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A Privacy-Preserving Distributed Wide-Area Automatic Generation Control Scheme

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ABSTRACT The increased penetration of renewable resources has made frequency regulation and generation control growing concerns for power system operators. Due to the variability of renewable resources and the reduced inertia leading to the deterioration of system frequency response, many balancing areas expect a need to increase their regulation services and non-spinning reserves. This also increases the total cost of system operation and may elevate location marginal energy prices. This article addresses the scheduling of energy interchange between balancing areas, in light of optimizing regulation services in the entire interconnected power system. A control architecture is defined to extend the existing area control error concept to allow more cooperation between interconnected balancing areas. In this scheme, regulation services from different balancing areas can be pooled such that a loss of generation in one control area can utilize regulation services from multiple areas resulting in a more economic dispatch of generation resources. The effectiveness of the wide-area control scheme is demonstrated in a large-scale testbed for two power systems with high renewable penetration.

INDEX TERMS Area control error, balancing area, frequency regulation, renewable resources, wide-area control.

I. INTRODUCTION

With the increase of renewable resources in power systems, frequency regulation and generation control have become a growing concern for power system operators. The potential issues foreseen with large amounts of renewable resources include [1], [2]:

- 1) the variability of renewable resources;
- 2) reduced inertia leading to the deterioration of system frequency response;
- 3) increased energy interchange between balancing areas due to excess renewable generation in neighboring balancing areas.

Under current operating standards, many balancing areas anticipate the need to increase regulation services and non-spinning reserves so that the area control error (ACE) signal and system frequency deviation can be quickly returned to

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zero after significant loss of either conventional or renewable generation [3], [4]. Securing such additional reserves increases the total costs of reserves and may also elevate locational marginal energy prices [5].

A number of system operators, such as the Electric Reliability Council of Texas (ERCOT), have proposed requiring renewable resources, such as wind farms, to reserve a small amount of generation capability to provide regulation services [6]. However, since renewable resources are intermittent, such approach does not completely resolve the issue.

There are two related issues with resource sharing across balancing areas. One is the dispatch of the most economic units to achieve ACE reduction, and the other is the technical implementation of the resource sharing scheme such that the resulting control system is stable and achieves its objective. In [7] the former issue has been addressed by a simple optimal regulation-service sharing scheme between balancing areas and the latter issue is addressed in this article with a distributed wide-area control architecture. This architecture

extends the existing ACE concept such that regulation-service sharing can be implemented automatically and with minimum communication. In the proposed scheme, regulation services from different balancing areas can be pooled so that the loss of generation in one area can utilize regulation services from multiple areas. The effectiveness of the regulation-service sharing scheme has been demonstrated in [7] on a simple 3-area system.

The advantage of the proposed scheme over other wide area generation control schemes such as [8]–[15], which address similar issues, is that the proposed scheme can be superimposed on existing automatic generation control (AGC) schemes. It makes the implementation of this wide-area AGC (wAGC) scheme significantly easier and reduces the need for additional more complex communication and control infrastructure.

Some work such as [13] proposed incorporating economic dispatch optimization problem into the AGC formulation; other work, such as [15], proposed using HVDC links connecting asynchronous areas for frequency regulation. However, similar to other wide-area approaches, such a scheme requires extensive modifications to existing assets, such as HVDC terminals.

By proposing a scheme with a significantly simpler implementation compared to those schemes proposed in [8]–[14], it is possible for balancing areas to quickly adapt their current business processes and operational practices and use the advantages of wide-area AGC. A number of utilities in the US already implement similar schemes based on manual coordination of power flows across their borders to support AGC. The proposed scheme aims to formalize and automate this approach by providing a simple scheme that can be superimposed on existing AGC schemes.

The wAGC scheme described in this article requires a combined, centralized energy cost curves, which can be dispatched in a distributed manner based on the existing ACE architecture. Also, there is no need for a balancing area to know the bid energy cost of each individual regulating unit in the neighboring balancing areas, thus, preserving the privacy of those regulating units. The method is shown to be able to drive both a modified ACE signal and the system frequency deviation to zero. As such, this high-level centralized and low-level decentralized control scheme can also be helpful to issues 1) and 2) listed earlier. In addition, the method is applicable to inter-area power transfers scheduled on HVDC transmission systems.

The proposed scheme is particularly relevant for control regions with high renewable penetration. The variability of renewable resources will increase ACE both in magnitude and frequency. Thus, the wAGC scheme allows a control region to have more resources to balance ACE.

The scheme is implemented on the Large-Scale Testbed (LTB) facility at the Center for Ultra-Wide-Area Resilient Electric Energy Transmission Networks (CURENT) to investigate the effectiveness of the scheme in large power systems with high penetration of renewables. In addition, the

operation of the scheme when some areas are not sharing their regulation resources is investigated. The analytical basis of this approach has been presented earlier in [7] using a three-area system. This article provides additional insights in the design and apply the control to a much larger system.

This article is organized as follows. Section II is a summary of the current automatic generation control scheme used by power system operators. Section III describes the wAGC scheme. Section IV briefly introduces LTB facility at CURENT and describes the implementation of the wAGC scheme in the testbed. Section IV also introduces the 68-bus Northeast Power Coordinating Council (NPCC) and Eastern Interconnection (EI) 523-bus reduced systems used to demonstrate the wAGC scheme. Section V describes the simulation results obtained from the LTB using the wAGC scheme in the NPCC system and the EI system with high renewable penetration. Finally, conclusions are provided in Section VI.

II. EXISTING AGC SCHEME

The goal of existing AGC systems is to provide secondary frequency control: to balance real-time load and generation uncertainties or sudden changes in load or generation; to restore the system frequency to the nominal level until the system operator is able to re-dispatch the generation resources; and to ensure power exchange between balancing areas is not impacted by these load and generation changes.

According to current North American Electric Reliability Corporation operating rules, Balancing Authorities (BAs) need to provide regulation services and non-spinning reserves such that any deviation in power exchange between balancing areas and any deviation from the nominal system frequency can quickly be returned to zero during normal operation or after a significant change in load or generation [16]. There are two main operating standards, CPS1 and CPS2, related to these requirements. CPS1 assigns each BA a share of responsibility for control of steady-state interconnection frequency [17]. CPS2 is intended to limit unscheduled power exchange between balancing areas [17]. In order to comply with both standards, the ACE in each balancing area should be as close to zero as possible at all times.

While the non-spinning reserves are dispatched by the BA, the regulating units are automatically dispatched by AGC systems. Generation units designated to restore the system frequency modify their active power output based on two components [18]:

- 1) primary frequency control (governor);
- 2) secondary frequency control (AGC).

Primary frequency control responds to a loss of generation or load almost immediately. By measuring the rotor speed of the generator, a governor can modify the mechanical power input of the unit, which affects the active power output to support the system. In most balancing areas the interconnection agreement specifies which units are required to support primary frequency control.

Secondary frequency control or AGC is used to restore the system frequency to the nominal level and ensure the inter-area power exchange is not affected by any changes in load or generation. In most balancing areas units providing secondary frequency control are selected by a BA and can provide an incremental amount of power as required. Should the change of load or generation exceed the designated resources, additional generation resources are dispatched manually from the spinning reserve pool.

At a higher level (also known as tertiary frequency control), a system operator will re-dispatch all generation units using a security-constrained economic dispatch program to balance generation and predicted load [18]. In the day-ahead market, regulation is scheduled in clearing ancillary services. The AGC is approached as a reliability problem separate from the economic dispatch. Frequency regulation (secondary level) takes place in real time. Generators responding to ACE signals are dispatched according to their participation factors, constituting an approximate optimization. Optimality is reached again when the next cycle of real-time economic dispatch (tertiary level) is performed, every 5 to 15 minutes. The economic dispatch is not considered in this work.

The BA of a balancing area i computes its ACE based on the scheduled power exchange with all connected neighboring areas, the actual power exchange with all connected neighboring areas, and the system frequency as

$$ACE_i = \beta_i \Delta f + \Delta IC_i \tag{1}$$

where β_i is the estimated load sensitivity to frequency, also known as the frequency bias for area i ; Δf and ΔIC_i are the deviation in system frequency and power exchange of area i , respectively, given by

$$\Delta f = f - f_0 \tag{2}$$

and

$$\Delta IC_i = IC_i - IC_{ref,i} \tag{3}$$

where $IC_{ref,i}$ and f_0 are the scheduled power exchange and nominal system frequency respectively, and IC_i and f are the actual interchange and system frequency, respectively. It should be noted that in (1) the load sensitivity β_i is taken to be positive, although in reality it is a negative value. The interchange error (3) is defined such that $ACE_i < 0$ implies that area i is deficient in power generation and needs to provide more power than scheduled in the last economic dispatch.

Each balancing area computes its own ACE and uses it to adjust the generation units within the area to restore the scheduled power interchange. Fig. 1 shows a 3-area system, each with its own AGC system and ACE signal. Under normal operation, balancing area 1 exports power to areas 2 and 3. If a loss of generation occurs in area 1, the system frequency in all three areas decreases, that is, $\Delta f < 0$. The power export from area 1 decreases because there is not enough generation to sustain the load and export, which means $\Delta IC_1 < 0$.

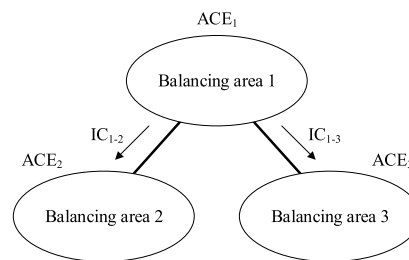


FIGURE 1. A 3-area system that illustrates traditional ACE computation with IC_j .

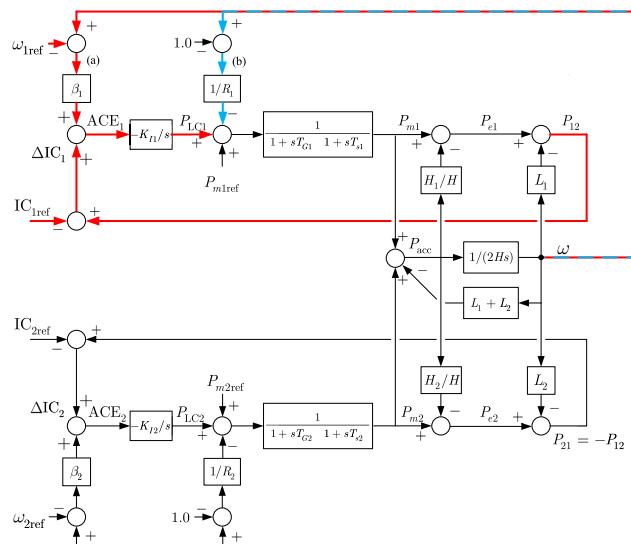


FIGURE 2. The 2-area system block diagram with traditional AGC (a) and primary frequency control (b) highlighted.

By symmetry this means areas 2 and 3 do not receive the full amount of scheduled power and $\Delta IC_j > 0$ for $j = 2, 3$. The ACE in areas 2 and 3 will be 0 (or very small due to transients) because the two terms in (1) cancel each other, while the ACE of area 1 will be non-zero. Therefore, the AGC system in area 1 is expected to increase the generator output to supply additional power to restore the system frequency and interchange flows.

Based on the total amount of power needed to return the ACE signal to 0 and the number of generating units participating in the secondary regulation service together with their cost functions, the BA sets a proportional constant for each unit and sends the appropriate AGC signal to the generators participating in the AGC system.

Fig. 2 [19], [20] shows a block diagram of a 2-area system with a single generating unit in each area participating in secondary regulation service and the signals and control paths used to modify the active power output of that unit. Blue path (b) is the primary frequency control component and is adjusted automatically by the governor based on the measured system frequency. Red path (a) is the secondary frequency control in area 1. Note that in this 2-machine system the system frequency f is equal to the center-of-inertia frequency $\omega/(2\pi)$.

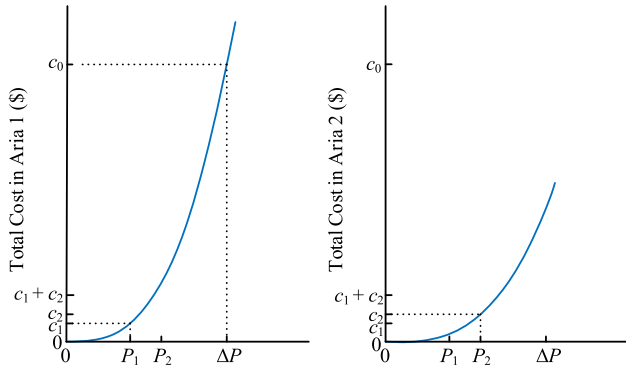


FIGURE 3. The 2-area system block diagram with traditional AGC (a) and primary frequency control (b) highlighted.

III. PRIVACY-PRESERVING WIDE-AREA AGC SCHEME

A. ECONOMIC JUSTIFICATION

Although the current AGC system introduced in Section II guarantees the power exchange between balancing areas will return to the scheduled level, it does not necessarily result in the most economic or desirable dispatch.

This is illustrated in Fig. 3, which shows the cost of secondary frequency regulation in 2 neighboring areas. If a generation loss or a load increase of ΔP MW occurs in area 1, that area has to provide an additional ΔP MW of power, which will cost c_0 . If area 2 were to provide some of the regulation services, the cost would be lowered to $(c_1 + c_2) < c_0$, where c_i is the cost for area i .

In particular, for systems with high penetration of renewable energy, the export from an area may be supported by the power output from wind or solar farms, possibly at a significantly lower cost. If the wind speed suddenly slows down the area will experience an immediate deficit in generation. A relevant question becomes which balancing area is responsible for making up the deficit due to renewable generation export? In such situations, a reasonable compromise is to pool the regulating units from the two areas together and combine AGC resources.

These examples illustrate that it could be economically more efficient for interconnected balancing areas to provide AGC services not only for changes in load or generation in their own control areas, but also for load or generation changes in other areas.

B. ACE MODIFICATION

This section describes a modification of the conventional AGC by adding an additional term in the ACE signal (1) to account for the availability of regulation services from other balancing areas.

The optimal additional power dispatched within each balancing area can be computed by minimizing the overall cost associated with the additional power necessary to make up for AGC generation shortfall:

$$\min_{\Delta P_i} \sum_{i \in A} c_i(\Delta P_i) \tag{4}$$

subject to the constraints

$$\begin{aligned} \Delta P &= \sum_{i \in A} \Delta P_i \\ \Delta P_i^{\min} &\leq \Delta P_i \leq \Delta P_i^{\max}, \quad i \in A \end{aligned} \tag{5}$$

where $c_i(x)$ is the cost of producing x MW of additional regulation power in area i , ΔP is the total AGC generation needed, ΔP_i is the additional power generated in area i , and A is the set of all interconnected, participating balancing areas. ΔP_i is bounded below by ΔP_i^{\min} and above by ΔP_i^{\max} as limited by the ramp rate over the AGC period. By convention $\Delta P > 0$ indicates additional generation needed to reduce the area control error to zero.

The optimization problem in (4) and constraints in (5) consider the additional generation that each area can participate in AGC response, as determined by the ramp rate of the units. As will be shown later, the cost function will accordingly account for the capabilities of the generators participating in area i .

Note that the traditional economic dispatch problem also includes constraints on unit ramp rates and generation balance based on load forecast [18]. However, the proposed wAGC scheme, as is the case in a generic AGC scheme, is a secondary frequency regulation acting to correct the ACE accumulated in the last frequency and tie-line monitoring period. In addition, secondary regulation services are generally designed to temporary support the system until a full economic dispatch is completed. In most BAs this is done every 5 minutes through a real time energy market dispatch. By using spinning reserves for secondary regulation, such as AGC, the BAs can provide ramp-rate limited generation until the next economic dispatch cycle.

To emphasize, the proposed scheme is based on the following assumptions:

- 1) Changes in the output power of the internal and external AGC units scheduled will not change the security of the internal and external areas. In the case of system emergencies, this operation will be superseded by control room operators.
- 2) The proposed scheme is not intended to be an optimal power flow solution with contingencies. It represents an enhanced ACE correction mechanism.
- 3) The external area cost function includes the cost of transmission losses.

It is important to note that not all balancing areas in an interconnected power system have to participate in this scheme, and the participating balancing areas do not have to be interconnected. For instance, in the power system in Fig. 1 it is possible for areas 2 and 3 to participate in wAGC without the need for area 1 to participate.

The extended ACE can be computed as

$$ACE_{\text{ext},i} = \beta_i \Delta f + (IC_i - IC_{\text{ref},i} - P_{\text{mod},i}) \tag{6}$$

where

$$P_{\text{mod},i} = \Delta P_i - \Delta P \tag{7}$$

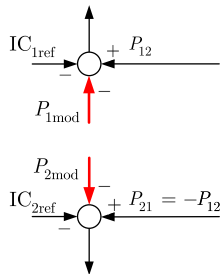


FIGURE 4. Wide-area AGC modification of the 2-area system block diagram to allow AGC resource sharing across balancing areas.

for the balancing area that experienced the loss of generation, and

$$P_{mod,i} = \Delta P_i \tag{8}$$

for all other participating balancing areas. To illustrate this wAGC scheme, the same 2-area system from Section II is used. Fig. 4 shows a portion of the same system as in Fig. 2 with the additional $P_{mod,i}$ term in the two ACE signals.

Assuming this system is in steady state it can be shown that

$$f = f_0 \tag{9}$$

and

$$\Delta IC_i = P_{mod,i} \tag{10}$$

The traditional ACE as introduced in Section II is then given by

$$ACE_i = P_{mod,i} \tag{11}$$

and the extended ACE in (6) is given by

$$ACE_{ext,i} = 0 \tag{12}$$

C. PRIVACY-PRESERVING DISPATCH

The optimization problem (4) which is used to determine $P_{mod,i}$ can be solved in a distributed fashion without the need to exchange large amounts of data between balancing areas.

The algorithm in Fig. 5 shows how a BA can compute its own $P_{mod,i}$ with only the secondary regulation service cost curves from all participating BAs.

To implement this regulation service sharing mechanism, each BA will aggregate the cost curves of all participating secondary regulating units. Stacking bids of individual generators will preserve privacy because the assembled cost curves do not show the bids from the individual units; hence, no BA will be able to obtain bid information from units outside its control area.

Furthermore, because the first 3 steps in Fig. 5 are identical for all participating areas they can be completed by a Central Clearing Authority (CCA), which is independent from the BAs. This organization can assemble the combined cost curve $C_{reg}(P)$, which is step 2 of the algorithm, and determine the combined incremental cost λ , which is step 3. The actual modification of the ACE signal and the unit dispatch can still

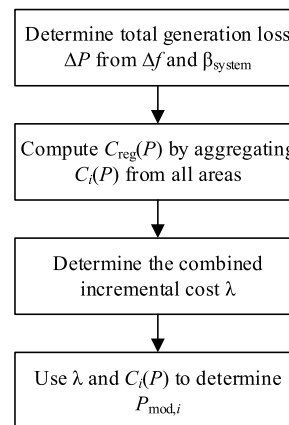


FIGURE 5. Algorithm to determine $P_{mod,i}$ in area i in a distributed fashion.

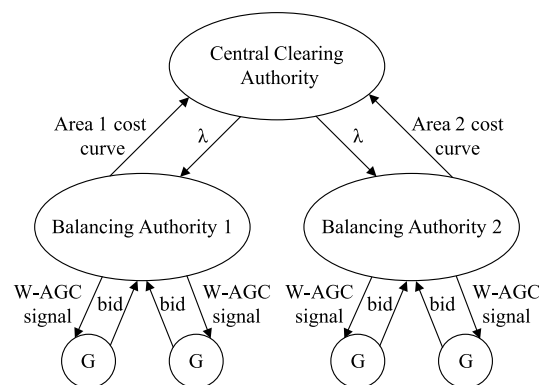


FIGURE 6. Illustration of data exchange between generators, BAs and CCA for wide-area AGC implementation.

be performed by the individual BA in step 4 of the algorithm. As all participating BAs only have to share their combined regulation cost curve $C_i(P)$ with the CCA but not with other BAs, there are fewer data confidentiality concerns associated with this scheme.

Thus, the coordination between BAs is based on neighboring areas providing generation to reduce the ACE error based on economic consideration. Since the power flows on the tie-lines between the control areas, there is no need for one control area to know which units from neighboring areas are providing the support. However, it is important that this additional flow on the tie-lines does not violate any contingency situation which will be evaluated before the additional power can be transferred.

The aggregation of the cost curves submitted by each area is done by solving the optimization problem that is very similar to the standard economic dispatch [19] and can be solved by applying a number of linear programming techniques. Examples are shown in Section III.D.

D. ILLUSTRATIVE EXAMPLES

Fig. 6 shows the necessary data exchange between the generators, the BAs and the CCA. The CCA may be a computer, with a software program to manage the combined regulation service clearing function.

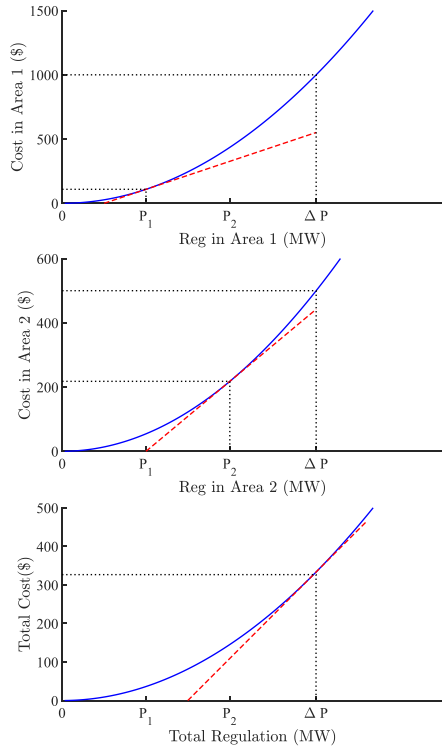


FIGURE 7. Secondary frequency regulation cost curve of a 2-area system to illustrate distributed nature of $P_{mod,i}$ computation.

Fig. 7 shows steps 2-4 of this algorithm in the 2-area system. Both areas have access to the combined regulation service cost curve in Figure 8. Based on the total loss of generation ΔP they determine the aggregate incremental cost

$$\lambda = \left. \frac{\partial C_{reg}(P)}{\partial P} \right|_{\Delta P} \quad (13)$$

Each BA then uses that incremental cost to determine $P_{mod,i}$ with the same incremental cost on its own cost curve $C_i(P)$ such that

$$\lambda = \left. \frac{\partial C_i(P)}{\partial P} \right|_{\Delta P_i} \quad \forall i = 1, 2 \quad (14)$$

Fig. 7 illustrates this process for areas 1 and 2.

Note that $\lambda = 0$ corresponds to $P_{mod,i} = 0$ in all BAs. This indicates no significant change in load or generation is observed in the system.

By measuring system frequency, the CCA is able to detect any significant change in generation or load and calculate ΔP as

$$\Delta P = \frac{\Delta f}{\beta_{system}} \quad (15)$$

where β_{system} is the total estimated load sensitivity of the entire interconnected system.

Thus, the wAGC scheme has the following hierarchy of signals:

- 1) frequency, which is a global signal for the whole system;

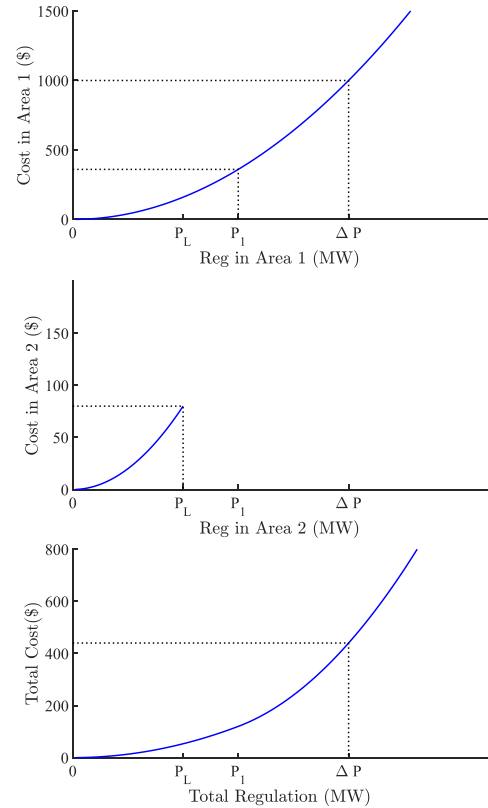


FIGURE 8. Secondary frequency regulation cost curve of a 2-area system to illustrate distributed nature of $P_{mod,i}$ computation when generation capability is limited.

- 2) incremental cost, which is a semi-global signal that is broadcasted to balancing areas participating in wAGC;
- 3) ACE, which is a local signal of each balancing area.

Fig. 8 shows a similar 2-area example when one of the two areas has constraints on the amount of additional generation available.

As discussed in Section III.B these constraints are incorporated into the cost curve. This is illustrated in Fig. 8 in the cost curve for area 2. At the value of regulation that is equal to P_L , the cost increases to a very large amount, meaning the area is unable to provide more power. In that case the combined regulation service cost curve in Fig. 8 results in a different λ and a higher P_1 than in the unconstrained case in Fig. 7.

E. PRACTICAL IMPLEMENTATION

In most control centers, the AGC function is not included in the Energy Management System (EMS) which is primarily used to settle day-ahead and real-time markets for energy and ancillary services. Instead, ACE is calculated by monitoring system frequency and interchange deviation on a separate accounting system. The proposed wAGC scheme can be readily incorporated into such an accounting system, with the following caveats.

1. The need of a centralized wAGC controller, which can be formed by the collaboration of several neighboring control areas.

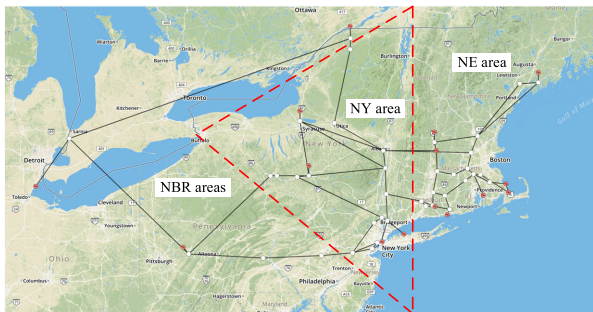


FIGURE 9. NPCC 68-bus system.

2. As mentioned in Section III.B, the committed units need to have the required ramp rate capability.

3. The external units selected for participating in wAGC should be close to the boundary of the control area that they are supplying power to. Extra generation from these units would minimize additional loading on the transmission lines in their own areas.

4. The extra generation coming in from the external areas still has to observe stability transfer limits between the areas. These transfer limits can be obtained from the EMS.

IV. TEST POWER SYSTEMS

This section introduces two large systems used to show the effects of the wAGC introduced in Section III. Section IV.A introduces the NPCC 68-bus system and Section IV.B introduces the EI 523-bus reduced system. Both systems are simulated in the CURENT LTB [21] using ANDES [22]. ANDES uses an implicit differential and algebraic equation (DAE) solver and is able to perform the wAGC emulation as an extended-term dynamic simulation.

A. NPCC SYSTEM

The NPCC 68-bus system is based on the New England (NE) and New York (NY) power systems. The neighboring (NBR) systems are approximated using a small number of large generators to achieve reasonable power interchange in the NE and NY borders.

Fig. 9 shows the system and the 3 balancing areas defined for AGC. To demonstrate the effectiveness of AGC and wAGC, the tripping of Generator 9 in the NE area, representing a loss of 800 MW, is simulated in Section V.A. While Generator 9 is modeled as a traditional synchronous generator, the trip of this unit represents a generic generation loss. The same effect could be achieved by dropping 800 MW of renewable generation such as wind farms.

B. EI REDUCED SYSTEM

The EI 523-bus system is a reduced model of the entire US Eastern Interconnection [23]. A total of 84 generators in 10 balancing areas are represented in the base case. Note that these control areas do not correspond to the balancing areas defined by NERC. Because this system is a reduced system some of the 97 balancing areas in the EI are not

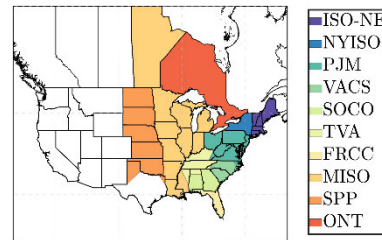


FIGURE 10. EI reduced system balancing areas.

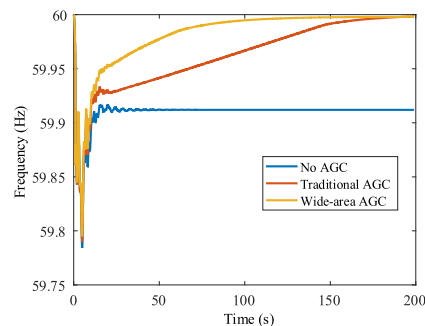


FIGURE 11. System frequency for a NE generator trip without AGC, with traditional AGC and wide-area AGC.

present in the reduced model. For this system, Reliability Coordinators [17] have been used to define 10 fictitious balancing areas for this study. Fig. 10 shows these areas.

To show the value of the proposed wAGC in a system with high renewable penetration, the system contains 20% renewable generation modeled as Type-3 Wind farms. The simulation in Section V.B shows the system responding to disconnection of an 800-MW wind farm in the ISO-NE balancing area.

V. LTB SYSTEM SIMULATION RESULTS

A. NPCC SYSTEM

This section shows the simulation results of the NPCC system introduced in Section IV.A. An 800-MW generation trip is simulated for 3 different scenarios:

- 1) no AGC;
- 2) traditional AGC with only the NE area responding to the generation loss;
- 3) wAGC with all 3 balancing areas responding to the generation loss.

For the wAGC a constant secondary regulation cost curve is assumed for each area. After the trip these curves results in

$$\begin{aligned}
 P_{\text{mod,NBR}} &= 200 \text{ MW} \\
 P_{\text{mod,NY}} &= 200 \text{ MW} \\
 P_{\text{mod,NE}} &= -400 \text{ MW}
 \end{aligned} \tag{16}$$

Fig. 11 shows the system frequency for all 3 cases. If there is no AGC active, the system frequency settles to below nominal value due to primary frequency control as well as some loads which are frequency dependent. If the traditional AGC system is active the system frequency recovers to the nominal value after 185 seconds. If wAGC is active the

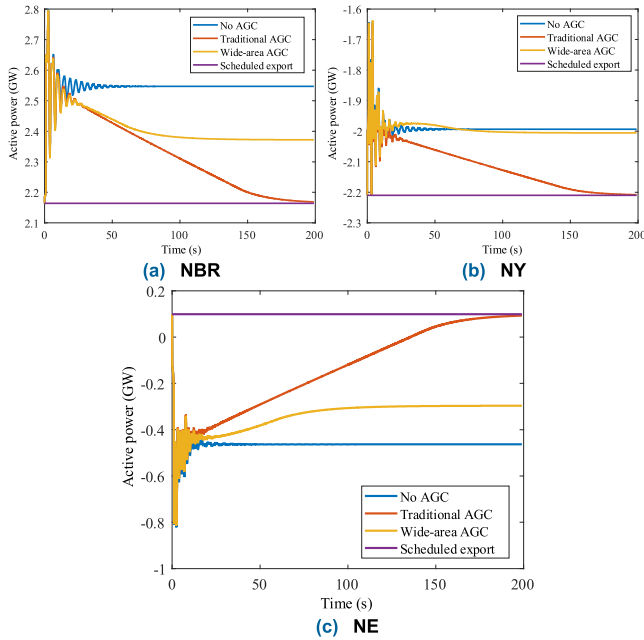


FIGURE 12. Power export after a NE generator trip without AGC, with traditional AGC and wide-area AGC.

frequency recovers after 145 seconds which is 22% faster. In the case of the wAGC the regulation service is shared between generators of multiple balancing areas which allows faster frequency recovery.

Fig. 12 shows the power export of each area. Fig. 12c shows that in the case without AGC the NE area power export drops 600 MW. Since all machines in the system are participating in primary frequency control the NE balancing area makes up part of the lost generation but not nearly all 800 MW. In the wAGC scheme, since the generators in the NY balancing area also participate in frequency control, the export of this balancing area increases as shown in Fig. 12b. Note that AGC control also improves the electromechanical mode damping resulting from the loss-of-generation disturbance.

The generators in the NBR also participate in primary frequency regulation; in addition, some frequency sensitive load is located in this balancing area which decreases when the system frequency decreases. Therefore, the power export of the NBR balancing area increases more than that of the NY area as seen in Fig. 12a.

When traditional AGC is active the power export of each area recovers to its schedule as seen in Fig. 12. When the wAGC system is used, the difference between the steady-state export and the scheduled export is given by (10) and Fig. 12 shows that this corresponds to (16).

B. EI REDUCED SYSTEM

This section shows the simulation results of the EI 523-bus reduced system introduced in Section IV.B. A 800-MW trip of a wind farm in the ISO-NE balancing area is simulated. For comparison, the same 3 scenarios as in Section V.A are considered.

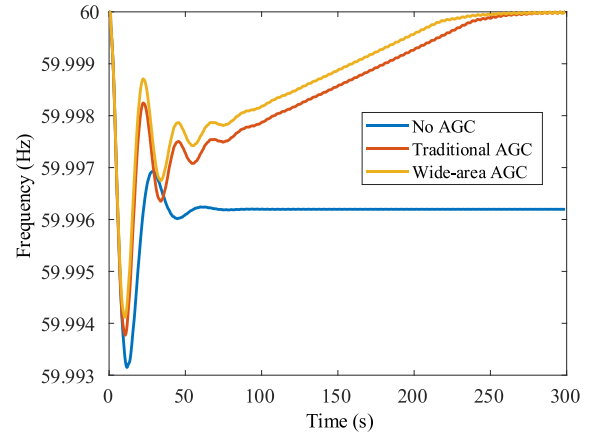


FIGURE 13. EI reduced system frequency without AGC, with traditional AGC and wide-area AGC.

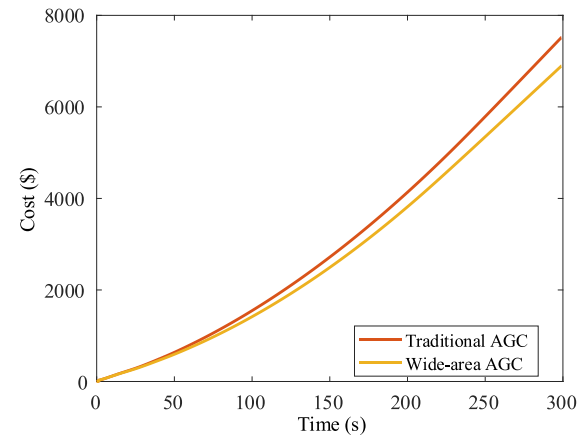


FIGURE 14. Cost associated with the wind farm trip.

Fig. 13 shows the system frequency for all 3 cases. Similar to the NPCC system simulation, the system frequency settles to a value slightly below nominal without any AGC system. Since the reduced EI system is significantly larger, the total frequency deviation is smaller than in the NPCC system. In addition, as the individual generators are represented by large aggregate machines, the aggregate frequency mode oscillation is much slower.

If the wAGC is active the frequency recovers to the nominal value and the recovery happens faster compared to the scenario when the traditional AGC is active.

Fig. 14 shows the cost associated with the wind farm trip in the ISO-NE area. In the case of the wide-area AGC the less expensive generation in neighboring areas is participating in restoring the frequency to the nominal value, meaning cheaper generators available in other areas can be dispatched. By the time of the next economic dispatch ($t = 300$ sec.) the wAGC scheme reduces the additional operating cost to replace generation of the tripped wind farm by 8% compared to traditional AGC. The operating cost savings increase with the increase in lost power and continue to increase over time until the wAGC is replaced by a new economic dispatch. The savings from the use of the wAGC can be achieved not only

after sudden changes in generation or load but also during ambient conditions when generation is adjusted to follow real-time load variations. The potential savings can be higher if the savings from procuring less regulation services are included.

VI. CONCLUSION

With increased penetration of renewable resources, frequency regulation and generation control have become a growing concern for power system operators. The variability of renewable resources and the increased energy interchange between balancing areas require an increased amount of regulation service for AGC.

This work has evaluated the performance of the wAGC scheme to extend the existing ACE concept to allow more cooperation between interconnected power systems. The scheme is based on modifying the existing ACE scheme and has several merits:

- 1) The scheme lowers the cost of AGC, especially when an area exporting wind power to neighboring areas experiences a sudden drop in wind energy output. In a case study the proposed scheme lowered the additional operating cost by 8% by the time of the next scheduled real-time economic dispatch.
- 2) The determination of the new ACE signal can be done by communicating the aggregate cost curves of the regulation service from the individual balancing areas to a central controller. The confidentiality of the bid cost from the individual generators can be hidden from the neighboring balancing areas. The decision can also be made in a distributed manner.
- 3) The control scheme can be implemented by adding a modified tie-line flow value to the incremental regulating unit output to the ACE signal in a balancing area, without the need of explicit coordination with other areas.
- 4) Simulations of the control scheme on the CURENT LTB have shown that in power systems with multiple balancing area the proposed approach can also increase the speed of frequency recovery. In a case study the proposed scheme reduced the frequency recovery time by 22%.

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