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Synchrophasor Measurement-Based Wind Plant Inertia Estimation

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Synchrophasor Measurement-Based Wind Plant Inertia Estimation

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***Abstract*—The total inertia stored in all rotating masses that are connected to power systems, such as synchronous generations and induction motors, is an essential force that keeps the system stable after disturbances. Typically, inertias respond to disturbances voluntarily, without any control actions; however, several types of renewable generation, particularly those with power electronic interfaces, have an inertial response governed by a control function. To ensure bulk power system stability, there is a need to estimate the equivalent inertia available from a renewable generation plant. An equivalent inertia constant analogous to that of conventional rotating machines can be used to provide a readily understandable metric.**

This paper explores a method that utilizes synchrophasor measurements to estimate the equivalent inertia that a wind plant provides to a system.

***Index Terms*—inertia, inertia constant, phasor measurement unit**

I. Introduction

Inertia decides a machine's initial response after a mismatch occurs between the electrical torque and the mechanical torque. In the appearance of real power that has been released from kinetic energy, the system frequency deviation will be slowed and the initial frequency dip will be lifted. The characteristics of inertial response can be described by the swing equation (1), which is directly derived from the Newton Law of Motion on rotating objects [1].

$$\frac{2H}{\omega_0}\frac{\partial^2 \Delta\delta}{\partial t^2} = P_M - P_E - K_D\Delta\omega$$

where:

H	inertia constant
ω_0	rated speed
δ	rotor angle
P_M	mechanical power
P_E	electrical power

The inertia constant H is typically used as an index to describe the amount of kinetic energy that can be released by each individual machine; however, this concept faces challenges from different types of renewable generation, such as wind. The majority of wind turbines deployed in the U.S. power system are either partially synchronized with the grid (doubly-fed) or completely desynchronized (full converter). Their inertial responses are realized by control functions of the power electronic devices (such as inverters) that connect the wind generators to the grid. Thus, for most wind plants, the inertia constant cannot be calculated directly using the swing equation. Furthermore, wind plants typically consist of tens or hundreds of wind turbines. Depending on wind conditions, the number of turbines online at a given time can be completely random. It is more important to learn the aggregate inertia of a wind plant regarding its point of interconnection than to accurately calculate the inertia of each individual turbine. Therefore, it is beneficial to compare wind to other generations to find an equivalent inertia constant for a wind plant with respect to the point of interconnection.

The increasing wind penetration to the power grid is raising concerns about the decline of the inertial response within interconnections [1–2]. Thus, for operators to maintain the minimum level of frequency stability with unit commitments, it becomes more critical to be able to estimate the inertial response that wind plants can provide to the grid.

Inertial response from synchronous generation provides real power support to the grid immediately after a disturbance. Most converter-based wind generators can achieve same functionality by utilizing wind turbine inertial controls [3–6]. The fast inertial control functions are imposed to fast power electronics to take advantage of the inertia in the rotor and temporally convert the energy into real power output. Thus, those control functions can be seen as virtual inertias of wind generators.

Because of the correlation between the virtual inertias of the wind generators and the real inertias of the synchronous machines, it is feasible to develop a method that addresses inertias across conventional generators and wind generators.

Multiple research efforts are focused on developing measurement-based inertia-estimation methods. Some of these concentrate on total inertia of the entire interconnection following major frequency events [7–10]. These methods require measurements at each bus, and they assume the knowledge of the total MW change in the system. The study that focused on estimating wind generator inertias used the physical parameter of a single turbine, and assumed the knowledge of the turbines that are online, to match the wind farm performance with synchronous generators [11]. This method can be less practical because a wind plant can consist of different types of turbines and the number of turbines online can vary.

In Section II, this paper develops mathematical algorithms to calculate inertias based on phasor measurement units (PMUs). Section III presents a variety of case studies, including a one-machine system simulation, a large

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interconnection simulation, and by PMU data. Section IV presents conclusions.

II. Mathematical Methods

The swing equation defines the inertial response of a rotating machine or a group of machines to a power system disturbance.

$$\frac{2H}{\omega_0}\frac{\partial^2 \Delta\delta}{\partial t^2} = P_M - P_E - K_D \Delta\omega$$

The rotor angle is an angular displacement of the rotor, so that by definition, the angular speed of the rotor equals the derivative of the rotor angle.

$$\omega = \frac{\partial \delta}{\partial t} \Rightarrow \Delta\omega = \frac{\partial \Delta\delta}{\partial t}$$

The rotor angle δ cannot be directly measured by synchrophasor measurements; however, the bus voltage angle θ follows the rotor angle closely.

The equation can be rewritten as

$$\frac{2H}{\omega_0}\frac{\partial^2 \Delta\theta}{\partial t^2} = P_M - P_E - K_D \frac{\partial \Delta\theta}{\partial t}$$

Obtaining mechanical power from real-time measurements could be difficult, especially when considering the aggregate mechanical power from each turbine of a wind farm. A further simplification can be made in the equation by assuming that the mechanical power input to the generator has a much slower time constant than the electrical power. Thus, the assumption that the mechanical power equals the predisturbance electrical power is relatively safe for a short timescale. During the initial swing of any disturbance, when the primary frequency controls are typically not yet active, it is safe to assume that the mechanical power output by the generator remains constant.

Thus, the swing equation is finally developed into

$$\frac{2H}{\omega_0}\frac{\partial^2 \Delta\theta(t)}{\partial t^2} = P_{E0} - P_E(t) - K_D \frac{\partial \Delta\theta(t)}{\partial t}$$

rewritten as

$$H\frac{2}{\omega_0}\frac{\partial^2 \Delta\theta(t)}{\partial t^2} + K_D \frac{\partial \Delta\theta(t)}{\partial t} = P_{E0} - P_E(t)$$

in that

$$\frac{\partial \Delta\theta(t)}{\partial t} = \Delta\frac{\partial \theta(t)}{\partial t} = \frac{\partial \theta(t+1)}{\partial t} - \frac{\partial \theta(t)}{\partial t}$$

$$\frac{\partial^2 \Delta\theta(t)}{\partial t^2} = \Delta\frac{\partial^2 \theta(t)}{\partial t} = \frac{\partial^2 \theta(t+1)}{\partial t} - \frac{\partial^2 \theta(t)}{\partial t}$$

Assuming the damping factor K_D is zero during the short time window after a disturbance, the equation can be rewritten as

$$H\frac{2}{\omega_0}\left(\frac{\partial^2 \theta(t+1)}{\partial t} - \frac{\partial^2 \theta(t)}{\partial t}\right) = P_{E0} - P_E(t) \quad (1)$$

Because the final goal of this development is to facilitate the discrete PMUs with a fairly small time interval, the equations should be represented in a discrete-time domain.

From the fundamental calculus, if the time interval Ts close to zero, the following equations stand:

$$\frac{\partial y(n)}{\partial t} = \frac{y(n+1) - y(n)}{Ts}$$

$$\frac{\partial^2 y(n)}{\partial t^2} = \frac{y(n+2) - 2y(n+1) + y(n)}{Ts^2}$$

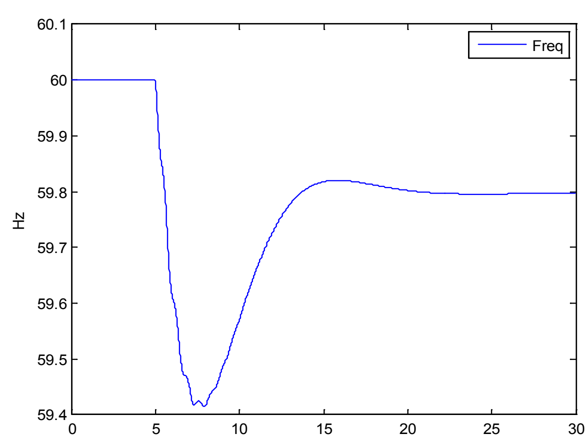
The time interval between each PMU point is very small, and equation (1) can be expressed as:

$$H\frac{2}{\omega_0}\left(\frac{\theta(n+3) - 3\theta(n+2) + 3\theta(n+1) - \theta(n)}{Ts^2}\right)$$

$$= P_{E0} - P_E(n)$$

In summary, this method can utilize the discrete PMUs (bus angles and real power) to estimate the generator inertia in a really short time window after a disturbance. For example, in case of loss of generation, as shown in Figure 1, the actual first angular swing lasts for a very short time period after the disturbance. Using the measurements prior to a disturbance and all the measurements during the first swing time window, inertia can be estimated in real time.

The online implementation of this method needs two preexisting conditions: (1) detection of disturbances and (2) detection of the peak (bottom) of the first angular swing [13–15]. The estimation of inertial response can be made using the data in between the start of a disturbance and the peak (bottom) of the first angular swing. However, for some fast events, the first swing can be short and the estimation accuracy suffers; thus, the actual calculation window can be expanded to the second or third swing. The assumptions of implementing this algorithm are still valid because the time window is still very small.



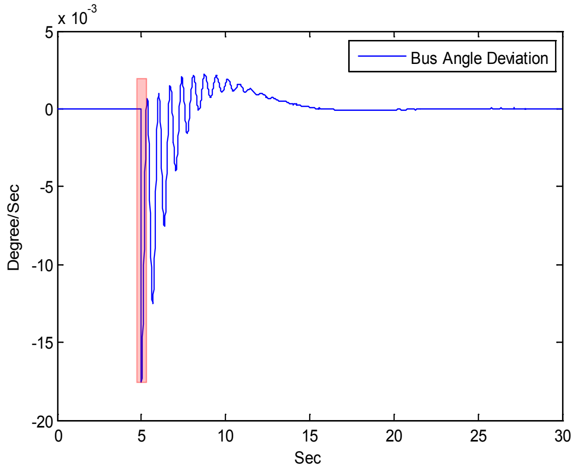


Figure 1 Time window for inertial estimation

As mentioned, most wind generation is decoupled from the grid so that the spinning mass would not provide any direct inertial energy to the grid when the electric torque suffers a sudden change, thus a single turbine's mechanical movement doesn't really follow the definition of the swing equation after disturbances.

However, most contemporary wind turbine controllers are capable of providing a boost of real power to the grid after under-frequency disturbances. Thus, using the bus angle and the real power measured at the wind power plant's point of interconnection, a "virtual" inertia of a wind plant can be calculated by the proposed algorithm.

To quantify the equivalent inertias of wind power plants, this algorithm essentially characterizes the energy that wind power plants provide to support the grid frequency right after disturbances to a similar format as that of conventional generators' inertias.

III. Case Studies

This section presents the results of the proposed method tested in several cases that simulated small-scale to large-scale power systems, as well as by PMU data. All the simulations were performed using General Electric's (GE) Positive Sequence Load Flow (PSLF) tool. For each test, the proposed method was first applied to conventional generators to decide the estimation accuracy, and then was used to decide the virtual inertias of wind plants in the same testing system to associate the wind virtual inertia with the system frequency response that can be driven by the same amount of conventional inertia.

A. Two-Machine Infinite Bus System

The two-machine system used in this study is described in Figure 2. The generator Gen 2 was tripped offline 5 seconds into the dynamic simulation to evoke an inertial response of generator Gen 1. First, Gen 1 used synchronous generator dynamic models. The governor control function was disabled so that the test illustrated only the impact of inertia on the system frequency response. A group of the inertia constant H values were assigned to the Gen 1 dynamic model and the simulation was repeated for each H value. The measurements (real power and bus angle) at the generator (Gen 1) bus were recorded for each test.

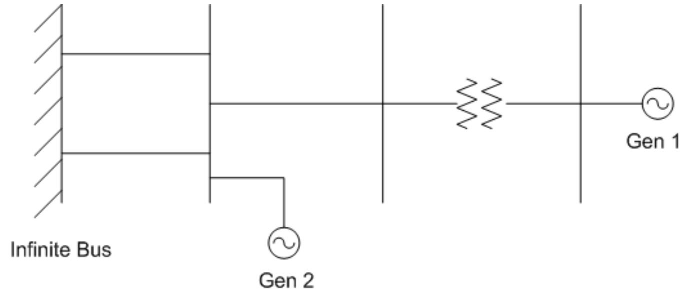


Figure 2 Two-machine infinite bus system diagram

Applying the algorithm to each data set when different inertia constant values were assigned to Gen 1, the estimation results are listed in Table 1.

The proposed algorithm was able to follow the trend of the inertial change at each case, and the average estimation error from the five testing cases was 0.178. Figure 3 shows the estimation error for each case.

Table 1 Inertial Estimation Results for Conventional Generation

H (Input)	2	4	6	8	10
H (Calc)	2.33	3.84	5.99	7.92	9.67

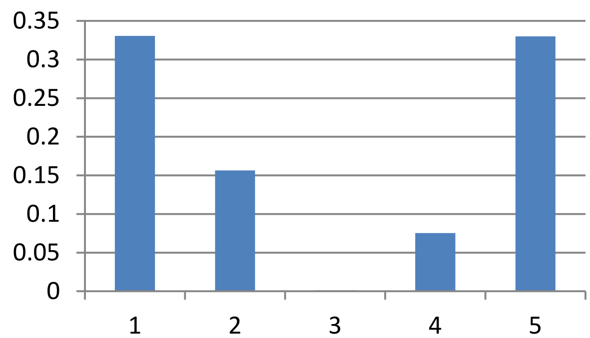


Figure 3 Inertial estimation errors

Replacing the Gen 1 dynamic model with GE Type 3 wind turbine, generator, and exciter models, the simulation was conducted with the same generation trip scenario, the GE wind turbine control model (WindINERTIA, which can emulate inertial response) was enabled.

Unlike the conventional generators, whose exact inertia constant can be known from its model parameters, the wind generator inertias can't be assigned simply to certain parameters. The correlation has to be drawn by comparing the system frequency response of the conventional generator and the wind generator.

Figure 4 shows a comparison of the system frequency response (measured at the Gen 1 bus) between a synchronous generator and a wind generator from the same system. The blue line represents the frequency response when Gen 1 was a synchronous generator with inertia constant H=2, and the red line represents the frequency response when Gen 1 was a wind generator. The frequency responses were closely aligned, which indicates a similar inertial support that both generators provided to the system. Thus, the wind generator inertia constant H can be approximated to 2.

Applying the algorithm to the wind generator simulation measurement data, the equivalent inertia constant was calculated as 1.832. Compare with the desired value 2, the error is 0.178.

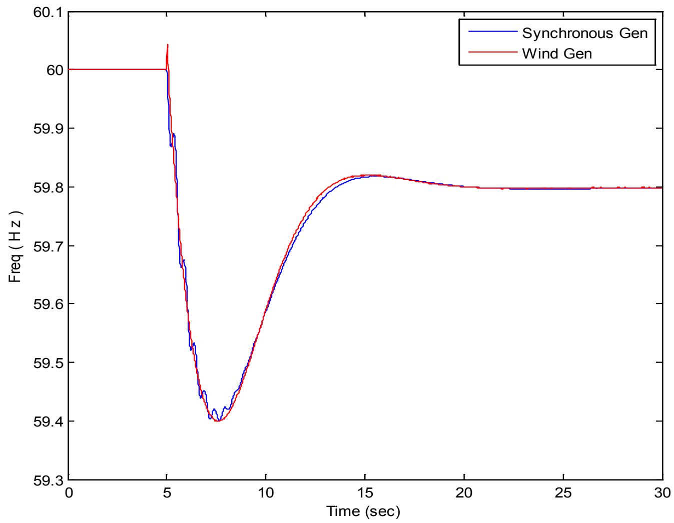


Figure 4 Frequency response comparison between a synchronous generator and a wind generator

B. Interconnection-Wide System

The one-machine system can provide a benchmark for the algorithm testing. However, to consider the interaction of the generators in an interconnected system as in reality, a large-scale model—such as the Western Electricity Coordinating Council (WECC) system model—was used to validate the algorithm. As in Section A, this test was conducted by dropping a 440-MW generator, and measurements from randomly selected synchronous generator buses were recorded.

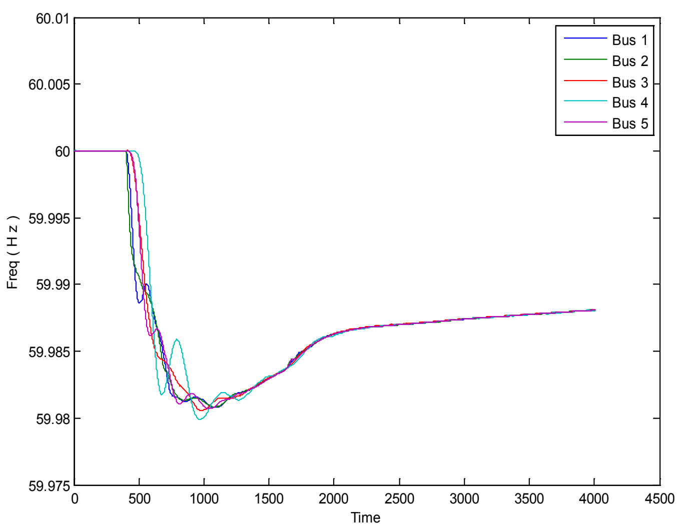


Figure 5 Frequency responses at five synchronous generator buses

The primary movers of these generators varied from steam turbine to hydro turbine, so the sample group was not uniform. The frequency response at each of the selected generator bus is displayed in Figure 5. The inertia constants of the selected generators were known so that the estimation accuracy could be decided by comparing them with the calculation results.

Table 2 presents the estimation results. In general, the algorithm could still recognize different inertias at random selected locations, with an average error of 0.215. The largest deviation was 0.56 at Bus 4. The estimation errors are shown in Figure 6.

Table 2 Inertial Estimation Results at Five Randomly Selected Buses for Conventional Generators

Bus	H (Input)	H (Calc)
1	2.3	2.326217
2	2.882	2.679543
3	6.059	5.778752
4	5.263	5.829989
5	2.13	2.131842

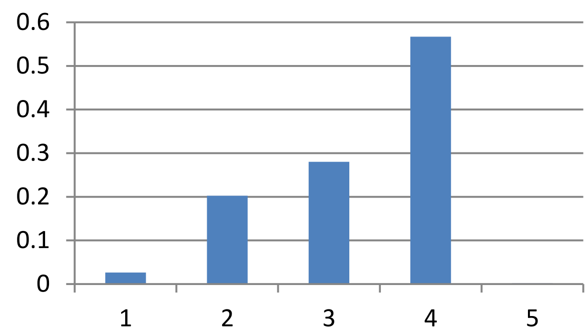


Figure 6 Inertial estimation errors

The second part of the test was to estimate the wind generator inertias at randomly selected locations in the WECC system.

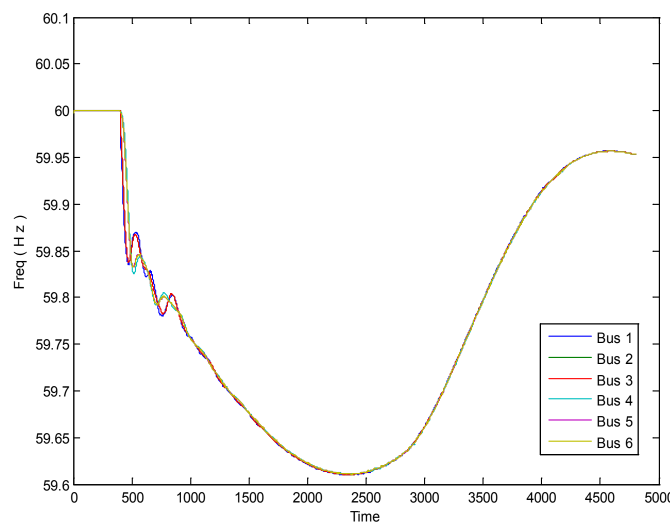


Figure 7 Frequency responses at six wind generator buses

In Section A, a type of wind generator that considered having a virtual inertia constant approximate to 2 was identified. The same GE Type 3 models were added at some random buses in the WECC system, and their responses to the same 440-MW generator trip disturbance were recorded. Figure 7 shows the frequency measured at the selected wind generator buses. The shapes of the frequency traces are different than those in Figure 5 because all the wind turbines in this case were providing inertial responses. That shifted the nadir as well as the initial slope.

Table 3 Inertial Estimation Results at Six Randomly Selected Buses for Wind Generators

Bus	H Input	H (Calc)
1	2	2.253811
2	2	1.843323
3	2	1.843323
4	2	1.505539
5	2	2.287092
6	2	2.266912

Because those wind generators were of the same size and used the same models, they all had virtual inertia constants approximate to 2.

The calculation results are listed in Table 3. Compared to the results with the inertia constant 2, the average error of the estimation was 0.269, as displayed in Figure 8.

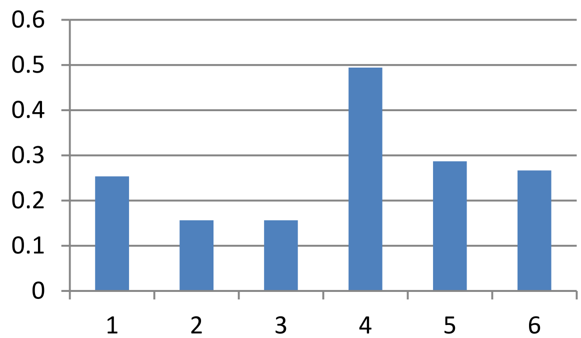


Figure 8 Inertial estimation errors

C. PMU Data Testing

The ultimate goal of this method was to utilize PMUs for inertial estimation. It is essential to find a PMU database with wind generator and synchronous generator recordings in the same interconnection.

The Oklahoma Gas and Electric (OGE) Energy Corporation is among the utilities in United States that has required all their wind power plants to install PMUs at their points of interconnection. Additional PMUs are also installed at some conventional generator locations. The nondisclosure agreement between OGE Energy Corp. and the National Renewable Energy Laboratory (NREL) allows the authors to test the algorithm on real system PMU data.

A frequency event that was picked up by the PMUs was selected for testing. As shown in Figure 9, four PMUs at conventional generator buses were selected. Their actual inertia constants could be derived from the system planning model that was also shared with NREL researchers by OGE Energy Corp. under the same nondisclosure agreement. Because there was only one generator at each of the four buses in the system model, if the measurements indicated they were in service, the online inertia should have been very close to the inertia constant that had been assigned to the model.

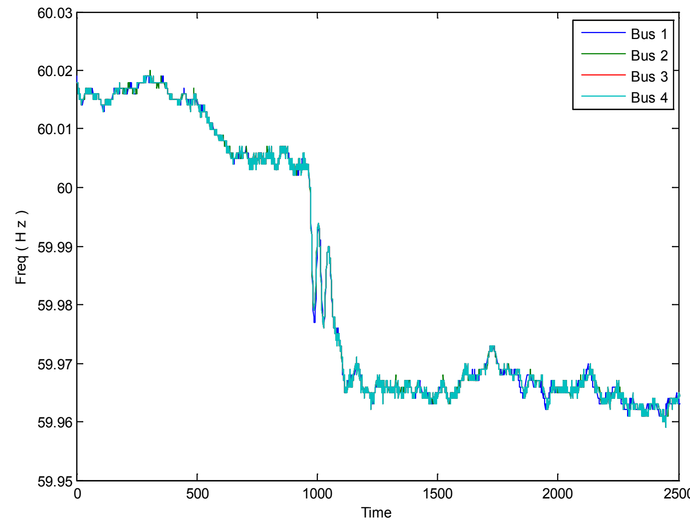


Figure 9 Frequency responses at four buses from PMUs

The actual inertia constants and the estimated results are listed in Table 4. The average estimation error was 0.105. The errors are illustrated by Figure 10.

Table 4 Inertial Estimation Results

Bus	H Input	H Calc
1	2.13	1.9314
2	2.41	2.5095
3	2.417	2.5195
4	2.38	2.4027

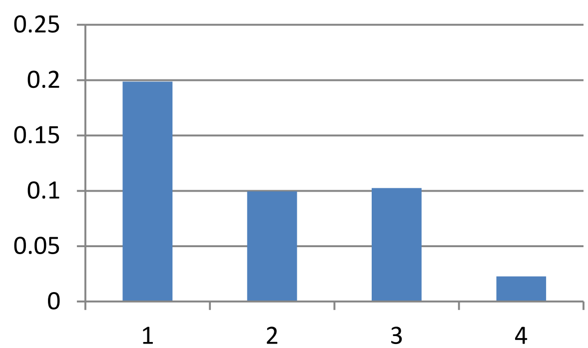


Figure 10 Frequency response at four buses from PMUs

Similarly, the PMU installed at a wind power plant also picked up the frequency event, as shown in Figure 11. However, applying the algorithm to the wind plant PMU data, the result was close to 0, which indicated that under the disturbance, the wind plant didn’t provide any immediate real power support to the grid; thus, there was no virtual inertial response from the wind power plant.

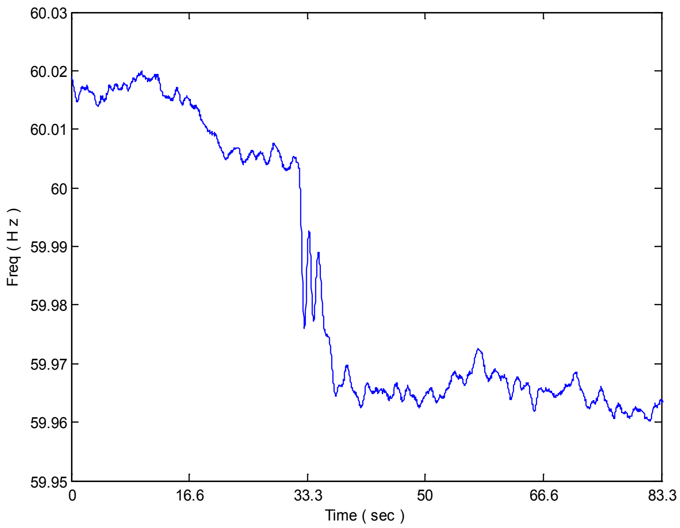


Figure 11 Frequency response at a wind generator bus

IV. CONCLUSION

This paper explored a mathematical algorithm to estimate generator inertias through PMUs. The algorithm was developed based on the swing equation. However, because it depends solely on real power injection and bus angle deviation at a generator bus, the inertias from different resources—weather that of a synchronous generator or the virtual inertia of a wind power plant—can be estimated at the same domain. Tests were done on different scale system simulations as well as PMU data. The results illustrated accurate performance of this algorithm.

The future work of this study should be focus on improving the algorithm accuracy, for example, finding out the correlation between event location and estimation accuracy.

V. ACKNOWLEDGEMENTS

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