Locating Generators Causing Forced Oscillations Based on System Identification Techniques

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Abstract— **This paper presents a method to locate the source of forced oscillations in power grids caused by maloperation of turbine-governor systems. The transfer function between the grid frequency and the output active power is first estimated for each generator in normal operation condition. The turbine-governor acting as the source of the forced oscillations is then detected by identifying rather large mismatches between the predicted output of its estimated transfer function and actual measurements from the grid. The proposed approach can locate both single and concurrent sources of forced oscillations. The method requires synchronized measurements of the grid frequency and the active power of the generator, preferably from PMU measurements. Results from simulations of the Nordic 44 grid model, which emulates the Nordic power system, demonstrate the validity of the proposed method.**

Keywords— Forced oscillation, PMU, System identification

I. Introduction

Power oscillations are a major concern in power system operation. Beside oscillations related to poorly damped system modes, forced oscillations may appear due to maloperation of one or more components in the grid, e.g. governors, automatic voltage regulators, power system stabilizers, wind farm controllers. Recently, forced oscillations caused by maloperation of a steam turbine control system have occurred and have been reported in [1]. When forced oscillations occur, it is necessary to locate the source of the oscillations and disconnect it from the grid. If the frequency of the forced oscillation is not close to any natural frequency, the oscillation is strongest at the source and it is attenuated when it is propagated into the grid [2]. Thus, the magnitude of the mode shape or the oscillation amplitude can be used to locate the source; these methods have been widely studied in the literature [3]-[5]. However, when a forced oscillation resonates with a system mode, the mode shape or oscillation magnitude is not a reliable indicator to locate the source of the oscillation [2]. The challenge is that a small forced oscillation can lead to large oscillations at other locations [6].

To locate the source of forced oscillations, several methods have been proposed [7]. Based on the dissipation energy concept, [8] detects the source of the oscillations by finding the generator that has negative dissipation energy, which is consistent with the dissipation energy created by the damping torque. This work is slightly modified in [9] to adapt the algorithm to a practical implementation and to benefit from Phasor Measurement Unit (PMU) measurements. These methods appear as rather simple to implement and promising results have been shown based on both numerical simulations and actual PMU measurements in the grid, but their reliability when implemented in real-life power systems should be further investigated [7].

A relevant approach where the generators presenting the smallest damping contribution are considered as the oscillation source is proposed in [10]. To identify the source, the algorithm tries to find two opposing groups among voltage phase angles, and the leading phase angle in the leading group is considered as the oscillation source. If the difference between the two groups is approximately 180 degrees or it is not clear what is the leading group, the location with leading phase is the one that is of interest. Although this algorithm seems straightforward and simple to implement, it is based on highly simplified assumptions. Moreover, in practice, it is difficult to find which phase angle is leading in a large power system, especially during forced oscillations. Alternatively, other methods based on damping torque, mode shape, equivalent circuit, hybrid simulation, artificial intelligent [7] have been proposed in the literature. Nevertheless, based on experience from the recent forced oscillation incident presented in [1], more efficient tools to locate the source of forced oscillations are still needed.

This paper aims at locating the oscillation source caused by maloperation of turbine-governor systems. The main idea is that the control system changes its behavior due to internal maloperation at the oscillation source. Therefore, if the transfer function of the control system is a priori known or can be estimated from measurements, it can be possible to predict the generators output by numerical processing of their measured inputs. Then, comparing the simulated output with actual measurements can reveal mismatches possibly to be attributed to changes in the control system behavior. Large mismatches can be an indicator of a defective unit while it is assumed that controller reactions to grid transients in generators that are operating normally would largely agree with the predicted behavior. This is the key feature allowing to locate one or multiple concurrent sources of forced oscillation.

The paper is structured as follows: first, a brief introduction about system identification and examples of its application in power system are given, and then the proposed algorithm is described in Section II. In Section III, results from numerical simulations on the Nordic 44 node model are presented and finally conclusions are drawn in Section IV.

II. Proposed Method for Locating the Source of Forced Oscillations

The main objective of the proposed method is to detect the source of the forced power oscillations in power systems caused by maloperation of the turbine-governor system at power plants with synchronous generators. The main idea is that the source of the oscillation exhibits a different dynamic behavior during the presence of forced oscillation compared to its normal characteristics. This feature can be detected by using system identification techniques with local

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measurements of active power and grid frequency, which can be obtained from PMUs. Based on this methodology, the proposed method is not limited to a single source of oscillations but can also identify concurrent sources.

System identification is a well-established field, which focuses on identifying the transfer function of a system based on measurements of the inputs and outputs. This methodology is extensively applied in control engineering and other fields [11]. An effort to use this approach for the dynamic characteristics of power generators is presented in [12] demonstrating that it is possible to properly estimate the transfer function of the hydro turbine-governors by system identification techniques and PMU measurements. Recently, a deeper investigation into this topic has been conducted and presented in [13]. Numerical software for system identification is also widely available (e.g. Matlab toolbox for system identification [14]).

A. Method implementation

As illustrated in Fig. 1, the main function of the governor is to control the speed of the generator and consequently the grid frequency. The governor will increase the mechanical power P_m when the speed of the generator is decreasing and vice versa. In normal operation, it is reasonable to assume that the grid frequency is equal to the generator's mechanical speed (in per unit). Hence, it can be assumed that the active power P_e of the generator is a function of the grid frequency, represented by a transfer function:

$$H(s) = \frac{P_e(s)}{f(s)} \tag{1}$$

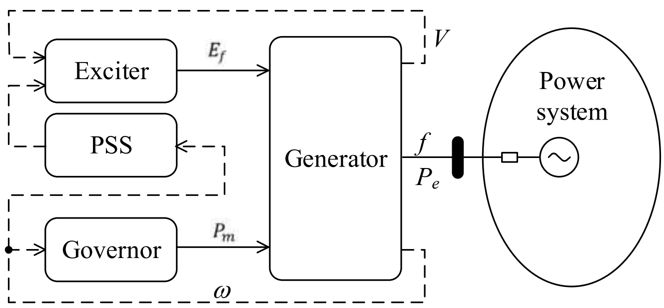

Fig. 1. Block diagram of a generator and its controllers.

Considering f as the input and P_e as the output, $H(s)$ can be identified by system identification techniques. When a component in turbine-governor system is defective, leading to forced oscillations in the grid, the transfer function $H(s)$ estimated in healthy condition is no longer valid. Thus, the relation between grid frequency and the mechanical speed of the generator can be slightly altered. The frequency obtained from actual measurements can be applied as the input for $H(s)$ to predict the active power for each generator. This calculated power will be different from the active power obtained from the actual measurements for the defective units that cause the oscillation. By contrast, the controllers of other generators operating normally experience changes in the frequency and voltage magnitude but still act according to a transfer function very close to what identified during normal operation.

The objective of this algorithm is to find the largest mismatch between simulated values and actual measurements, which helps identify the oscillation source. Further, if the measurements of the generator's mechanical speed are available and synchronized with the measurements of active power, this mechanical speed can be used as the input, instead of the grid frequency to improve the performance. Based on the above analysis, a method to locate the source of forced oscillations caused by maloperation of turbine-governor system is proposed as follows:

1. Estimate the transfer function of the turbine-governor system in normal conditions. Measurements of the grid frequency and active power of each generator at the terminal are needed, preferably from PMU measurements.

2. To prepare for the identification process, a period when the oscillation is clearly observed and rather stable should be selected. This period should last for a few minutes.

3. The identification process begins only when oscillations of active power have been detected. This means the oscillation magnitude must be larger than a predefined threshold. This threshold depends on the rated power of the generator, operating conditions, and experience of the system operators. A threshold in the range of 5 to 20 MW can be assumed for generators connected to transmission systems. Since forced oscillations are generally sustained oscillations, the oscillation magnitude is defined as the rms value of the active power after this signal has been detrended.

4. Use the frequency measurement and the previously estimated transfer function to predict the active power.

5. To quantify the mismatch between the estimated and actual values, the normalized root mean squared error (*NRMSE*) is used as an indicator, which is by definition computed as:

$$NRMSE = 1 - \frac{\|P_{meas} - P_{sim}\|}{\|P_{meas} - \text{mean}(P_{meas})\|} \tag{2}$$

where P_{meas} and P_{sim} are a series of the measured and predicted values, respectively, and $\| \quad \|$ stands for the norm operator.

6. The source of the forced oscillation is the generator whose *NRMSE* is low (e.g. < 50%) and clearly different from the normal value. It should be remarked that the *NRMSE* can be negative, which indicates a very large mismatch between the simulated and measured values (higher than for positive values).

B. General considerations on the algorithm

- The proposed algorithm identifies the source of the oscillations based on detecting changes in each turbine-governor transfer function based on the local measurements. The algorithm is not affected by the number of forced oscillation sources that coexist in the power grid. In other words, the proposed method can detect multiple sources, which are simultaneously creating oscillations. Compared to other methods in the literature, this is a clear advantage.

- The approach presented in this paper requires measurements of the grid frequency and active power of each generator, which are normally available. However, the measurements need to be synchronized in time, which is not the case in the present situation when PMU measurements are not widely installed at power plants. Systemwide, the grid operators need to have access to these measurements at power plants to be able to detect the source of the forced oscillation.

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- The proposed method is to detect the source of oscillations that are happening in the grid. In this context, it can be considered as an online tool. However, the algorithm requires a measurement window that contains the latest data of power and frequency. The length of this window can be up to one minute, meaning that the oscillations must have been occurring longer than one minute to be detected. This condition was fulfilled in historical forced oscillations [1], [6].

- System identification algorithms estimate the transfer function of the turbine-governor system only based on measurements of the input (grid frequency) and output (active power). With default settings, the algorithms can provide satisfactory results without required knowledge or operating condition of the turbine-governor or the power grid. There is also no need for initialization to estimate the transfer function although this might help the estimation process. This issue is however beyond the scope of this paper.

- Besides, maloperation of power system stabilizer, exciter and voltage regulator can also lead to forced power oscillations, which has been not addressed in this paper. This topic will be a subject in the future work.

III. Numerical Simulation Results

The proposed method has been validated with numerical simulations in DIgSILENT PowerFactory on the Nordic 44 bus model. This model is developed to emulate the main characteristics of the Nordic power system. The model contains 13 hydro and 5 steam turbine power plants. More detail of the model can be found in [15]. First, the loads in the system are randomly varied in a dynamic (time domain) simulation to trigger response of all the governors. Fig. 2 shows the grid frequency at bus 3249 and the active power of the power plant at that location. As can be seen, the governor of the generator responds to the grid frequency variations.

In this paper, the function ARX in Matlab is used to estimate the turbine-governor transfer function based on the measured frequency and active power of each generator. The estimated transfer function is validated by comparing the measured active power with the active power calculated as output of the transfer function when assuming the measured frequency as an input. Fig. 3. shows the actual value of active power of the generator at bus 3459 and its corresponding estimation. As can be seen, the two values are comparable, which indicates that the transfer function has been estimated properly. It is noted that in Fig. 3 the two signals have been detrended in order to get better visualization of the signals.

Based on random load variations, all the turbine-governor transfer functions in the grid are estimated. Table I shows *NRMSE*s of all the estimated transfer function. As can be seen, all the *NRMSE*s are close to 100%, meaning that the simulated values are very close to the corresponding measurements. Thus, it is realistic to assume that all the transfer functions are properly estimated. Compared with the results in [12], where real-life PMU measurements were used to estimate the transfer function of some hydro turbine-governor systems in Norway, the results in this paper are comparable.

A. Oscillation without resonance

After all the transfer functions have been estimated, they can be used to locate the source of the forced oscillation. In this section, the first oscillation in a dynamic simulation is created at bus 3359 by applying a sinusoidal reference at 0.5 Hz to the governor of the generator located at this node. Since the oscillation is not close to any natural frequencies, the power oscillation is largest at the source as seen in Fig. 4, where active power of all generators in the grid is plotted. This is in line with the findings in [2].

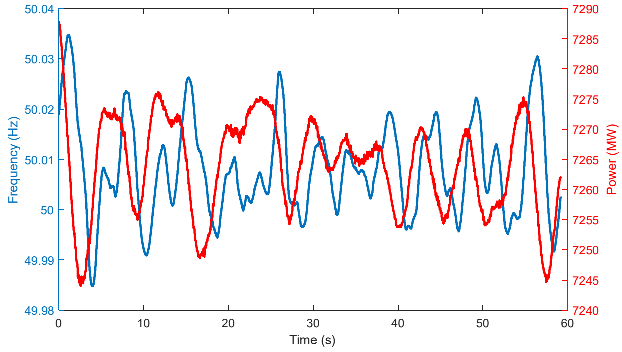

Fig. 2. Frequency and active power of a power plant.

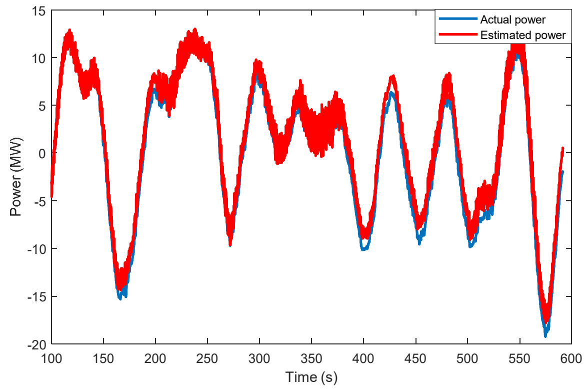

Fig. 3. Measured and estimated power of the generator at bus 3459.

TABLE I. Fit for the estimated transfer functions

Generator	NRMSE (%)	Generator	NRMSE (%)
Bus 3000	86.98	Bus 5500	83.97
Bus 3115	83.61	Bus 5600	83.01
Bus 3245	83.18	Bus 6000	98.33
Bus 3249	81.07	Bus 6100	83.29
Bus 3300	86.87	Bus 6500	82.99
Bus 3359	95.46	Bus 6700	81.99
Bus 5100	82.72	Bus 7000	88.27
Bus 5300	84.07	Bus 7100	83.96
Bus 5400	82.66	Bus 8500	95.84

Fig. 5 shows the actual active power of the generator at bus 3359 and its estimated value based on the transfer function. As noticed, there is a significant difference between the two curves. The main reason is that there is a malfunction in the turbine-governor system associated to a different transfer function than during normal operation. Conversely, the actual and estimated active power of generator at node 6000 are very close to each other as seen in Fig. 6, meaning that this location is not the source of the oscillation. Results from all the generators are presented in Table II, which shows that most of the generators present high *NRMSE*, therefore not causing the forced oscillation. The exceptions are the generators at node 3000 and 6700 presenting *NRMSE*s of

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-23.47% and 52.76%, respectively. However, it can be observed that oscillation magnitude is also one of the criteria to locate the oscillation source. This magnitude must be larger than a predefined threshold, e.g. 10 MW. This threshold is chosen based on the rated power of the generator and on the grid operating conditions. Fig. 7 shows that the oscillation magnitude at bus 3000 is below the threshold, and that this location should be neglected. Similarly, the oscillation magnitude at bus 6700 is 0.2 MW, which also should be discarded. Finally, bus 3359 can be identified as the oscillation source since its *NRMSE* is smallest (1.05%).

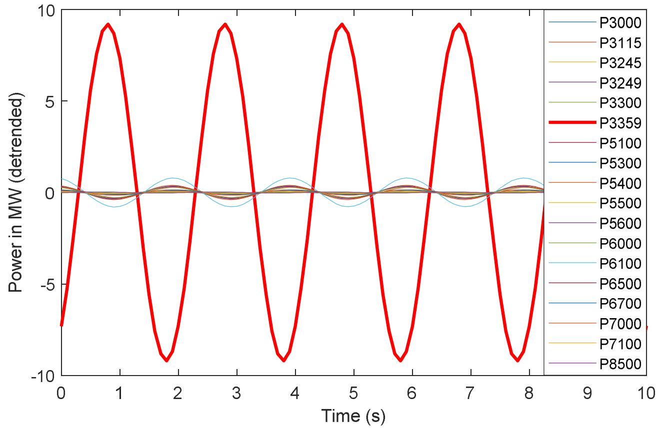

Fig. 4. Active power of all generators in the grid.

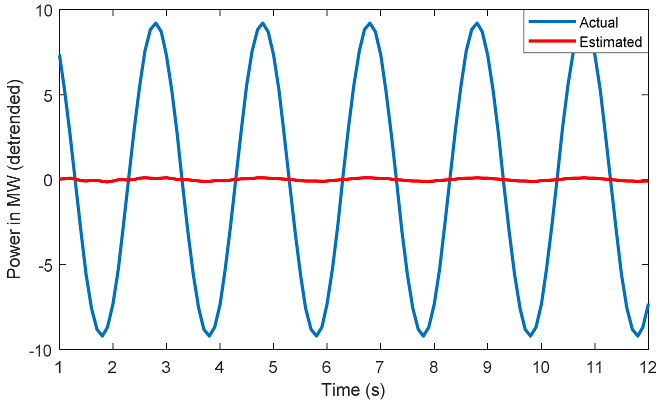

Fig. 5. Measured and emulated active power of generator at bus 3359.

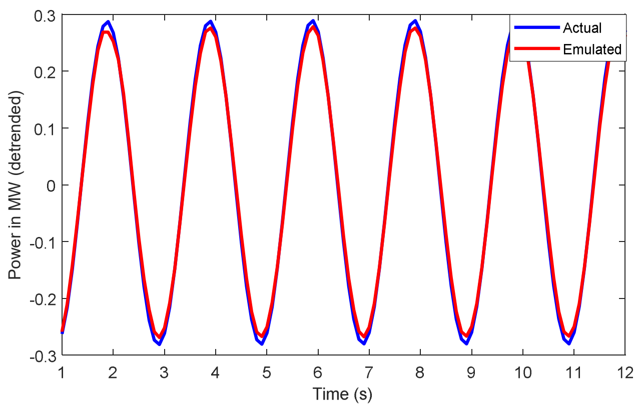

Fig. 6. Measured and emulated active power of generator at bus 6000.

The proposed method assumes that the grid frequency and the generator's speed are approximately equal during the forced oscillation period. This assumption seems reasonable as seen in Fig. 8, which shows these parameters at bus 6100. Moreover, from all the simulations conducted on the Nordic 44 model, it has been observed that this assumption is valid, especially after the first transients have extinguished.

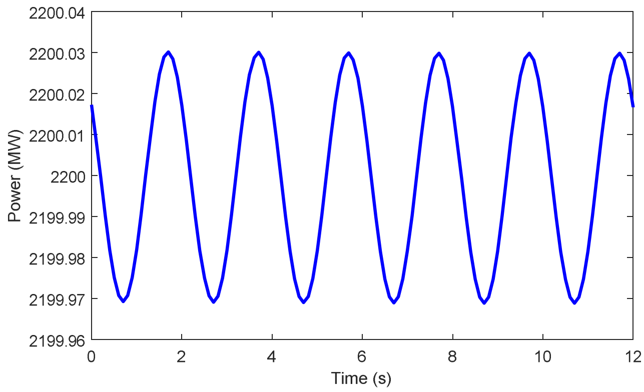

Fig. 7. Active power of generator at bus 3000.

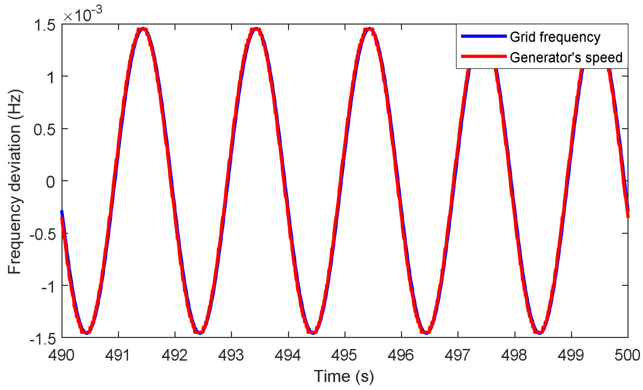

Fig. 8. Deviation of grid frequency and generator's speed at node 6100.

TABLE II. FIT OF ESTIMATED TRANSFER FUNCTIONS WHEN THERE IS A 0.5HZ FORCED OSCILLATION AT BUS 3359

Generator	NRMSE (%)	Generator	NRMSE (%)
Bus 3000	*-23.47*	Bus 5500	83.62
Bus 3115	90.91	Bus 5600	94.47
Bus 3245	79.33	Bus 6000	95.06
Bus 3249	96.38	Bus 6100	97.40
Bus 3300	90.06	Bus 6500	72.72
Bus 3359	**1.05**	*Bus 6700*	*52.76*
Bus 5100	88.60	Bus 7000	96.53
Bus 5300	97.57	Bus 7100	95.65
Bus 5400	93.32	Bus 8500	77.47

B. Oscillations with resonance

In this time-domain simulation, forced oscillations are created at bus 6500, and the oscillation frequency is 1.46 Hz, which is in the proximity of a natural frequency of the grid. Due to resonance, the forced oscillation at bus 6500 leads to a larger power oscillation of the generator at bus 6700 as shown in Fig. 9. Thus, the largest oscillation is not located at the source of the oscillation. Similar to the previous case, the estimated transfer function and grid frequency are used to locate the oscillation source. Table III shows that bus 6500 can be concluded as the source of the oscillation since the *NRMSE* is -22.45%, which is very dissimilar from the normal value presented in Table 1 and much lower than the *NRMSE*s of other generators. It is noted that the oscillation magnitudes at

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node 3115, 5300, 5400, 5600, 6000 and 6100 are lower than the threshold and these nodes could be discarded.

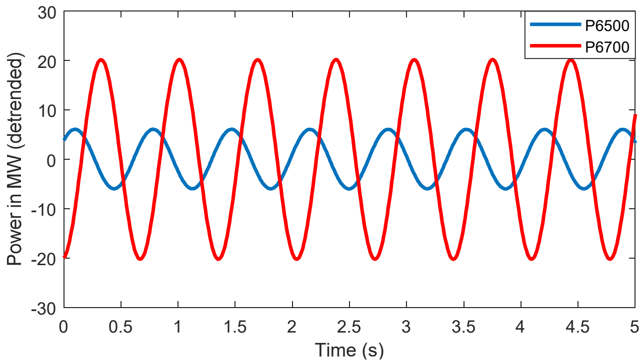

Fig. 9. Active power of generator at bus 6500 and 6700.

TABLE III. FIT OF ESTIMATED TRANSFER FUNCTIONS WHEN THERE IS A 1.46 HZ FORCED OSCILLATION AT BUS 6500

Generator	NRMSE (%)	Generator	NRMSE (%)
Bus 3000	90.69	Bus 5500	72.57
Bus 3115	*N/A*	*Bus 5600*	*N/A*
Bus 3245	91.83	*Bus 6000*	*N/A*
Bus 3249	71.14	*Bus 6100*	*N/A*
Bus 3300	95.90	**Bus 6500**	**-22.45**
Bus 3359	97.90	Bus 6700	92.27
Bus 5100	68.68	Bus 7000	67.65
Bus 5300	*N/A*	Bus 7100	71.69
Bus 5400	*N/A*	Bus 8500	97.61

TABLE IV. FIT OF ESTIMATED TRANSFER FUNCTIONS WHEN THERE ARE TWO SOURCES OF FORCED OSCILLATIONS AT BUS 3000 AND 6100

Generator	NRMSE (%)	Generator	NRMSE (%)
Bus 3000	**44.27**	Bus 5500	87.59
Bus 3115	97.11	Bus 5600	95.99
Bus 3245	92.29	Bus 6000	96.87
Bus 3249	97.91	**Bus 6100**	**26.11**
Bus 3300	97.21	Bus 6500	84.87
Bus 3359	96.26	Bus 6700	95.87
Bus 5100	96.50	Bus 7000	97.28
Bus 5300	96.52	Bus 7100	93.38
Bus 5400	97.75	Bus 8500	98.91

C. *Multiple oscillation sources*

Results from the third dynamic simulation are presented in this subsection to demonstrate the capability to locate simultaneous sources of oscillations. In this simulation, generators at node 3000 and 6100 generate oscillations at 0.7 Hz and 0.4 Hz, respectively. Table IV shows the mismatch between measurements and estimated values obtained from the transfer function. From this table, it is obvious that these generators have the smallest *NRMSE*s, which are much different from the normal values shown in Table 1.

IV. CONCLUSION

In this paper, a method to locate the source of forced oscillations caused by turbine-governor systems has been presented. The proposed method employs system identification techniques to estimate the transfer function of the turbine-governor system and then uses this transfer function to detect the abnormal behavior when the system malfunctions. Based on this methodology, the proposed algorithm can locate simultaneous oscillation sources, which is a challenge for existing methods in the literature. From simulation results, it has been shown that the proposed algorithm works as expected

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