highest final benefit and stabilizes earlier than the other methods.

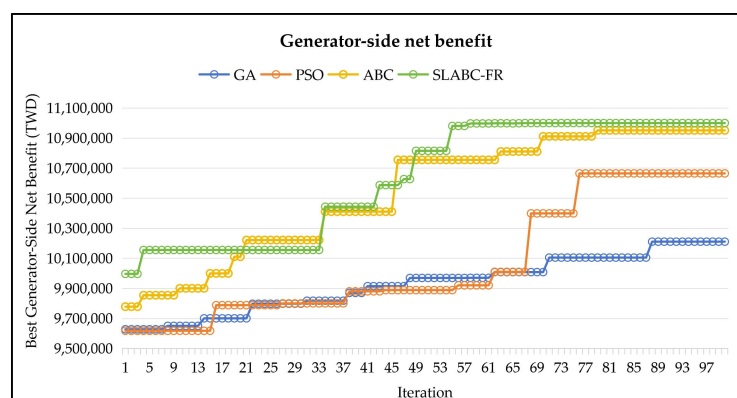


Figure 7. Convergence curves of generator-side net benefit for different algorithms.

After the convergence test, SLABC-FR is used to rank the retained candidate lines for UPFC installation. Because the optimization outcome changes across runs, the comparison is based on repeated solutions rather than on a single favorable run. The average generator-side net benefit is therefore adopted as the main ranking index, while the minimum and maximum values are kept to show the variation range. Table 1 lists the five leading candidates. Among them, transmission line No. 59 gives the highest average generator-side net benefit, reaching TWD 11,000,763. It is therefore selected as the final UPFC installation corridor for the subsequent case studies.

5.2. Annual Daily Average Load Results

Table 2 gives the annual daily average load results for the four study cases. The main differences lie in generator-side profit, transmission loss, carbon-related settlement, and fuel-dispatch patterns. The electricity revenue is identical in all cases because the same load-side cleared energy is settled at the same market-clearing price. The generation entries

in the table denote gross dispatched generation obtained from the ECI-based network solution; therefore, they may vary with losses and dispatch changes under different UPFC and PCOPF settings.

Table 2. Annual daily average load test results.

Metrics	Case 1	Case 2	Case 3	Case 4
Total profit of power generators (TWD)	68,615,167	53,773,928	20,326,516	11,000,763
Total revenue of power generators (TWD)	1,774,734,960	1,774,734,960	1,774,734,960	1,774,734,960
Total expenditure of power generators (TWD)	1,706,119,793	1,720,961,032	1,754,408,444	1,763,734,197
Carbon-trading expenditure (TWD)	1350	33,447,412	0	34,607,162
Refund (TWD)	0	7,028,193	0	7,362,845
Total gross dispatched generation (MWh)	573,873.8	567,026.92	572,179.31	567,026.92
Taipower gross dispatched generation (MWh)	372,871.13	365,384.69	371,581.58	365,384.69
IPP gross dispatched generation (MWh)	201,002.67	201,642.23	200,597.73	201,642.23
Line losses (MWh)	27,126.55	22,059.18	26,859.03	21,281.92
Dispatch-based carbon allowance benchmark (tCO ₂)	300,985.71	205,920.66	300,522.27	201,538.56
Total carbon emissions of all generators (tCO ₂)	300,988.72	281,296.24	300,522.27	279,527.7
Carbon-trading volume (tCO ₂)	3.01	75,375.58	0	77,989.14
Coal (MWh)	57,862.95	56,262.95	57,162.95	53,592.26
Oil (MWh)	13,174.15	12,874.15	13,274.15	10,024.63
Gas (MWh)	115,167.45	114,367.45	115,367.45	115,880.91

The four cases are designed to separate the transmission-to-settlement effect of UPFC control from the security effect of preventive PCOPF.

Case 1 is used as the reference case. Without UPFC and contingency-constrained PCOPF, it yields the highest generator-side profit, TWD 68,615,167, and the lowest total expenditure, TWD 1,706,119,793. This economic advantage is accompanied by the highest line losses, 27,126.55 MWh, and high emission levels, with the dispatch-based carbon allowance benchmark and total carbon emissions reaching 300,985.71 tCO₂ and 300,988.72 tCO₂, respectively. Carbon trading is almost inactive in this case.

Case 2 introduces the UPFC without imposing contingency-constrained PCOPF. The main change appears in the network-related indicators. Under the adopted settlement setting, the market-cleared total generation is 567,026.92 MWh, including 365,384.69 MWh from Taipower units and 201,642.23 MWh purchased from IPPs. The corresponding ECI-based power-flow result gives a line loss of 22,059.18 MWh. The dispatch-based carbon allowance benchmark and total carbon emissions decrease to 205,920.66 tCO₂ and 281,296.24 tCO₂, respectively. Although a refund of TWD 7,028,193 is received, the generator-side profit decreases to TWD 53,773,928 because the carbon-trading expenditure rises to TWD 33,447,412.

Case 3 keeps the original network and applies contingency-constrained PCOPF. The changes in generation, losses, and emissions are much smaller. The market-cleared total generation becomes 572,179.31 MWh, line losses 26,859.03 MWh, and total carbon emissions 300,522.27 tCO₂. In this case, both the carbon-trading volume and carbon-trading expenditure become zero. Even so, the total expenditure increases to TWD 1,754,408,444, and the generator-side profit falls to TWD 20,326,516. The operating point is therefore safer but more conservative.

Compared with the other cases, it gives the lowest line losses, 21,281.92 MWh, the lowest dispatch-based carbon allowance benchmark, 201,538.56 tCO₂, and the lowest total carbon emissions, 279,527.70 tCO₂. The same cleared generation total does not mean that the AC network state is unchanged. The decrease in coal- and oil-fired generation is not only a loss-reduction effect. In Case 4, the UPFC lowers losses and redistributes

branch flows, while the PCOPF constraints keep the dispatch feasible under the selected contingency. Coal and oil generation decrease to 53,592.26 MWh and 10,024.63 MWh, while gas generation increases slightly to 115,880.91 MWh. The refund reaches TWD 7,362,845, the highest value among the four cases. The carbon-trading expenditure remains high, at TWD 34,607,162, but the generator-side profit is still positive at TWD 11,000,763. Thus, Case 4 is not the most profitable dispatch from the generator-side perspective. Relative to Case 1, it reduces line losses by 21.55% and carbon emissions by 7.13%, while generator-side profit decreases from TWD 68,615,167 to TWD 11,000,763. The case therefore shows that lower emissions and stronger post-contingency security are obtained with a lower generator-side profit.

The role of contingency-constrained PCOPF is clearer in the post-contingency results. The outage of line No. 56 is taken as an example. Figures 8 and 9 compare the line-flow and bus-voltage distributions with and without PCOPF.

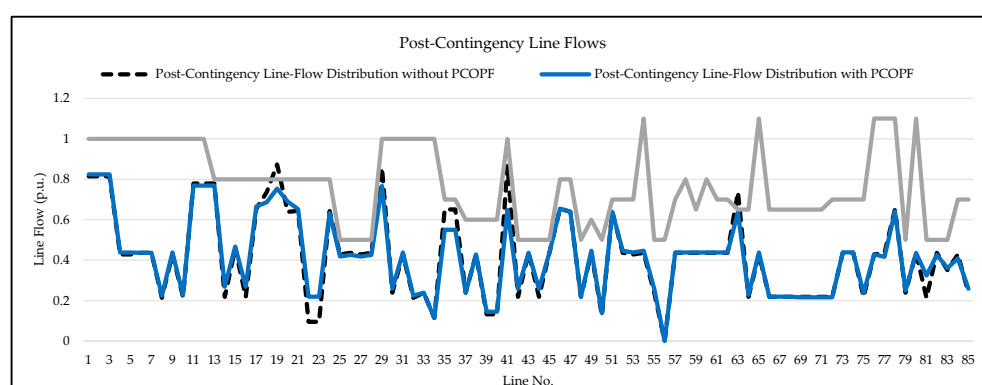


Figure 8. Post-contingency line-flow profile under line No. 56 outage.

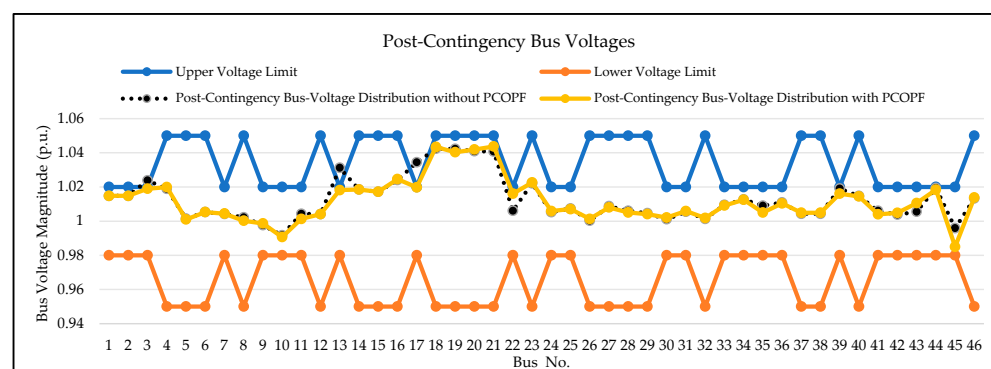


Figure 9. Post-contingency voltage profile under line No. 56 outage.

Figure 8 shows that, without PCOPF, the outage produces overloads on line No. 19 and line No. 63, where the flows rise to 0.8729 p.u. and 0.7365 p.u., exceeding their limits of 0.8 p.u. and 0.65 p.u., respectively. After PCOPF is imposed, these values fall to 0.7533 p.u. and 0.6365 p.u. The overloads disappear.

Figure 9 shows a similar contrast in the voltage profile. Without PCOPF, bus No. 3, bus No. 13, and bus No. 17 exceed their upper voltage limits, reaching 1.0238 p.u., 1.0312 p.u., and 1.0344 p.u., respectively. With PCOPF, they are reduced to 1.0190 p.u., 1.0182 p.u., and 1.0198 p.u. No voltage-limit violation remains in the post-contingency state. These changes show that the PCOPF part mainly improves the screened post-contingency security, while the UPFC mainly affects the loss and emission-related indices.

Overall, the UPFC mainly affects losses and emission-related settlements, while PCOPF removes the screened post-contingency violations. Using both gives a lower-emission and secure operating point, but not the highest generator-side profit.

5.3. Full-Year Average Load Results

Table 3 extends the comparison to the full-year horizon. The same load-side cleared energy and market price are used in all cases, so the differences mainly come from expenditures, carbon settlement, line losses, emissions, and the fuel-dispatch structure.

Table 3. Full-year average load test results.

Metrics	Case 1	Case 2	Case 3	Case 4
Total profit of power generators (109 TWD)	7.4913	5.871	2.2192	1.201
Total revenue of power generators (1011 TWD)	6.389	6.389	6.389	6.389
Total expenditure of power generators (1011 TWD)	6.3141	6.3303	6.3668	6.377
Carbon-trading expenditure (109 TWD)	0.0004	12.427	0	12.8601
Refund (109 TWD)	0	4.2182	0	4.419
Total gross dispatched generation (108 MWh)	2.0609	2.0363	2.0548	2.0363
Taipower gross dispatched generation (108 MWh)	1.3235	1.2969	1.3189	1.2969
IPP gross dispatched generation (107 MWh)	7.3742	7.3977	7.3593	7.3977
Line losses (106 MWh)	9.6251	7.8271	9.5302	7.5513
Dispatch-based carbon allowance benchmark (107 tCO ₂)	11.2239	7.6892	11.207	7.5256
Total carbon emissions of all generators (108 tCO ₂)	1.1224	1.049	1.1207	1.0424
Carbon-trading volume (107 tCO ₂)	0.0001	2.8008	0	2.8984
Coal (106 MWh)	12.385	12.0425	12.2352	11.4709
Oil (106 MWh)	6.8665	6.7101	6.9186	5.2249
Gas (106 MWh)	47.98	47.6467	48.0633	48.2772

Case 1 remains the economic reference. Without a UPFC and without contingency-constrained PCOPF, it yields the highest generator-side profit, 7.4913×10^9 TWD. That result comes with the weakest physical performance in the table. Line losses reach 9.6251×10^6 MWh. The allocated carbon allowance and total carbon emissions rise to 11.2239×10^7 tCO₂ and 1.1224×10^8 tCO₂, respectively. Carbon trading is almost absent in this case.

In Case 2, the introduction of a UPFC changes the full-year operating indices. The generator-side profit decreases to TWD 5.871×10^9 . Under the adopted settlement setting, the market-cleared total generation is 2.0363×10^8 MWh, while the ECI-based line loss is reduced to 7.8271×10^6 MWh. Total carbon emissions decrease to 1.049×10^8 tCO₂, and the refund increases to TWD 4.2182×10^9 . Over the full-year horizon, the effect of UPFC is therefore observed mainly in lower losses and improved emission-related indices.

Case 3 reflects the effect of contingency-constrained PCOPF alone. Its influence on the annual energy and emission indices is much smaller. The market-cleared total generation is 2.0548×10^8 MWh, line losses are 9.5302×10^6 MWh, and total carbon emissions are 1.1207×10^8 tCO₂. The generator-side profit drops further, to 2.2192×10^9 TWD. A notable point is that both carbon-trading volume and carbon-trading expenditure become zero. The dispatch is more secure but also more conservative.

Case 4 reflects the joint effect of a UPFC and contingency-constrained PCOPF. Line losses decrease to 7.5513×10^6 MWh, which is the lowest value among the four cases. The market-cleared total generation remains the same as in Case 2; however, the lower loss level suggests that PCOPF modifies the feasible network operating point after UPFC installation rather than changing the cleared energy quantity itself. The allocated carbon allowance decreases to 7.5256×10^7 tCO₂, and total carbon emissions fall to 1.0424×10^8 tCO₂. Coal and oil outputs are further reduced, while the gas output increases slightly to

48.2772×10^6 MWh. The refund reaches TWD 4.419×10^9 , the highest value in Table 3. Although generator-side profit decreases to TWD 1.201×10^9 , it remains positive.

The full-year results follow the same pattern as the annual daily average load case. The UPFC reduces losses and emissions, while PCOPF provides the screened contingency security. The coordinated case still gives the lowest loss and emission levels, with a lower but positive generator-side profit.

The economic results are tied to the carbon price, allowance rule, and benefit-sharing coefficient used in this study. The changes in branch flows, losses, and emissions come from the ECI-based network solution. The carbon-trading expenditure, refund, transmission-side settlement, and generator-side net benefit are settlement results, so their values will change if the carbon price or allocation rule is changed. UPFC investment and operating costs are not included here, since the paper deals with dispatch-stage carbon settlement, not long-term device investment planning.

6. Conclusions

This study examined how UPFC-induced changes in transmission flows affect carbon-trading settlement under preventive security constraints. The research problem was not simply to add carbon accounting to an OPF result, but to calculate how branch-flow redistribution changes network losses, thermal generation, emissions, allowance balance, trading volume, and settlement cost. For this purpose, a UPFC-assisted preventive contingency-constrained OPF model was formulated in an equivalent current injection form, and SLABC-FR was used to handle the resulting constrained search problem.

In the algorithm comparison, SLABC-FR reached the low-cost region earlier than GA, PSO, and ABC, and obtained the highest generator-side net benefit among the compared methods. The candidate-line screening selected line No. 59 as the UPFC installation corridor. The operating cases further show different roles of the two control factors. The UPFC mainly reduces network losses and emission-related indices, while preventive PCOPF removes post-contingency overloads and voltage-limit violations. When both are used, the result is not the highest short-term generator-side profit, but a more balanced dispatch with lower losses, lower emissions, and secure post-contingency operation.

The Taipower 345 kV results show the transmission-to-carbon path. UPFC control changes branch flows and losses; the changed loss level modifies thermal generation; and the new generation schedule changes emissions, allowance balance, trading volume, and settlement cost. Carbon settlement therefore changes with the dispatch variables that determine network losses and contingency feasibility. This is the main difference from a sequential treatment in which OPF is solved first and carbon accounting is added afterward. Further work will extend the model to multiple severe contingencies, time-varying carbon prices, and several controllable transmission devices.

Although a Pareto frontier between generator-side profit and carbon emissions can provide additional multi-objective insight, the present study adopts a single-objective settlement formulation in which the carbon-price signal converts emissions into carbon-trading expenditure. Therefore, the profit–emission trade-off is reflected through the generator-side net benefit rather than through a separate Pareto analysis.

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Appendix A. Reproducibility Settings and Algorithm Parameters

The shared settings were as follows: population size = 50, maximum iteration number $k_{max} = 300$, stopping rule = maximum iteration reached or no improvement in 20 consecutive iterations, equality-constraint penalty coefficient $\rho_{eq} = 1.0 \times 10^7$, inequality-constraint penalty coefficient $\rho_{in} = 1.0 \times 10^6$, equality-feasibility tolerance = 10^{-6} , and inequality-feasibility tolerance = 10^{-4} . Candidate solutions violating variable bounds were projected back to the admissible range before evaluation.

Table A1. Algorithm-specific parameter settings used in the optimization tests.

Algorithm	Parameter	Value
GA	Selection method	Tournament
	Tournament size	3
	Crossover rate	0.8
	Mutation rate	0.05
	Elitism count	2
PSO	Inertia weight ω	Linearly decreased from 0.90 to 0.40
	Cognitive coefficient c_1	2
	Social coefficient c_2	2
	Velocity limit	20% of variable range
ABC	Scout limit L	40
	Perturbation factor range ϕ_{ij}	$[-1, 1]$
	Scout limit L	40
SLABC-FR	Learning coefficients	Updated adaptively by Equations (54) and (55)
	Repair strategy	bound projection + power-balance redistribution + carbon-trading repair
Category	Parameter	Value/Setting
Electricity price	Average IPP price	3.56 TWD/kWh
Electricity price	Summer–autumn price	3.70 TWD/kWh
Electricity price	Spring–winter price	2.68 TWD/kWh
Carbon benefit allocation	η_t	0.5
Coal heat-rate coefficient	a, b, c, d	182.25, 2.68515, 0.000385155, -9.86175×10^{-8}
Oil heat-rate coefficient	a, b, c, d	158.76, 2.70675, 0.000257715, -1.85895×10^{-7}
Gas heat-rate coefficient	a, b, c, d	237.06, 2.57175, 4.35915×10^{-5} , -5.4945×10^{-8}
Carbon emission factor	Coal	25.8 kgC/GJ; oxidation rate 0.98
Carbon emission factor	Oil	21.1 kgC/GJ; oxidation rate 0.99
Carbon emission factor	Gas	15.3 kgC/GJ; oxidation rate 0.995
Carbon-trading limits	Hourly purchasing/selling limits	Adopted from the hourly settlement data used in the simulations
Load demand	Seasonal 24 h load profile	Adopted from the seasonal load data used in the simulations

Table A2. Statistical comparison of algorithms based on minimum operating cost over 30 independent runs.

Algorithm	Best Cost (10 ⁶ TWD)	Mean Cost (10 ⁶ TWD)	Worst Cost (10 ⁶ TWD)	Std. Dev. (10 ⁶ TWD)	Feasibility Rate (%)	Mean CPU Time (s)	Mean Convergence Iteration
GA	496.42	497.65	510.08	2.35	93.33	18.76	186
PSO	495.39	497.55	499.83	0.58	96.67	16.42	92
ABC	494.41	497.56	501.91	1.01	96.67	9.35	108
SLABC-FR	496.34	497.45	499.61	0.45	100	15.84	61

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