scenarios for T+1. PV or nose curve is the media for assessing the voltage stability, which the area above the nose point is stable operating zone. Different scenario with the different operating condition will have different PV curve, which in that figure indicates as "S1" and "S2". "S1" can represent the non-contingency scenarios while "S2" can represent one of the contingency scenarios. Moreover, there is a permissible voltage operating zone lies between two dashed lines commonly uses as voltage regulation criteria.

In the illustration, "S2" seems cannot meet the voltage regulation requirement. For that purpose, the corrective control for "S2" is necessary as indicated by "S2*" prepared if in the T+1 operating point goes to "S2" direction.

For general analysis, all scenarios operating point of the time-slot T+1 can be simulated. The proper preventive control can be determined for T+1. The corrective scheme can secure the remaining violated scenarios obtained from the simulation. The control center will prepare the corrective control solutions for the remaining violated scenarios.

C. Traditional Method

The first existing traditional method is called the simple optimal power flow (OPF), which only consider the normal scenario (predicted VRE output and non-contingency scenario) presented in [1], [2], [22], [24] Considering the occurrence of line contingency and VRE fluctuation, the problem is formulated in the stochastic problem which leads to some scenarios. There is some technique like genetic algorithm [27], bender decomposition [24]and the HCOPF [22]. Those algorithms try to satisfy all of the scenarios in the PC stages, which usually result in higher generation cost than the simple OPF. This traditional method objective is to simplify the computation burden for accelerating the computation speed as presented as the second common research direction in the previous section.

1) Formulation of the Preventive Control

The objective function of the Stochastic SCOPF is formulated to minimize the total generation fuel cost (F_T) related, as shown in eq. (2), where decision variables are reactive power compensator (capacitor and reactor), generator power, reserve power, and voltage. Considered constraints are shown in eqs (3)-(15); available generation range (3),(4), permissible voltage range (4), voltage stability limit (5) defined in [28], voltage regulation (5), voltage stability limit (6), required spinning reserve (7), generator changes as effects of VRE injection (8), reactive power compensator's tap limits (9), reactive power injection from compensators (10), net reactive power (11), net active power (12), active and reactive power flows (13),(14), and transmission line capacity limit (15).

Objective function:

$$Min\ F_T = \frac{\sum_{r=1}^{NS} A_r^{RE} \sum_{i=1}^{NG}(a_i P_{GOir}^2 + b_i P_{GOir} + c_i)}{\sum_{r=1}^{NS} A_r^{RE}} \tag{2}$$

Subject to:

$$P_{G_{imin}} \leq P_{GOir} + P_{GREVi} \leq P_{G_{imax}} \tag{3}$$

$$Q_{G_{imin}} \leq Q_{GOir}^k \leq Q_{G_{imax}} \tag{4}$$

$$V_{j_{min}} \leq V_{jr}^k \leq V_{j_{max}} \tag{5}$$

$$VSI_{svb\,r}^k > \begin{cases} 0.05, \ if\ k = 0 \\ 0, \ if\ k \neq 0 \end{cases} \tag{6}$$

$$\sum_{i=1}^{NG} P_{GREVi} = 0.1 \sum_{j=1}^{NB} P_{Djr}\ ,\ for\ r = 1 \tag{7}$$

$$P_{GOir} = P_{GOib} - \alpha_i \left(\sum_{j=1}^{Nre} P_{j\,r}^{RE} \right) \tag{8}$$

$$Tap_{nmin} \leq Tap_n \leq Tap_{nmax} \tag{9}$$

$$Q_{Nnr}^k = V_{jr}^{k\,2} Tap_n Q_{Nn}^{base},\ \ if\ j = n \tag{10}$$

$$Q_{Djr}^k = Q_{Nnr}^k + Q'_{Dj},\ \ if\ j \neq n, Q_{Nnr}^k = 0 \tag{11}$$

$$P_{Djr} = P'_{Dj} - P_{j\,r}^{RE} \tag{12}$$

$$P_{GOjr} - P_{Djr} = V_{jr}^k \sum_{m=1}^{NB} V_{mr}^k \left(G_{jm}^k \cos\theta_{jmr}^k + B_{jm}^k \sin\theta_{jmr}^k \right) \tag{13}$$

$$Q_{GOjr}^k - Q_{Djr} = V_{jr}^k \sum_{m=1}^{NB} V_{mr}^k \left(G_{jm}^k \sin\theta_{jmr}^k - B_{jm}^k \cos\theta_{jmr}^k \right) \tag{14}$$

$$S_{jmr}^k \leq S_{maxjm} \tag{15}$$

Total generator reserve power is determined to be 10% of the total load. Generally, the scenario is modeled as the combination of VRE and line contingency scenarios indexed by notation pairs $r - k$.

2) Formulation of the Corrective Control

Simultan reactive power control and load shedding (LS) control with the objective function for minimizing the amount of load curtailment (F_{LS}. Therefore, the decision variable are the amount of LS and reactive power control:

Objective function:

$$Min\ FL_{r-k}^{vio} = \sum_{m=1}^{NL} P_{LS_{mr}}^k \tag{16}$$

Subject to:

Equations (5), (6), (9)–(11), (13)–(15) with the additional constraints:

$$P_{Djr} = P'_{Dj} - P_{LSmr}^k - P_{j\,r}^{RE} \tag{17}$$

$$P_{LS_{min}} \leq P_{LSmr}^k \leq P_{LS_{max}} \tag{18}$$

$$P_{GOir}^{LSk} = P_{GOir}^k - \alpha_i \sum_{m=1}^{NL} P_{LSmr}^k \tag{19}$$

Equation (17) modifies eq (12) to match the problem formulations. Equation (18) gives the limitation in the amount of load curtailment while eq. (19) shows the generator active power changes due to the LS.

D. Proposed Method

The proposed method manages the optimal allocation of the total cost resulted by PC and CC, which can cover two common research direction presented in the previous section. The solver clusters scenarios into PC and CC for achieving the most economical total cost. The proposed method is the latest version of modified hybrid computational optimal power flow (HCOPF), which was developed by the author as presented in [22]. In the traditional HCOPF, all selected scenarios were intentionally solved by PC (in the upper dashed box), which results in a high increment of generation cost.

Moreover, if the solution of PC was infeasible, which there was still a violation in some scenarios, the violation

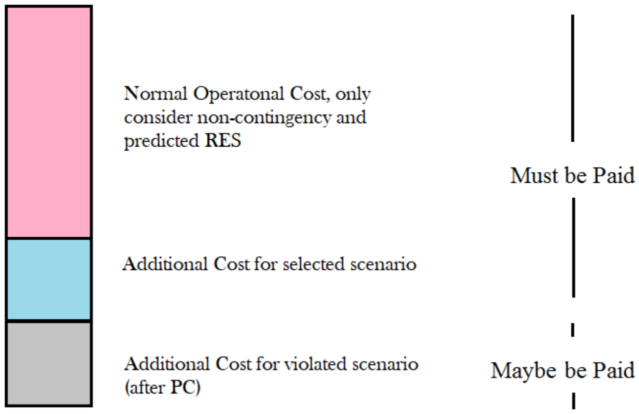

Fig 4 Phylosophy of the proposed method

was converted as penalty cost. The improvement made in the proposed method are:

- Line contingency scenario selection in PCCost stage
- Converting the penalty cost calculation into Corrective control cost (CCCost) calculation, which calculated for any violated scenario

Using the proposed method, there is a guarantee that the proposed method will have a feasible solution since some cases are using the existing methods, which are infeasible. Another advantage of the proposed method that, the total cost can be controlled to be more economical as illustrated in Fig 4.

The red area illustrates the standard operating cost that must be paid by power system utility, which only considers the central scenario (non-contingency and predicted VRE). The blue area illustrates the additional cost for performing the defensive scheme for securing some selected scenario while the grey area illustrates the unselected scenarios which should be paid if the power system goes into that scenario for the upcoming timeslot T+1. The characteristic of red and blue areas are "must be paid" while the grey area is "may be paid." The total cost adjustment can be controlled by selecting the number of selected scenario considered the blue area, which means a shift some of them into the grey area. Most of the existing method tend to enlarge the blue area, which the cost "must be paid" so that the total operating cost is not optimal.

The whole algorithm will be based on genetic algorithm (GA) with the continuous variable are solved using the numerical method based on primal-dual interior point and the discrete variables are solved using the GA procedures. One population in GA will represent one solution. The whole solution is presented in Fig 5 consist of two main part called preventive control (PC) and corrective control (CC) parts. Addressing proper scenarios into PC or CC stages will confirm the optimal solutions.

1) Preventive Control Part

After defining scenarios (contingency and VRE penetration point) the algorithm in the upper dashed-box will decided the compensator tap position, generator output limit and selecting scenarios randomly as further explain in [22]. After manipulating the new constraint, the new generation

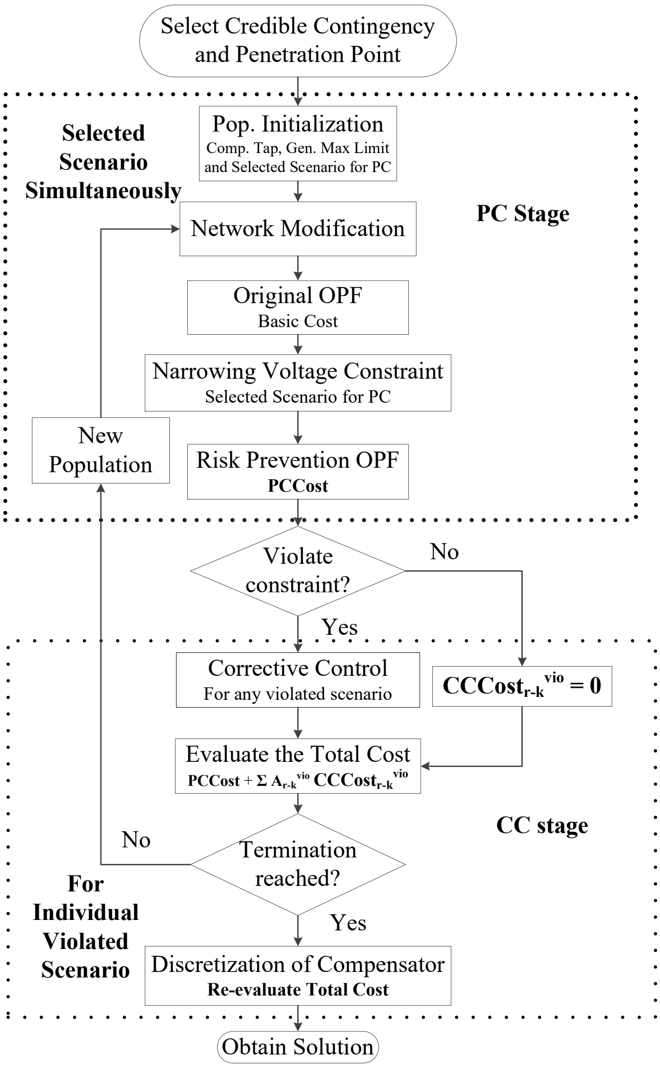

Fig 5 Flowchart of the proposed algorithm

cost consist of PC cost will be obtained for every population. If there is no violation for all scenarios within a population the total cost is the PCCost. However, for a population having violated scenario after the PC stage will be executed in the CC stage (lower dashed-box).

2) Corrective Control Part

For any violated scenarios within one population, the prepared corrective control will be calculated individually using the algorithm in this box following the corrective control scheme presented by the objective function in eq. (16). Depending in the number of violated scenarios remained in each population, CC stage part will be oftently acces or not which can become the computation burden.

3) Total Cost Evaluation

For evaluating the total cost for a population, since the violated scenarios are not going to really occur the CC cost may be unneccesary to be paid. For this reason, it is belong to the "may be paid" group which should be weighted by the scenario's occurrence probabilities.

The optimal management between CC and PC stages are determined by the procedures presented in the flowchart.

TABLE I
BASE CASE SIMULATION RESULT

Method	Number of Violated Scenario in PC	PCCost (unit cost)	PC + Cccost (unit cost)
Trad	0	16718	16718
Prop1	27	15576	15817
Prop2	27	15587	15769

TABLE II
REQUIRED COMPUTATION TIME FOR BASECASE

Method	Covered line Contingency in PC	Comp. time (second)	Control Windows (minutes)
Trad	5, 19, 20 and 53	28	15 – 30 minutes
Prop1	5, 19 and 20	600	
Prop2	5, 19 and 20	120	

Initially the scenarios for PC stage are selected randomly by the population generation process, then final evaluation is determined by the total cost. For evaluation purpose, the CCCost for any violated scenario should be weighted by the scenarios probability as presented in this equation:

$$Totalcost = PCCost + \sum A_{r-k}^{vio}\, CCCost_{r-k}^{vio} \quad (20)$$

With:

$$PCcost = FT \quad (21)$$

$$CCCost_{r-k}^{vio} = FL_{r-k}^{vio} \quad (22)$$

E. Simulation Set Up

The simulation are conducted in modified IEEE 57 test system in stressed operating point for voltage stability monitoring purpose, which the VRE penetrate at bus 14, 18 and 56 with the output for the upcoming time-slot are 9, 12 and 7 MW respectively, with controllable capacitor bank at 18 and 34 while the reactor at bus 25 and 46, each with the maximum compensation value 1 Mvar. Those compensators have 10 taps regulations. The total load is 576 MW and the economic load dispatch without considering any uncertainty resulting in the average operating cost at 15463 unit cost. For the base case, line contingency are considered at line 5, 19, 20 and 53, so in total there will be 135 considered scenarios with given occurrence probability.

All of the simulations is conducted using MATLAB, with the MATPOWER [29] for solving the power flow equation and HCOPF solver [22] for solving the OPF using 64-bit PC with 3.00 GHz CPU and 32 GB memory. The voltage stability problem is evaluated using the technique presented in [28]. The traditional solution which solves the problem only by the preventive scheme are used as the comparison.

III. RESULT AND DISCUSSION

The effectiveness of the proposed method is demonstrated using two scenario cases, a base scenario with 135 scenarios and larger scenarios with 810 scenarios. There are three control strategies to be compared for showing the merit of the proposed method. Those control strategies are:

- Trad for the original HCOPF
- Prop1 for the proposed method with discretization
- Prop2 for the proposed method without discretization

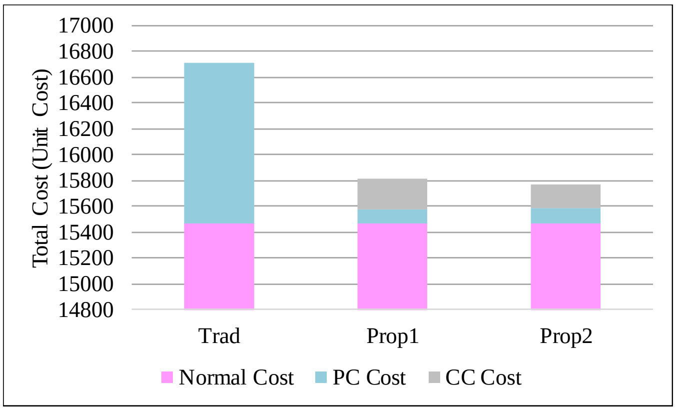

Fig 6 Cost allocation for base scenario

The difference between Prop1 and Prop2 is how to generate the compensator tap status. Since the status of the compensator is a discrete variable, the solution should be chosen from the population generation stage (Prop1). However, the computation burden is more substantial. Therefore, the simplification for ignoring the compensator as a discrete variable can be made, which can be included in the digital process for both CC and PC stages. The final value of the discrete variable will be normalized after the final evaluation process.

A. Base Scenario

Base scenario considers 135 scenarios, 27 scenarios at non-contingency and 108 scenarios at contingency. There are 3 methods that should be considered that are Trad, Prop1, and Prop2. The Trad method focus on solving as many scenarios as possible in the PC stage and the remaining violated scenario in CC. Prop1 and Prop2 manage the scenarios to be handled in PC and CC simultaneously. The difference between Prop1 and Prop2 are the consideration of reactor and capacitor as a discrete variable (1) and a continuous variable (2) for the CC.

It can be inferred from Table 1 that the Trad method can secure all of the scenarios with the generation cost 16718 unit cost compared to the 15463 for not considering the uncertain scenario. Even if, the system can secure all scenarios the generation cost dramatically increases. The proposed method is choosing the scenarios for PC and CC, consider the occurrence probability and also severity, for that reason the generation cost is still below the Trad, which result in 15576 and 15587 unit cost, respectively. It is proved that the proposed method achieves a more economical operating point. The cost allocation for the base scenario are presented in Fig 6 shows that the proposed method can optimize the total cost by managing the PC and CC stages (Trad algorithm only focus on the PC stage). Since some scenarios are not likely going to happen, it is wise for intentionally managing those into CC stage only even some risk remain (existence of grey zones). From the risk existence point of view, the Trad is better since no grey zones remained even the total cost is very high.

From the computation burden, modifying HCOPF [22] into some subproblems (CCCost algorithm) increase the computation burden, since the subproblem should be xecuted in each iteration. It described in Table 2 that the computation time is increasing for the proposed method, especially when the subproblem still consists of the discrete variable. However, the computation times are still acceptable for each method since the efficient control window lies between 15-30 minutes.

B. Extended to Larger Scenario

Considering larger scenario by considering line contingencies 2, 3, 5, 7, 8, 12, 14, 15, 19, 20, 23, 24, 25, 27, 30, 35, 38, 39, 47, 53, 59, 60, 61, 63, 64, 65, 71, 78, and 79 in the formulation problem, the problem size will be larger since 810 scenarios should be considered in the problem. The results are shown in Table 3, in which the traditional method solution is not feasible for the Trad. Therefore, the CC is needed. Trad will use the operating point from the CC result and executed the CC individually when the scenarios occur. The risk cost is calculated using the same manner as the penalty cost [22].

On the other hand, the Prop2 solution is feasible for a complete solution solver. Moreover the total cost is more economical than the trad, even if the PCCost is more expensive. From this case, it can be inferred for some heavy loading condition case that, it will be not possible trying to solve all of the scenarios in the PC stage, like the traditional. Risk management of the proposed method once against showing the merit of the proposed method over the Trad. From the cost allocation, it can be inferred that scenarios selection management by the proposed method confirms the more economical total cost. Moreover, the grey zones of Trad is very large, which means the Trad algorithm is not effective for very large scenarios resulting in a higher penalty cost. In this case, the proposed method has better performance in both cost and risk minimization, which is rather different from the base scenario. Considering only the “must be paid” cost (pink and blue zones), Trad has less expensive cost. However, the risk cost is too high. Usually, the power system utility will not operate their system in a high-risk option.

Both algorithms try to eliminate the scenario related to line-20 contingency, which is the most severe from the voltage stability problem [28]. From the computation speed aspect, it can be inferred that the proposed method is consistently longer than Trad as shown in Table IV. However, both of them still acceptable for the practical use.

C. Performance in the corrective scheme

Looking closer to larger scenarios, which both of them still result in a violated scenario after PC stage, the system stability and security is evaluated using the tools presented in the previous section. The comparison between Trad and Prop2 described in Fig 8**Error! Reference source not found.** and Fig 9**Error! Reference source not found.**. Those figures describe the severity of voltage stability performance for the violated scenarios, in which the voltage stability is dramatically decreased after the contingencies. Normal indicates the non-contingency and VRE as a predicted scenario. N-1 indicates one of the contingency scenario (in this case line-20 contingency), and N-1x indicates the operation point after the CC (load shedding).

TABLE III
LARGER CASE SIMULATION RESULT

Method	Number of Violated Scenario in PC	PCCost (unit cost)	PC+CC cost (unit cost)
Trad	18	15487	18481
Prop2	18	15965	17176

TABLE IV
REQUIRED COMPUTATION TIME FOR LARGER CASE

Method	Covered line Contingency in PC	Comp time (second)
Trad	All except 20	234
Prop2	All except 20	858

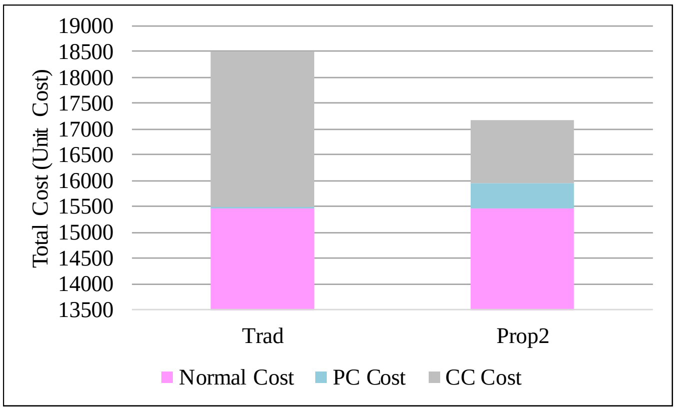

Fig 7 Cost allocation for larger scenario

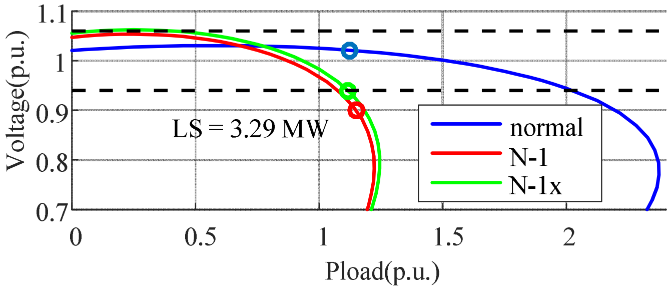

Fig 8 Corrective scheme in the Trad

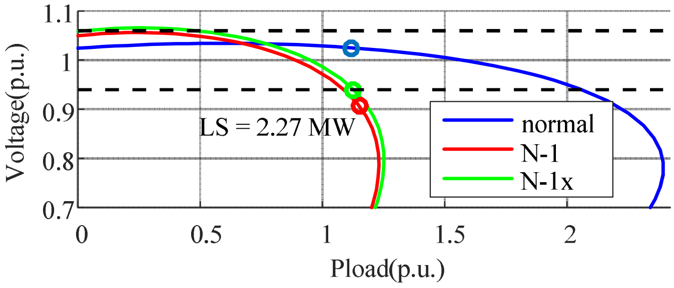

Fig 9 Corrective scheme in the Prop2

N-1x indicates the safe operation point after CC. Both of the control strategies having the potential violated scenarios can secure the operating point after CC. From those figures, it can be inferred that distance to the safe operation (lie between the dash lines) for the proposed method is closer than Trad. It is shown that the required amount of load shedding is smaller than Trad (2.27 MW compare to 3.39 MW). Therefore, the proposed method warrant a more economical operating point.

One more advantage that the proposed method has is for every numerical method there is always a feasible solution, which the global optimum is confirmed even the considered scenario is very large. The existing methods presented in the previous section did not guarantee the feasible solution for the very large scenario.

IV. Conclusions

Extending the HCOPF into the proposed method gives us more flexibility which can summarize as follow: Controlling the generation cost is possible for obtaining more economical operating point which showing the proposed method can optimize the management between PC and CC stages. Any larger problem can be feasible since the computation burden in PC stage can be controlled, then shift to the CC stages even if the risk cost will be very high. Even if the computation time is quite increasing, the computation time is still feasible for the control and operation purposes.

Nomenclature

Sets

i index for generators.
j, m ithe ndex for buses.
n index for buses with reaca tive power compensator.
r index for VRE scenario.
k index for line contingency scenario.
NG number of generators.
NB number of buses.
NRE number of injected VRE buses
NS number of VRE scenarios.
NK number of considered line contingency scenarios.
NT number of total scenarios (VRE and contingency)
NL number of buses which are available to curtail.

Variables

F_T generation cost ($PCCost$).
FL_{r-k}^{vio} corrective cost ($CCCost$).
A_r^{RE} occurrence probability of VRE scenario.
a, b and c are generator cost coeficient.
P_{GOir} generator active power dispatch.
Q_{GOir} generator reactive power.
P_{GOib} generator active power without affected by VRE.
P_{GREVi} generator reserve power.
α_i generator power reduction coefficient.
$VSI_{svb\,r}^k$ voltage stability index (VSI) of the most severe bus.
P'_{Dj} active power demand.
$P_{j\,r}^{RE}$ VRE's power.
P_{LSmr}^k load curtailment amount for load shedding (LS).
Q'_{Dj} reactive power demand.
Tap_n reactive power compensator tap position.
Q_{Nnr}^k reactive power of reactive compensator.
Q_{Nn}^{base} reactive power of each tap unit.
P_{Djr} net active power.
Q_{Djr}^k net reactive power.
G_{jm}^k line conductance.
B_{jm}^k line susceptance.
θ_{jmr}^k voltage angle difference.
S_{jmr}^k line apparent power flow.
A_{r-k}^{vio} Probability of violated scenario

Bounds

S_{maxjm} line loading limit.
$P_{G_{imin}}$ lower bound of generators's active power.
$P_{G_{imax}}$ upper the bound of generators's active power.
$Q_{G_{imin}}$ lower bound of generators's reactive power.
$Q_{G_{imax}}$ upper the bound of generators's reactive power.
$V_{j_{min}}$ lower bound of buses's voltage.
$V_{j_{max}}$ upperthe bound of buses's voltage.
Tap_{nmin} lower bound of reactive power compensator's taps.
Tap_{nmax} upper bthe ound of reactive power compensator's taps.

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This research topic is strategic for supporting the renewable energy integration into the national grid, which the integration level is 23% in 2025 as mention in National Energy Policy.

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