UTILIZING LOCAL CUSTOMER'S REGULATION CONTROL ERROR IN BILATERAL REGULATION SERVICE

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Abstract - In the ongoing trend of restructuring the electricity market worldwide, Ancillary Services are introduced for operating entities to realize the market function and maintain system security. The generation providers willing to join the regulation market would be interested in how the direct regulation service between suppliers and customers be effectively realized at lower operating costs while maintaining the operating service at the satisfactory level. This paper presents a method to estimate specific customer's regulation control error and use it as a control reference for generation suppliers to provide the bilateral regulation service. Results showing the proposed method in the simulated condition are performing as desired. Control issues related to the advantages of utilizing the local customer's frequency bias setting in the bilateral regulation are examined.

Keywords - Regulation, Frequency Bias, Frequency Response Characteristic, Ancillary Service

1 Introduction

UPON open access of the transmission grid and unbundling of the generation supply, the independent operating entities such as IPPs will be able to provide regulation, load following, and operative reserves for contractual customers. Such operating costs are significant for an entity that is competing to provide ancillary services. To achieve better control performance, the operating entities are interested in new regulation control that can reduce their regulation costs and yet comply with customer needs.

The effectiveness of generation to maintain the real-time load-generation balance is based upon the regulation control. While the online unit governor reacts to halt the frequency excursion from a disturbance, the supplemented action of secondary control is to yield a generation trend to match sum of control area's load and loss, maintain the scheduled tie flow, and area's portion of frequency support. The conventional tie-line bias control is to use area's tie-flow deviation with area's frequency response to indicate area's generation control error (ACE). The signal of ACE is not only widely adopted as an index for the evaluation of area's regulation performance but utilized as a control reference for secondary control [1].

Exporting a portion or total generation control error to the other operating entities other than the host control area has been proposed in [2, 3]. As long as the real-time sum of power flows connecting the target zone to the host is available, the operating entity could still use power flow information as dynamic schedule to export zonal regulation to the other entity. However, such control without considering the frequency bias setting may neglect the impact of frequency response on load frequency control dynamics. Based on the experience of using variable bias setting on area's ACE control [4, 5], adopting a zonal frequency bias setting may be beneficial for a more efficient bilateral regulation service.

This paper will first present the use of β estimation of a defined zone to adjust frequency bias setting for operating entities to realize bilateral regulation control. Following which, we will also explore how the operating entities could use the defined regulation control error (RCE) to offer the regulation service for contractual customers. Some regulation issues about the control interactions from the influence of zonal frequency bias setting will be discussed from simulation results.

2 Frequency Response Background

2.1 Load frequency control dynamics

The operating condition of a power system is continuously varying because of disturbances from the time-varying loads or circuit changes in the network. While a disturbance from a tripped unit or load creates a power imbalance in the system, temporary imbalance is first compensated by changes in kinetic energy of rotating inertias of generators, and results in a change in frequency. The frequency change will in turn affect frequency sensitive load. Once system frequency goes beyond the governor deadband, the governor will act to increase or decrease the output power of the generating unit. The control action of unit governor is called primary control. For normal disturbances, the primary control action will halt the frequency excursion to a new state of frequency which is above or below the rated value. A follow-up control is to return the frequency back to the rated value. This supplementary control action can be made either manually or automatically. An automatic supplementary control is also referred to the automatic generation control (AGC).

2.2 Frequency response characteristic

While the primary control responds to maintain load-generation balance, the value of frequency deviation, ΔF, is affected by the governor's characteristics of generating units and the damping of frequency-sensitive loads. As a result, area's frequency response characteristic (FRC) can be related to the equivalent on-line governor's speed droop regulation, R_{eq}, and the damping coefficient of the connected load, D_{eq}. That is,

$$-10\beta = \sum \left(\frac{1}{R_{eq}} + D_{eq} \right) \quad (1)$$

where -10β is area's FRC.

The extent of the system response to intercept the runaway frequency would reflect on the magnitude of frequency deviation. That is, the higher the -10β reacts to the disturbance, the smaller the frequency deviation from the rated value.

2.3 Effect of frequency bias setting on ACE control

The control strategy of using ACE as a control reference for a better regulation control still remains challenging. Since area's -10β is not easily measurable but is approximated, the control areas usually use frequency bias setting, $-10B$, to offset -10β for the calculation of ACE. It is known that some of AGC actions due to the indiscriminate use of $-10B$ could result in extraneous regulation effort or tie flow oscillations [6]. Some control approaches of using adaptive frequency bias setting by β estimate of a control area has exhibited its advantages on the performance of regulation control [4, 5].

The β estimation method introduced in [5] is to determine a control area's β in real time. The algorithm needs to use some of AGC variables that represent the operating states of the overall area. However, when the estimating scope is reduced to some local customers or defined zones, the estimating method should be modified so that the β estimate can be applicable in sub-area's basis.

3 Zonal β Estimation Algorithm

To yield a sub-area's FRC, we start from the electromechanical power balance equation,

$$P_{Gj}(t) - P_{Lj}(t) - P_{aj}(t) = -10\beta_j \Delta F(t) + M_j \Delta \dot{F}(t) \quad (2)$$

where P_{Gj} is Zone j's unit generation that is directed by control area's central AGC. P_{Lj} is the total load demand within the defined Zone j. P_{aj} is defined as the net power flow from Zone j to the external. $-10\beta_j$ is Zone j's FRC. M_j is the lump of rotating inertia of the connected units within Zone j. ΔF is the system frequency deviation.

Our examination shows the value of $M_j \Delta \dot{F}(t)$ term is negligibly small compared to the other terms in (2). Ignoring $M_j \Delta \dot{F}(t)$, (2) can be reduced to

$$P_{Gj} - P_{Lj} - P_{aj} = -10\beta_j \Delta F \quad (3)$$

where the notation of t is also omitted for simplicity.

In practice, P_{Gj}, P_{aj}, and ΔF are measurable variables from zone's SCADA system. However, P_{Lj} and $-10\beta_j$ are not directly measurable but estimated. To estimate these two unknown variables from (3), we separate the known and unknown variables, (3) can be represented by the following matrix form.

$$(P_{Gj} - P_{aj}) = [1 \quad \Delta F][P_{Lj} \quad -10\beta_j]^T \quad (4)$$

which is similar to the linear equation form

$$b = A \cdot x \quad (5)$$

When the time sequence of matrices b and A become available, vector x could be estimated by minimizing $\|Ax - b\|^2$. That is, the unknown variables, P_{Lj} and $-10\beta_j$, can be obtained using the recursive least square algorithm [7].

4 Performance of The Estimation Algorithm

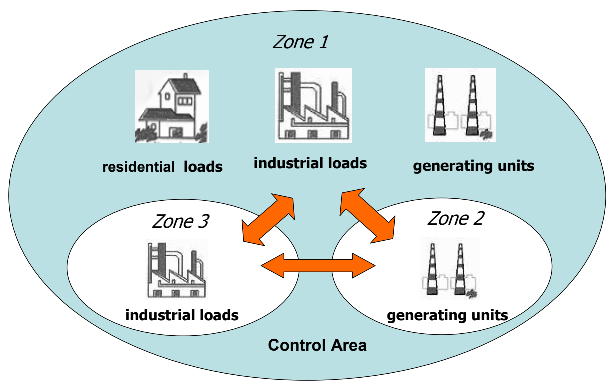

Figure 1: Schematic of a single area power system with 3 sub-zones

Simulation studies are convenient for examining the behavior of the algorithm under conditions not easily controllable in the real system and for exploring the factors that may affect the estimation algorithm. A simulation system was created to test the efficacy of target zone's -10β estimation. Figure 1 shows the schematic of a single area power system. The control area is sub-divided into three zones with different features: Zone 2 is defined as a generating zone that contains online generating units and plant demands. Zone 3 is defined as a customer zone that is represented by blocks of customer loads. Zone 1 is defined as a composite zone which covers the remainder of the units and demands within the control area. In simulation, the LFC regulates representative generating units to serve load demands in three zones. The loading profiles used in the simulation are real samples [illegible] from the utility.

4.1 *Accuracy of the zonal -10β estimate*

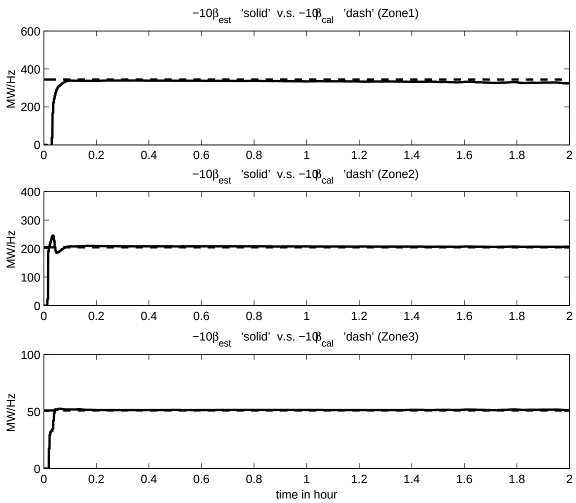

Figure 2: Zones' β_{cal} and β_{est} over 2 hours

Figure 2 shows the estimated values of -10β corresponding to three zones within the control area. To check the accuracy of estimation algorithm, we compare each zone's $-10\beta_{est}$ with its theoretical value, $-10\beta_{cal}$, which is defined in (1). After a short settling period, each zone's $-10\beta_{est}$ estimate (marked in solid-lines) converges rapidly to its corresponding $-10\beta_{cal}$ value (marked in dash-lines). Note that $-10\beta_{est3}$ coincides with a smaller value compared to the values of other zones. It is because $-10\beta_{est3}$ only contains the load damping coefficient, D_{eq3}.

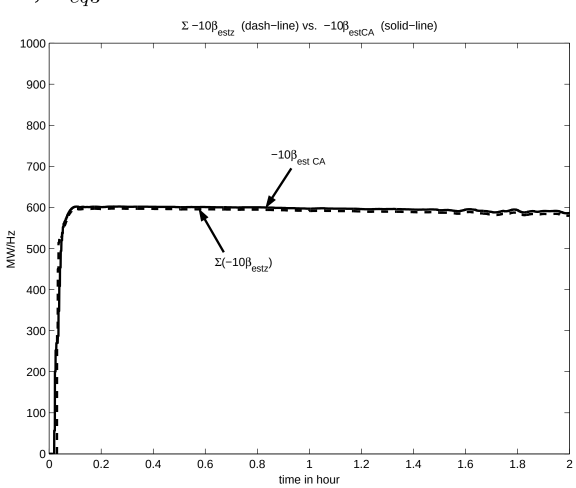

Figure 3: Algebraic sum of zones' $-10\beta_{est}$s and control area's $-10\beta_{est}$ over 2 hours

We also observe that the -10β components estimated from zones within the control area are additive in the algebraic sense. The additive nature of distributed -10β is illustrated in Figure 3. The dash line represents the algebraic sum of 3 zones' $-10\beta_{est}$s. The solid line is the value of estimated -10β for the whole control area (CA). The close tracing between two lines implies the nature of CA's -10β in distributable sense. For cross check, CA's theoretical $-10\beta_{cal}$ value is 600 MW/Hz in engineering unit.

4.2 *Accuracy of the estimate when -10β is varying*

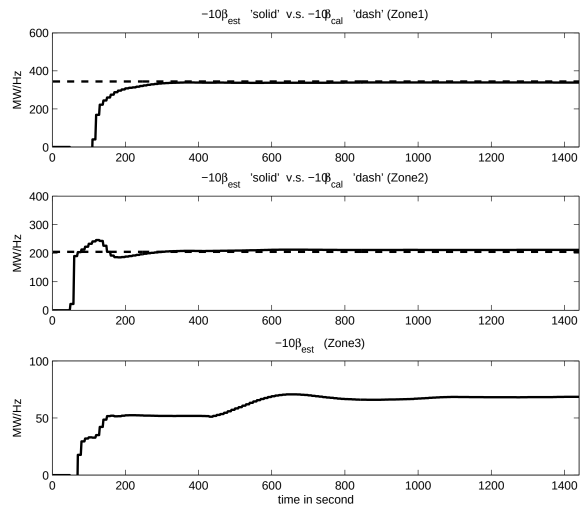

Figure 4: Sensitivity of $-10\beta_{est}$ when -10β is varying

One of the question we had about the estimation algorithm was whether the -10β estimate would closely trace the variation of zonal -10β due to the changes of on-line regulating units or load damping in the network. Figure 4 shows an example where the Zone3 had a sudden change of load and caused a change in load damping. After a short settling period, the estimation algorithm can quickly reflect the change after the occurrence of disturbance in Zone3 while other zones' $-10\beta_{est}$s remain unchanged. Therefore, we can conclude that the traceability of the estimated $-10\beta_{est}$ could be well maintained with -10β variation.

4.3 *Effect of non-linearities on estimate*

It is known that the effective speed droop of unit governor in transient operation under the non-linearities is less than the speed droop of steady-state dc gain [5, 8]. As a result, the value of zone's -10β could be affected by unit's non-linearities or limits. The following example is the test to see whether the estimation algorithm could reflect the effects of non-linearities.

Again, the schematic of the test system is similar to the previous case but with non-linearities and limits applied in the LFC loops in Zone 1 and Zone 2. The governor deadband, rate and range limits are applied on all on-line units participating the regulation control.

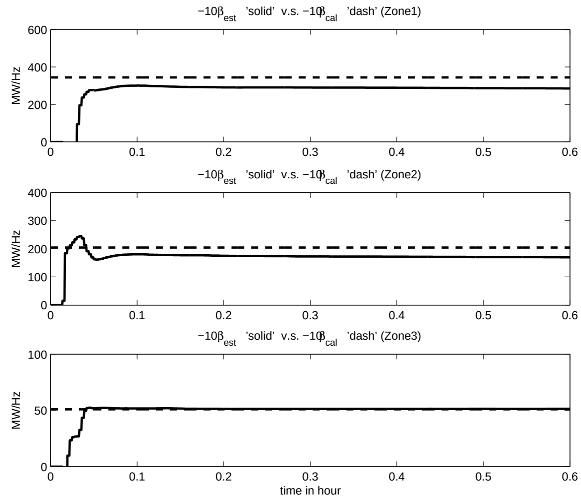

Figure 5: β_{cal}s and β_{est}s with non-linearities and limits in zone 1 and zone 2

Figure 5 gives the estimated -10βs for three zones. Note that the estimated $-10\beta_{est1}$ and $-10\beta_{est2}$ are lower than their corresponding $-10\beta_{cal}$s computed from the speed droop of steady-state dc gains. The result agrees with the conclusions of [5, 8] that the non-linearities and generating limits can affect the corresponding -10β values. Figure 5 also proves that the estimating algorithm is capable of reflecting the non-linearities effects for the target zones.

5 Definition of Regulation Control Error (RCE)

Traditionally, the real-time regulation service is carried out by central AGC of a control area. The AGC calculates area's ACE as the regulation reference to provide the real-time power balance service for the whole territory of the control area. With system operation now changed to the deregulated environment, the IPPs will have chances to serve direct regulation for customers. The control loop of local units may use the similar control approach that has been employed in the central AGC. In order to formulate the control reference signal that would be utilized in the local unit control loop, we define the regulation control error (RCE) as follows,

$$RCE_{zj} = (P_{aj} - P_{sj}) - 10B_{zj}\Delta F \quad MW \qquad (6)$$

where RCE_{zj} is the calculated RCE for Zone j; P_{aj} and P_{sj} are the actual and scheduled power interchange between Zone j and neighboring zones; $-10B_{zj}$ is Zone j's frequency bias setting; ΔF is the system frequency deviation.

The control strategy of using RCE for the regulation service is similar to the tie-line bias control in the interconnection. The system operators of the independent units can adjust their units' generating references according to the schedule or RCEs. For example, when IPP plans to provide regulation for Zone j, RCE_{zj} shall be included in the unit control loop. To avoid over-regulation from central AGC, the portion of RCE_{zj} should be excluded from area's ACE. The proposed unit control loop for bilateral regulation service is shown in Figure 6. Figure 7 demonstrates RCEs with respect to their load characteristics. The sizes of zonal RCE correspond with the variation of loads. A flatter load profile gives less RCE magnitude. The $-10B_{zj}$ settings in (6) are equal to their $-10\beta_{zj}$ estimates in this case.

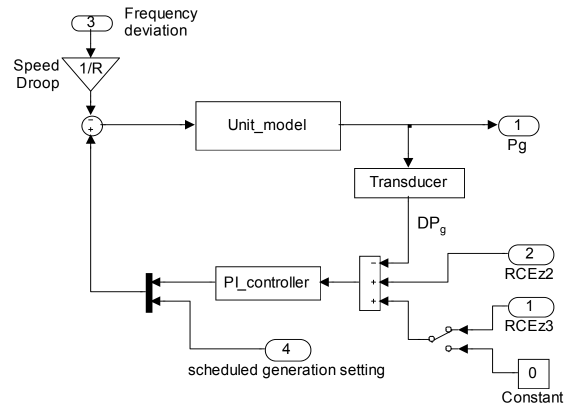

Figure 6: Unit control loop using RCE for bilateral regulation

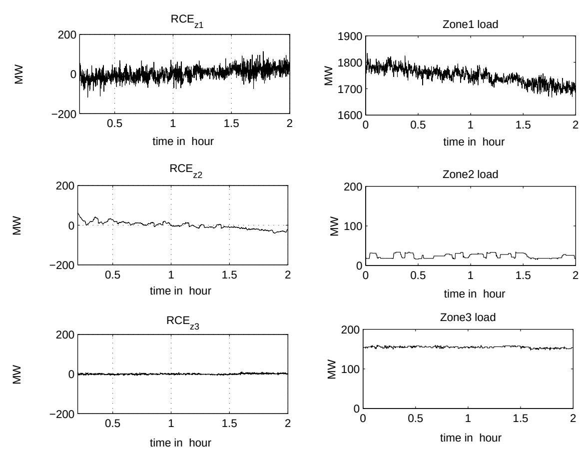

Figure 7: Zonal RCEs and their loading

6 Utilize Regulation Control Error For Bilateral Regulation Service

To verify the feasibility of using zonal RCE for bilateral regulation service, we establish the simulation platform that is similar to Figure 1 but with minor changes. We create power flow response from Zone3 load, a 3 pu. constant load pattern with 0.5 pu. unexpected step load disturbance was created in Zone3. To clarify the control interaction from Zone3 load, Zone1 load is assigned zero. In the following test cases, the transmission losses and effects of scheduled load flow errors are not considered.

6.1 CASE I: Scheduled generation service from IPP

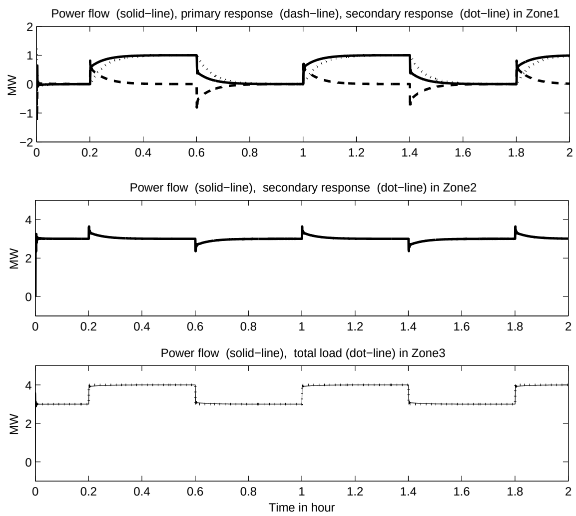

Figure 8: Response plots for three zones in Case I

Test is first conducted to gauge the control interaction between zones within the control area when Zone3 is receiving a 3 pu. scheduled generation from Zone2 but regulation support from the central AGC located in Zone1. Since Zone3's scheduled load flow is provided from Zone2 but regulation from CA's central AGC, the reference signal of unit control loop in Zone2 only includes 3 pu. scheduled value. The simulation results are shown in Figure 8.

The dot-line in the lowest window of Figure 8 represents the load characteristic in Zone3. It contains 3 pu. constant load and 1 pu. unexpected step load disturbance as we assigned. The solid-line illustrates the net power flow flowing into Zone3. The close trace between solid- and dot-lines shows that the power flow completely supply Zone3's load. The top window of Figure 8 shows the regulation effect from Zone1. The variation of power flow curve (marked in solid-line) shows that Zone1's AGC is serving generation for Zone3's disturbance. The dash- and dot-lines are the contributions from unit's primary response and AGC control, respectively. The middle window in Figure 8 shows 3 pu. power flow is generated from Zone2. The transient part of the power flow curve is from Zone2's primary response during the instant when Zone1's regulation can not fully support the load disturbance. The degree of primary response that Zone2 involves will depend on the regulation response of Zone1. The faster the regulation response of Zone1, the less primary response that Zone2 reacts.

6.2 CASE II: Scheduled generation and regulation services from IPP

Assume the regulation responsibility of Zone3 is to be transferred from Zone1 to Zone2, the reference signal of unit control loop should not only includes 3 pu. scheduled generation but RCE_{z3} of Zone3. Meanwhile, control area's AGC should remove the amount of RCE_{z3} from ACE. The test results are shown in Figure 9. Since the central AGC in Zone1 no longer provides regulation for Zone3, the power flow of Zone1 (marked in solid-line) states the fact that Zone1's online units only react to the primary response (marked in dash-line) during the transient period. The dot-line shows that the effort of AGC is negligibly small. In other words, AGC does not provide the regulation for Zone3 as long as Zone2 can fully support the load disturbance. The middle window in Figure 9 shows Zone2's power flow (marked in solid-line) and unit generation (marked in dot-line). The overlap of these two traces indicate Zone2's generation is reacting to Zone3's load demand with the unexpected disturbance.

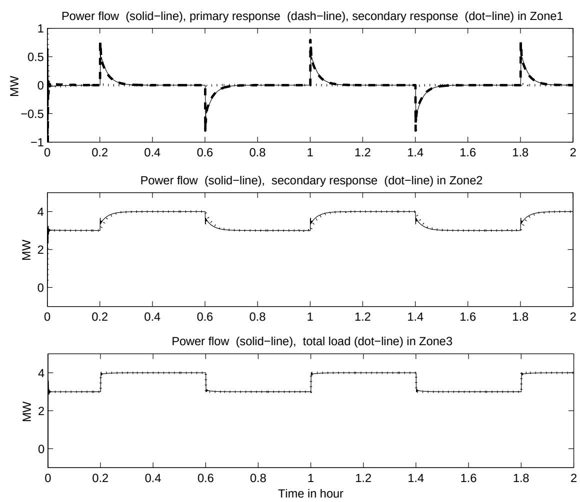

Figure 9: Response plots for three zones in Case II

7 Effects of Frequency Bias Settings on Bilateral Regulation

The capability of estimating zonal β in real-time basis offers the opportunity of using the estimated value to adjust frequency bias setting for bilateral regulation service. We expect a proper value of zonal frequency bias setting, B_z, for the calculation of RCE may be beneficial to the regulation improvement.

To explore how the B_z would affect the impact of regulation response and power flow oscillations, simulation test is conducted to establish the response of generation (ΔP_z), power-flow error (ΔP_a), and frequency deviation (ΔF) to a change in B_{z3} settings of RCE_{z3}.

The sample kind of the transient response from the test case when Zone3 is receiving regulation from IPP of Zone2. Here, we calculate RCE_{z3} with different bias setting (B_{z3}) and proceed the regulation coordination described in the previous section. The RMS value of the defined variable is the root mean square difference between measured and steady-state values over the observation time interval.

RMS error for power flow among zones within CA			
	ΔP_{z1} pu	ΔP_{z2} pu	ΔP_{z3} pu
$B_{z3} = 0$	0.073	0.086	0.014
$B_{z3} = \beta_{z3}$	0.069	0.081	0.014
$B_{z3} = 2\beta_{z3}$	0.066	0.078	0.014
$B_{z3} = B_{CA}$	7.476	5.828	2.230
RMS value for RCE_{z2}, ACE_{CA}, and ΔF			
	RCE_{z2} pu	ACE_{CA} pu	ΔF Hz
$B_{z3} = 0$	0.113	0.026	0.222
$B_{z3} = \beta_{z3}$	0.122	0.018	0.221
$B_{z3} = 2\beta_{z3}$	0.132	0.017	0.221
$B_{z3} = B_{CA}$	23.614	4.576	30.778

Table 1: Transient responses for step disturbance in Zone3

Table 1 shows the transient responses of power flow, RCE in Zone2, ACE in CA, and frequency deviation to the step load disturbance in Zone3.

The RMS errors of power flow in Table 1 decrease with higher B_{z3}/β_{z3} ratio for a disturbance in Zone3. Note that the dynamic schedule method is equivalent to the case when $B_{z3} = 0$. It is apparent that adding a higher value of zonal frequency bias for defined zone's RCE would mitigate power flow oscillations and transients from unit output. However, a comparably high value of zonal frequency bias (Zone3's frequency bias is equal to CA's area bias setting, i.e. B_{z3} = B_{CA} in this case) would tend to enlarge the power flow and generation oscillations. Note that RCE_{z2} increases but ACE_{CA} decreases with higher B_{z3}/β_{z3} ratio. This may be explained by the fact that frequency response affects more on the control index of the regulation provider (Zone2), but alleviates other units' duty of frequency regulation from Zone3.

8 Conclusion

In this paper, we have presented an algorithm to estimate defined zone's -10β online for the reference of zonal frequency bias setting. Since the estimation algorithm uses variables that are commonly available in the existing SCADA system, it does not require additional equipment or measurement. Demonstrated are the test results showing that the traceability of the estimation algorithm for defined zones is performing as expected. The algorithm also exhibits its robustness under the influence of non-linearities and FRC variations due to the change of unit regulation or load disturbance.

Also presented in this paper is the use of zonal RCE for regulation service. Simulation and analytical results validate the feasibility of the proposed method for operating entities to provide bilateral regulation for specific customers. When applying zonal frequency bias setting on the regulation control, there are advantages over the dynamic schedule method in reducing the unit movement and power flow oscillations. In addition, the proposed control approach may be extended to inter-area regulation service. If RCE control is widely adopted, the contractual regulation will operate more efficiently in the deregulated utility industry.

9 Acknowledgement

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