Distributed Hierarchical Control of Multi-Area Power Systems with Improved Primary Frequency Regulation

Jianming Lian, Laurentiu Marinovici, Karanjit Kalsi, Pengwei Du and Marcelo Elizondo

Abstract—The conventional distributed hierarchical control architecture for multi-area power systems is revisited. In this paper, a new distributed hierarchical control architecture is proposed. In the proposed architecture, pilot generators are selected in each area to be equipped with decentralized robust control as a supplementary to the conventional droop speed control. With the improved primary frequency control, the system frequency can be restored to the nominal value without the help of secondary frequency control, which reduces the burden of the automatic generation control for frequency restoration. Moreover, the low frequency inter-area electromechanical oscillations can also be effectively damped. The effectiveness of the proposed distributed hierarchical control architecture is validated through detailed simulations.

NOMENCLATURE

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\delta_i$</td>
<td>generator rotor angle (rad)</td>
<td></td>
</tr>
<tr>
<td>$\omega_i$</td>
<td>generator rotor speed (rad/sec)</td>
<td></td>
</tr>
<tr>
<td>$\omega_{ri}$</td>
<td>generator relative rotor speed ($=\omega_i-\omega_0$, $\omega_0 = 2\pi f_0$)</td>
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</tr>
<tr>
<td>$B_{ij}$</td>
<td>the $i$-th row and $j$-th column element of the nodal susceptance matrix (p.u.)</td>
<td></td>
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<tr>
<td>$D_i$</td>
<td>damping coefficient (p.u.)</td>
<td></td>
</tr>
<tr>
<td>$E_{di}^v$</td>
<td>d-axis transient EMF (p.u.)</td>
<td></td>
</tr>
<tr>
<td>$E_{di}^e$</td>
<td>equivalent EMF in the excitation coil (p.u.)</td>
<td></td>
</tr>
<tr>
<td>$E_{qi}^v$</td>
<td>q-axis transient EMF (p.u.)</td>
<td></td>
</tr>
<tr>
<td>$f_j$</td>
<td>the $j$-th area frequency (Hz)</td>
<td></td>
</tr>
<tr>
<td>$f_0$</td>
<td>nominal system frequency (60 Hz = 1 p.u.)</td>
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</tr>
<tr>
<td>$G_{ij}$</td>
<td>the $i$-th row and $j$-th column element of the nodal conductance matrix (p.u.)</td>
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<tr>
<td>$H_i$</td>
<td>inertia constant (sec)</td>
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</tr>
<tr>
<td>$K_{vi}$</td>
<td>voltage regulator gain</td>
<td></td>
</tr>
<tr>
<td>$K_{ei}$</td>
<td>governor gain</td>
<td></td>
</tr>
<tr>
<td>$K_{mi}$</td>
<td>turbine gain</td>
<td></td>
</tr>
<tr>
<td>$P_{ci}$</td>
<td>power control input (p.u.)</td>
<td></td>
</tr>
<tr>
<td>$P_{mi}$</td>
<td>mechanical power (p.u.)</td>
<td></td>
</tr>
<tr>
<td>$P_{tj}$</td>
<td>net power interchange on the tie lines of the $j$-th area (MW)</td>
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</tr>
<tr>
<td>$P_{tj}^s$</td>
<td>scheduled net power interchange on the tie lines of the $j$-th area (MW)</td>
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<td>$R_i$</td>
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<td>$T_{mi}$</td>
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<td>$x_{qi}^f$</td>
<td>q-axis transient reactance (p.u.)</td>
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I. INTRODUCTION

The power industry is currently facing the challenges of integrating large amounts of intermittent renewable generation and accommodating changes in load composition brought by electrification of transportation. In addition, new communication and sensor technologies introduce new opportunities to resolve the above challenges by revisiting the way the power system is controlled and operated. The traditional power system control is distributed and hierarchical [1]. At the local level, purely decentralized primary generator controls are implemented. Typically, governor control is a proportional controller that compensates for instantaneous frequency deviations and avoids large frequency deviations resulted from sudden large active power imbalance. The other typical primary control is the excitation control including Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS). The AVR maintains a local bus voltage at a desired level by automatically modifying the reactive power generation. The PSS is used to effectively increase system damping during transients. At the area level, the central control actions are applied by areas (e.g., balancing authorities in the western interconnection of the USA) through Automatic Generation Control (AGC), whose objective is to maintain active and reactive power balance. The AGC is also in charge of restoring the system frequency back to the nominal value by secondary frequency control with a response time constant of minutes. The AGC automatically modifies the active power output of selected generators by sending commands every few seconds. With the increased penetration of renewable generation in the transmission level, the slow frequency restoration achieved by the AGC may not be sufficient to account for the intermittency of renewable energy.

On the other hand, the increased power exchange between different areas in large scale interconnected power systems often causes poorly damped inter-area electromechanical oscillations [2], [3]. That is, different groups of generators in different areas oscillate against each other. The traditional solution to inter-area oscillations involves the use of the PSS to increase the system damping torque at the frequencies...
where the oscillations appear. However, the PSS is designed based on linearized power system models considering a set of operating conditions. The tuning of the PSS is not flexible and it is not capable of accounting for the change of system structure. Thus, it may not provide enough damping to the low frequency inter-area oscillation. Recently, an alternative solution is proposed to install Flexible AC Transmission Systems (FACTS) devices on the places where inter-area oscillation happens [4]. Among different FACTS devices, the Unified Power Flow Controller (UPFC) [5] is the most popular choice. When the topology of power systems becomes more complicated, the location and the cost to widely install FACTS devices become an issue.

To overcome the above mentioned problems, a new distributed hierarchical control architecture with improved primary frequency regulation is proposed for multi-area power systems. Supplementary local decentralized robust controllers are applied to selected pilot generators in each area to improve the transient stability and restore the system frequency to the nominal value immediately after disturbances. Meanwhile, they will also provide enough damping to the low frequency inter-area oscillation. The employed decentralized robust controller was originally proposed in [6]–[9]. However, unlike the previous designs, the two-axis generator model is used herein as opposed to the conventionally used one-axis flux decay model. The one-axis flux decay model is actually not valid for most of the generators although it is simple for the controller design. Furthermore, the governor and the exciter dynamics are considered simultaneously in the controller design because they interact with each other and should not be considered separately. The implementation issue of local decentralized robust controllers that are ignored in the literature is also discussed, where a solution is proposed to make the implementation practical. With the improved primary frequency control, the AGC will not contribute much to the system frequency restoration through secondary frequency control. This will reduce the burden of the AGC, and also mitigate the effect of inaccurate frequency bias used in the Area Control Error (ACE) signal. Simulation studies demonstrate the efficacy of the proposed distributed hierarchical control architecture.

II. MULTI-AREA POWER SYSTEM MODEL

The large scale mult-area power system usually consists of a number of generators, denoted by $N$, that are interconnected through a transmission network. Geographically, these generators are grouped into different areas. At the local level, each generator is equipped with the governor for primary frequency control and the exciter for voltage control. At the area level, the automatic generation control deals with system frequency restoration and interchange power scheduling simultaneously. In the following, we describe the models of the generator and the AGC in details.

A. Two-Axis Generator Modeling

In this paper, we describe the dynamics of interconnected generators using the two-axis model [1], [10] instead of the one-axis flux decay model as commonly used in the literature (see, for example, [7], [11], [12]). The validity of the two-axis model requires that $x'_{qi} = x'_{di}$, whereas the one-axis model is derived under the assumption of $x_{qi} = x'_{di}$, which is usually not considered valid for most of the generators. In the two-axis model, each generator is modeled as the voltage behind direct axis transient reactance and the network is reduced to internal node representation. The dynamic model of the $i$-th generator, $i = 1, \ldots, N$, with both power and voltage control, is given by the following differential and algebraic equations,

**Rotor Dynamics:**

$$\dot{\delta}_i = \omega_{ri},$$  
(1)

$$\dot{\omega}_{ri} = -\frac{D_i}{2H_i} \omega_{ri} + \frac{\omega_0}{2H_i} (P_{mi} - P_{ei}),$$  
(2)

**Turbine Dynamics:**

$$\dot{P}_{mi} = -\frac{1}{T_{mi}} P_{mi} + \frac{K_{mi}}{T_{mi}} X_{ei},$$  
(3)

**Governor Control:**

$$X_{ei} = -\frac{K_{ei}}{T_{ei} R_i} \omega_{ri} - \frac{1}{T_{ei}} X_{ei} + \frac{1}{T_{ei}} P_{ei},$$  
(4)

$$0 \leq X_{ei} \leq 1,$$

**Electrical Dynamics:**

$$T_{dqi} \dot{E}_{qi}' = -E_{qi}' - (x_{di} - x'_{di}) I_{di} + E_{fdi},$$  
(5)

$$T_{qdi} \dot{E}_{di}' = -E_{di}' + (x_{qi} - x'_{qi}) I_{qi},$$  
(6)

**Excitation Control:**

$$T_{ai} E_{fdi} = -E_{fdi} + K_{ai} \left(V_{ti}^{ref} - V_{ti}\right),$$  
(7)

$$E_{fdi}^{min} \leq E_{fdi} \leq E_{fdi}^{max}.$$

**Electrical Constraints:**

$$P_{ei} = E_{qdi}' I_{qi} + E_{dzi} I_{di},$$  
(8)

$$I_{qi} = \sum_{j=1}^{N} (G_{ij} \cos \delta_{ij} + B_{ij} \sin \delta_{ij}) E_{qj}' + \sum_{j=1}^{N} (B_{ij} \cos \delta_{ij} - G_{ij} \sin \delta_{ij}) E_{dj}',$$  
(9)

$$I_{di} = \sum_{j=1}^{N} (G_{ij} \sin \delta_{ij} - B_{ij} \cos \delta_{ij}) E_{qj}' + \sum_{j=1}^{N} (G_{ij} \cos \delta_{ij} + B_{ij} \sin \delta_{ij}) E_{dj}',$$  
(10)

$$V_{ti} = \sqrt{(E_{qdi}' - x_{di}' I_{di})^2 + (E_{dzi}' + x_{qi}' I_{qi})^2},$$  
(11)

where $P_{ei} = P_{ref}^{ci}$ with the prescribed power control input reference $P_{ref}^{ci}$, and $\delta_{ij} = \delta_i - \delta_j$.  


B. Automatic Generation Control

The conventional primary frequency control is achieved through the governor by droop speed control, which uses the frequency deviation to distribute load changes among generating units for the stable operation during disturbance. With primary frequency control, any load change or generation loss usually results in a steady-state frequency deviation, depending on the governor droop characteristics and the frequency sensitivity of the system. However, the restoration of system frequency to the nominal value requires the secondary frequency control action, which is achieved by automatic generation control. The primary objectives of the AGC are to regulate frequency to the specified nominal value and to maintain real-time balance between load and generation.

The participation factors

\[
\lambda_i = \sum_j^N \lambda_i \rightleftharpoons \frac{\partial P_{ij}}{\partial E_i}
\]

for generators on AGC are pre-determined based on technical consideration or economics factors. Mathematically, this can be represented as

\[
P_{ci} = P_{ci}^{ref} + \lambda_i \Delta P_j,
\]

where \(0 \leq \lambda_i \leq 1\) and \(\sum_i^N \lambda_i = 1\). Thus, the power control input signal of each generator is updated in taking part in adjusting the power generation and the frequency.

III. IMPROVED PRIMARY FREQUENCY CONTROL

The conventional primary frequency control, that is, droop speed control, is easy to be implemented in practice, but it has two major shortcomings. The first one is that the steady state frequency deviation must be corrected by secondary frequency control that could be slow. The second one is that the steady state frequency deviation may be improved to overcome the above two shortcomings.

The two-axis generator model described in Section II is actually highly nonlinear due to the interconnections through the transmission network, which makes the controller design quite challenging. In [7], a class of linear matrix inequality (LMI) based decentralized robust controllers has been proposed for multimachine power systems, where only the one-axis model with governor control was considered by assuming constant exciter output \(E_{fd}\). In this section, we extend the methodology proposed in [7] to consider the two-axis generator model with both governor and exciter dynamics herein. In the following, we briefly describe the controller design with emphasis on the difference from [7] when the two-axis model is considered.

A. Local Decentralized Robust Control

To proceed, let \(x_i = [\delta_i \ \omega_{ri} \ P_{mi} \ X_{ei}]^T\) and \(x = [x_1 \ \ldots \ x_N]^T\). Then the dynamics of the \(i\)-th generator described by (1), (2), (3), (4) and (8) can be represented as state space model in the following,

\[
\dot{x}_i = A_i x_i + B_i P_{ci} + G_i P_{ci}(x),
\]

where

\[
A_i = \begin{bmatrix}
0 & 1 & 0 & 0 \\
0 & -\frac{D_i}{2\eta_i} & \frac{\omega_{ri}}{2\eta_i} & 0 \\
0 & 0 & -\frac{1}{\tau_{e_i}} & \frac{\omega_{ri}}{\eta_i} \\
0 & -\frac{K_{e_i}}{\tau_{e_i}} & \frac{1}{\tau_{e_i}} & 0
\end{bmatrix}, \\
B_i = \begin{bmatrix}
0 \\
0 \\
0 \\
0
\end{bmatrix}, \\
G_i = \begin{bmatrix}
0 \\
-\frac{\omega_{ri}}{2\eta_i} \\
0 \\
0
\end{bmatrix},
\]

In the above, the electrical power \(P_{ci}\) models the unknown interconnections between different generators. Now define the local decentralized controller as

\[
\dot{u}_i = k_i (x_i - x_i^e)
\]

so that \(P_{ci} = P_{ci}^{ref} + u_i\), where \(x_i^e = [\delta_i^e \ \omega_{ri}^e \ P_{mi}^e \ X_{ei}^e]^T\) is a prescribed operating point, which is chosen to be pre-fault equilibrium state in the simulations, and \(k_i\) is the feedback gain matrix. Let \(x_i^e = [\delta_i^e \ \omega_{ri}^e \ P_{mi}^e \ X_{ei}^e]^T\) denote the post-fault equilibrium state of (14) corresponding to the equilibrium input \(u_i^e\). It follows from (15) that the equilibrium state \(x_i^e\) satisfies the following algebraic equation,

\[
0 = Ax_i^e + B_i P_{ci}^{ref} + G_i P_{ci}(x_i^e),
\]

where \(P_{ci}^{ref} = P_{ci}^{ref} + u_i^e\) with \(u_i^e = k_i (x_i^e - x_i^d)\). To study the system transient stability of (14) driven by the controller (15) after faults or disturbances, we consider the perturbed system about the post-fault equilibrium state. Let \(\Delta x = [\Delta x_1^e \ \ldots \ \Delta x_N^e]^T\) with \(\Delta x = [\Delta x_1 \ \Delta x_2 \ \Delta x_3 \ \Delta x_4]^T\). Let \(\delta_i^e\), \(\omega_{ri}\), \(P_{mi}\) and \(X_{ei}\) denote the deviations of \(\delta_i\), \(\omega_{ri}\), \(P_{mi}\) and \(X_{ei}\), respectively, from their post-fault equilibrium values. That is,

\[
\Delta x_i = [\delta_i - \delta_i^e \ \omega_{ri} \ P_{mi} \ X_{ei} - X_{ei}^e]^T,
\]

where \(\omega_{ri}^e = 0\). Then the dynamics of the \(i\)-th perturbed system can be represented as

\[
\dot{\Delta x}_i = A_i \Delta x_i + B_i \Delta u_i + G_i h_i(\Delta x),
\]
where \( \Delta u_i = u_i - u_i^c = k_i \Delta x_i \) and

\[
h_i(\Delta x) = P_{ei}(x) - P_{ei}(x^c),
\]

or equivalently,

\[
h_i(\Delta x) = h_{qq}^i(\Delta x) + h_{qd}^i(\Delta x) + h_{dd}^i(\Delta x)
\]

with

\[
h_{qq}^i(\Delta x) = \sum_{j=1}^{N} E_{qj}^i E_{qj}^T (G_{ij} \cos \delta_{ij} - \cos \delta_{ij}^c) + B_{ij} \sin \delta_{ij} - \sin \delta_{ij}^c,
\]

\[
h_{qd}^i(\Delta x) = \sum_{j=1}^{N} E_{qj}^i E_{dj}^T (B_{ij} \cos \delta_{ij} - \cos \delta_{ij}^c) + G_{ij} \sin \delta_{ij} - \sin \delta_{ij}^c,
\]

\[
h_{dd}^i(\Delta x) = \sum_{j=1}^{N} E_{d1}^i E_{dj}^T (G_{ij} \cos \delta_{ij} - \cos \delta_{ij}^c) + B_{ij} \sin \delta_{ij} - \sin \delta_{ij}^c.
\]

In [7], the interconnection term only contains \( q \)-axis components due to the use of the one-axis model. With the two-axis model, the interconnected term \( h_i(\Delta x) \) consists of more components, which makes the corresponding analysis complicated. Let us first consider \( h_{qq}^i(\Delta x) \). Applying the same argument as in [7], we have

\[
h_i^{qq}(\Delta x) = y_i^T D_i^{qq} y_i \leq \left( \frac{\sum_{i=1}^{N} a_i}{N} \right)^2 \leq \frac{\sum_{i=1}^{N} a_i^2}{N}
\]

where \( y_i = [y_{i1} \cdots y_{iN}]^T \) with

\[
y_{ij} = \frac{\delta_{ij} - \delta_{ij}^c}{2} = \frac{\Delta x_{i1} - \Delta x_{ij}}{2},
\]

and \( D_i^{qq} = \text{diag}[d_{i1}^{qq} \cdots d_{iN}^{qq}] \) with

\[
d_{ij}^{qq} = 4E_{qj}^2 E_{qj}^T (G_{ij}^2 + B_{ij}^2) \frac{1}{2} \sum_{k=1}^{N} E_{qk}^2 (G_{ik}^2 + B_{ik}^2) \frac{1}{2},
\]

where \( E \) represents the allowable maximum absolute value. Similarly, we can apply the same arguments as above to \( h_{qd}^i(\Delta x), h_{dd}^i(\Delta x) \) and \( h_{dd}^i(\Delta x) \). Then, by inequality

\[
\left( \frac{\sum_{i=1}^{N} a_i}{N} \right)^2 \leq \frac{\sum_{i=1}^{N} a_i^2}{N},
\]

it follows from (18) that

\[
h_i^{qq}(\Delta x)h_i(\Delta x) \leq 4y_i^T D_i y_i,
\]

where \( D_i = D_i^{qq} + D_i^{qd} + D_i^{dd} + D_i^{qd} \). Consequently, from [7] we have

\[
h_i^{qq}(\Delta x)h_i(\Delta x) \leq \Delta x^T H_i^{QQ} \Delta x,
\]

or, more generally,

\[
h_i^{qq}(\Delta x)h_i(\Delta x) \leq \eta_i^2 \Delta x^T H_i^{QQ} \Delta x
\]

with \( \eta \geq 1 \), where \( H_i \) is directly determined from \( D_i \) defined above. The interested readers can refer to [7] for more details.

It follows from the above quadratic inequalities that we can apply the LMI based optimization framework proposed in [7] to determine the gain matrices \( k_i \) of local decentralized controllers in (15). It can be shown using similar arguments as in [7] that local decentralized controllers can stabilize the perturbed system (16) if the following optimization problem is feasible,

\[
\begin{align*}
\text{minimize} & \quad \sum_{i=1}^{N} (\gamma_i + \kappa_{Y_i} + \kappa_{L_i}) \\
\text{subject to} & \quad Y_D > 0
\end{align*}
\]

\[
\begin{bmatrix}
W_D & G_D & Y_D H_N^T \cdots Y_D H_1^T \\
G_D^T & -I & O & \cdots & O \\
H_N Y_D & O & O & \cdots & -\gamma_N I \\
\vdots & \vdots & \ddots & \ddots & \ddots \\
H_1 Y_D & O & O & \cdots & -\gamma_1 I \\
L_i & -I & \cdots & \cdots & \cdots \\
& & & \kappa_{Y_i} I \\
& & & & \kappa_{L_i} I
\end{bmatrix} < 0,
\]

\[
\gamma_i - \frac{1}{\eta_i} < 0, \quad i = 1, \ldots, N,
\]

where \( \gamma_i = 1/\eta_i, \eta_i \geq 1, W_D = A_D Y_D + Y_D A_D^T + B_D L_D + L_D B_D^T \) with \( A_D = \text{diag}[A_1 \cdots A_N] \) and \( B_D = \text{diag}[B_1 \cdots B_N] \), and \( \kappa_{Y_i} \) and \( \kappa_{L_i} \) are prescribed positive limits imposed on the magnitude of the solution \( L_i \) and \( Y_i \). Once we solve the above optimization, we can calculate the gain matrices of local decentralized controllers as

\[
K_D = L_D Y_D^{-1},
\]

where \( K_D = \text{diag}[k_1 \cdots k_N] \). When we solve the optimization problem (29), we are actually maximizing the interconnection strength between different generators that can be handled by the designed local controllers. With the selection of \( \eta_i \geq 1 \), the resulting local decentralized controllers can robustly stabilize the power system to insure collective stability in the presence of interconnection strength specified by \( \eta_i \).

### B. Practical Implementation

Although the optimization framework (29) proposed in [7] guarantees the robustness of local decentralized robust controllers with respect to interconnection uncertainties, the calculated feedback gain matrices are usually of large magnitude. This introduces technical difficulties in practical implementation because physical constraints that are ignored in the above optimization formulation can be violated with large feedback control gain. In order to overcome this problem, note that the quadratic inequality defined in (28), where \( H_i \) is directly determined by (25), is unnecessarily
too conservative. Mathematically, this conservative bound enables the system to be stabilized for any big disturbances. Nevertheless, the resulting system transient may not be practically allowed due to system protection. After running many simulation studies under various faults or disturbances, we found out that the actual value of $h_i(\Delta x)$ as defined in (17) is small. Hence, we can replace $D_i$ in (23) with another diagonal matrices that have small diagonal elements. In this way, we can obtain the feedback gain matrices of reasonable magnitude to avoid the problems mentioned above. This practical implementation is validated in the following case study. The determination of tighter bounds on $h_i(\Delta x)$ is considered for the next step research.

### IV. PROPOSED DISTRIBUTED HIERARCHICAL CONTROL

To incorporate the above improved primary frequency control into the conventional distributed hierarchical control architecture, an important consideration is how many generators should be equipped with the decentralized robust controller. There are cases when the generators do not possess a speed governor module, or they are characterized by larger turbine time constants that slow down the response to speed changes, as is the case with hydraulic turbines [14]. These cases may not be suitable candidates for having a robust controller. Instead of considering all the generators, it is more effective to apply the improved primary frequency control to several selected pilot generators in each area. Then these pilot generators will contribute to fast system frequency restoration and inter-area oscillation damping. The proposed new distributed hierarchical control architecture for multi-area power systems is shown in Fig. 1.

In this new architecture, because the improved primary frequency control can restore the system frequency much faster, it reduces the burden of the AGC in secondary frequency control. Actually, as mentioned in [15], it is difficult to obtain or predict the accurate frequency bias used in the ACE signal (13) because it is time varying. However, because the system frequency will be restored to the nominal value in the fast time scale under the improved primary frequency control, the frequency deviation term in the ACE signal becomes insignificant. Thus, the accuracy of the frequency bias is not an issue now.

![Proposed distributed hierarchical control architecture](image)

**Fig. 1.** Proposed distributed hierarchical control architecture

<table>
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<th>Parameter</th>
<th>Value</th>
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### V. CASE STUDY

In this section, we illustrate the effectiveness of the proposed distributed hierarchical control architecture by testing it on an IEEE 2-area, 4-machine, 13-bus test system shown in Fig. 2, which is available in the Power System Toolbox (PST) manual [16]. The parameter values of each generator are the same in the PST simulation, which are listed in Table I. The system is initially at pre-fault steady state, where the pre-fault equilibrium states are given in Table II. We implement the improved primary frequency control to Generator 1 and Generator 3 only. As discussed in Section III-B, we use $D_i = I$ instead of the original $D_i$ derived in Section III-A in the calculation of feedback gain matrices.

For the simulation of disturbance, we consider a symmetrical three phase short circuit fault followed by a line trip at bus 3 on line 3-101. The fault sequence is simulated as

1. At $t = 0$ sec, the system is at pre-fault steady state;
2. At $t = 0.1$ sec, the fault occurs;
3. At $t = 0.15$ sec, the near end of the fault line is cleared;
4. At $t = 0.2$ sec, the far end of the fault line is cleared;

![IEEE 2-area, 4-machine, 13-bus test system](image)

**Fig. 2.** IEEE 2-area, 4-machine, 13-bus test system [16].

**TABLE I**

**Generator Parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Parameter</th>
<th>Value</th>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$H_i$</td>
<td>6.5</td>
<td>$D_i$</td>
<td>6.5</td>
<td>$T_{ai}$</td>
<td>0.05</td>
</tr>
<tr>
<td>$T_{e1}$</td>
<td>0.1</td>
<td>$K_{e1}$</td>
<td>1.0</td>
<td>$K_{ai}$</td>
<td>200</td>
</tr>
<tr>
<td>$T_{mi}$</td>
<td>0.5</td>
<td>$K_{mi}$</td>
<td>1.0</td>
<td>$R_e$</td>
<td>0.04</td>
</tr>
<tr>
<td>$x_{qi}$</td>
<td>1.6</td>
<td>$x_{di}$</td>
<td>1.8</td>
<td>$\omega_0$</td>
<td>377</td>
</tr>
<tr>
<td>$x_{di}$</td>
<td>0.25</td>
<td>$x_{di}'$</td>
<td>0.25</td>
<td>$E_{\text{min}}^{\text{fdi}}$</td>
<td>-3</td>
</tr>
<tr>
<td>$T_{qdi}$</td>
<td>0.4</td>
<td>$T_{dvi}$</td>
<td>8.0</td>
<td>$E_{\text{max}}^{\text{fdi}}$</td>
<td>6</td>
</tr>
</tbody>
</table>

**TABLE II**

**Pre-fault Equilibrium States**

<table>
<thead>
<tr>
<th>Generator 1</th>
<th>Generator 2</th>
<th>Generator 3</th>
<th>Generator 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\delta_1$</td>
<td>1.0933</td>
<td>0.9537</td>
<td>0.6330</td>
</tr>
<tr>
<td>$\omega_{\delta 1}$</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$P^d_{mi}$</td>
<td>0.7878</td>
<td>0.7778</td>
<td>0.7956</td>
</tr>
<tr>
<td>$X_{\delta 1}$</td>
<td>0.7863</td>
<td>0.7778</td>
<td>0.7956</td>
</tr>
</tbody>
</table>
oscillation. It is noteworthy that the AGC with the same $\kappa_{ij}$ restores the tie line power schedule slower with the improved primary frequency control than the conventional one. This is because the vanishment of the frequency deviation weakens the AGC control action. If we increase the integral gain $\kappa_{ij}$ in the proposed distributed hierarchical control, the power restoration becomes faster.

VI. CONCLUSIONS

We have proposed a new distributed hierarchical control architecture for multi-area power systems. The proposed architecture deploys the local decentralized robust control on selected pilot generators in each area as a supplementary to the droop speed control. The improved primary frequency control can provide sufficient damping to both the generator rotor oscillation and the inter-area oscillation during disturbance. Moreover, it can restore the system frequency to the nominal value in the fast time scale without the help of secondary frequency control. This alleviates the burden of the AGC on frequency restoration, and thus mitigates the effect of inaccurate estimation of the frequency bias.

REFERENCES