Decentralized robust dispatch for multi-area AC/DC system considering wind power uncertainty

Gang Du1 | Dongmei Zhao1 | Xin Liu2 | Zhiqiang Wu2 | Chao Li2

1 School of Electrical and Electronic Engineering, North China Electric Power University, Beijing, China
2 State Grid Jilin Electric Power Co., Ltd., Changchun, China

Abstract
This paper proposes a decentralized robust dispatch method for multi-area AC/DC system considering wind power uncertainty. The accommodated wind power interval model is adopted to handle the inherent uncertainty and volatility of wind generation, which is modelled based on the affinely adjustable robust optimization method. The accommodated wind power interval and the automatic generation control participation factors are optimized simultaneously to accommodate more wind energy and ensure operational reliability of the entire multi-area system. The flexible adjustment model of HVDC converter station is also presented to accommodate more wind power. Then, the resulting economic dispatch model for multi-area system is solved in a fully decentralized and parallel manner using accelerated alternating direction method of multipliers algorithm to preserve the information privacy and dispatch independence of each region. Case studies illustrate the effectiveness of the proposed model.

1 | INTRODUCTION

Due to the low carbon emissions and costs, renewable energy, for example, wind power generation, has grown rapidly over the past decade. However, the output uncertainty of renewable energy generation brings challenges to the safe operation of modern power systems. Meanwhile, the large-scale wind power integration in remote areas has led to high requirement for long distance power transmission [1]. Transmission through high voltage direct current (HVDC) links has become a new preferable option, which lead to less power losses over long distance power transmission. Meanwhile, the HVDC converters can increase the controllability of modern power systems [2]. Nowadays, more and more HVDC projects are established to transfer large-scale renewable energies to load centre. This trend brings a greater necessity to research the economic dispatch (ED) problem of multi-area AC/DC system with large-scale renewable energy integration.

A common condition for multi-area AD/DC system is that several AC regional subsystems are connected by HVDC tie-linelines or high voltage alternating current (HVAC) tie-lines, for example, the high-voltage long distance power transmission system in Western China. In [3], a unified power flow calculation algorithm for AC/DC hybrid system based on the grid partitioning is presented. In [4], a flexible regulation model for the multi-terminal flexible direct current (MTDC) grid is proposed to promote wind power accommodation, and the distributed optimization is adopted to achieve the operation independently of regional dispatch entities. In [5], the HVDC tie-line adjustment capacity and reserve sharing are optimized with regional generators to deal with the large-scale wind power uncertainty. In [6], the potential flexibility by controlling the HVDC power flow in AC/DC hybrid system to deal with large-scale renewable energy uncertainty is exploited. In short, the HVDC power transmission in AC/DC hybrid system has an increasing importance in accommodating large-scale renewable energy and is worthy of in-depth research.

If the ED problem of multi-area AC/DC system is solved by a centralized manner, all the generation information and network topology need to be sent to the single super central entity. However, complete information of regional grids may not be available and the information privacy and dispatch independence cannot be ensured. Moreover, the multi-area AC/DC system can be seen as several AC grids divided by the HVDC or HVAC links. This structure makes it preferable to address the ED problem in a decentralized manner. Generally, decentralized algorithms can be classified into three types: (1) the
Lagrangian relaxation-based approaches such as the analytical target cascading (ATC), alternating direction method of multipliers (ADMM) and auxiliary problem principle (APP); (2) the Karush–Kuhn–Tucker conditions-based approaches such as the heterogeneous decomposition (HD) algorithm and the optimality condition decomposition (OCD) algorithm; and (3) the benders decomposition (BD) algorithm. In [4, 7], the ATC algorithm is, respectively, applied to security-constrained unit commitment problem for multi-area large-scale power systems and MTDC systems. In [8], the ADMM algorithm is used to reformulate the centralized model into a distributed model for each conventional generator and wind farm in a single area dispatch problem. In [9], the APP algorithm is applied to multi-area optimal power flow (OPF) problem. In [10], the HD algorithm is applied to the coordinated operation for integrated transmission-distribution systems. In [11], the OCD algorithm is adopted to solve the decentralized DC-OPF problem. In [12], the BD algorithm is applied to the decentralized reactive power optimization for integrated transmission-distribution systems.

Besides, as a primal decomposition method, the critical region exploration algorithm is recently proposed in [13, 14] based on the marginal equivalent decomposition method[15]. As an augmented Lagrangian relaxation method, ADMM has shown its superiority in its convergence property. To enhance the cost-effectiveness of interconnected power systems, ADMM has been adopted in multi-area ED [16] and unit commitment [17], multi-area power flow [18], and AC/DC distribution system operation [19] problems.

To overcome the output uncertainty of renewable energy generation, stochastic optimization (SO) and robust optimization (RO) are two main approaches. However, SO approach characterizes the uncertainty parameters by multiple stochastic scenarios based on the probabilistic information, whose solution accuracy critically depends on the number of scenarios. However, the probabilistic information is hard to acquire in reality. RO approach applies the uncertainty set to describe uncertainties, which seeks for the optimal solutions for the worst-case scenario. In RO approach, the uncertainty model can be transformed into a two-stage problem, then solved by decomposition algorithms [20, 21]. However, when applied to decentralized ADMM optimization, the calculation burden will be enlarged as the inner master–subproblem iteration of the decomposition algorithm for RO is needed in each outer ADMM iteration. Unlike to the above two-stage RO approach, the affinely adjustable robust optimization (AARO) model can provide a slightly conservative, yet single tractable solution to the adjustable robust formulation. In [22], the do-not-exceed (DNE) limits model is introduced to maximize the renewable generation ranges that can be accommodated without sacrificing system reliability. Then, the affine policy with fixed automatic generation control (AGC) participation factor (PF) approach and the affine policy with optimal PFs approach are proposed. However, the former approach is rather conservative (because the PFs are predefined) and the latter approach is a non-convex bilinear problem. In [23–25], the AARO-based OPF problems are proposed. In [26], the robust UC for integrated electricity and thermal systems to improve the admissible region of renewable energy is proposed. For the AARO model, one key issue is to determine a proper uncertainty set for uncertainty parameters, otherwise, the obtained solution may be conservative.

Here, a decentralized adjustable robust dispatch model for the multi-area AC/DC system considering large-scale wind power uncertainty is proposed. To fully explore the potential of AGC systems in dealing with uncertainties, the AARO-based accommodated wind power interval model coincident with the AGC systems is proposed. To take full advantage of the flexible adjustment ability of HVDC converter in AC/DC system, the HVDC tie-line power is optimized together with regional generators. Then, to reduce communication burden and enhance information privacy, a fully decentralized structure based on accelerated ADMM algorithm is proposed. The main contributions of this paper are as follows:

1) Based on the AARO, the accommodated wind power interval is modelled to handle large-scale wind power uncertainty. Then, the accommodated wind power interval and the AGC participation factors are optimized simultaneously to accommodate more wind power and ensure the operational reliability of the entire system.

2) The flexible adjustment model of HVDC converter in multi-area AC/DC system is proposed. In this way, the HVDC tie-line power can be jointly optimized together with regional generating units to promote wind power accommodation.

3) A fully decentralized and parallel scheme based on the accelerated ADMM algorithm is proposed to improve the convergence speed. Only limited information on HVDC converters is exchanged among adjacent regional grids, which can preserve information privacy and area dispatch independence. Besides, the robust counterpart of the regional AARO-based accommodated wind power interval model is a single tractable problem, which can reduce the computation burden of each ADMM iteration.

This paper is organized as follows. Section 2 presents the multi-area AC/DC system. Section 3 addresses the AARO-based accommodated wind power interval model. Section 4 proposes the separable formulation of ED problem for multi-area AC/DC system. Section 5 proposes the decentralized solution procedure. Section 6 presents case studies. Section 7 concludes this paper.

2 | MULTI-AREA AC/DC HYBRID SYSTEM

Here, we first introduce the topology of the multi-area bulk AC/DC system, then the HVDC converter operation model is
addressed to achieve jointly optimization with regional generating units.

### 2.1 Topology of bulk AC/DC hybrid system

Figure 1 shows the topology of the multi-area AC/DC system where two receiving-side AC grids are connected to one sending-side AC grid through two HVDC tie-lines, respectively. In this way, the large-scale renewable energy generation is transmitted to the receiving-side AC grids via HVDC tie-lines. In practice, this type of multi-area AC/DC system allows to design a decentralized decision-making scheme, in which each regional dispatch entity is operated locally while cooperating with its neighbours by sharing a limited set of data. As a result, proprietary data, for example, operation states and topological information, can be kept confidential in each regional grid.

### 2.2 Linear power flow model for HVDC line

Similar to the commonly used DC power flow model in AC system, a linear power flow approximation for the HVDC lines or the HVDC grids is presented in [27], which provides a trade-off between the solution accuracy and calculation complexity. The quadratic power flow model for HVDC line is as follows:

$$PC_{mt} = U_{mt} (U_{mt} - U_{nt}) / r_{mn},$$  \hspace{1cm} (1)

Assuming that the voltages of the DC buses are very close to the nominal voltage, defined as 1 p.u., the linear power flow approximation for the HVDC lines in multi-area AC/DC system can be described as

$$PC_{mt} = \frac{U_{nt} - U_{nt} - U_{ref}}{r_{mn}},$$  \hspace{1cm} (2a)

$$U_{nt} = U_{nt} - U_{ref},$$  \hspace{1cm} (2b)

where $r_{mn}$ denotes the DC line resistance between converters $m$ and $n$, $U_{mt}$ denotes the voltage magnitude of converter $m$ at time $t$, $U_{nt}$ denotes the voltage magnitude difference between converter $m$ and reference bus at time $t$, $U_{ref}$ denotes the reference voltage.

### 2.3 HVDC converter operation model

Here, the operating characteristics of HVDC converters are represented by the pseudo-generators added to the boundary buses [4]. Then, the HVDC transmission power is jointly optimized with the regional generating units. The HVDC converter operation model in multi-area AC/DC hybrid system is established as follows:

$$P_{+}^{C} \leq P_{mt} \leq P_{-}^{C},$$  \hspace{1cm} (3a)

$$\sum_{t \in T} P_{mt} = E_{Cm}^{C},$$  \hspace{1cm} (3b)

$$|P_{mt}^{C} - P_{mt}^{C}+1| \leq \left( \eta_{mt}^{+} + \eta_{mt}^{-} \right) R_{mn}^{+},$$  \hspace{1cm} (3c)

$$|P_{mt}^{C} - P_{mt}^{C}+1| \geq \left( \eta_{mt}^{+} + \eta_{mt}^{-} \right) R_{mn}^{-},$$  \hspace{1cm} (3d)

$$\left( \eta_{mt}^{+} + \eta_{mt}^{-} \right) \leq 1,$$  \hspace{1cm} (3e)

$$\left( \eta_{mt}^{+} + \eta_{mt}^{-} - 1 \right) \leq 1,$$  \hspace{1cm} (3f)

$$\left( \eta_{mt+1}^{+} + \eta_{mt}^{-} \right) \leq 1,$$  \hspace{1cm} (3g)

$$\sum_{t \in T} \left( \eta_{mt}^{+} + \eta_{mt}^{-} \right) \leq K,$$  \hspace{1cm} (3h)

$$P_{mt}^{C} - P_{mt+1}^{C} \leq M^{+} \eta_{mt+1}^{+} - 1,$$  \hspace{1cm} (3i)

$$P_{mt}^{C} - P_{mt+1}^{C} \leq M^{-} \eta_{mt+1}^{-} - 1,$$  \hspace{1cm} (3j)

$$\mu^{+}_{mt} = \min \left( \{T \mid t+\delta \} \right) \mu^{+}_{mt},$$  \hspace{1cm} (3k)

$$\mu^{+}_{mt} \geq \eta_{mt+1}^{+} + \eta_{mt}^{-} - \eta_{mt}^{+} - \eta_{mt}^{-},$$  \hspace{1cm} (3l)

$$\mu^{-}_{mt} \geq \eta_{mt}^{+} + \eta_{mt}^{-} - \eta_{mt+1}^{+} - \eta_{mt+1}^{-},$$  \hspace{1cm} (3m)

$$\forall m \in N^{C}, \forall a \in R, \forall t \in T.$$

Equation (3a) denotes the lower and upper power limit of HVDC converters. Equation (3b) denotes the total transmission energy of HVDC tie-line during the entire dispatching periods. Equations (3c) and (3d) denote the power adjustment rate limit of HVDC converters. Equations (3e)–(3g) denote the power adjustment direction limit, which can ensure that the HVDC
transmission power cannot be reversed during adjacent periods. Equation (3h) limits the number of power adjustments to the HVDC converter to ensure its reliable operation. Equations (3) and (3i) denote the relationship of transmission power and power adjustment direction for HBDV converters. Equations (3k)–(3m) denote the stepwise operating limit of HVDC converters.

3 | AARO-BASED ACCOMMODATED WIND POWER INTERVAL MODEL

This section proposes the AARO-based accommodated wind power interval model for multi-area AC/DC system.

The wind output interval is treated as the decision variables here, that is, the accommodated wind power interval is uncertain. By optimizing the upper limit of the accommodated wind power interval, the goal of minimizing wind power curtailment in the entire system is achieved. Meanwhile, the PFs of AGC units are also regarded as the decision variables here to realize the optimal allocation of uncertain wind power among AGC units. By introducing auxiliary decision variables \( \omega_i \), the accommodated wind power \( w_{kt} \) can be represented as:

\[
w_{kt} = w_{kt}^{LB} + \omega_i \Delta w_{kt}, \quad k \in N_a^W, \quad a \in R, \quad i \in T,
\]

where the wind forecasting error \( \Delta w_{kt} \in [w_{kt}^{LB} - \bar{w}_{kt}, 0] \). Thus, the relationship of the upper and lower limit of accommodated wind power interval can be described as

\[
w_{kt}^{LB} = w_{kt}^{LB} - \omega_i \left( \bar{w}_{kt} - \bar{w}_{kt} \right), \quad k \in N_a^W, \quad a \in R, \quad i \in T.
\]

Thus, the accommodated wind power interval model is given by

\[
0 \leq w_{kt}^{LB} \leq \bar{w}_{kt}, \quad 0 \leq w_{kt}^{LB} - \omega_i \left( \bar{w}_{kt} - \bar{w}_{kt} \right) \leq \bar{w}_{kt}, \quad 0 \leq \omega_i, \quad \forall k \in N_a^W, \quad \forall a \in R, \quad \forall t \in T.
\]

Based on the AARO, the PFs of AGC units and the accommodated wind power interval are optimized simultaneously to accommodate more wind power and ensure the operational reliability of the entire system. The actual output of AGC units can be denoted as the non-adjustable term that denotes the reference base-point output and the adjustable term that responds to the uncertain wind power forecasting error as follows:

\[
\tilde{p}_g^G = p_g^G - \alpha_i \omega_i \sum_{k \in N_a^W} \Delta w_{kt}, \quad 0 \leq \alpha_i \leq 1,
\]

\[
\sum_{k \in N_a^G} \alpha_i = 1,
\]

\[
\forall i \in N_a^G, \forall a \in R, \forall t \in T.
\]

However, the bilinear term \( \alpha_i \omega_i \) in (7a) is a non-convex term, which is hard to solve. Here, we introduce new affinely variable \( \beta_i \) and let \( \beta_i = \alpha_i \omega_i \), then (7) can be equivalently expressed as:

\[
\tilde{p}_g^G = p_g^G - \beta_i \sum_{k \in N_a^W} \Delta w_{kt},
\]

\[
0 \leq \beta_i \leq \bar{w}_{kt} / \left( \bar{w}_{kt} - \bar{w}_{kt} \right),
\]

\[
\sum_{k \in N_a^G} \beta_i = \omega_i, \quad \forall i \in N_a^G, \forall a \in R, \forall t \in T.
\]

After the above equivalent expression, the bilinear term in accommodated wind power interval model is eliminated to avoid the non-convex optimization in [22].

4 | SEPARABLE FORMULATION OF ED PROBLEM FOR MULTI-AREA AC/DC SYSTEM

This section first proposes the ED problem for single region. Then, the affinely adjustable robust counterpart (AARC) of regional ED problem is addressed.

4.1 | Regional ED problem

The regional ED problem aims for the minimum generating cost of units and the penalty cost of wind power curtailment, while ensuring the safe operation of regional grid. Taking region \( a \) as an example, the regional ED problem is denoted as:

\[
\min_{P_g} \sum_{k \in T} \sum_{a \in N_a^G, a \in N_a^N} \left[ a_i (p_g^G)^2 + b_i p_g^G + c_i \right] + \sum_{k \in N_a^W} c^W \left( \bar{w}_{kt} - \bar{w}_{kt}^L \right)^2 + \left( \bar{w}_{kt} - \bar{w}_{kt}^U \right)^2, \quad (9a)
\]
s.t.  \[
\sum_{j \in \mathcal{N}_G^+} p_{j}^G + \sum_{k \in \mathcal{N}_W^D} w_{k,j}^B \]
\[- \sum_{j \in \mathcal{N}_G^-} p_{j}^G = \sum_{d \in \mathcal{D}_D} p_{d}^D, \quad t \in \mathcal{T}, \quad (9b)\]
\[0 \leq r_{i}^{U} \leq R_{i}^{U}, \quad i \in \mathcal{N}_G^G \cup \mathcal{N}_W^NG, \quad t \in \mathcal{T}, \quad (9c)\]
\[0 \leq r_{i}^{D} \leq R_{i}^{D}, \quad i \in \mathcal{N}_G^G \cup \mathcal{N}_W^NG, \quad t \in \mathcal{T}, \quad (9d)\]
\[p_{i}^G \leq p_{i}^G - p_{i}^D, \quad i \in \mathcal{N}_G^G \cup \mathcal{N}_W^NG, \quad t \in \mathcal{T}, \quad (9e)\]
\[p_{i}^G + p_{i}^D \leq \bar{P}_i, \quad i \in \mathcal{N}_G^G \cup \mathcal{N}_W^NG, \quad t \in \mathcal{T}, \quad (9f)\]
\[- R_{i}^{D} \leq p_{i}^G - p_{i}^{G-1} \leq R_{i}^{U}, \quad i \in \mathcal{N}_W^NG, \quad t \in \mathcal{T}, \quad (9g)\]
\[- R_{i}^{D} \leq p_{i}^G - p_{i}^{G-1} - \beta_d \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j}, \quad (9h)\]
\[+ \beta_{d-1} \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j} \leq R_{i}^{U}, \quad i \in \mathcal{N}_G^G, \quad t \in \mathcal{T}, \quad (9i)\]
\[P_{i}^G \leq \bar{P}_i - \beta_d \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j}, \quad (9j)\]
\[- r_{i}^{D} \leq - \beta_d \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j} \leq R_{i}^{U}, \quad i \in \mathcal{N}_G^G, \quad t \in \mathcal{T}, \quad (9k)\]

Objective function (9a) minimizes the regional generating costs and the penalty costs for the deviation of accommodated wind power interval from the forecasted interval. Note that objective function (9a) is denoted as \(c_G^a\) in Section 5 for simplicity. Equation (9b) denotes the power balance constraint. Equations (9c) and (9d) denote the reserve capacity limits of AGC and non-AGC units. Equations (9e) and (9f) denote the output limits of AGC and non-AGC units. Equations (9g) and (9h) denote the ramp up/down limits of non-AGC and AGC units, respectively. Equation (9i) ensures the real-time adjustments to AGC unit outputs obey the chosen reserve capacities. Equation (9j) denotes the internal line transmission capacity limits. Equation (9k) denotes the accommodated wind power interval limits and the HVDC converter operation limits.

### 4.2 Affinely adjustable robust counterpart of regional ED problem

The constraints of the AARC formulation are established in this subsection. In this way, the regional ED problem remains feasible for all outputs in the accommodated wind power interval. The AARC of the reserve capacity limits can ensure that the affine control decision can keep the AGC units’ outputs within their output limits even for the worst-case wind power scenario.

Thus, the reserve capacity limit (9j) is equal to:

\[
\max_{\Delta w_{k,j}} \left( - \beta_d \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j} \right) \leq r_{i}^{U}, \quad (10a)\]

\[
\max_{\Delta w_{k,j}} \left( \beta_d \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j} \right) \leq r_{i}^{D}, \quad (10b)\]

\[\forall i \in \mathcal{N}_G^G, \forall a \in \mathcal{R}_a, \forall t \in \mathcal{T}.\]

Since the worst-case wind power scenario must be the one in which the wind power equals to its upper bound or lower bound, the AARC form of (10) is as follows:

\[
\beta_d \sum_{k \in \mathcal{N}_W^D} \left( w_{k,j} - \bar{w}_{k,j} \right) \leq r_{i}^{U}, \quad (11a)\]

\[r_{i}^{D} \geq 0, \quad (11b)\]

\[\forall i \in \mathcal{N}_G^G, \forall a \in \mathcal{R}_a, \forall t \in \mathcal{T}.\]

Similarly, the AARC form of ramp up/down limits (9j) is as follows:

\[
p_{i}^G - p_{i}^{G-1} + \beta_d \sum_{k \in \mathcal{N}_W^D} \left( w_{k,j} - \bar{w}_{k,j} \right) \leq R_{i}^{U}, \quad (12a)\]

\[
p_{i}^G - p_{i}^{G-1} + \beta_d \sum_{k \in \mathcal{N}_W^D} \left( w_{k,j} - \bar{w}_{k,j} \right) \leq R_{i}^{D}, \quad (12b)\]

\[\forall i \in \mathcal{N}_G^G, \forall a \in \mathcal{R}_a, \forall t \in \mathcal{T}.\]

The internal transmission line flow limits (9j) are equal to:

\[
\max_{\Delta w_{k,j}} \left( \sum_{k \in \mathcal{N}_W^D} H_{ik} w_{k,j} - \sum_{i \in \mathcal{N}_G^G} H_{ij} \beta_d \sum_{k \in \mathcal{N}_W^D} \Delta w_{k,j} \right) \leq \left( \begin{array}{c}
F_i - \sum_{k \in \mathcal{N}_W^D} H_{ik} w_{k,j}^B + \sum_{d \in \mathcal{D}_D} H_{id}^D p_{d}^D \\
+ \sum_{m \in \mathcal{N}_F^C} H_{im}^C - \sum_{j \in \mathcal{N}_G^G} H_{ij} \beta_d - \sum_{j \in \mathcal{N}_G^G} H_{ij}^G p_{j}^G
\end{array} \right), \quad (13a)\]
Consensus-based ADMM

In order to guarantee the agreement on HVDC tie-line power between regional grids, it is necessary to ensure the output power from sending-side grid be equal to the input power to receiving-side grid while implementing decentralized optimization. Note that HVDC converter can directly take the transmission power as its control variable, that is, the transferred power can be regarded as the coupling variable. Hence, the following regional coupling constraint (15) can be established.

\[ P_{mt}^{C} = P_{mt}^{C}, \quad m \in N_{a}^{C}, n \in N_{b}^{C}, \quad a, b \in \mathcal{R}, \quad t \in T. \]

The ED problem for each regional grid is an independent decision-making process. Only HVDC converters’ information is shared between neighbouring grids to ensure consistency in operating. Therefore, the entire ED problem for multi-area AC/DC system can be solved in a fully decentralized way, which can preserve the information privacy and the independent decision of regional system operators.

5 | DECENTRALIZED SOLUTION PROCEDURE

In this section, we first tailor the consensus-based ADMM algorithm to the decentralized ED problem for multi-area bulk AC/DC hybrid system, then the accelerated ADMM algorithm is proposed.

5.1 | Consensus-based ADMM

The key of applying consensus-based ADMM to solve the multi-area ED problem for AC/DC system in a fully decentralized manner is to achieve consensus between neighboring regions with respect to region coupling. To this end, we introduce consensus variables \( P_{mt}^{C} \) and the following affine equality constraints

\[ P_{mt}^{C} - P_{mt}^{C} = 0 \quad | \lambda_{mt}, \]

\[ P_{mt}^{C} - P_{mt}^{C} = 0 \quad | \lambda_{mt}, \]

After the above AARC transformation, the regional adjustable robust ED problem can be solved efficiently by commercial solvers.

4.3 | Coupling of regional grids

In order to guarantee the agreement on HVDC tie-line power between regional grids, it is necessary to ensure the
Algorithm 1 Consensus-based ADMM

Initialization:
Initialize $P_{mt}^C(0)$ and $\lambda_{mt}(0)$ for all $m \in N_a^C, n \in N_b^C, a \in R, t \in T$.

Repeat:
1. Each region $a \in R$ solve (17) in parallel

\[
C_a + \min \sum_{t \in T} \sum_{m \in N_a^C, n \in N_b^C} \left[ \lambda_{mt} \left( P_{mt}^C(t) - P_{mt}^C \right) + \frac{\rho}{2} \left\| P_{mt}^C(t) - P_{mt}^C \right\|^2 \right]
\]

subject to (9b) - (9g), (9k), (11), (12), (14)

2. Then send solutions $P_{mt}^C(t+1)$ and $P_{mt}^C(t+1)$ to its neighbors.
3. Update $P_{mt}^C(t+1)$, $\lambda_{mt}(t+1)$ and $\lambda_{mt}(t+1)$ in each region.

\[
P_{mt}^C(t+1) = \frac{P_{mt}^C(t+1) + P_{mt}^C(t+1) - \lambda_{mt}(t) + \lambda_{mt}(t)}{2}
\]

\[
\lambda_{mt}(t+1) = \lambda_{mt}(t) + \rho \left( P_{mt}^C(t+1) - P_{mt}^C(t+1) \right)
\]

\[
\lambda_{mt}(t+1) = \lambda_{mt}(t) + \rho \left( P_{mt}^C(t+1) - P_{mt}^C(t+1) \right)
\]

Check stopping criterion:
Calculate the primal and dual residual in each region

\[
p_{mt}(t+1) = \left\| P_{mt}^C(t+1) - P_{mt}^C(t+1) \right\| \leq \epsilon_1
\]

\[
d_{mt}(t+1) = \left\| P_{mt}^C(t+1) - P_{mt}^C(t) \right\| \leq \epsilon_2
\]

If stopping criteria (19) is satisfied in all regions, the algorithm stops. Otherwise, go to Repeat step.

Algorithm 2 Accelerated ADMM

Initialization:
Initialize $P_{mt}^C(0)$ and $\lambda_{mt}(0)$ for all $m \in N_a^C, n \in N_b^C, a \in R, t \in T$.

Repeat:
1. Each region $a \in R$ solve (17) in parallel and send solutions $P_{mt}^C(t+1)$ and $P_{mt}^C(t+1)$ to its neighbors.
2. Update $P_{mt}^C(t+1)$, $\lambda_{mt}(t+1)$ and $\lambda_{mt}(t+1)$ in each region using (18).

Check stopping criterion:
Calculate the primal and dual residual in each region using (19). If satisfied, the algorithm stops. Otherwise, update $P_{mt}^C(t+1)$, $\lambda_{mt}(t+1)$ and $\lambda_{mt}(t+1)$ in each region using (20). Then go to Repeat step.

5.2 Accelerated ADMM

The accelerated ADMM is recently proposed in [28] based on the work in [29], which introduces a general form for accelerating gradient decent algorithms. In accelerated ADMM algorithm, extra steps (20) are added in standard ADMM for updating coupling variables and dual variables. Algorithm 2 outlines the accelerated ADMM algorithm for decentralized ED problem of multi-area bulk AC/DC hybrid system.

6 Numerical Results

Case studies are carried out on a 2-area 12-bus AC/DC hybrid system and a 3-area 275-bus AC/DC hybrid system. All cases are solved by MATLAB R2019a on a single computer with 8 quad-core processors, 3.2 GHz and 8 GB of RAM, using Gurobi 8.0. Each regional subproblems are solved in parallel.

6.1 Two-area 12-bus AC/DC system

In Case 1, two 6-bus systems [30] are linked with one HVDC tie-line located at bus 5 of region $a$ to bus 5 of region $b$. Buses 2 and 4 of region $a$ are installed with two wind farms (named as wind farms 1 and 2) with 68.9% wind power penetration ratio. The wind power curtailment cost is 10$/MW$. The three units of region $a$ are all considered as AGC units (named as units 1, 2 and 3). For HVDC converters, the power adjustment rate is [20, 80] MW/h, the lower/upper power limit is [50, 150] MW, the allowable number of power adjustments is 6, the minimum duration time is 2 h, the planned electrical energy transmission is 1500 MW h. The optimization horizon is 24 h and the time resolution is 1 h, which is the same as the following Case 2. The load, wind output interval, grid topology data, and other detailed parameters have been made available online [31]. For ADMM algorithm, the convergence threshold is set at 0.001, the initial values of coupling variables are all set at zero, the multiplier $\rho = 1$.

6.1.1 Accommodated wind power interval

The wind power interval that can be accommodated by the entire system using the proposed AARO-based accommodated wind power interval model is shown in Figure 3. Since the load demand in periods 1 to 8 and periods 23 to 24 is relatively low, the entire system cannot accommodate the wind power in the predicted output interval, leading to wind power curtailment. In the remaining periods, with the load demand increasing, the accommodated wind power interval enlarges. By simultaneously optimizing the accommodated wind power interval and the AGC participation factors, more wind power will be accommodated and the operational reliability of the entire system is ensured.
### 6.1.2 Convergence performance

The proposed accelerated ADMM-based decentralized dispatch approach is compared with the traditional centralized approach. Taking hour 4, 8, 12, and 20 as examples, the primal residue and dual residue optimized by the accelerated ADMM algorithm for Case 1 are depicted in Figure 4. We can see that the accelerated ADMM algorithm converges after 54 iterations with the maximum primal and dual residue smaller than the predefined convergence threshold.

The HVDC transmission power, the comparison with predefined PFs method, and the comparison of decentralized and centralized approach in Case 1 are summarized together with Case 2 in the following subsection.

### 6.2 Three-area 275-bus AC/DC system

In Case 2, one IEEE 39-bus (region $a$) and two IEEE 118-bus system (regions $b$ and $c$) are linked, where one HVDC tie-line connects bus 1 of region $a$ to bus 25 of region $b$ and one HVDC tie-line connects bus 19 of region $a$ to bus 65 of region $c$. Buses 1, 8, 16, and 22 of region $a$ are installed with four wind farms (named as wind farms 1–4) with 67.7% wind power penetration ratio. The wind power curtailment cost is also 10$/MW$. The five units located at buses 30–34 of region $a$ (named as units 1–5) are considered as AGC units. For HVDC converters, the power adjustment rates of tie-lines $ab$ and $ac$ are $[200, 600]$ and $[300, 900]$ MW/h, respectively, the lower/upper power limits of tie-lines $ab$ and $ac$ are $[500, 1500]$ MW and $[500, 2000]$ MW/h, respectively, the allowable number of power adjustments for both tie-lines is 6, the minimum duration time for both tie-lines is 2 h, the planned electrical energy transmission of tie-lines $ab$ and $ac$ is 28 and 30 GWh, respectively. Other detailed parameters have also been made available online [31]. For ADMM algorithm, the convergence threshold is set at 0.001, the initial values of coupling variables are all set at zero, the multiplier $\rho = 0.5$.

#### 6.2.1 Accommodated wind power interval

The wind power interval in Case 2 that can be accommodated by the entire system using the proposed AARO-based accommodated wind power interval model is shown in Figure 5. In Case 2, since the load demand in periods 1 to 9 and periods
18 to 24 is relatively low, the entire system cannot accommodate the wind power in the predicted output interval, leading to wind power curtailment. In the remaining periods, with the load demand increasing, the accommodated wind power interval enlarges.

6.2.2 Convergence performance

The proposed accelerated ADMM-based decentralized dispatch approach is also compared with the traditional centralized approach in Case 2. Taking hour 4, 12, 16, and 20 as examples, the primal residue and dual residue of accelerated ADMM algorithm for Case 2 are depicted in Figure 6. We can see that the decentralized solution converges after 49 iterations with the maximum primal and dual residue smaller than the convergence threshold.

6.2.3 HVDC transmission power

The HVDC transmission power in Cases 1 and 2 optimized by the proposed HVDC converter flexible adjustable model is shown in Figure 7. Taking Case 2 as an example, since the HVDC power is jointly optimized with the units in each regional grids, the HVDC transmission power is in accordance with the wind power variability in region a and the high load demand in regions b and c. As the potential wind power in region a increases in periods 6 through 9, the HVDC transmission power also rises, causing more power to transfer from region a to regions b and c. From periods 17 to 23, the HVDC transmission power also increases. In this way, more power will be transferred to regions b and c to support their higher load demand. It shows that the proposed HVDC converter flexible adjustable model can adjust the HVDC transmissions to adapt the wind power variations. As a result, the wind power accommodation can be promoted to make the multi-area AC/DC system operate more flexibly and cost-effectively.

6.2.4 Comparison with predefined PFs method

The traditional PFs of AGC units are generally predefined according to their unit capacity [32]. This paper treats the PFs of AGC units as decision variables. To verify the effect of optimizing the PFs, the generation cost is compared with the predefined PFs method, shown in Table 1. We can see that optimizing PFs can reduce the generation cost by 4.7% of Case 1 and 2.2% of Case 2, respectively. This is because different PFs correspond to different allocations of wind power among AGC units. If the decision-maker adopts the predefined PFs method, a larger PF will be allocated to the unit which has larger generation capacity. Then its allocated wind power will be also large. However, the unit cost for providing the reserve of the large-capacity unit is not necessarily low. This unreasonable allocation will increase the total operation cost for the entire system.

The PFs of AGC units optimized by the proposed model for both Cases are shown in Tables A.1 and A.2. Taking Case 1 as an example, since there are accommodated wind power interval (shown in Figure 3) in periods 1–2, 9, and 11–22, the optimized AGC PFs are not equal to 0. Then, the allocated wind power in each AGC unit can be determined according to the optimized PFs.
TABLE 2 Comparison of decentralized and centralized approach

| Cases | Schemes     | Iter. | Generation costs (k$) | Solution gap | Computation time (s) |
|-------|-------------|-------|-----------------------|--------------|----------------------|
| 1     | Centralized | —     | 247.5                 | —           | 1.2                  |
|       | Acc. ADMM   | 54    | 247.5                 | 0           | 4.6                  |
|       | Cons. ADMM  | 76    | 247.5                 | 0           | 7.1                  |
| 2     | Centralized | —     | 7891.2                | —           | 6.8                  |
|       | Acc. ADMM   | 49    | 7898.4                | 0.09%       | 28.7                 |
|       | Cons. ADMM  | 66    | 7895.6                | 0.06%       | 40.7                 |

The PFs correspond to different allocations of imbalanced power among generating units. The intention of involving AGC reference base-points and optimized PFs is to account for how the AGC units would respond to the power mismatch caused by wind power uncertainties, but not to generate signals to control the actual output of AGC units. Reference base-points and the optimized PFs are provided to AGC units for reference only, and the actual power outputs of these units are ultimately determined and controlled by the AGC system to compensate the area control error.

6.2.5 Comparison of consensus ADMM, accelerated ADMM, and centralized approach

The solution of consensus ADMM in Algorithm 1, accelerated ADMM in Algorithm 2, and traditional centralized approach is compared in Table 2. We can see that the solution obtained from the consensus ADMM and the accelerated ADMM nearly coincides with the traditional centralized approach. The solution gap of the two decentralized solutions is fairly small, which indicates the effectiveness and high solution quality of the proposed decentralized dispatch approach for multi-area AC/DC system. The iterations of the consensus ADMM and the accelerated ADMM needed to converge in Case 1 are 54 and 76, respectively. In Case 2, the iterations are, respectively, 49 and 66. The comparison of computation time is also shown in Table 2. We can conclude that the proposed accelerated ADMM-based decentralized algorithm can improve the convergence speed.

Additionally, the required computation time of the two decentralized models is slightly higher than the centralized model. Since only a limited set of information is shared among each region, communication burdens, which usually account for more processing time in practice, are alleviated and information privacy is preserved. With the growth in the scale of multi-area system, the centralized model will become more difficult to deploy as it requires data for all regional grids which generally correspond to different market regulations.

It should also be noted that the traditional centralized approach can be only used for a case in which the multi-area bulk AC/DC hybrid system is operated by a single central super dispatch entity. However, complete information of regional grids may not be available and the information privacy and dispatch independence cannot be ensured. Moreover, the multi-area bulk AC/DC hybrid system can be seen as several subsystems divided by the HVDC links. This proposed decentralized scheme is practically acceptable as they allow regional system operators to operate their respective systems independently, which can preserve the information privacy and dispatch independence of each regional grid.

7 CONCLUSIONS

This paper proposes a decentralized robust dispatch approach for multi-area bulk AC/DC hybrid system with high share of wind power. The AARO-based accommodated wind power interval model is adopted to handle the inherent uncertainty and volatility of wind generation. To take full advantage of the flexible adjustment ability of HVDC converter, the HVDC tie-line power is optimized together with regional generators. Then, to reduce communication burden and enhance information privacy, the resulting economic dispatch problem for multi-area system is solved in a fully decentralized and parallel manner using accelerated ADMM algorithm to preserve the information privacy and dispatch independence of each regional grid.

NOMENCLATURE

\( E_a \) Set of transmission lines in area \( a \)
\( \mathcal{N}_c^a \) Set of converters in area \( a \)
\( \mathcal{N}_d^a \) Set of loads in area \( a \)
\( \mathcal{N}_g^a \) Set of AGC units in area \( a \)
\( \mathcal{N}_w^a \) Set of wind farms in area \( a \)
\( \mathcal{N}_{NG}^a \) Set of non-AGC units in area \( a \)
\( \mathcal{R} \) Set of areas
\( \mathcal{T} \) Set of time periods
\( \tau \) Index of iterations
\( a, b, c \) Index of areas
\( d \) Index of loads
\( i, j \) Index of units
\( k \) Index of wind farms
\( m, n \) Index of converters
\( t \) Index of time periods
\( \Delta w_{kt} \) Wind power forecasting error
\( \delta \) Minimum duration time interval of converters
\( \bar{F}_l \) Capacity of transmission line \( l \)
\( \rho \) Lagrangian multipliers
$$p^c_m / p^c_m$$ Lower/upper output limit of converter $m$
$$w_{kl}^+ / w_{kl}^-$$ Lower/upper limit of predicted wind power interval
$$p_G^i / p_G^i$$ Lower/upper output limit of unit $i$ at time $t$
$$a_i, b_i, c_i$$ Cost coefficients of unit $i$
$$P_{\text{cur}}$$ Penalty cost of wind power curtailment
$$H_{ij}^G, H_{ij}^{GN}, H_{ij}^W, H_{ij}^C$$ Power transfer distribution factors
$$M^+, M^-$$ Big constants
$$r_{\text{up}}^t / r_{\text{up}}^t$$ Upward/downward limit of unit $i$ at time $t$
$$\alpha_i$$ PF of AGC unit $i$ at time $t$
$$\eta_{\text{up}} / \eta_{\text{up}}$$ Binary variables to represent whether converters adjust power upward/downward at time $t$
$$\lambda_{\text{con}}, \lambda_{\text{ad}}$$ Dual variables of ADMM
$$\mu_{\text{con}}, \mu_{\text{ad}}$$ Binary variables to represent whether converters begin/end power adjustment at time $t$
$$\omega_i, \beta_i$$ Auxiliary variables
$$p_{\text{ref}}^i$$ Actual output of AGC unit $i$ at time $t$
$$p_{\text{ref}}^i$$ Reference base-point output of AGC unit $i$ at time $t$
$$p_{\text{cons}}^i$$ Consensus variable
$$p_{\text{cog}}^i$$ Output of converter $m$ at time $t$
$$r_{\text{up}}^t / r_{\text{up}}^t$$ Upward/downward adjustment limit of converter $m$
$$w_{kl}^{i, t} / w_{kl}^{i, t}$$ Lower/upper limit of accommodated wind power interval
$$z_{\text{g}}^+, z_{\text{g}}^-, z_{\text{d}}^+, z_{\text{d}}^-$$ Slack variables

**ORCID**

**Gang Du** https://orcid.org/0000-0001-7586-8021

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### APPENDIX A

#### TABLE A.1  Participation factors of AGC units for Case 1

| Time periods | Unit 1 | Unit 2 | Unit 3 |
|--------------|--------|--------|--------|
| 1            | 0      | 1      | 0      |
| 2            | 0      | 1      | 0      |
| 3            | 0      | 0      | 0      |
| 4            | 0      | 0      | 0      |
| 5            | 0      | 0      | 0      |
| 6            | 0      | 0      | 0      |
| 7            | 0      | 0      | 0      |
| 8            | 0      | 0      | 0      |
| 9            | 0      | 1      | 0      |
| 10           | 0      | 0      | 0      |
| 11           | 0      | 1      | 0      |
| 12           | 0.40   | 0.60   | 0      |
| 13           | 0.40   | 0.60   | 0      |
| 14           | 0      | 1      | 0      |
| 15           | 0.40   | 0.60   | 0      |
| 16           | 0.55   | 0      | 0.45   |
| 17           | 1      | 0      | 0      |
| 18           | 0      | 1      | 0      |
| 19           | 0.40   | 0.60   | 0      |
| 20           | 0      | 1      | 0      |
| 21           | 0.40   | 0.60   | 0      |
| 22           | 0.40   | 0.60   | 0      |
| 23           | 0      | 0      | 0      |
| 24           | 0      | 0      | 0      |

#### TABLE A.2  Participation factors of AGC units for Case 2

| Time periods | Unit 1 | Unit 2 | Unit 3 | Unit 4 | Unit 5 |
|--------------|--------|--------|--------|--------|--------|
| 1            | 0      | 0      | 0      | 0      | 1      |
| 2            | 0      | 0      | 0      | 0      | 0      |
| 3            | 0.55   | 0.32   | 0      | 0      | 0.13   |
| 4            | 0      | 0      | 0      | 0      | 0      |
| 5            | 0      | 0      | 0      | 0      | 0      |
| 6            | 0      | 0      | 0      | 0      | 0      |
| 7            | 0      | 0      | 0      | 0      | 0      |
| 8            | 0      | 0      | 0      | 0      | 0      |
| 9            | 0      | 0      | 0      | 0      | 0      |
| 10           | 0.64   | 0.10   | 0.26   | 0      | 0      |
| 11           | 0.68   | 0.07   | 0.25   | 0      | 0      |
| 12           | 0.83   | 0      | 0.14   | 0      | 0.03   |
| 13           | 1      | 0      | 0      | 0      | 0      |
| 14           | 0.73   | 0.04   | 0.23   | 0      | 0      |
| 15           | 0.16   | 0      | 0.49   | 0      | 0.35   |
| 16           | 0.57   | 0      | 0.33   | 0      | 0.10   |
| 17           | 0.16   | 0      | 0.84   | 0      | 0      |
| 18           | 0.08   | 0.45   | 0.47   | 0      | 0      |
| 19           | 0.29   | 0.27   | 0.34   | 0      | 0.10   |
| 20           | 0.37   | 0      | 0.60   | 0      | 0.03   |
| 21           | 0.73   | 0.04   | 0.23   | 0      | 0      |
| 22           | 0.63   | 0      | 0.37   | 0      | 0      |
| 23           | 0      | 0      | 0      | 0      | 0      |
| 24           | 0      | 0      | 0      | 0      | 0      |