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ABSTRACT

Decentralized and regional load-frequency control of power systems operating in normal and near-normal conditions has been well studied; and several analysis/synthesis approaches have been developed during the last few decades. However in contingency and off-normal conditions, the existing emergency control plans, such as under-frequency load shedding, are usually applied in a centralized structure using a different analysis model.

This paper discusses the feasibility of using frequency-based emergency control schemes based on tie-line measurements and local information available within a control area. The conventional load-frequency control model is generalized by considering the dynamics of emergency control/protection schemes and an analytic approach to analyze the regional frequency response under normal and emergency conditions is presented.

1. Introduction

Following a large generation loss disturbance, a power system's frequency may drop quickly if the remaining generation no longer matches the load demand. System frequency changes of a large scale power system are a direct result of the imbalance between the electrical load and the power supplied by system connected generators [1]. Therefore, system frequency provides a useful index to indicate the system generation and load imbalance. Any short term energy imbalance will result in an instantaneous change in system frequency as the disturbance is initially offset by the kinetic energy of rotating plant. Significant loss of generating plant without adequate system response can produce extreme frequency excursions outside the working range of plant. Off-normal frequency deviation can directly impact on power system operation, system reliability and efficiency. A large frequency deviation can damage equipments, degrade load performance, overload transmission lines, and interfere with system protection schemes. These events can ultimately lead to system collapse [2].

If the amount of electrical load in a control area (region) is increased rapidly, due to changes in consumer load demands, then the extra energy required is drawn from the generating units' rotors. These rotors therefore slow down, thus reducing system frequency. For small load changes, the corresponding generation changes can be slower. In the market environment, the system's responses to load changes are provided as regulating ancillary ser-

vices i.e., automatic generation control (AGC) or load-frequency control (LFC) mechanism. Use of LFC as an ancillary service has a long history. A simplified LFC mechanism is first introduced in [3,4], and has since evolved over several decades. There has remained a continuing interest in designing LFC with improved ability to maintain system frequency close to nominal value using various control methodologies [5].

Continuing with the example of increased customer load demand, in response to large sudden load changes a rapid increase in generation would be required to initially arrest the decline in system frequency, and to then restore the frequency to the nominal level. For a very large changes in system frequency, such as might arise from a multiple contingency event, the combined response of the generating units' and supplementary control from LFC may not be enough, and may not be reliable. Additional contingency ancillary services or emergency control plans maybe required to avoid market failure can further frequency decline to the point where generating units are beyond their reliable operating limits. For example, it might be reasonable to require customers to make a percent of their load available for such emergency shedding by under-frequency relays. This emergency load shedding would only be used if the frequency falls below the frequency threshold.

Some frequency response models and control scenarios have attempted to address such contingency conditions using emergency control strategies during the past years [6–9]. A centralized emergency control approach can be seen in most of the proposed schemes. Moreover, most published works on the power system frequency regulation have considered separate modeling (and even

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Table 1
Frequency operating and control actions.

Frequency deviation range	Condition	Control action
Δf_1	No contingency or load event	Normal operating
Δf_2	Generation/load or network event	LFC operating
Δf_3	Separation event	Emergency operating
Δf_4	Multiple contingency event	Emergency operating

analysis techniques) for the normal/LFC conditions and emergency conditions.

This paper's key objective is to analyse the feasibility of regional emergency control schemes. For this purpose a new analytic approach is used to examine the frequency regulation under normal, LFC and emergency operating conditions. Our aim is to adapt the well-known conventional LFC model for use in contingency and emergency circumstances by proposing analysis tools that include the effects of both emergency control and protection dynamics. Our provided generalized regional load-frequency control model could be useful before and after separation. The paper first presents the mathematical representation of the frequency response and important related concepts for a control area using a low-order dynamic model. Following that, the analytical results are examined on a three control area power system.

2. Frequency operating standards: an Australian experience

Depending on the size of the frequency deviation experienced, LFC, emergency control and natural governor response could all be required to maintain power system frequency. One method of characterizing frequency deviations is in terms of the frequency deviation ranges and related control actions shown in Table 1. The frequency variation ranges $\Delta f_1, \Delta f_2, \Delta f_3$ and Δf_4 are identified in terms of different power system operating conditions (perhaps specified in terms of local regulations). Under normal operation, frequency is maintained near to nominal frequency by balancing generation and load. This is, for small frequency deviations up to Δf_1, these deviations can be attenuated by the governor natural autonomous response (primary control). A LFC system can be used to restore area frequency if it deviates more than Δf_1 Hz. In partic-

ular, any LFC system must be designed to maintain the system frequency and time deviations within the limits in specified frequency operating standards. The value of Δf_2 is mainly determined by the available amount of operating reserved power in the system [10].

Although, the sensitive equipment might also be designed to operate satisfactorily if the frequency is normally within 0.3–0.5 Hz of nominal, specific studies such as IEEE standard 446-1995 and BS EN50160:1995 state that a maximum of ±0.5 Hz frequency variation should be used as a tolerance for major end-use equipment [11]. For even larger frequency deviations and in a more complex condition (such as Δf_3 and Δf_4 frequency deviation events) the emergency control and protection schemes must be used to restore the system frequency. There is a risk that these large frequency deviation events might be followed by additional generation events, load/network events, separation events or multiple contingency events.

The frequency operating standards could be different from network to network. For example in Australia, for the mainland regions, the $\Delta f_1, \Delta f_2, \Delta f_3$ and Δf_4 are specified as 0.3 Hz, 1 Hz, 2 Hz and 5 Hz, respectively [12]. Further, in the Australian network, the frequency threshold to start the under-frequency load shedding is considered to be 49 Hz (50 Hz is the nominal system frequency).

As previously mentioned, system reliability is strongly impacted by frequency changes that are sufficient to cause undesired load shedding, generator tripping, damaged equipment; which all threaten the stability of the system. In a centralized control structure, equal sharing of emergency control actions, means that appropriate load shedding between control areas cannot always be achieved. Improved emergency response to a large frequency deviation would require determination of which control areas were responsible for the observed frequency deviations. For this reasons, it seems desirable to improve the real-time observability of the power system and to supply security coordinators with tools that enable them to determine: when frequency excursions are occurring, where the initial rate of frequency change occurred, and which control area is responsible.

Fig. 1 shows the regional power system frequency and its gradient deviations in four region centers following a significant incident on Friday 13 August 2004 in Australia. An equipment failure
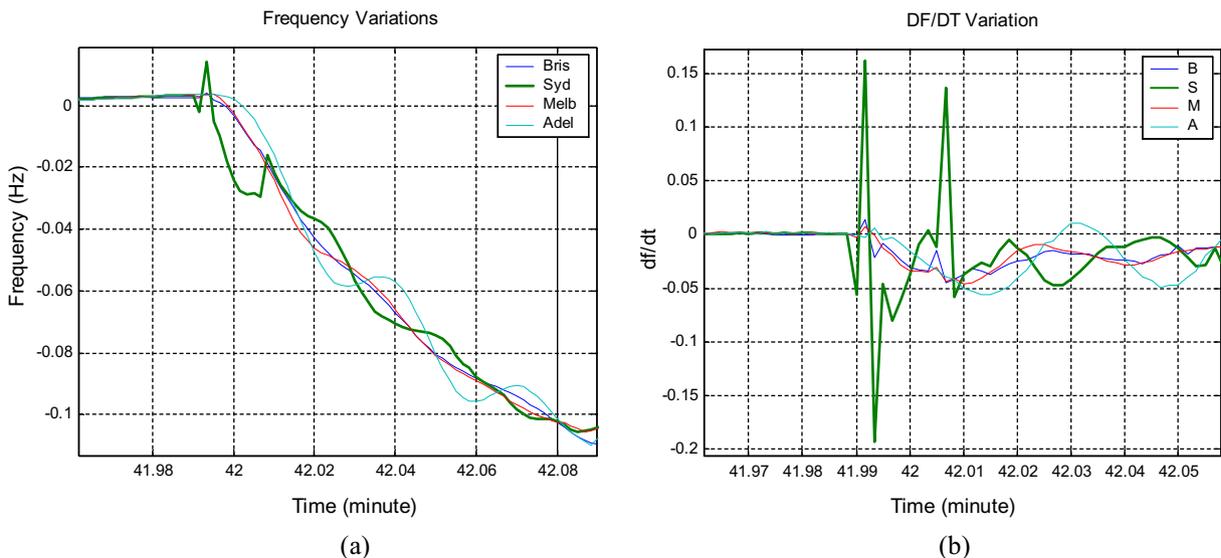

Fig. 1. Regional frequency response following the 13 August event in the main cities (Brisbane, Sydney, Melbourne, Adelaide) of the affected regions; (a) frequency deviation, (b) frequency gradient.
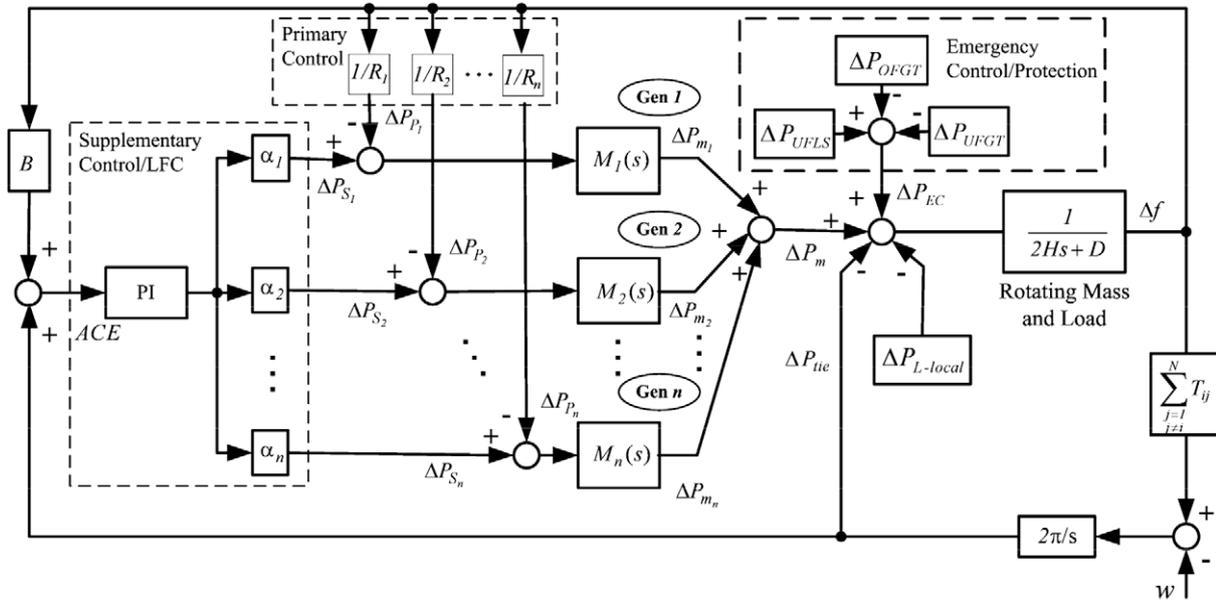
Fig. 2. Generalized control area model.

in New South Wales (NSW) led to the loss of six major electricity generating units in that region, resulting in some customers in NSW, Queensland, Victoria and South Australia losing supply. For this event, approximately 1500 MW of customer load was automatically shed from the system and power was progressively restored within 2.5 h of the incident occurring [13]. In Australian network, National Electricity Market Management Company (NEMMCO) coordinates the National Electricity Market (NEM) and states that the policy is to share the load-shedding requirements.

The initially low transfer from Queensland is one reason why load-shedding actions undertaken in this state, and the resulting increased transfer to NSW, did not cause overload and trip events on the interconnecting line. A better load-shedding strategy, such as selected load shedding in NSW could have significantly reduced the risk of reaching transfer limits, tripping of more generators and further cascade events. The initial frequency gradient strongly suggests that NSW had the fastest initial acceleration and a biased shedding approach for NSW could be significantly increased load shedding in that state. Analysis of this event show that regional load shedding is desirable and feasible and, in this situation, would have limited the peak stresses on interconnections.

As is shown in Fig. 1 and is analytically illustrated in Section 5, measuring the initial rate of frequency change in the regions effectively identifies the location of incident, and could be used to organize appropriate load-shedding actions.

3. Generalized regional load-frequency control model

The conventional low-order load-frequency control (LFC) model is well discussed in [3,4]. Here, in order to cover emergency control/protection schemes (as well as primary and supplementary control loops), a modified dynamical structure is introduced for representing the regional power system frequency response Fig. 2 shows the block diagram of the modified control area with n generator units. The shown blocks and parameters are defined as follows:

Δf	frequency deviation
ΔP_m	mechanical power

ΔP_S	supplementary control action
ΔP_P	primary control action
ΔP_{tie}	net tie-line power flow
ΔP_{EC}	emergency control/protection action
$\Delta P_{L\text{-}local}$	local load deviation
ΔP_{UFLS}	under-frequency load-shedding effect
ΔP_{UFGT}	under-frequency generation trip effect
ΔP_{OFGT}	over-frequency generation trip effect
H	equivalent inertia constant
D	equivalent damping coefficient
T_{ij}	tie-line synchronizing coefficient between area i and j
B	frequency bias
w	area interface
R_i	droop characteristic
ACE	area control error
α_i	participation factors
$M_i(s)$	low-order governor-turbine model
PI	proportional integral controller.

As shown in Fig. 2, the frequency performance of a control area is represented approximately by a lumped load generation model using an equivalent frequency, inertia and damping factors [14].

$$\Delta f = \Delta f_{sys} = \sum_{i=1}^{N}(H_i \Delta f_i) \bigg/ \sum_{i=1}^{N} H_i \qquad (1)$$

$$H = H_{sys} = \sum_{i=1}^{N} H_i, D = D_{sys} = \sum_{i=1}^{N} D_i \qquad (2)$$

Following a load disturbance within the control area, the frequency of the area experiences a transient change and the feedback mechanism generates appropriate rise/low signal to the participated generator units according to their participation factors (α_i) to make generation follow the load. In the steady state, the generation is matched with the load, driving the tie-line power and frequency deviations to zero. As there are many generators in each area, the control signal has to be distributed among them in proportion to their participation in the LFC.

The real-world LFC systems usually use proportional integral (PI) controllers [15,16]. According to Fig. 2, in a control area the

ACE performs the input signal for the supplementary control system. Therefore the output signal of the mentioned system has the following form

$$\Delta P_{S_i}(s) = \alpha_i \left(K_P + \frac{K_I}{s} \right) ACE(s) \tag{3}$$

Block scheduling in a free market, which defines power transactions as fixed power levels over fixed time period blocks, makes it more difficult to control the system frequency. The difference between the block schedule and the actual load profile must be accommodated by tuning other generators.

In the case of a large generation loss disturbance, the available power reserve may not be enough to restore the system frequency and the power system operators may follow an emergency control plan such as under-frequency load shedding (UFLS). The UFLS strategy is designed so as to rapidly balance the demand of electricity with the supply and to avoid a rapidly cascading power system failure. Allowing normal/LFC frequency variations to move within expanded limits will require the coordination of primary and supplementary controls with generations and load set points, for example under-frequency generation trip (UFGT), over-frequency generation trip (OFGT) and other frequency controlled protection devices.

The conventional LFC model in [3,4] gives the free response of the LFC based system following a contingency. In the case of contingency analysis, the emergency protection and control dynamics must be properly taken account in the frequency response model. Since they directly change the area power generation/load, the mentioned dynamics can be easily added to the area control system model as shown in Fig. 2.

The emergency control schemes and protection devices dynamics are usually represented using incremented/decremented step behavior. Thus in Fig. 2, the related blocks can be modeled as a sum of incremental (decremental) step functions. For a fixed UFLS scheme [6], the function of ΔP_{UFLS} in time domain could be considered as a sum of incremental step functions of $\Delta P_j u(t - t_j)$. Therefore, for L load-shedding steps we have

$$\Delta P_{UFLS}(t) = \sum_{j=0}^{L} \Delta P_j u(t - t_j) \tag{4}$$

where ΔP_j and t_j denote the incremental amount of load shed and time instant of the jth load-shedding step, respectively. Similarly, to formulate the ΔP_{OFGT} and ΔP_{UFGT}, we can use appropriate step functions. Therefore using the Laplace transformation, is it possible to represent $\Delta P_{EC}(s)$ in following summarized form

$$\Delta P_{EC}(s) = \sum_{l=0}^{N} \frac{\Delta P_l}{s} e^{-t_l s} \tag{5}$$

where ΔP_l is the size of equivalent step load changes due to generation/load event or a load-shedding scheme at t_l.

4. Regional frequency response analysis

Considering the modified model in Fig. 1, the system frequency can be obtained as follows:

$$\Delta f(s) = \frac{1}{2Hs + D} [\Delta P_m(s) + \Delta P_{EC}(s) - \Delta P_{tie}(s) - \Delta P_{L\text{-}local}(s)] \tag{6}$$

where

$$\Delta P_m(s) = \sum_{i=0}^{n} \Delta P_{mi}(s) \tag{7}$$

$$\Delta P_{m_i}(s) = M_i(s)[-\Delta P_{P_i}(s) + \Delta P_{S_i}(s)] \tag{8}$$

and

$$\Delta P_{EC}(s) = \Delta P_{UFLS}(s) - \Delta P_{UFGT}(s) - \Delta P_{OFGT}(s) \tag{9}$$

$$\Delta P_{P_i}(s) = \frac{\Delta f(s)}{R_i} \tag{10}$$

$$\Delta P_{S_i}(s) = \alpha_i \left(K_P + \frac{K_I}{s} \right)(\Delta P_{tie}(s) + \beta \Delta f(s)] \tag{11}$$

Practically, the integral coefficient K_I is enough small and can be ignored in the computation. The expressions (5), (8)–(11) can be substituted into (6) with the result

$$\Delta f(s) = \frac{1}{2Hs + D} \left(\left[K_P \sum_{i=1}^{n} \alpha_i M_i(s) - 1 \right] \Delta P_{tie}(s) \right.$$
$$\left. - \left[\sum_{i=1}^{n} M_i(s) \left(\frac{1}{R_i} - \alpha_i \beta K_P \right) \right] \Delta f(s) + \sum_{l=0}^{N} \frac{\Delta P_l}{s} e^{-t_l s} - \Delta P_{L\text{-}local}(s) \right) \tag{12}$$

For the sake of load disturbances analysis we are usually interested in $\Delta P_L(s)$ in the form of a step function, i.e.,

$$\Delta P_{L\text{-}local}(s) = \frac{\Delta P_d}{s} \tag{13}$$

Substituting $\Delta P_{L\text{-}local}(s)$ in (12) and summarizing the result yields

$$\Delta f(s) = \frac{g_2(s)}{g_1(s)} \Delta P_{tie}(s) + \frac{1}{sg_1(s)} \left(\sum_{l=0}^{N} \Delta P_l e^{-t_l s} - \Delta P_d \right) \tag{14}$$

where

$$g_1(s) = 2Hs + D + \sum_{i=1}^{n} M_i(s) \left(\frac{1}{R_i} - \alpha_i \beta K_P \right) \tag{15}$$

and

$$g_2(s) = K_P \sum_{i=1}^{n} \alpha_i M_i(s) - 1 \tag{16}$$

Several low-order models for representing turbine-governor dynamics $M_i(s)$ have been proposed for use in power system frequency analysis and control design. In these models, the slow system dynamics of the boiler and the too fast generator dynamics are usually ignored. A simplified turbine-governor model (first order) was proposed in [7]. The following more appropriate second order model, which is widely used by LFC researchers, was introduced in [4] for use in load-frequency control analysis and synthesis.

$$M_i(s) = \frac{1}{(1 + T_g s)} \cdot \frac{1}{(1 + T_t s)} \tag{17}$$

where T_g and T_t are governor and turbine time constants, respectively.

Substituting $M_i(s)$ from (17) in (15) and (16), and using the final value theorem, the frequency deviation in steady state (Δf_{ss}) can be obtained from (12).

$$\Delta f_{ss} = \lim_{s \to 0} s \cdot \Delta f(s) = 0 + \frac{1}{D + \sum_{i=1}^{n} \frac{1}{R_i} - \beta K_P \sum_{i=1}^{n} \alpha_i} \left(\sum_{l=0}^{N} \Delta P_l - \Delta P_d \right) \tag{18}$$

By definition [1], system's frequency response characteristic (β) is equivalent to

$$\beta = D + \frac{1}{R_{sys}} \tag{19}$$

and considering

$$\sum_{i=1}^{n} \alpha_i = 1; \quad 0 \leqslant \alpha_i \leqslant 1 \tag{20}$$

the Eq. (18) can be rewritten into the following form

$$\Delta f_{ss} = -\frac{\Delta P_D}{(D + \frac{1}{R_{sys}})(1 - K_P)} \tag{21}$$

where

$$\Delta P_D = \Delta P_d - \sum_{l=0}^{N} \Delta P_l e^{-t_l s} \tag{22}$$

and using

$$\sum_{i=1}^{n} \frac{1}{R_i} = \frac{1}{R_{sys}} \tag{23}$$

Since the value of droop characteristic R_i is generally bounded between about 0.05 and 0.1 for most generator units ($0.05 \leqslant R_i \leqslant 0.1$) [7], for a given control system according to (23) we can write

$$R_{sys} \leqslant R_{i,min} \tag{24}$$

and for a small enough DR_{sys}, (21) can be reduced to

$$\Delta f_{ss} = -\frac{R_{sys}\Delta P_D}{(DR_{sys} + 1)(1 - K_P)} \cong -\frac{R_{sys}\Delta P_D}{(1 - K_P)} \tag{25}$$

5. System inertia and equivalent load change

As previously mentioned, frequency changes can induce a corresponding change in demand load. This effect is called *load relief* and is taken into account for calculating the amount of required ancillary service [17]. The change in demand is always in a direction that tends to alleviate the frequency deviation. i.e., for a reduction in frequency, the load relief is negative (decrease in demand), which tends to alleviate the falling frequency. In the mainland part of the Australian power network, for every 1% change in frequency (0.5 Hz) it is assumed there will be a corresponding 1.5% change in demand [17].

From (25), the magnitude of ΔP_D can be estimated as follows:

$$\Delta P_D = -\frac{(1 - K_P)}{R_{sys}} \Delta f_{ss} \tag{26}$$

To compensate the power imbalance ΔP_D, the total necessary secondary regulation should be

$$\Delta P_S = -\Delta P_D = \frac{(1 - K_P)}{R_{sys}} \Delta f_{ss} \tag{27}$$

For the sake of dynamic frequency analysis in the presence of sudden load changes, it is usual to model the multi machine dynamic behavior by an equivalent single machine [7]. Using the concept of an equivalent single machine, we can simplify the control area block diagram (Fig. 2) as shown in Fig. 3. Here, ΔP_D covers the effect of local load disturbance, network and generation events. R_{sys} and $M_{sys}(s)$ are equivalent droop characteristic and governor-turbine model, respectively.

According to Fig. 3, we can write

$$\Delta f(s) = \frac{-1}{2Hs + D} \Delta P_D(s) \tag{28}$$

or

$$\Delta P_D(t) = -2H \frac{d\Delta f(t)}{dt} - D\Delta f(t) \tag{29}$$

To express the result into a form suitable for sampled data, (29) is written as difference equation.

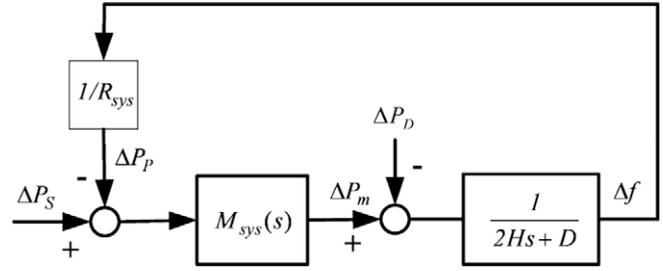$$\Delta P_D = -\frac{2H}{T_S}[\Delta f(t_1) - \Delta f(t_0)] - D\Delta f(t_1) \tag{30}$$

Fig. 3. Simplified control area model.

where the T_S is the sampling period. The t_0 and t_1 are boundary samples within the assumed interval. For a control area with a small enough damping factor, (30) can be approximated as follows:

$$\Delta P_D \approx -\frac{2H}{T_S}[\Delta f(t_1) - \Delta f(t_0)] \tag{31}$$

Thus, the frequency gradient in a control area is proportional to the magnitude of overall disturbance in that area. This result agrees with the obtained results in other published works [18–21]. The factor of proportionality is the system inertia H. Actually the inertia constant is loosely defined by the mass of all the synchronous rotating generators and motors connected to the system. For a specific load decrease, if H is high, then the frequency will fall slowly and if H is low, then the frequency will fall faster.

6. A simulation example

A power system with three control areas, shown in Fig. 4, is used to illustrate the analytic approach developed in the previous sections. Each control area has some generator units and, at the same time, is connected to other areas. The power system parameters are given in Table 2. It is assumed that each control area is responsible to maintain its frequency close to a specified nominal value.

It is assumed that the maximum reserved LFC power ΔP_{Rmax} in area-1 available to track area-1 power imbalance is fixed at 100 MW. For the first scenario, the system frequency response is tested following a step loss of generation 0.1 pu in area-1, with simultaneous increase of 0.02 pu load steps in area-2 and area-3. The frequency deviation and the corresponded frequency gradient for three control areas is shown in Fig. 5. The higher frequency rate
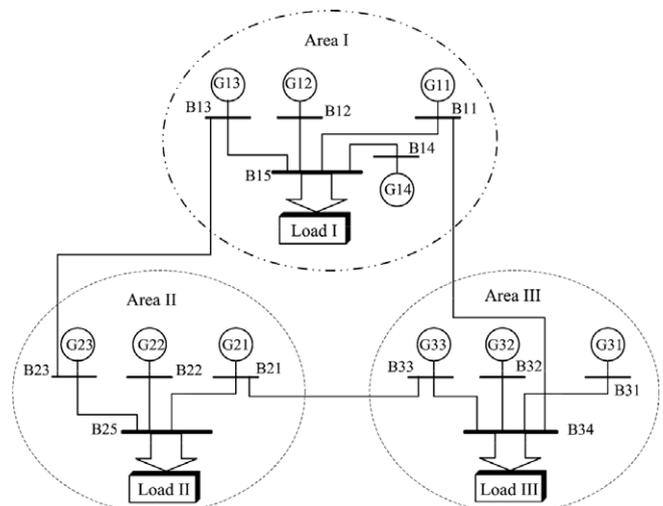
Fig. 4. 3-Control area power system.

Table 2
Applied data for simulation.

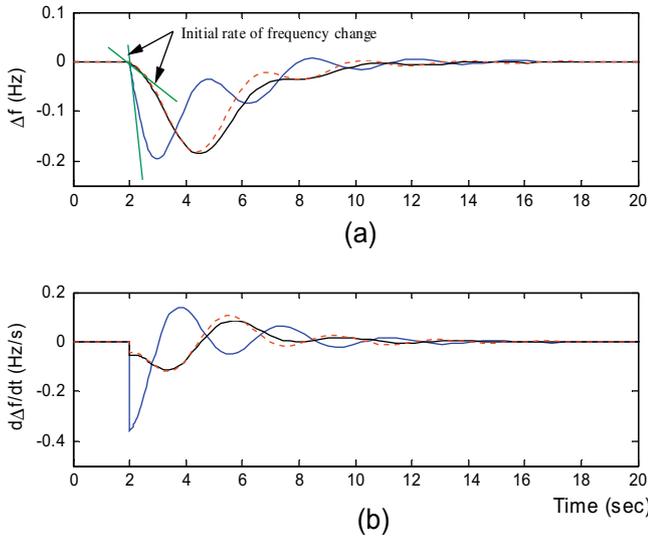| Control area	Area-1				Area-2			Area-3		
Generator unit	G11	G12	G13	G14	G21	G22	G23	G31	G32	G33
Rating (MW)	1200	600	800	800	600	1200	800	1400	600	600
H_i (s)	6	4	5	5	5	5	4	6	5	5
D_i (pu MW/Hz)	0.05	0.08	0.05	0.04	0.05	0.08	0.05	0.07	0.05	0.04
R_i (%)	3	3	3.2	2.7	2.7	2.6	2.5	2.8	3	3
T_{ti}	0.40	0.36	0.42	0.45	0.44	0.32	0.40	0.30	0.40	0.41
T_{gi}	0.30	0.20	0.07	0.10	0.30	0.20	0.15	0.15	0.15	0.20
α_i	0.4	0.3	0.2	0.1	0.6	0.0	0.4	0.0	0.5	0.5
β_i (pu MW/Hz)		1.3686				1.1857			1.0735	
K_{Pi}, K_{Ii}		−0.31, −0.03				−0.24, −0.01			−0.16, −0.02	

Fig. 5. System response following step load changes in control areas at 2 s; (a) frequency deviation, (b) frequency gradient. Area-1 (solid), area-2 (dotted) and area-3 (dashed-line).

changes occur in area-1. Recalling (31), since the disturbance magnitude in area-1 was higher than the other areas, this behavior is easily understandable. The rate of frequency change is proportional to the power imbalance, and it also depends on the area system inertia. From Fig. 5, it can be concluded that the disturbance location affects the frequency behavior of power systems and consequently the design and selection of a suitable emergency control plan.

In steady state, the frequency deviation (Δf_{ss}) reaches the value given by (21). Since the frequency deviations remained within near-normal frequency operating bound (Δf_1 and Δf_2) and the available LFC power reserve (100 MW) could match the power demand, the system recovered within 15 s.

After the primary (governor) response, the supplementary (LFC) control responds by using the available instantaneous reserve to raise the frequency back to the nominal level. However, following disturbances of large magnitude, or when there is not enough reserved power, the frequency (in steady state) may not return to a normal operating condition. Consider the system frequency response following a large load disturbance of 0.3 pu in area-1. Here, the total area load demand is much higher than the ΔP_{Rmax}. The normal and LFC controls are not able to maintain the frequency at the nominal value and the steady state frequency may pass the threshold frequency f_t.

In order to assess whether the frequency passes the frequency threshold (i.e., execution of an emergency control action may be necessary), one may recall (26). According to (26), the maximum amount of available area power reserve ΔP_{Rmax} can compensate the following steady state area frequency deviation.

$$\Delta f_{max} = \left| \frac{R_{sys}}{(1 - K_P)} \Delta P_{Rmax} \right| \tag{32}$$

Therefore, the load-shedding frequency threshold, which can be determined as follows:

$$f_t = f_0 - \Delta f_{max} \tag{33}$$

In a realistic multi-area power system, there must be sufficient reserve from the energy market to ensure that no more than a small percent of annual customer demand may be at risk of not being supplied over the long term (in Australian power network it is considered to be 0.002%). The reserve margins for each region of the market must be calculated appropriately. For example in Australian network, NEMMCO determined the following reserve margins, which applied from late in June 2004: Queensland 610 MW; New South Wales −290 MW; and 530 MW of reserve shared across the combined regions of Victoria and South Australia, provided that 265 MW of this amount is available within South Australia [22].

Continuing with the simulation example, assume that the frequency has passed the load-shedding frequency threshold f_t and thus *UFLS* emergency control actions are needed to recover the system frequency. In this case, the system is in an emergency condition and we need to follow a suitable load disconnection (load shedding) procedure to recover the system frequency. To clarify the impact of different control actions considered in the scenario, only the primary control is used at the beginning. The simulation
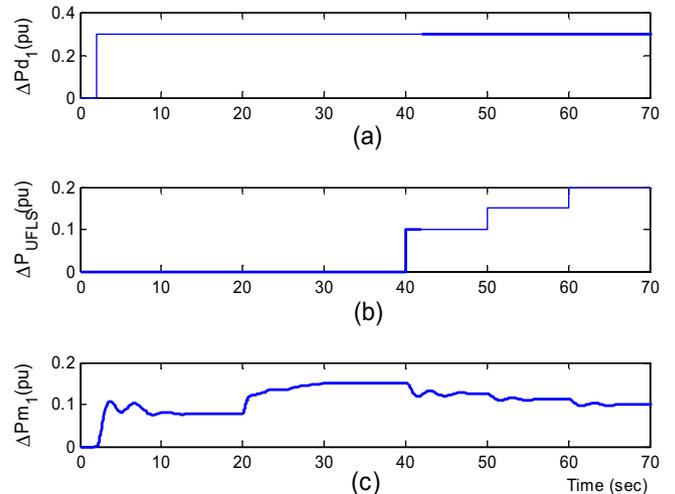

Fig. 6. Area-1 response: (a) Local load disturbance, (b) Incremental load shedding; and (c) total mechanical power.
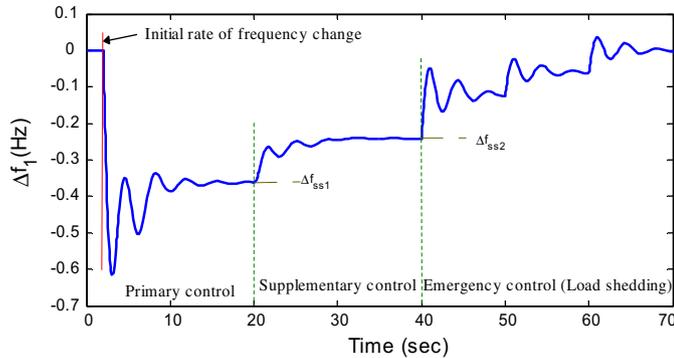
Fig. 7. Applied control actions to recover the area frequency.

results for area-1 are shown in Figs. 6 and 7. Considering the applied disturbance (Fig. 6a) and the overall area load disturbance magnitude (26), a three staged load-shedding plan is investigated and started at 40 s, as shown in Fig. 6b. The loads 0.1 pu, 0.05 pu and 0.05 pu are disconnected at 40 s, 50 s and 60 s, respectively.

$$\Delta P_{UFLS}(t) = 0.1u(t-40) + 0.05u(t-50) + 0.05u(t-60) \qquad (34)$$

The mechanical power changes and frequency deviation during the three different operating conditions are shown in Figs. 6c and 7. It is assumed that in the other control areas, the LFC loops separately control their local load changes. The Δf_{ss1} and Δf_{ss2} in Fig. 7 can be analytically calculated using (25). To obtain Δf_{ss1} accurately, the gain K_P must be fixed at zero.

7. Remarks

Motivated by real-world considerations, we complete our analysis with the following points:

- During frequency excursions, the characteristic times of the processes and devices that are activated will range from fraction of seconds, corresponding to the response of devices such as *UFLS* and generator controls and protections, to several minutes, corresponding to the response of devices such as prime mover energy supply systems and load voltage regulators [23]. The supplementary control response is usually slower than primary response [24], and much slower than emergency dynamic response (e.g., load shedding). Thus, the supplementary loop response is not usually taken into account in emergency frequency control studies and analysis. This is similar to what is done in Section 4 by ignoring K_I.
- The unpredictable nature of power system contingency events means that it is not possible to optimize the regional load shed properties by a centralized emergency control scheme for all contingency incidents. Thus, for each control area, the first objective is to ensure that the area will remain secure for the loss of its interconnections with adjoining areas. The performance of regional emergency control schemes depends on the amounts of frequency control ancillary service enabled in each region at the time of the incident.
- Our results show that the power system regions as authorized control areas can share the frequency-based emergency control plans such as under-frequency load shedding, before and after separation. This does not mean that there is no need for centralized supervision. In a multi-area market, an independent supervisor organization is still needed to organize the interchange powers and stabilize the overall market.
- In this paper, it is assumed that the advanced computing techniques and fast hardware facilities are available to measure the regional rate of frequency changes in appropriate time (less

than 500 ms) to prevent spurious operation. The initial assessment, based upon NEMMCO's studies of the Australia power system, suggest that load would have to be shed within about 500 ms to be effective in preventive loss of interconnections on the first swing.
- It should be noted that although the frequency gradient provides a good measurement index to describe the regional behavior, it does not include all necessary knowledge of the actual event. Therefore to decrease the potential risks of unintended adverse consequences (such as over-shedding of load leading to excessive over frequency an unnecessarily shedding of load following a minor event), other information and parameters may be needed.

8. Conclusions

This paper introduced a generalized load-frequency control model suitable for analysis of a power system's frequency response during both normal and emergency conditions. The effects of emergency control/protection dynamics are properly considered. Using the mentioned model, possibility of regional emergency control plans, such as under-frequency load shedding, are studied and an analytic approach to examine the frequency regulation under normal, LFC and emergency operating conditions is presented. Finally, the analytical results are examined using simulation of a three control area power system. These simulation results agree with those obtained analytically.

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