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An Underfrequency Load Shedding Scheme with Minimal Knowledge of System Parameters

Abstract: Underfrequency load shedding (UFLS) is a common practice to protect a power system during large generation deficit. The adaptive UFLS schemes proposed in the literature have the drawbacks such as requirement of transmission of local frequency measurements to a central location and knowledge of system parameters, such as inertia constant H and load damping constant D. In this paper, a UFLS scheme that uses only the local frequency measurements is proposed. The proposed method does not require prior knowledge of H and D. The scheme is developed for power systems with and without spinning reserve. The proposed scheme requires frequency measurements free from the oscillations at the swing mode frequencies. Use of an elliptic low pass filter to remove these oscillations is proposed. The scheme is tested on a 2 generator system and the 10 generator New England system. Performance of the scheme with power system stabilizer is also studied.

Keywords: elliptic filter, power system island, spinning reserve, underfrequency load shedding

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1 Introduction

Whenever there is a generation-load imbalance in a power system, the generator rotors accelerate or decelerate depending on whether the generation in the system is surplus or deficit. This may lead to rise or fall in the system frequency. When the generators decelerate due to active power deficit, the primary frequency control tries to increase the mechanical power input. However, if the frequency decay is rapid because of a large generation deficit, the primary frequency control may not be sufficient as its speed of activation is limited. Large generation deficit may be due to sudden increase in the system load, sudden outage of a large generating unit or sudden outage of tie lines, which can lead to formation of power system islands. Such large disturbances may cause the system frequency to decay below the acceptable limits.

Operating the generating equipment at low frequencies is hazardous and the effects are explained by Akers et al. [1] and in IEEE Standard [2]. The effects are very prominent in generators with steam turbines. If the frequency is not brought back to an acceptable level within a short duration, the turbine protection relays of generators may get activated and this may lead to cascaded loss of generation and ultimately system blackout. Underfrequency load shedding (UFLS) is a common practice, globally accepted by the utilities, as the last resort to prevent such blackouts and also to protect the generating equipment. Controlled islanding followed by load shedding is also proposed by a few researchers as a corrective control measure against large disturbances [3, 4].

Many publications on UFLS schemes are presented in the literature over the years [5–14]. According to Delfino et al. [9], various frequency-based UFLS schemes can be classified as (1) the traditional, (2) the semi-adaptive, and (3) the adaptive UFLS schemes. A hybrid method based on both the frequency and power is proposed by Giroletti et al. [15] for industrial load shedding. Concepts of intelligent systems also have been applied to solve the UFLS problem [16].

The traditional schemes shed predetermined percentages of loads in multiple stages, as the frequency decays through certain threshold frequencies [10]. The values of the thresholds and of the relative amounts of load to be shed are decided off-line. These schemes, which are purely empirical and do not take the changing system parameters or state into consideration, often shed either more or less load than what is required. As a step forward, the semi-adaptive schemes with frequency trend relays choose the percentage of load to be shed from a set of predetermined values depending upon the *df/dt* at the threshold frequencies [17]. Usually, this is done only at the first stage, whereas the traditional method is used for subsequent stages.

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Adaptive schemes make use of the frequency derivative immediately after a disturbance (at $t = 0^+$) and is based on the reduced order model developed by Anderson and Mirheydar [18]. These schemes estimate the magnitude of disturbance using the equation given below [6].

$$\left.\frac{df}{dt}\right|_{t=0^+} = -\frac{\Delta P_L}{2H} \tag{1}$$

where f is the frequency in p.u., ΔP_L is the size of the disturbance in p.u. (increase in load power) which occurs at $t = 0$ and H is the system inertia constant in seconds. This scheme has the following drawbacks:

- magnitude of disturbance calculated at different buses will not be the same as the initial slope of frequency decay at different buses will be different due to swing mode oscillations in a multimachine system and it depends on the location of the disturbance [13].
- the value of inertia constant H cannot be fixed as the boundary of island or the number of synchronous machines in the system is not known in advance [9, 11].
- if one should use the frequency of the equivalent inertial center and its derivative to estimate the magnitude of disturbance, a highly sophisticated communication facility is necessary [12, 13, 19].

Apart from this, the load damping constant (D) plays a major role in the dynamic frequency response of the system. It is a measure of frequency dependency of the load and defined as the percent change in load real power for one percent change in frequency [17]. Obviously, this parameter varies with operating conditions as the nature of the load is always changing. UFLS schemes proposed by Chuvychin et al. [7] and Aik [5] assume some fixed value for this parameter and this assumption may affect the performance of such schemes. To overcome these issues, an approach that does not require the knowledge of the system parameters is proposed by Rudez and Mihalic [20]. The scheme presented by Rudez and Mihalic [20] is based on the minimum frequency forecast, obtained by successive numerical integration of frequency second derivative curve. However, the scheme requires measurement of the frequency second derivative, which is more challenging than measuring the frequency [20].

In this paper, a load shedding scheme, that uses only the locally available frequency measurements and that does not assume any value for the system parameters, H and D, is presented. The parameters are estimated online and the decision on load shedding is taken based on the predicted final steady-state frequency. The amount of load to be shed, if required, is computed using the estimated system parameters and magnitude of disturbance. Also, the proposed scheme does not require the knowledge of the exact instant of disturbance and takes care of the swing mode oscillations in a multimachine power system by the use of a low pass filter. The proposed scheme is tested in a 2 generator system and the 10 generator New England system.

This paper is organized as follows. Section 2 discusses the suitability of a reduced order system model to device the proposed UFLS scheme. Section 3 gives the filter details and Section 4 explains the proposed scheme in detail. Section 5 presents the case studies followed by discussion and conclusion in Sections 6 and 7.

2 Reduced order system model

The frequency variation of a power system subjected to a disturbance can be obtained to a good degree of accuracy by a reduced second-order model shown in Figure 1 [18].

The quantities in Figure 1 are as follows:

ΔP_m = Change in turbine mechanical power in p.u.
ΔP_L = Step change in electrical load power in p.u.
Δf = Deviation in frequency from nominal value in p.u.
F_H = Fraction of total power contributed by the HP turbine
T_R = Reheater time constant in seconds
R = Governor speed regulation

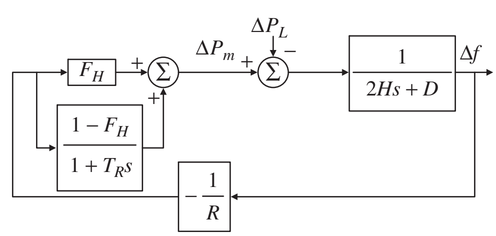

Figure 1 The reduced order system model

The power system under study may contain thermal, hydro- and gas power plants. For cases with spinning reserve, it is assumed that the spinning reserve is available in a generating station having steam turbine. The model considers only the reheater time constant T_R and the system inertia constant H. Power system is represented by a simplified model obtained by assuming coherent response of all generators to changes in system load [17, 18]. The effects of the system loads are lumped into a single damping constant D. The speed of the equivalent generator is equal to the average frequency of the overall system, when both the quantities are in p.u. ΔP_L is the step change in electrical load power in p.u., which is actually the initial load-generation imbalance, created by the disturbance. For the undefrequency study reported in this paper, the cases with step increase in electrical load (i.e. the disturbances creating overload in the system) alone are considered. The disturbance may be a sudden increase in load or decrease in generation or loss of generator(s) or islanding that would result in more load than generation in one or more islands.

When there is no spinning reserve available, for a step increase in load, the input mechanical power remains constant and the governor-turbine dynamics can be ignored. Therefore, the whole system can be represented by a first-order system as shown in Figure 2.

The accuracy of the reduced order models is illustrated by conducting case studies on realistic systems and comparing the actual frequency variation with that obtained from reduced order models.

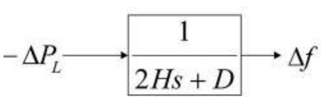

Figure 2 The reduced order system model with no spinning reserve

Consider the 10 generator New England system shown in Figure 3. All generators are represented by fourth-order model with static exciter. The system data are given by Padiyar [21]. The loads are represented by composite model consisting of constant power type and induction motor. Consider the following disturbance: tripping of lines 26–29 and 28–29. This disturbance results in two islands. Generator 9 and buses 9 and 29 are in the overgeneration area and all other generators and buses are in the undergeneration area. Figure 4 shows the frequency variation at bus 7 which is in the undergeneration area, assuming no spinning reserve at any generator. The frequency variation of an equivalent first-order model is also shown in Figure 4. It can be seen that the actual frequency follows a first-order exponential decay with superimposed synchronizing oscillations.

The accuracy of the reduced order (second-order) model, whenever spinning reserve is available, is validated by conducting a study on a 2 generator 4 bus system shown in Figure 5. The system data are given in Appendix. The generators and loads are represented by detailed models as in the previous case. Generator 1 has spinning reserve and its turbine-governor is represented

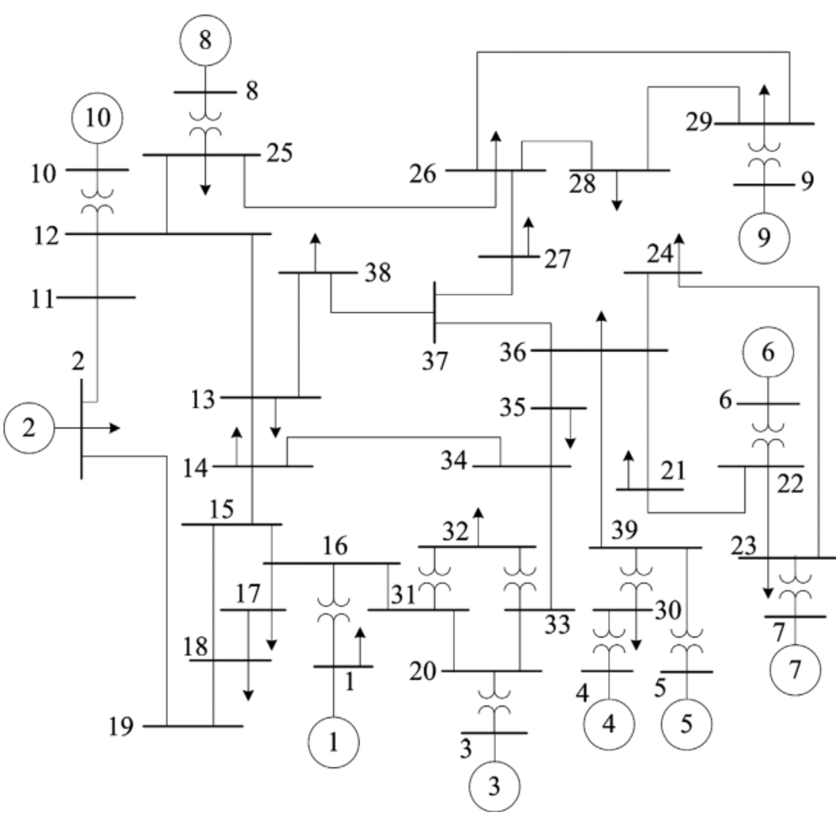

Figure 3 10 generator 39 bus New England system

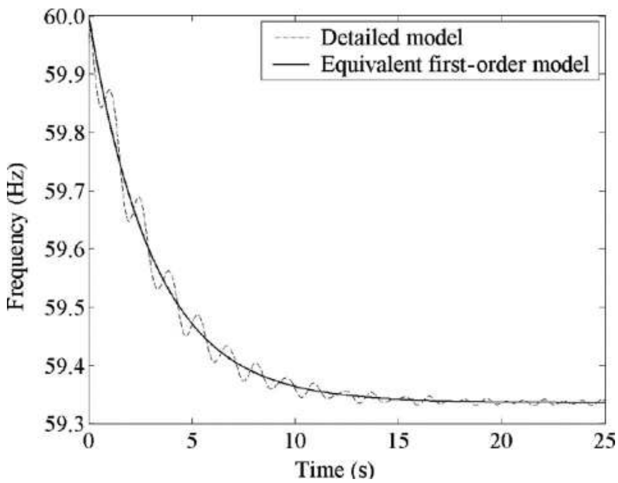

Figure 4 Plot of frequency at bus 7 of 10 generator system without spinning reserve and frequency of the equivalent reduced order model

Figure 5 2 generator 4 bus test system

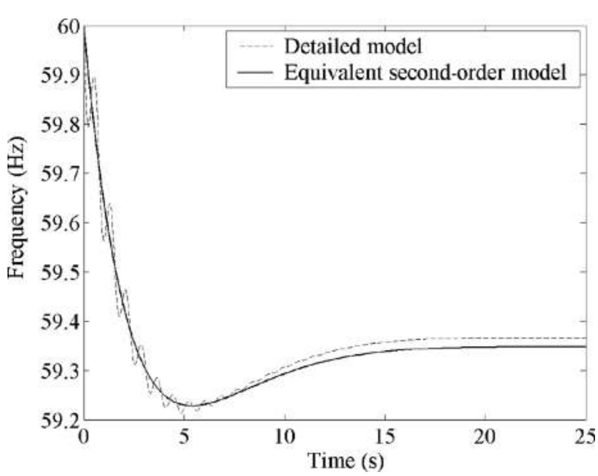

Figure 6 Plot of frequency at bus 2 of 2 generator system with spinning reserve and frequency of the equivalent reduced order model

by tandem compound single reheat type with typical values [17, 21]. Figure 6 shows the frequency variation at bus 2 for a reduction in the generation of generator 2 by 0.45 p.u. The figure also shows the frequency variation of the equivalent second-order system shown in Figure 1.

In both cases (with and without spinning reserve), if the oscillations in the frequency variation are removed, then the resulting response is very close to the response of the respective equivalent reduced order models.

3 Filter

The objective of this work is to devise a load shedding scheme that uses only the locally available frequency measurements, based on the reduced order models explained in Section 2. A digital filter is designed to filter out the oscillations in the measured frequency, so that the filtered output can be represented by the response of the equivalent reduced order system model.

Since the synchronizing oscillations fall in the frequency range of 0.2 to 3 Hz [21], a low pass causal filter with cutoff frequency of 0.2 Hz is used. As these dominant frequencies to be attenuated have a narrow bandwidth, it is desirable that the filter has a transition band as narrow as possible. The order of the filter also should be low, so that the physical realization is easier and the overall group delay is minimum. The infinite impulse response (IIR) filter has a lower order than the finite impulse response filter for same filter specifications [22, 23]. Of the class of IIR filters, elliptic filter has the smallest transition bandwidth for a given order and a given set of specifications [22]. For these reasons, a second-order elliptic filter with cutoff frequency of 0.2 Hz is used in this work. The transfer function of the filter is of the form,

$$H(z) = \frac{b_0 + b_1 z^{-1} + b_2 z^{-2}}{1 + a_1 z^{-1} + a_2 z^{-2}}$$

where the filter coefficients are found using the software Octave [24]. Having fixed the order and the cutoff frequency of the filter, the other specifications in designing the filter are the ripple in the passband and minimum stopband attenuation. The filter coefficients for each system are found by varying these specifications so that the filtering is acceptable for the proposed UFLS scheme.

4 The proposed UFLS scheme

The first step is to filter out the synchronizing oscillations by passing the locally available discrete time bus frequency measurements through the digital filter. The next step is to compute the parameters of the equivalent reduced order model using a few selected frequency measurements and then to use these parameters to estimate the magnitude of disturbance and the amount of load to be shed if necessary, so that the system frequency recovers to an acceptable value (f_{des}), within the desired frequency band. The desired frequency band is the range of frequencies in which continuous time operation of the system is allowed and the limits of the band are decided based on the abnormal frequency capability of the steam turbines present in the system. An action is initiated if the frequency falls below a threshold value f_{th}. The lower limit of the continuous operation band is taken as f_{th}. If the frequency declines below the lower limit of the desired band and the predicted steady-state frequency is lower than f_{des}, an appropriate amount of load has to be shed. The amount of load shed will be minimum if the desired steady-state system frequency, f_{des}, is made equal to the lower limit of the desired band.

Following an overload, the frequency starts decaying. With the microprocessor-based frequency relays, frequency measurements are available at every half cycle [25]. An action is to be initiated if the frequency falls below f_{th}. In the proposed scheme, the time instant at which the filtered frequency becomes either equal to or less than the threshold value f_{th} is taken as the time reference ($t = 0$) and a few frequency measurements f_1, f_2,..., f_n at time instants $t = 0$, Δt,...,$(n-1)\Delta t$ are picked up to estimate the unknown parameters of the equivalent reduced order model by fitting the selected points to the response of the equivalent reduced order model. n is the number of unknown parameters of the response. For the equivalent reduced order model, the frequency is assumed to start declining at the time instant $t = -\tau$, which is actually not known. f_1 may be either equal to the threshold frequency f_{th} or just less than f_{th}. Also, it should be noted that, even though frequency measurements are available at every half cycle, we choose measurements a few cycles apart to improve the accuracy of estimation. Figure 7 shows the actual, filtered and equivalent reduced order model responses for a typical case along with instants of three frequency measurements being considered for computation.

Assuming that the system is operating at the nominal frequency, variation in frequency of the equivalent reduced order model with spinning reserve for an overload is given by Anderson and Mirheydar [18],

$$\Delta f = \Delta f_{s0}\left[1 - \frac{1}{\sqrt{1-\zeta_0^2}} e^{-\zeta_0\omega_{n0}(t+\tau)} \sin\{\omega_{d0}(t+\tau)+\theta_0\} + \frac{T_R\omega_{n0}}{\sqrt{1-\zeta_0^2}} e^{-\zeta_0\omega_{n0}(t+\tau)} \sin\{\omega_{d0}(t+\tau)\}\right] \quad (2)$$

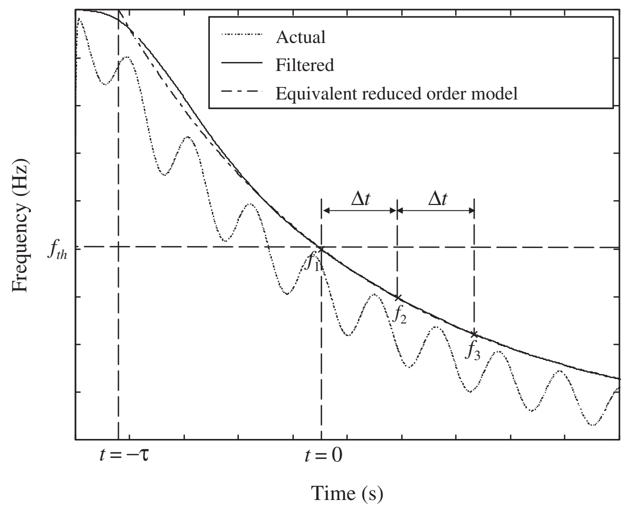

Figure 7 Actual, filtered and equivalent reduced order model responses with the time instants of frequency measurements being considered

where

$$\Delta f_{s0} = -\frac{R\Delta P_L}{DR+1} \quad (3)$$

$$\omega_{n0} = \sqrt{\frac{DR+1}{2HRT_R}} \quad (4)$$

$$\zeta_0 = \left\{\frac{2HR + (DR+F_H)T_R}{2(DR+1)}\right\}\omega_{n0} \quad (5)$$

$$\theta_0 = cos^{-1}(\zeta_0) \quad (6)$$

$$\omega_{d0} = \omega_{n0}\sqrt{1-\zeta_0^2} \quad (7)$$

When no spinning reserve is available, the variation in frequency due to an overload is given by,

$$\Delta f = \Delta f_{s0}\left(1 - e^{-\frac{t+\tau}{T_0}}\right) \quad (8)$$

where $\Delta f_{s0} = -\Delta P_L/D$ is the steady-state frequency deviation in p.u and $T_0 = 2H/D$ is the time constant of the exponential decay.

A load shedding scheme is proposed for both cases: with and without spinning reserve.

4.1 Without spinning reserve

Systems without spinning reserve are considered first. There are three unknowns $\Delta f_{s0}, T_0$ and τ, in eq. (8) and they can be computed with three frequency measurements

$\Delta f_1, \Delta f_2$ and Δf_3 at $t = 0$, Δt and $2\Delta t$ respectively. By fitting these three frequency measurements to eq. (8), we get

$$\Delta f_{s0} = \frac{\Delta f_1 \Delta f_3 - \Delta f_2^2}{\Delta f_1 + \Delta f_3 - 2\Delta f_2} \tag{9}$$

$$T_0 = -\frac{\Delta t}{\ln\left(\frac{\Delta f_{s0} - \Delta f_2}{\Delta f_{s0} - \Delta f_1}\right)} \tag{10}$$

If the computed f_{s0} is lower than f_{des}, load shedding has to be done to bring the frequency to f_{des}. But the amount of load shedding cannot be determined without the knowledge of D, which is an unknown. Hence, an indirect method is devised to estimate the load to be shed using the parameters of the response before and after shedding a small known fraction of the load.

Let the total load in the system immediately after the disturbance (i.e. at $t = -\tau^+$) be P_L and a fraction x_1 of P_L be shed at time t_1, which is actually $2\Delta t + t_t$. In all the computations and expressions throughout the paper, P_L represents the total load in the system immediately after the disturbance but before any load shedding. Even after the first stage load shedding, the definition of P_L remains the same. t_t is the tripping time which includes relay and circuit breaker operating time as well as the computation time. But due to the time delay introduced by the filter, the tripping point is reflected in the filtered frequency at t_1' after a time delay of τ_d. This is illustrated in Figure 8. Since the exact filter time delay is not known, t_1' and hence the frequency deviation Δf_{t1} at $t = t_1'$ become unknown quantities.

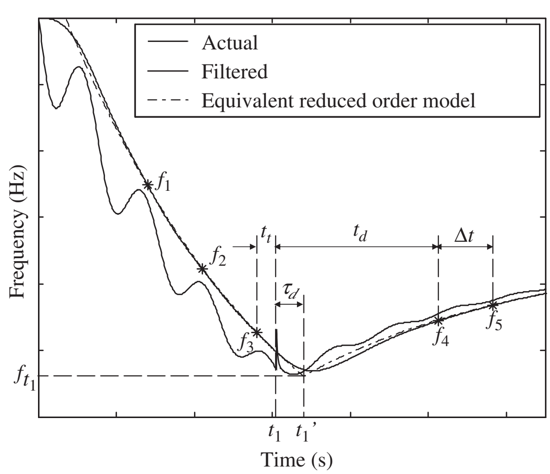

Figure 8 Actual, filtered and equivalent reduced order model responses around the load shedding point

The value of load damping constant changes following the load shedding, according to the expression [17],

$$D_1 = (1 - x_1)D \tag{11}$$

where D_1 is the load damping constant after load shedding. The variation in filtered frequency after load shedding can be represented by,

$$\Delta f = \Delta f_{s1} + (\Delta f_{t1} - \Delta f_{s1}) e^{-\frac{(t - t_1')(1 - x_1)}{T_0}} \tag{12}$$

where Δf_{s1} is the steady-state frequency deviation after load shedding. Δf_{s1} can be computed using two frequency measurements f_4 and f_5 taken after load shedding at $t = t_1 + t_d$ and $t = t_1 + t_d + \Delta t$ respectively.

$$\Delta f_{s1} = \frac{\Delta f_5 - \Delta f_4 e^{-\frac{\Delta t(1 - x_1)}{T_0}}}{1 - e^{-\frac{\Delta t(1 - x_1)}{T_0}}} \tag{13}$$

As the filter output samples immediately after load shedding may comprise the transient part, they have to be discarded and a time delay t_d is allowed before taking the measurement f_4. This is illustrated in Figure 8.

If $f_{s1} \geq f_{des}$, further load shedding is not required. Otherwise, second stage of load shedding is necessary. It will be shown that, from the knowledge of the quantity P_L/D, the amount of load required to be shed in the second stage can be determined. P_L/D can be obtained from the following expression for Δf_{s1}.

$$\Delta f_{s1} = \frac{1}{1 - x_1}\left(\Delta f_{s0} + \frac{x_1 P_L}{D}\right) \tag{14}$$

Let a fraction x_2 of the total load P_L, be shed in the second stage at time t_2. The steady-state frequency deviation, Δf_{s2}, after second stage load shedding is given by,

$$\Delta f_{s2} = \frac{1}{1 - x_1 - x_2}\left(\Delta f_{s0} + \frac{x_1 P_L}{D} + \frac{x_2 P_L}{D}\right) \tag{15}$$

The objective is to shed minimum amount of load so that the steady-state frequency deviation is Δf_{des}. The fraction x_2 of total load to be shed, such that the steady-state deviation after second stage shedding is Δf_{des} (i.e. $\Delta f_{s2} = \Delta f_{des}$), can be found from eq. (15). The entire load shedding scheme is shown by the flowchart in Figure 9.

4.2 With spinning reserve

With spinning reserve, the expression governing the response is given by eq. (2). In eq. (2), the turbine-governor parameters (F_H and R) and reheater time constant (T_R) can be assumed to be equal to the typical values: $F_H = 0.3$, $R = 0.05$ and $T_R = 5$ s. The remaining four unknowns D, H, ΔP_L and τ can be computed numerically with four frequency measurements f_1, f_2, f_3 and f_4 at

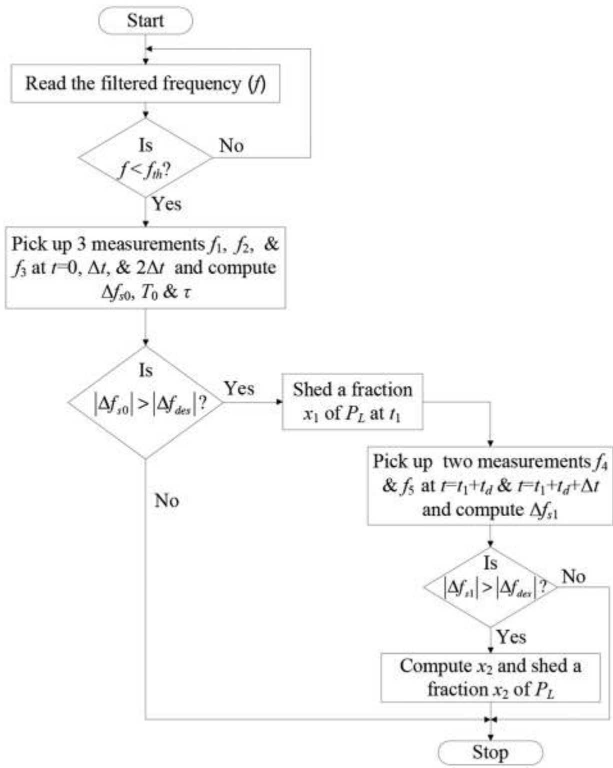

Figure 9 Flowchart representing the proposed scheme without spinning reserve

$t = 0$, Δt, $2\Delta t$ and $3\Delta t$. The four equations are solved using Newton–Raphson method. Once these quantities are obtained, the steady-state frequency deviation Δf_{s0} can be found from eq. (3).

If the computed $f_{s0} < f_{des}$, load shedding has to be done. A fraction x_1 of the total load P_L is shed at time $t = t_1$ and let the corresponding time instant with respect to the filtered frequency be t_1'. Incorporating the reduction in the value of load damping constant, the variation in the filtered frequency can be represented by,

$$\Delta f = \Delta f_{s1} + \frac{1}{\sqrt{1-\zeta_1^2}} e^{-\zeta_1 \omega_{n1}(t-t_1')} \left[(\Delta f_{t1} - \Delta f_{s1}) \sin\{\omega_{d1}(t-t_1') + \theta_1\} + \frac{\Delta f_{t1}'}{\omega_{n1}} \sin\{\omega_{d1}(t-t_1')\} \right] \tag{16}$$

where Δf_{t1} and $\Delta f_{t1}'$ are the frequency deviation and the rate of change of frequency deviation at $t = t_1'$. Δf_{s1} is the steady-state deviation after load shedding. Δf_{s1} can be computed by fitting four more frequency measurements, taken after shedding a known fraction x_1 of load, to the expression given in eq. (16) as there are four unknowns viz. Δf_{t1}, $\Delta f_{t1}'$, t_1' and Δf_{s1}. Measurements f_5, f_6, f_7 and f_8 are taken at $t = t_1 + t_d, t_1 + t_d + \Delta t, t_1 + t_d + 2\Delta t$ and $t_1 + t_d + 3\Delta t$ respectively and the four equations are solved.

If the computed f_{s1} is still lower than f_{des}, second stage load shedding is required. As the knowledge of P_L is necessary to determine the fraction x_2 of the total load to be shed in the second stage, it is obtained from the following expression for Δf_{s1}.

$$\Delta f_{s1} = -\frac{R(\Delta P_L - x_1 P_L)}{D(1-x_1)R + 1} \tag{17}$$

The steady-state frequency deviation, Δf_{s2}, after second stage load shedding is given by,

$$\Delta f_{s2} = -\frac{R(\Delta P_L - x_1 P_L - x_2 P_L)}{D(1-x_1-x_2)R + 1} \tag{18}$$

The value of x_2 for shedding minimum amount of load such that Δf_{s2} becomes equal to Δf_{des} can be found from eq. (18). The scheme is shown as a flowchart in Figure 10.

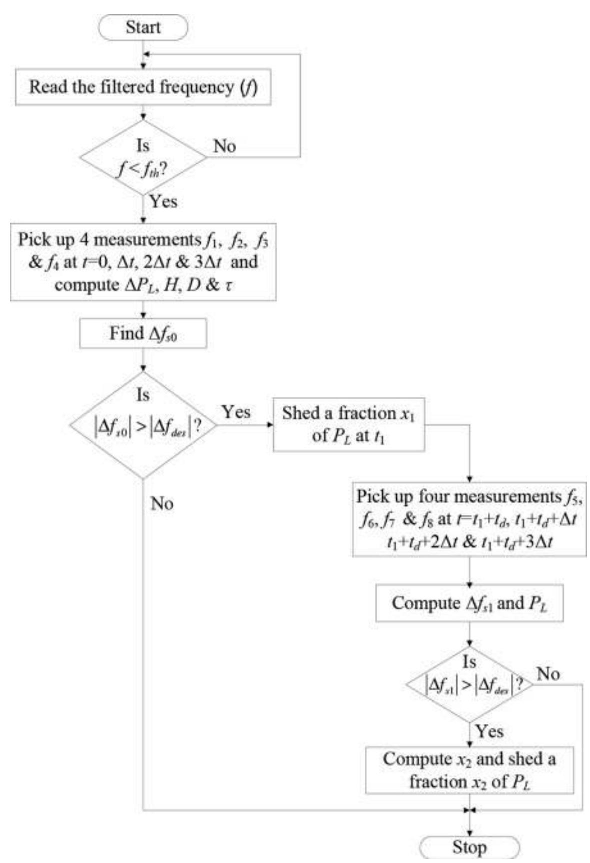

Figure 10 Flowchart representing the proposed scheme with spinning reserve

5 Case studies

The proposed scheme is tested on multimachine systems through simulation studies. In the simulation, generators are represented by the detailed 1.1 (two axis) model with static exciter and the loads by composite model comprising 50% constant power static load and 50% dynamic load. Dynamic load is induction motor. Induction motor parameters are taken from the IEEE Task Force Report [26]. The load model is such that both the active and reactive powers consumed by the loads are dependent on both voltage and frequency. Load shedding is done by tripping equal amounts of static and dynamic loads. Bus frequency is evaluated by computing the numerical time derivative of the bus voltage phase angle [27]. The discrete time frequency measurements are assumed to be available at every half cycle.

Since the lower limit of frequency for continuous operation for most of the generating units is 59.5 Hz [2], the threshold frequency f_{th} and the desired steady-state frequency f_{des} are set at 59.5 Hz. The transients associated with the filter are also considered while choosing the threshold frequency as the filter transients immediately after the disturbance are significant and can lead to inaccurate results, if they are not taken care of. For accurate decision making, it is necessary that the measurements taken for computations do not contain any transient response due to the filter. In all the cases reported in this paper, it is found that by the time the frequency reaches 59.5 Hz, the filter transients have decayed. Therefore, it is not advisable to increase f_{th} above 59.5 Hz. However, lowering the value of f_{th} can be considered in systems which allow continuous operation below 59.5 Hz; this will result in a more accurate estimate of the load to be shed.

Relay and circuit breaker operating time t_t along with computation time is taken as 15 cycles [26]. The first 250 samples after first load shedding, which may contain the transient response introduced by the filter, are discarded and hence t_d is taken as 125 cycles. The percentage of load to be shed at the first stage should be set at some minimum value to avoid overshedding and is taken as 5%, i.e. $x_1 = 0.05$. The time interval between the measurements that are considered for computation, Δt, affects the accuracy of the results as well as the time needed to initiate load shedding. More delay in initiation of load shedding causes more frequency decline and this decreases the system minimum frequency. Smaller the Δt, lesser is the time needed to initiate load shedding; larger the Δt, lesser is the error in estimation. Also, Δt depends on the resolution of the available frequency measurements. For a given Δt, the error in estimation decreases with increase in the resolution of frequency measurement. Considering the above facts, for systems without spinning reserve, for a resolution of 0.001 Hz, Δt is fixed at 42 cycles as a trade off between accuracy and speed. For systems with spinning reserve, it is observed that higher resolution is required to obtain accurate results. Hence, Δt is taken as 42 cycles and a resolution of 0.0001 Hz is used for systems with spinning reserve.

5.1 Without spinning reserve

The proposed scheme for systems without spinning reserve is tested through dynamic simulation of two power systems: 2 generator system and New England 10 generator system. By simulation of the two generator system, the feasibility of the proposed scheme is investigated. On the other hand, more realistic scenarios are simulated with ten generator system.

5.1.1 2 generator 4 bus system

Figure 5 shows the two generator test system and the system data are given in Appendix. The filter co-efficients are: $a_1 = -1.94875$, $a_2 = 0.95009$, $b_0 = 5.2716 \times 10^{-4}$, $b_1 = 2.7639 \times 10^{-4}$ and $b_2 = 5.2716 \times 10^{-4}$. Three different levels of disturbances are created in the system to study the feasibility of the proposed scheme. The disturbances are,

I reduction in the generation of generator-2 by 40 MW creating an overload of 20.88%,

II loss of generator-1 creating an overload of 42.05% and

III reduction in the generation of generator-2 by 80 MW creating an overload of 52.79% in the system.

In all the three disturbances, the overload (ΔP_L) is created by the step reduction/loss of generation. The values of ΔP_L for the disturbances I, II, and III are 0.4 p.u., 0.6855 p.u. and 0.8 p.u respectively. Thus the frequency is found to decay below f_{th} and the proposed scheme is applied. All the three disturbances require two stages of load shedding to bring back the system frequency to f_{des}. Table 1 gives the actual values of f_{s0} and f_{s1} (obtained by simulation), estimated values of f_{s0}, f_{s1} and x_2 at the load buses (by the proposed load shedding scheme), final steady-state frequency after load shedding (f_{ss}) and minimum frequencies (f_{min}) in the system. Optimum amount of load to be shed to bring back the final system frequency exactly to f_{des} is obtained by trial and error. Figure 11 shows the frequency variation at the load buses with load shedding, using the proposed scheme, for disturbance I.

It is observed that for disturbances I and II, the system frequency is brought back close to the desired frequency of 59.50 Hz by shedding appropriate amount of loads. For the disturbance III, it is observed that the deviation from the

Table 1 Results for 2 generator 4 bus system

Disturbance	Bus No.	Actual f_{s0} (Hz)	Estimated f_{s0} (Hz)	Estimated T_0(s)	Actual f_{s1} (Hz)	Estimated f_{s1} (Hz)	Estimated x_2 (%)	Total load shed (MW)	Optimum load to be shed (MW)	f_{ss} (Hz)	f_{min} (Hz)
I	1	58.903	58.869	3.082	59.220	59.220	3.64	20.462	21.735	59.464	59.202
	2	58.903	58.930	2.850	59.220	59.225	4.23			59.464	59.182
II	1	57.995	58.084	2.737	58.321	58.328	18.46	52.298	53.728	59.461	58.478
	2	57.995	58.055	2.728	58.321	58.328	16.80			59.461	58.485
III	1	57.808	58.030	2.327	58.129	58.166	31.27	71.661	61.640	59.772	58.308
	2	57.808	57.850	2.790	58.129	58.118	19.51			59.772	58.301

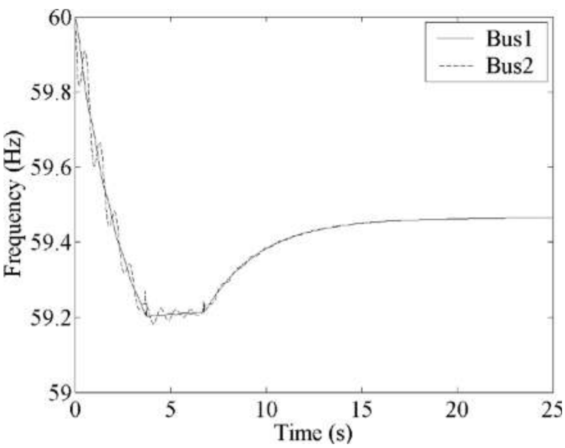

Figure 11 Frequency variation at load buses of 2 generator system with the proposed load shedding scheme for a sudden loss of 40 MW generation (Disturbance I)

desired frequency is comparatively large. This is due to a relatively large error in the estimation of f_{s0} at bus 1. When the magnitude of disturbance is very large, the magnitude of oscillations will also be large which will result in oscillations of smaller magnitude even in the filtered output. This introduces an error in the estimation of f_{s0} and x_2. As the magnitude of disturbance increases the error introduced in the estimation may also increase. This may lead to a small amount of deviation in the final settling frequency above or below the desired frequency. In such cases, if the deviation is above the desired frequency, as in this case, it does no harm to the system. On the other hand, if the system settles at a frequency slightly lower than the desired frequency, the operator will have enough time to correct the situation, as the turbines can operate continuously for about 3 h between 59 Hz and 59.5 Hz [6]. But one should note that a loss of more than 33% of total generation, which means an overload of more than 50%, is, by any standard, a severe contingency. Disturbance III falls in this category and for such a large disturbance, the steady-state deviation from the desired frequency is just 0.272 Hz. We can conclude from the above simulation results that the proposed scheme can shed near-optimum amount of load, covering a wide range of the magnitude of disturbance.

5.1.2 10 generator 39 bus New England system

The system is shown in Figure 3. The filter co-efficients are: $a_1 = -\ 1.98502$, $a_2 = 0.98518$, $b_0 = 2.3699 \times 10^{-4}$, $b_1 = -3.1817 \times 10^{-4}$ and $b_2 = 2.3699 \times 10^{-4}$. An example case, the outage of the lines 25–26, 27–37, 36–37 and 35–36, is presented. Outage of these lines separates the integrated system into three islands:

– Island I: Comprising generator 9 and buses 9, 26, 27, 28 and 29 with real power generation and load of 8.300 p.u and 9.095 p.u. respectively creating an overload of 9.58%,
– Island II: Comprising generators 1, 2, 3, 8 and 10 and buses 1 to 3, 8, 10 to 20, 25, 31 to 35, 37 and 38 with real power generation and load of 29.920 p.u. and 34.005 p. u. respectively creating an overload of 13.65% and
– Island III: Comprising generators 4, 5, 6 and 7 and buses 4 to 7, 21 to 24, 30, 36 and 39 with real power generation and load of 23.500 p.u. and 18.145 p.u. respectively creating an overgeneration of 29.51%.

In islands I and II, there is an overload and ΔP_L represents the mismatch between the load and the generation in the island. ΔP_L has an actual value of 0.975 p.u in Island I and 4.085 p.u. in Island II. Therefore, in both of these islands the conditions for operation of the underfrequency relays exist. Table 2 gives the results.

In island I, the actual steady-state frequency without any load shedding is 59.312 Hz and with first stage of load shedding itself the island frequency is brought bank to 59.645 Hz, which is above the desired frequency. The estimated steady-state frequencies by the proposed

Table 2 Results for 10 generator 39 bus system

Island	Bus No.	Estimated f_{s0} (Hz)	Estimated T_0 (s)	Estimated f_{s1} (Hz)	Estimated x_2 (%)	Total load shed (p.u.)	f_{ss} (Hz)	f_{min} (Hz)
I	26	59.327	0.622	59.677	–	0.06950	59.645	59.320
	27	59.327	0.622	59.677	–	0.14050	59.645	59.319
	28	59.328	0.608	59.676	–	0.10300	59.645	59.321
	29	59.328	0.608	59.676	–	0.14175	59.645	59.321
II	1	59.161	4.193	59.425	1.32	0.00582	59.468	59.257
	2	59.083	5.042	59.512	–	0.55200	59.468	59.314
	13	59.049	5.713	59.471	0.32	0.17139	59.468	59.276
	14	59.113	4.844	59.448	0.72	0.28602	59.468	59.272
	17	59.188	3.760	59.437	1.19	0.14462	59.468	59.274
	18	59.149	4.276	59.446	0.85	0.30536	59.468	59.276
	25	59.049	5.713	59.471	0.32	0.11923	59.468	59.276
	32	59.113	4.844	59.448	0.72	0.00429	59.468	59.267
	35	59.113	4.844	59.448	0.72	0.18305	59.468	59.271
	38	59.049	5.713	59.471	0.32	0.08410	59.468	59.276

scheme (f_{s0} and f_{s1}) are also very close to the actual ones. Since $f_{s0} < f_{des}$ and $f_{s1} > f_{des}$, only 5% of the load is shed at the first stage and the second stage load shedding is not effected.

In island II, the actual steady-state frequencies without any load shedding and with first stage of load shedding are 59.065 and 59.425 Hz respectively. Since the estimated $f_{s0} < f_{des}$ at all the load buses in the island, 5% of the load is shed in the first stage. And the estimated f_{s1} at all the load buses except bus 2 is less than f_{des}, second stage of load shedding is done at all the buses except bus 2. By shedding the load in two stages the island frequency is brought back to 59.468 Hz, which is very close to the desired frequency of 59.5 Hz. We observe that only 1.85588 p.u. of load is shed in total to bring back the island frequency close to the desired frequency, whereas the island overload is 4.085 p.u. The optimum total amount of load to be shed to bring back the final system frequency exactly to 59.5 Hz is found to be 2.06410 p.u. by trial and error. It is observed that the total amount of load shed by the proposed scheme is near optimum and the deviation from the desired frequency is just 0.032 Hz.

The frequency variation at the load buses in islands I and II is shown in Figures 12 and Figure 13 respectively.

It is observed from the frequency plots that, the first stage load shedding is done earlier in island I (at around 3.9 s) than in island II (at around 6.18 s). As the frequency decay is steeper and the frequency crosses f_{th} earlier in island I than in island II, the load shedding algorithm is initiated first in the island I and then in island II. That is, steeper the frequency decay; faster is the control action.

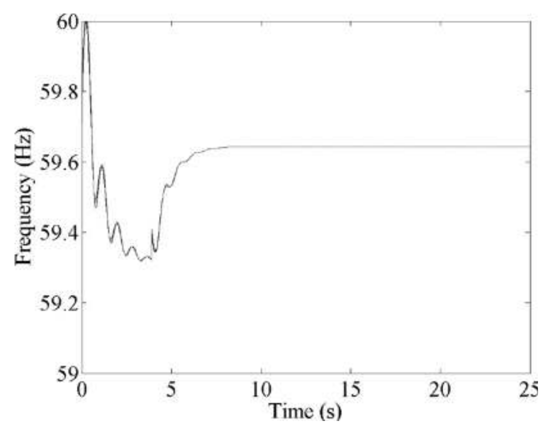

Figure 12 Frequency variation at load buses in island I of 10 generator system with the proposed load shedding scheme

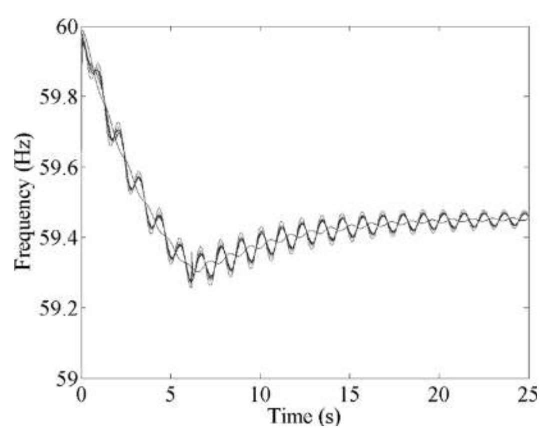

Figure 13 Frequency variation at load buses in island II of 10 generator system with the proposed load shedding scheme

Table 3 Results for 2 generator 4 bus system with spinning reserve

Disturbance	Bus No	Actual	Estimated				Actual	Estimated		Total load shed (MW)	Optimum load to be shed (MW)	f_{ss} (Hz)	f_{min} (Hz)
		f_{s0} (Hz)	f_{s0} (Hz)	D	H (s)	ΔP_L (MW)	f_{s1} (Hz)	f_{s1} (Hz)	x_2 (%)				
I	1	59.5776	59.5708	20.779	27.127	29.17	–	–	–	–	–	59.5776	59.3114
	2	59.5776	59.5629	25.780	28.453	33.35	–	–	–	–	–	59.5776	59.3115
II	1	59.1527	59.1258	20.658	27.099	59.24	59.3175	59.2915	5.94	25.222	24.610	59.5099	58.9776
	2	59.1527	59.1521	19.056	24.211	55.19	59.3175	59.3055	6.00			59.5099	58.9776

5.2 With spinning reserve

The proposed scheme for systems with spinning reserve is tested on the 2 generator system shown in Figure 5. The simulation was done with PSS, placed at generator 2. The PSS transfer function and the parameters are given below:

$$H_{pss}(s) = K_{pss}\left(\frac{sT_w}{1+sT_w}\right)\left(\frac{1+sT_1}{1+sT_2}\right)^2$$

$$K_{pss} = 0.036; T_w = 1\text{s}; T_1 = 1.4143\text{s}; T_2 = 0.010826\text{s}$$

The filter co-efficients are: $a_1 = -1.97055$, $a_2 = 0.97121$, $b_0 = 0.28352$, $b_1 = -0.56638$ and $b_2 = 0.28352$. Table 3 gives the results for reduction in the generation of generator 2 by 30 MW (disturbance I) and 60 MW (disturbance II) creating an overload of 14.88% and 34.98% respectively. Actual values of ΔP_L for the disturbances I and II are 0.3 p.u and 0.6 p.u respectively.

For disturbance I, though the frequency drops below 59.5 Hz and reaches a minimum frequency of 59.3114 Hz, the actual steady-state frequency is 59.5776 Hz, which means no load shedding is required. Estimated f_{s0} at both the buses 1 and 2 are very close to the actual steady-state frequencies and since they are above f_{des}, no load is shed at both buses. Thus, unnecessary load shedding is avoided. For disturbance II, we observe that two stages of load shedding is necessary and near-optimum amount of load is shed at both the load buses in two stages to bring back the system frequency to 59.5099 Hz. Figure 14 shows the frequency variation at the load buses of the system for disturbance II.

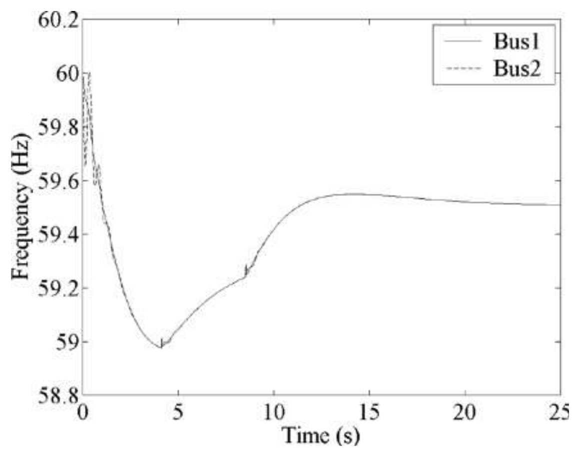

Figure 14 Frequency variation at the load buses of 2 generator 4 bus system with the proposed scheme for a loss of 60 MW (Disturbance II)

6 Discussion

From eqs (15) and (18), it is understood that the correct information of system parameters, H and D, is vital in determining the amount of load to be shed. Though H does not appear explicitly in these equations, it is involved in the computation of P_L/D appearing in eq. (15) and P_L appearing in eq. (18). In the proposed scheme, these system parameters are estimated online (explicitly or implicitly) using the frequency measurements alone and are used in computing the future frequency behavior and the amount of load to be shed. This ensures that the system frequency settles at the neighborhood of the desired steady-state value.

It may be noted that, though the filter coefficients are different for different systems, the same filter is used for all the islands formed within a particular system. For example, in the 10 generator system case study, island I is relatively smaller one consisting of 4 load buses and a single generator, whereas island II is larger one with 10 load buses and 5 generators. Nevertheless, the same filter is used in both islands. Though the use of the same filter in all the islands within a system resulted in slight difference in the degree of filtering in each island, the proposed scheme is found to work satisfactorily.

The issues in using the local frequency measurement are the presence of swing mode oscillations and the deformation of voltage waveform (which would be used for measuring the frequency) due to network transients at the instants of disturbance and load shedding. However, the network transients (and hence the deformation of voltage waveform) are of very short duration. From Moore et al. [28] and Szafran and Rebizant [29], it is understood that the frequency measured from the voltage waveform at a load bus closely follows the rotor speed except during the very short initial transient period. The network transients do not affect the proposed scheme for the following reasons. First, the frequency measurements are filtered using a low pass filter and only the filtered frequencies are used in computations. Second, the filtered frequencies used in the computation are taken after a time interval, which is sufficient for the network transients to die out. Rotor speed measurement does not have the problem of voltage deformation. But, the advantage of using frequency measurement at load bus is that communication from generating stations can be avoided.

Delay in load shedding due to the filter delay and the corresponding decline in system minimum frequency is insignificant. For example, the plot of frequency at bus 30 of the 10 generator 39 bus system for Contingency I is shown in Figure 15; the minimum frequency with the proposed scheme is 59.385 Hz. The time delay, τ_d, introduced by the filter is 1.08 s. The minimum frequency would have improved by 0.030 Hz, had the first stage load shedding been advanced by 1.08 s. Similar observations for other cases also show that the decline in the minimum frequency introduced by the filter delay is less than 0.1 Hz, which is not so significant. It may also be noted, as mentioned in Section 3, that a second-order filter is chosen to keep the group delay introduced by the filter low.

By passing the discrete time frequency measurements through a low pass filter, we get the average system frequency at each load bus. Therefore, the filtered frequency curves at all the load buses are very close to each other and hence reach f_{th} almost at the same instant. The time instants of a filtered frequency measurement at all load buses would be very close. Also, the time instants of load shedding, at all load buses, would be very close. It is necessary to have filter at all the load buses. As an example, Figure 16 shows the filtered frequency curves at all the load buses in islands I and II of the 10 generator system with only one stage load shedding. It is found that, in island I, filtered frequency at all the load buses reaches f_{th} (59.5 Hz) at 2.25 s. In island II, filtered frequency at load bus 1 reaches f_{th} at 4.517 s, at bus 2 it reaches at 4.542 s, at buses 13, 14, 17, 18, 35 and 38 it reaches at 4.533 s and at buses 25 and 32 it reaches at 4.525 s. The range of these time instants is just 0.025 s (one and a half cycle). Operating time of the relay and circuit breaker introduces a time delay (15 cycles) between the last measurement (of the first set of measurements) and the instant of first stage load shedding ensuring that all the required measurements at all the load buses are taken before the first stage load shedding. This is applicable to the second stage load shedding too. Also, the first of the second set of measurements after the first stage load shedding is taken after a time delay (t_d) of 125 cycles, which is very large, compared to the range of the first stage load shedding time instants. This ensures that load shedding at all the buses would have been performed before the first of the second set of measurements is taken. Also, the

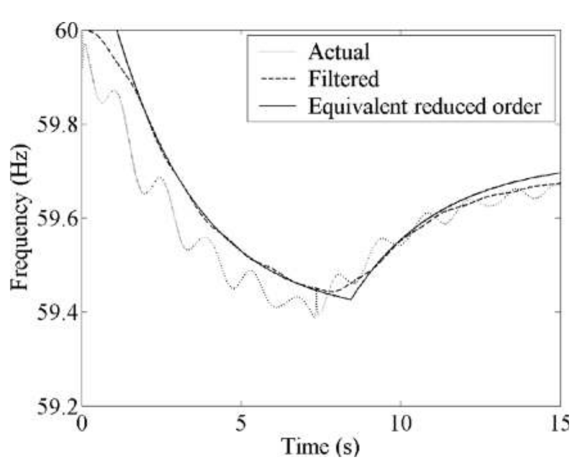

Figure 15 Actual, filtered and equivalent reduced order frequency response at bus 30 for outage of lines 26–29 and 28–29 of the 10 generator 39 bus system

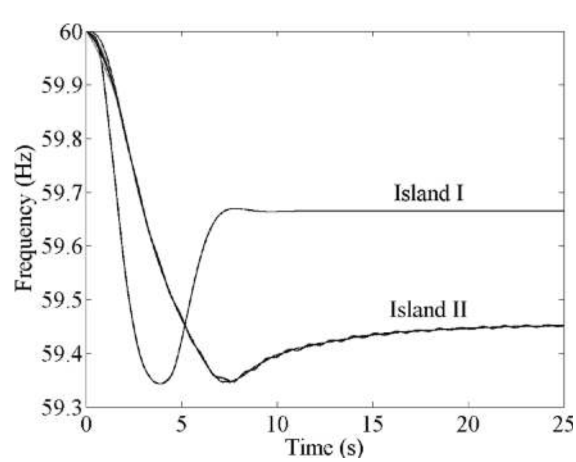

Figure 16 Filtered frequencies at the 4 load buses of island I and 10 load buses of island II with only one stage load shedding

dynamics due to first stage load shedding have the same effect on the second set of measurements at all buses. This can be observed in Figure 16. It is seen that the filtered frequencies at all the load buses are very close, even after first stage load shedding. From the above discussion, it is clear that, communication between relays is not required for the proposed scheme. However, the problem becomes challenging if an island has overload and there is a loss of synchronism among the generators of the island. Under such conditions, use of wide area measurements may help in improving the load shedding scheme.

Even though shedding major part of the overload in the second stage did not result in any frequency overshoot in the case studies done, such a situation is possible in some systems depending upon the system parameters. In such cases, the fraction x_2 of initial load, estimated by the proposed scheme, can be shed in two or more steps with a time delay in between.

When compared to available traditional and semi adaptive schemes, which are empirical in nature, the proposed scheme is adaptive to the variations in the system parameters, accurate and sheds just the minimum percentage of load to restore the system frequency to a safe value.

When compared to the adaptive UFLS schemes proposed by Terzija and Koglin [12], Terzija [13] and Rudez and Mihalic [20], the major advantage of the proposed method is that the estimation of amount of load to be shed to bring the frequency back to a safe value is done using only the local frequency measurements. This eliminates the need for sophisticated communication facility and the problem of measuring the first or second frequency derivative. Elimination of communication facility improves the reliability of the load shedding scheme and provides cost benefits.

Use of low pass filter to remove oscillations in the frequency measurements is another novelty in the paper. Since the synchronizing oscillations are removed from the bus frequency measurements, the frequency decay trace at all the buses is almost the same and therefore the estimated percentage of load to be shed is almost equal at all the load buses. This facilitates uniform load shedding throughout the system, even without any communication facility.

7 Conclusion

The frequency variation in any system can be approximated to a good degree of accuracy by the response of an equivalent system with one or two states (depending on the presence or absence of spinning reserve). In this paper, an underfrequency load shedding strategy, which does not need a prior knowledge of inertia constant or load damping constant, is developed using the reduced order system model. Load shedding scheme has been developed for systems with and without spinning reserve. For both systems, at most two stages of load shedding are required. The proposed scheme does not require any communication between the relays and any central location; rather, it uses only the locally available frequency measurements. The synchronizing oscillations in the frequency measurements can be removed by an elliptic low pass filter. From the case studies, it is found that the total amount of load shed using the proposed scheme is near-optimum for a reasonable range of the magnitude of the disturbance. When spinning reserve is available, the proposed scheme avoids unnecessary load shedding. No load would be shed even if the frequency decays to a value below f_{th}, if the frequency can be restored to or above the desired value by the primary frequency control action. However, it is observed that the error in estimation by the proposed scheme increases marginally as the magnitude of the disturbance increases. This is due to the use of linearized reduced order model and the presence of oscillations of small magnitude in filtered frequency for larger disturbances.

The proposed scheme in this paper has assumed that the overload is supplied by spinning reserve from a generator driven by steam turbine. Load shedding in the presence of spinning reserve available from other types of sources, such as hydroelectric plant, needs further research.

Appendix

A.1 2 generator 4 bus system data

Transformer reactances are 0.0576 p.u. (between buses 1 & 3) and 0.0625 p.u. (between buses 2 & 4).

Line parameters (between buses 4 & 3): $R = 0.042$ p.u., $X = 0.246$ p.u. and $B_c = 0.482$ p.u.

Turbine-governor parameters: $R = 5\%$, $T_G = 0.1$ s, $T_{CH} = 0.2$ s, $T_R = 5$ s, $T_{CO} = 0.4$ s, $F_H = 0.3$, $F_I = 0.3$ and $F_L = 0.4$.

The generator and machine data are given in Table 4.

All p.u. values are to the system base. Base MVA is 100.

Table 4 Generator and exciter data

	H (s)	x_d (p.u.)	x'_d (p.u.)	x_q (p.u.)	x'_q (p.u.)	T_{d0} (s)	T_{q0} (s)	K_A	T_A (s)
Generator 1	23.64	0.146	0.0608	0.0969	0.0969	8.96	0.31	20	0.2
Generator 2	6.4	0.8958	0.1198	0.8645	0.1969	6.0	0.535	20	0.2

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