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# Analysis of the Correlation between Wind Power Generation and System Response Characteristics Following Unit Trips on the ERCOT Grid

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# Analysis of the Correlation between Wind Power Generation and System Response Characteristics Following Unit Trips on the ERCOT Grid

**by**

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# Dedication

For Grandpa Bill

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Thanks to:

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## Abstract

## Analysis of the Correlation between Wind Power Generation and System Response Characteristics Following Unit Trips on the ERCOT Grid

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The University of Texas at Austin, 2010

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Electric power generation using wind turbines is on the rise in not only the United States but the entire globe. While the benefits from such methods of generation include clean and renewable energy, wind turbines may pose a potential risk to the stability of grid operation. Wind turbine generators are similar to conventional generators; however, the manner with which the wind turbine is coupled to the grid may reduce system inertia and increase the magnitude of transient stability problems. This study empirically examines the effect of wind generation on ERCOT system response characteristics following unit trips such as frequency drop, and phasor oscillation frequency and damping. It is shown with a high degree of certainty that an increase in wind generation is leading to a greater phasor oscillation frequency and lesser system inertia. Wind generation may also be leading to less system damping and smaller power frequency drops.

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# Chapter One: Introduction

The percentage of wind power generation in the World is constantly growing, and with growth comes an ever changing power system. During a system disturbance characteristics of the power system may cause it to respond differently than it had before; therefore, it is important to study and analyze the system response under new conditions in order to understand how it may respond. It is also important to know strengths or weaknesses of specific scenarios such as an increase in wind generation.

In IEA (International Energy Agency) member countries the amount of wind generation increased from 1.6% to 2.3% of the electric demand from 2007 to 2008 [1]. In the United States alone the amount of wind generation increased by 50%, providing 1.9% of the electric demand or 25,369 MW [2]. The Electric Reliability Council of Texas (ERCOT) grid contains a large amount of wind generating capacity. During some periods the wind generation can approach 20% of the electric demand. The fact that ERCOT contains a large amount of wind generation coupled with it being a power "island" in relation to the eastern and western grids creates a perfect location to study the effect of wind generation on a large power system. In the case of this study, data was taken from ERCOT's daily grid operations reports available on the ERCOT website. Further data was also obtained from a remote data logger located in San Angelo, TX and a server located at the University of Texas at Austin campus.

Large system disturbances happen every day on the ERCOT grid and it is important to understand what leads to these disturbances as well as how the system is protected from them. One such common disturbance, a unit trip, occurs when a generator is suddenly brought offline in the interest of protection. As an example a lightning strike causes a fault which in turns draws a large current on the affected line. If the circuit breakers on the line fail, the current will not be isolated and a generator supplying the affected line may be subject to a large over-current. A protective relay will detect the large current and respond by opening a circuit breaker isolating the generator. This action will immediately bring the power supplied by the generator to zero; however, the load is still drawing the same power prior to the unit trip. This creates a disparity that can cause transient disturbances to several power system characteristics such as voltages, power angles (phasors), and power frequency.

Typical response of a large power system is based primarily on the use of the large synchronous generators employed by coal and gas power plants that are strongly coupled to the grid; however, the generators used in the majority of wind turbines can be connected to the grid in a manner such that they are effectively decoupled from the grid as shown in [3], [4], and [5]. As the amount of wind generation increases on the grid, the system response characteristics following disturbances such as unit trips may change as well. There are two factors determining how a system will respond to a sudden loss of power; an inertia constant as well as a damping factor. As certain types of wind turbines can provide little to the system inertia constant, a large percentage of wind power on the grid could create different response characteristics such as maximum power frequency amplitude variations and increased phasor oscillation frequency.

[1] Executive Committee for the Implementing Agreement for Co-operation in the Research, Development, and Deployment of Wind Energy Systems of the International Energy Agency, *IEA Wind Energy Annual Report 2008.* Boulder, Colorado: PWT Communications, 2009. Pg. 7

[2] Executive Committee for the Implementing Agreement for Co-operation in the Research, Development, and Deployment of Wind Energy Systems of the International Energy Agency, *IEA Wind Energy Annual Report 2008.* Boulder, Colorado: PWT Communications, 2009. Pg. 291

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[4] Doherty, Ronan, Alan Mullane, Gillian Nolan, Daniel Burke, Alexander Bryson, and Mark O'Malley. "An Assessment of the Impact of Wind Generation on System Frequency Control," IEEE Transactions on Power Systems, vol. 25, no. 1, pp. 452-460, February 2010.

[5] Lalor, Gillian, Alan Mullane, and Mark O'Malley. "Frequency Control and Wind Turbine Technologies," IEEE Transactions on Power Systems, vol. 20, no. 4, pp. 1905-1913, November 2005.

# Chapter Two: Theory

## The Swing Equation

As shown in [4] a unit trip can be described in three separate stages: the pre-disturbance phase, the deceleration phase, and the control phase. During the pre-disturbance phase the system is operating in steady state. At the time of the unit trip there results in a negative difference between the electrical power at the load and the mechanical power being generated. In order for the existing online generators to make up the power difference stored kinetic energy is expended as the rotor speed drops and the electric torque increases. At some point the non-ideal rotor speed is detected and commands are dispatched to the turbine governor to accelerate the rotor speed, which eventually settles in equilibrium assuming the system is stable.

The response of a system following a unit trip can be described using Newton's second law as shown in [1] as follows:

$$J \propto = T_m - T_e \quad (1)$$

where $J$ is the moment of inertia, $\alpha$ is the rotor angular acceleration, $T_m$ is the mechanical torque, and $T_e$ is the electrical torque. If (1) is applied to the case of an electric power generator an equation is derived as shown in [2] as follows:

$$M\ddot{\delta} + D\dot{\delta} + P_G(\delta) = P_M \quad (2)$$

where $M$ is the inertia constant, $D$ is the damping factor, $\delta$ is the position of the rotor angle in relation to some reference (the phase angle), $P_M$ is the mechanical power being created by the generators, and $P_G(\delta)$ is the electrical power, which is dependent on the rotor position, being consumed by the load. In the case of the unit trip, $P_M$ is less than$P_G(\delta)$; therefore, the initial acceleration (change in frequency) of $\delta$ is negative.

In order to analyze a power system as a whole it is important to look at the swing equation case consisting of several generators. In [3] this multi-machine case is addressed. The exact connections of the ERCOT grid are not modeled here; however, an example of a power system consisting of two groups of generators weakly coupled together with the generators in each group being strongly coupled together can be used. The system $M$ and $D$ for generator group A can be defined as follows:

$$M_A = \sum_{i=0}^{n} M_i \quad (3)$$

$$D_A = \sum_{i=0}^{n} D_i \quad (4)$$

where $i$ is the generator number and $n$ is the number of generators in each group. Similar equations can be shown for $M_B$ and $D_B$.

The system $M$ and $D$, $M_s$ and $D_s$ respectively, are defined in [3] as follows:

$$M_s = \frac{M_A M_B}{(M_A + M_B)} \quad (5)$$

$$D_s = \frac{D_A M_B}{(M_A + M_B)} \quad (6)$$

The system swing equation for the multi-machine case can be described as follows in [3] and is similar to (2). Being that this is not an analytic study and in order to remove complexity, $M_s$ and $D_s$ were used in the place of $M$ and $D$ in (2). That is strongly coupled generators and generator groups add their respective $M$'s and $D$'s to obtain the system $M$ and $D$ while weakly coupled generators and generator groups use (5) and (6) to calculate the system $M$ and $D$.

Several assumptions can be made to simplify (2). As shown in [2], (2) can be linearized through a Taylor expansion and remain valid for small fluctuations in δ. For the unit trips studied, the total generation lost was no more than 4% of the total electric demand. This means a small initial disparity between $P_M$ and $P_G(\delta)$ and it can be assumed that the fluctuation of $\delta$ is relatively small as well. It is later shown that the fluctuations in δ are around 3° to 5°. The linearized version of (2) is as follows:

$$M\Delta\ddot{\delta} + D\Delta\dot{\delta} + T\Delta\delta = 0 \quad (7)$$

where $\Delta\delta = \delta - \delta_0$ and $T = \frac{dP_G(\delta_0)}{d\delta}$. (7) can be used under the assumption that δ does not vary greatly. It is shown later in this paper that $\delta$ varies a couple of degrees.

A description of the dynamics of a generator following a unit trip is described in [4] as follows. At the moment preceding a unit trip $P_M$ and $P_G$ are roughly equal and the differential equation is in equilibrium. When the circuit breakers protecting a generator suddenly open, $P_M$ becomes less than $P_G$ from the viewpoint of the remaining online generators. By looking at (2) this means that at the instant of the unit trip the acceleration of the rotor angle, or the change in the frequency, is negative. During this state the phase angle oscillates (usually around 2 seconds). In order to make up for the power imbalance kinetic energy from the individual generators is expended and the grid frequency drops until it reaches some minimum (usually around 10 seconds after the unit trip). Finally the governors of each generator's react and bring the frequency back to a state of equilibrium.

### EFFECT OF INERTIA AND DAMPING ON THE SYSTEM RESPONSE

In order to show the effect of $M$ and $D$ on the phase angle attention needs to be turned back to (7). With assumptions shown in [2], the characteristic equation can be found with roots at

$$s_{1,2} = \frac{-D \pm \sqrt{D^2 - 4MT}}{2M} \qquad (8)$$

Assuming $MT >> D$ and $T$ is always positive, the attenuation, $\alpha$, and damped natural frequency, $\omega_d$, of the phasor oscillations are shown to be

$$\propto = \frac{-D}{2M} \qquad (9)$$

$$\omega_d \cong \sqrt{\frac{T}{M}} \qquad (10)$$

This means that assuming a constant $D$, as $M$ decreases the attenuation becomes negatively larger and the frequency becomes positively larger. So a smaller inertia constant should provide a shorter recovery time with a greater frequency of oscillation possibly leading to instability. In this paper $\omega_d$(rad/s) is commonly converted to $f_d$(Hz) where $\omega_d = 2\pi f_d$.

The damping ratio is important in determining a normalized amount of damping in an oscillation. Using equations (11) and (12) found in [9], an equation for the damping ratio can be derived as shown with (13) as follows:

$$\alpha = \zeta\omega_n \quad (11)$$

$$\omega_d = \sqrt{1-\zeta^2}\,\omega_n \quad (12)$$

$$\zeta = \frac{\alpha}{\sqrt{\alpha^2+\omega_d^2}} \quad (13)$$

where $\zeta$ is the damping ratio, $\omega_n$ is the natural frequency, $\omega_d$ is the damped natural frequency, and α is the attenuation. Again assuming $D$ remains constant, a reduction in $M$ will lead to an increase in $\alpha$ and $\omega_d$ which should lead to a decrease in $\zeta$.

The change in $\Delta\delta$ can be described as shown in [1] as follows:

$$\frac{d\Delta\delta}{dt} = \omega_e(t) - \omega_{syn} \quad (14)$$

where $\omega_e(t)$ is the power system frequency at time $t$, and $\omega_{syn}$ is the synchronous power frequency of the grid. In this case $\omega_{syn}$ would be 60 Hz; therefore, it can be shown that, assuming the power angle initially drops, as M becomes smaller $\frac{d\Delta\delta}{dt}$ becomes larger negatively. This means that with a lower inertia constant the difference between $\omega_e(t)$ and $\omega_{syn}$ becomes larger and $\omega_e(t)$ drops (during the phasor oscillations) faster from 60 Hz. This is all assuming $D$ remains constant; however, (6) shows that in the multi-machine case the system $D$ is a more complex calculation then the system $M$ as it is directly affected by not only the $M$'s of the individual generators but the $D$'s as well. Furthermore, it is stated in [5] that "due to their construction, a wind plant has smaller inertia and speed so that the kinetic energy stored in it is reduced by a factor of approximately 1.5 when compared to a traditional plant of the same rating." This reduction in stored kinetic energy may lead to an increase in the amplitude of frequency variations.

### EFFECT OF WIND TURBINES ON THE SYSTEM RESPONSE

Wind turbines in use today typically come in several varieties. In [6], three separate configurations are examined. The fixed speed wind turbine usually employs a squirrel cage induction machine. Since the frequency of the generated power remains constant, the turbine can be directly connected to the grid. This creates a strong coupling to the grid and the generator is allowed to contribute inertia to the total system inertia; Variable speed wind turbines employ doubly fed induction generators (DFIG) or multi-pole synchronous generators (SG) that are connected to the grid through back-to-back (AC/DC/AC) converters. In the case of the multi-pole SG the frequency of the power being generated is not dependent on the frequency of the power system since there is no direct connection and the wind turbine is effectively decoupled from the power system. This means the wind turbine provides very little to the total system inertia; therefore, the wind turbine is taking the place of a generator that could provide inertia and effectively lowering the total system inertia during times of large wind power generation for any given electric demand. In the case of the variable speed DFIG wind turbine there does exist a connection (not direct) to the grid and the wind turbine provides at least a small amount of inertia to the system inertia. The variable speed DFIG wind turbine is only completely decoupled in the case of “large current controller bandwidths.” [6] This idea is reinforced in [7] where it is stated that “… both increased DFIG wind penetration and

HVDC [High-Voltage DC] capacity have a detrimental effect on both maximum ROCOF [rate of change of frequency] and nadir [minimum frequency] performance…" It is also concluded in [8] that "As fixed-speed wind turbines displace conventional synchronous generation, there is no significant change in minimum frequency reached following a loss of generation…" and that "As DFIG wind turbines displace conventional synchronous generation, the frequency nadir following a loss of generation reduces." With this in mind [7] states that "Even at relatively low wind power output levels, empirical data collected suggest that there is likely a relatively large stored wind turbine kinetic energy resource available…" which if controlled properly may positively affect the grid power frequency drop following a unit trip.

Earlier it was shown how changes in $D$ and $M$ can affect the system response following a unit trip. Given that a large number of variable speed wind turbines on the grid are producing power the system inertia constant $M$ could be much lower than if that power was being produced by conventional steam turbines using large synchronous generators. So as the inertia constant is much smaller, an arbitrary unit trip should produce a higher frequency swing in the power angle with a smaller settling time and possibly larger initial drop in the power frequency. These deviations to a response sans wind generation could create problems with system transient stability, causing a greater quantity and amplitude of power quality phenomena.

[1] Glover, J. Duncan, Mulukutla S. Sarma, and Thomas J. Overbye. *Power System Analysis and Design*, 4th ed. Toronto, Ontario: Thomson Learning 2008. Pg 697-699.

[2] Bergen, Arthur R., and Vijay Vital. *Power System Analysis,* 2d ed. Upper Saddle River, New Jersey: Prentice-Hall Inc. 2000. Pg 528-538.

[3] Bergen, Arthur R., and Vijay Vital. *Power System Analysis,* 2d ed. Upper Saddle River, New Jersey: Prentice-Hall Inc. 2000. Pg 556-563.

[4] Machowski, Jan, Janusz W. Bialek, and James R. Bumby. *Power System Dynamics: Stability and Control* , 2d ed. West Sussex, United Kingdom: John Wiley & Sons, Ltd., 2008. Pg 335-381.

[5] Machowski, Jan, Janusz W. Bialek, and James R. Bumby. *Power System Dynamics: Stability and Control* , 2d ed. West Sussex, United Kingdom: John Wiley & Sons, Ltd., 2008. Pg 296-297.

[6] Mullane, Alan, and Mark O'Malley. "The Inertial Response of Induction-Machine-Based Wind Turbines," IEEE Transactions on Power Systems, vol. 20, no. 3, pp. 1496-1503, August 2005.

[7] Doherty, Ronan, Alan Mullane, Gillian Nolan, Daniel Burke, Alexander Bryson, and Mark O'Malley. "An Assessment of the Impact of Wind Generation on System Frequency Control," IEEE Transactions on Power Systems, vol. 25, no. 1, pp. 452-460, February 2010.

[8] Lalor, Gillian, Alan Mullane, and Mark O'Malley. "Frequency Control and Wind Turbine Technologies," IEEE Transactions on Power Systems, vol. 20, no. 4, pp. 1905-1913, November 2005.

[9] de Silva, Clarence W. *Vibration and Shock Handbook.* Boca Raton, Florida: Taylor and Francis Group, LLC. 2005.

# Chapter Three: Methodology

## PHASOR OSCILLATIONS

As theorized in [3] [4] [5], an increase in wind power should result in an increase in the damped natural frequency of oscillation of the power angle due to a decrease in system inertia. Data was taken from PMUs (Phasor Measurement Units) in west Texas, San Antonio, Austin, and Houston, and stored in a server on the UT-Austin campus. Phasor measurements were taken 30 times every second and stored in txt files. The large size of these files led Dr. Grady to write a program in visual basic to view the data in an organized manner. Since measurements did not start until March of 2009, any earlier unit trips were not considered. Being that the method of data acquisition (nomenclature, programming, etc.) did not remain constant, not all of the data was usable. For example, early data contains naming conventions of PMUs that make finding their locations very difficult and some data either shows no oscillations or cannot be viewed reasonably. In order to see the oscillations in the power angle, the unit trip would need to occur in between two of the PMUs; therefore, it was understood that legitimate data should mostly be taken by referencing the PMU in west Texas to one of the other PMUs (or vice versa). Out of the approximately fifty unit trips used in the frequency drop analysis from February 2009 through November 2009, nine could not be used at all.

An example of a phasor oscillation following a unit trip is shown in Fig. 1.

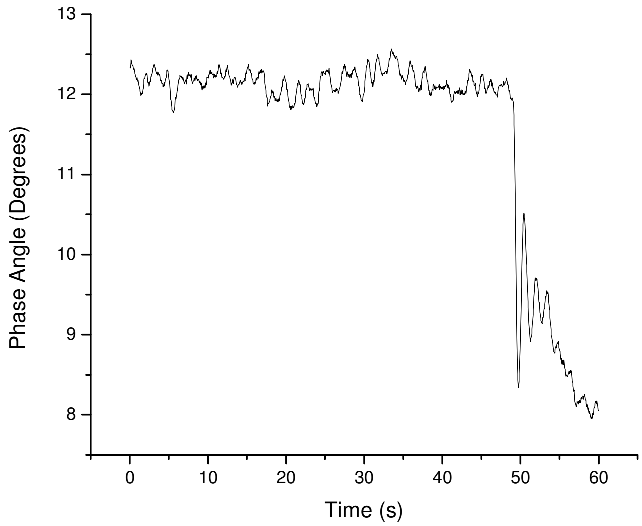


Fig. 1. Phasor oscillation following a unit trip occurring on 4/09/09 at approximately 7:10 AM CST (Event #11)

As can be seen in Fig. 1 there is a discernable oscillation that occurs. From this data several points of information were obtained, most notably the damped natural frequency $\omega_d$ and the attenuation $\alpha$ of the oscillation. The frequency was measured by determining the time between the first two minima of the oscillation and the time between the first two maxima. The two time periods were then averaged to obtain the measured frequency. While the two time periods should have been nearly equal, some data gave relatively large. In the case of the unit trip event in Fig. 1, the time periods were 1.5 and 1.47 seconds, resulting in a frequency of 0.673 Hz.

Measuring $\alpha$ was much more difficult then measuring frequency. As was stated before the phase angle does not cleanly oscillate around a straight line which presents a difficult problem; however, a method was devised to extract the attenuation. Using Origin Pro the data was cropped so that only the data from the first minimum to the second maximum was being viewed. A line was fitted to the existing data and the difference between the critical points and the line was measured. An exponential decay with an offset of zero was fitted to these points and the attenuation was extracted after normalizing to the frequency of oscillation. An example of a fitted line is shown in Fig. 2 along with the accompanying exponential decay in Fig. 3.

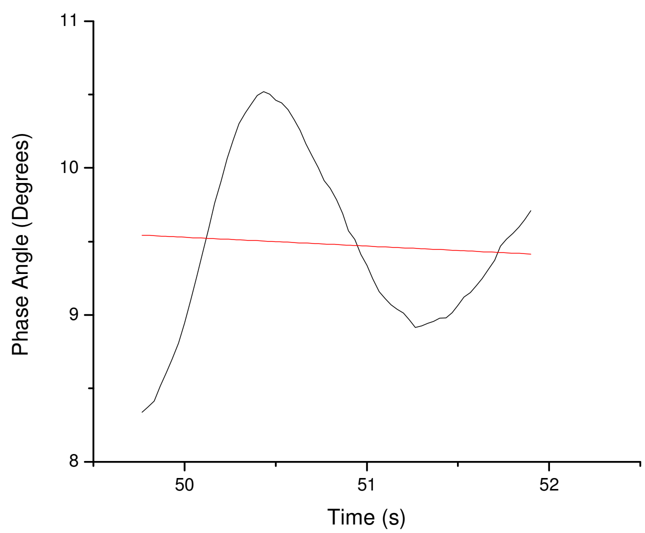


Fig. 2. Fitted line on phasor oscillations in Fig. 1. (Event #11)

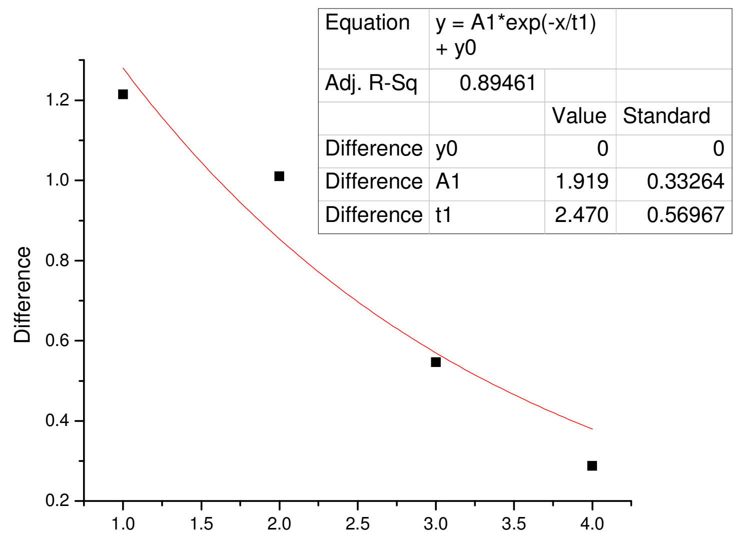


Fig. 3. Exponential decay of phasor oscillations in Fig. 1 and Fig. 2. (Event #11)

As can be seen in Fig. 3 it looks as if the first point is not correct. This may be due to the oscillations moving around a steep drop elbowing into a straight line rather than the oscillations moving around an instantaneous drop into a straight line. For this reason the first point in many of the decays was thrown out; furthermore, any maximums or minimums that did not look as if they followed correctly were not used. While this adds subjectivity into the study it should present a clearer picture of the actual attenuation.

Using the calculated value of the decay constant along with the period of the oscillations, the attenuation $\alpha$ was found to be 0.676. This value was recorded along with the coefficient of determination, $R^2$, of 0.9595, the reference PMU of “McDonald”, the measured PMU of “Austin”, and a damped natural frequency of oscillations of 0.673 Hz. Using (13) $\zeta$ was calculated to be 0.158. The $R^2$ was used to guess if the fitted line was accurate; however, a high $R^2$ does not always mean the fitted line was correct. In some cases the oscillations may be moving around an oscillating or curved center, not the straight line this method is assuming. Some oscillations using the measured $\alpha$ are superimposed above the actual oscillations in Appendix B.

### FREQUENCY DROPS

Measurements for frequency were taken every second from a data logger in San Angelo, TX on equipment operated by the Concho Valley EC. The frequency events were stored in csv files for unit trips occurring from February '09 through September '09; however, csv files could not be obtained for unit trips occurring in October '09 and November '09 (a total of six). In this case printouts of jpg files were analyzed. Data such as total electric generation and total wind generation were taken from a data logger located on the University of Texas at Austin campus archiving data from the ERCOT website. The server was operated by Moses Kai and Dr. Grady. Daily grid operations reports from [1] were also used to determine the time and magnitude of unit trips. Data points were only used that were a known unit trip, and the accompanying ERCOT data was available. An example of a typical frequency drop following a unit trip is shown in Fig. 4.

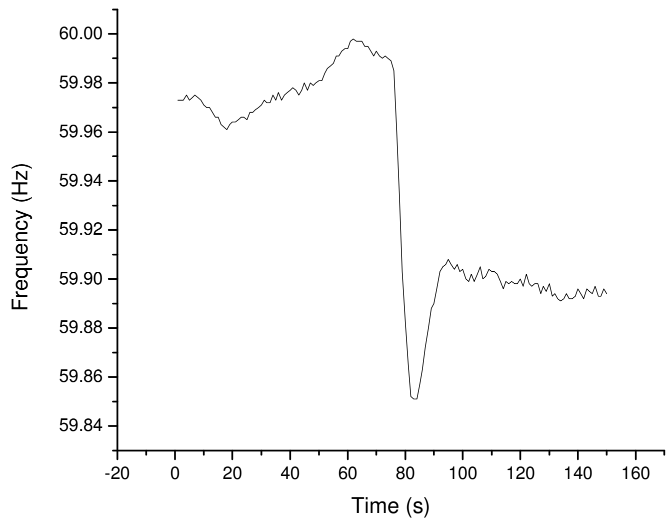


Fig. 4. Frequency drop following a unit trip occurring on 3/27/09 at approximately 9:54 AM CST (Event #9)

In order to characterize the frequency drop, a method was used that was proposed in [2]; Frequency "A" is the pre disturbance frequency, frequency "C" is the minimum frequency, and frequency "B" is the post-disturbance frequency at equilibrium. Since frequency "A" is not easy to determine with one point, five points immediately preceding the drop were averaged to obtain a measurement. Frequency "C" was easy to determine by simply measuring the minimum frequency over the entire period; however, since the data resolution was only one second the actual minimum may be lower. Frequency "B" is the most difficult to measure; however, it is not important in the case of measuring the initial frequency drop. In Fig. 4 Frequency "A" was determined to be 59.9916 Hz and frequency "C" was determined to be 59.851 Hz. This corresponds to a total frequency drop of 0.1406 Hz during a unit trip of 451 MW. During the unit trip the total generation and wind generation were found to be 30891 MW and 3772 MW, respectively. This means that 1.47% of the generation was lost while the total generation included 12.21% wind. A large portion of the frequency drops were of the general shape seen in Fig. 4 and concrete numbers for the total drop in frequency were easily recorded; however, there were a small number of abnormal drops, examples of which are shown in Fig. 5, Fig. 6., & Fig. 7.

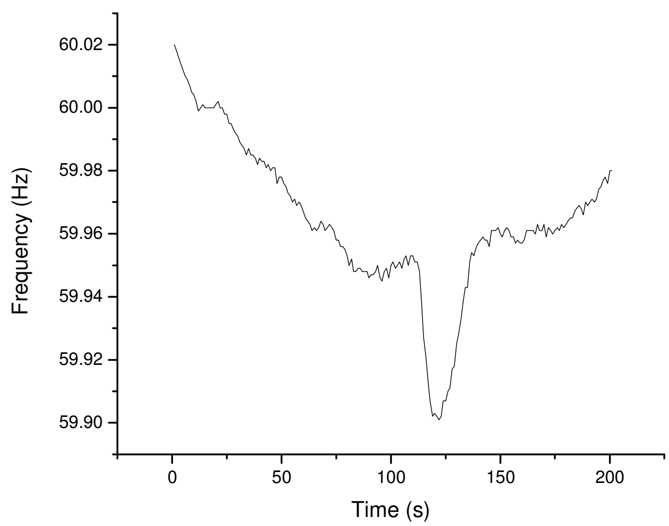


Fig. 5. Frequency drop following a unit trip occurring on 3/09/09 at approximately 1:42 PM CST

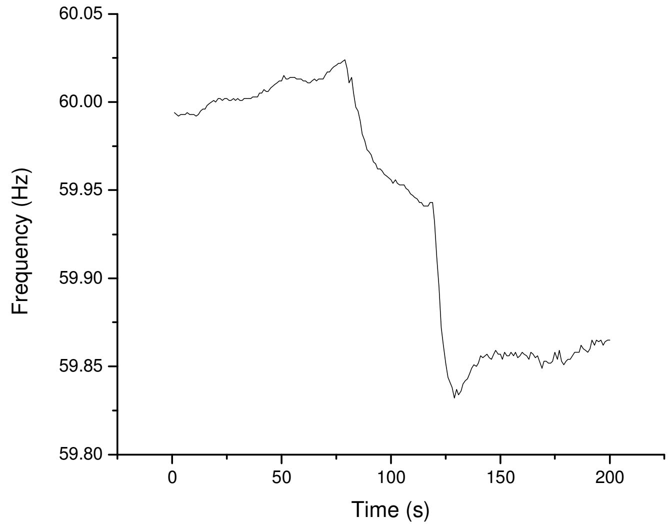


Fig. 6. Frequency drop following a unit trip occurring on 8/15/09 at approximately 9:18 PM CST

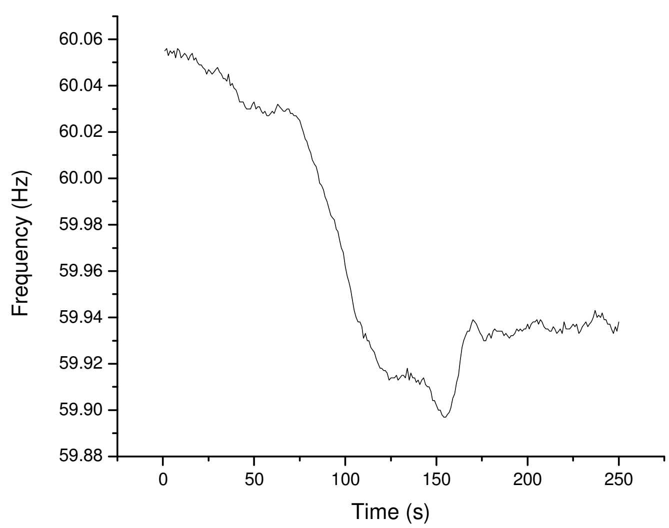


Fig. 7. Frequency drop following a unit trip occurring on 3/09/09 at approximately 8:11 AM CST

In addition to the unusual trace seen in Fig. 5, similar drops of around 0.5 Hz occurred on 7/2/09 at 4:58 PM (Event #28) and 7/08/09 at 3:17 PM. In Fig. 6 a double drop is observed, a similar trace occurred on 7/17/09 at 4:43 PM. The aforementioned unusual drops along with the drop in Fig. 7 were confirmed as unit trips from [1]; however, due to the difficulty of measuring the start and end of the frequency variation, these measurements were not used.

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[2] NERC. "Frequency Response Characteristic Survey Training Document." *NERC*. 2008. <http://www.nerc.com/docs/standards/sar/opman_12-13Mar08_FrequencyResponseCharacteristicSurveyTrainingDocument.pdf>

[3] Mullane, Alan, and Mark O'Malley. "The Inertial Response of Induction-Machine-Based Wind Turbines," IEEE Transactions on Power Systems, vol. 20, no. 3, pp. 1496-1503, August 2005.

[4] Doherty, Ronan, Alan Mullane, Gillian Nolan, Daniel Burke, Alexander Bryson, and Mark O'Malley. "An Assessment of the Impact of Wind Generation on System Frequency Control," IEEE Transactions on Power Systems, vol. 25, no. 1, pp. 452-460, February 2010.

[5] Lalor, Gillian, Alan Mullane, and Mark O'Malley. "Frequency Control and Wind Turbine Technologies," IEEE Transactions on Power Systems, vol. 20, no. 4, pp. 1905-1913, November 2005.

# Chapter Four: Results

## PHASOR OSCILLATION FREQUENCY

Results for the phasor oscillation frequency measurements are shown in Appendix A. Fig. 8 shows the measured damped natural frequency $\omega_d$ ($f_d$) versus wind generation as a percentage of demand.

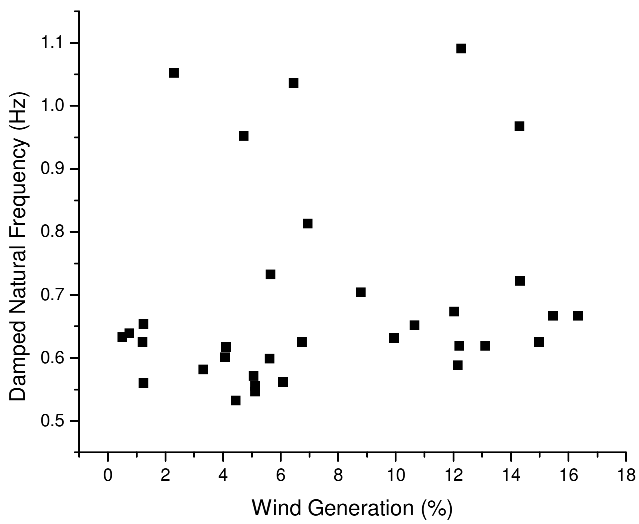



Fig. 8 Damped Natural Frequency vs. Wind Generation (% of Demand)

As can be seen in Fig. 8 the data seems to follow a trend around 0.6 Hz with a positive slope; however, there are some outliers. There does not seem to be a strong correlation between these outliers as they occur in different months/seasons with a large range of wind generation (2%-14%). They also seem to occur in a large range of unit trips (1%-1.8%) which nearly spans the entire spectrum of unit trips observed. The magnitude of the phasor oscillations is also low (approximately 0.3) to high (approximately 1.0) for the outlier events. The only clear similarity between them is that they are marked by noticeably high frequencies above 0.5-0.7 Hz. It is unknown what is happening differently during these outliers, but it is clear that these points are also outliers in other figures as explained later. If it assumed that the outliers are occurring in an abnormal mode and are removed, a linear function can be fitted to the data as shown in Fig. 9.

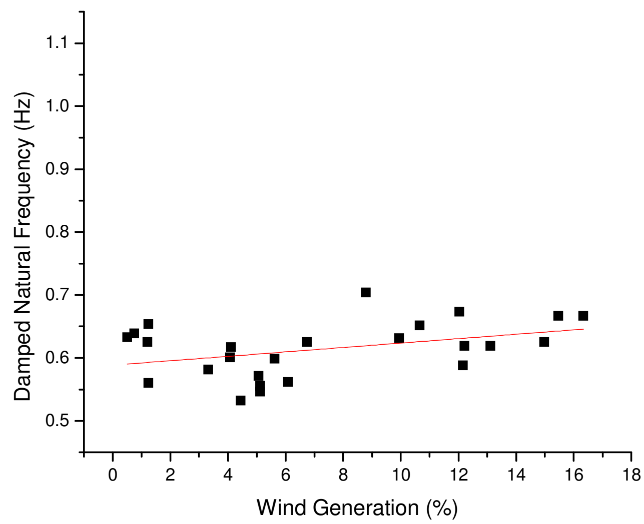



Fig. 9. Damped Natural Frequency vs. Wind Generation (% of Demand) (No Outliers)

Assuming the data follows a linear trend, the coefficient of determination ($R^2$) of 0.122 is relatively high, and if the relatively shallow slope of the line (0.0035) indicates the effect of wind generation on the damped natural frequency, $f_d$, it would show that a large change in wind generation results in a small change in $f_d$. It can be surmised with a large amount of certainty that an increase in the wind generation on the grid leads to an increase in $f_d$. From (10) and (12) there are two factors affecting $f_d$ ($\omega_d$): the damping ratio $\zeta$ and system inertia $M$. Since $\zeta$ is generally small (0.1-0.2), (12) shows that $\zeta$ is having little affect on $f_d$. This means that Fig. 9 is showing an increase in wind generation is leading to a reduction in system inertia.

Using the theory provided earlier an increase in $f_d$ should lead to an increase in the change of frequency and possibly an increase in the total frequency drop.

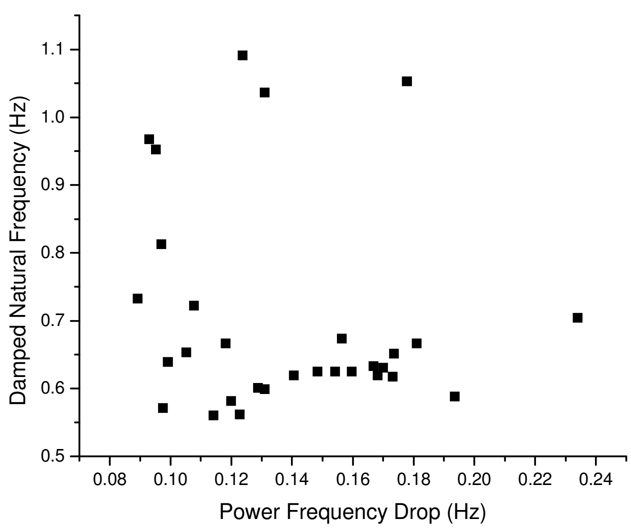



Fig. 10. Damped Natural Frequency vs. Power Frequency Drop

Notice that the outliers in Fig. 10 correspond almost exactly to the outliers shown in Fig. 8. Making the same assumptions, a linear function can be fitted to the data without the outliers present.

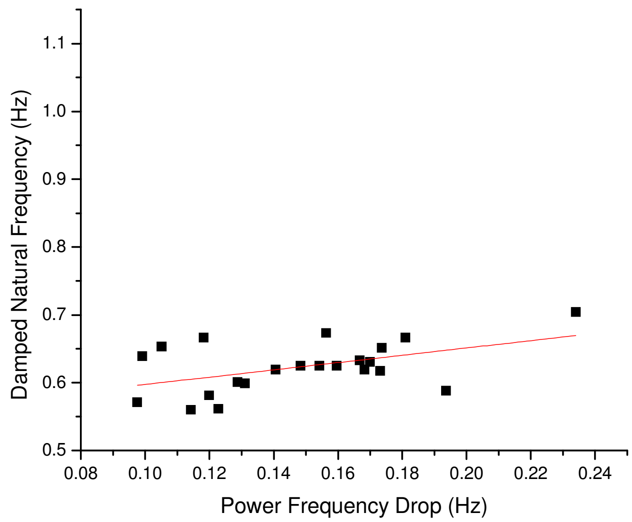



Fig. 11 Damped Natural Frequency vs. Power Frequency Drop

(No Outliers)

While the fitted line in Fig. 11 has an $R^2$ value (0.200) similar to the $R^2$ value of the fitted line in Fig. 9, if this number is again assumed to be relatively high the data predicts with a relatively small slope (0.539) that a large increase in the frequency drop equates to a small increase in $f_d$.

Wind generation seems to have a definite effect on the damped natural frequency, $f_d$, as seen in Fig. 8 and Fig. 9. The increase in $f_d$ also seems to be leading to an increase in frequency drop magnitude; however, unit trip magnitude needs to be taken into account. The wind generation at one time could be primarily composed of fixed speed wind turbines coupled to the grid directly or well-controlled DFIG wind turbines. Even with the wind turbine types on ERCOT unknown, Fig. 9 is showing that an increase in wind generation on ERCOT is leading to a reduction in system inertia.

### PHASOR OSCILLATION DAMPING

Results for the phasor oscillation damping measurements are shown in Appendix A. Fig. 12 and Fig. 13 show the measured phasor oscillation attenuation, $\alpha$, and damping ratio, $\zeta$, respectively versus wind generation as a percentage of demand.

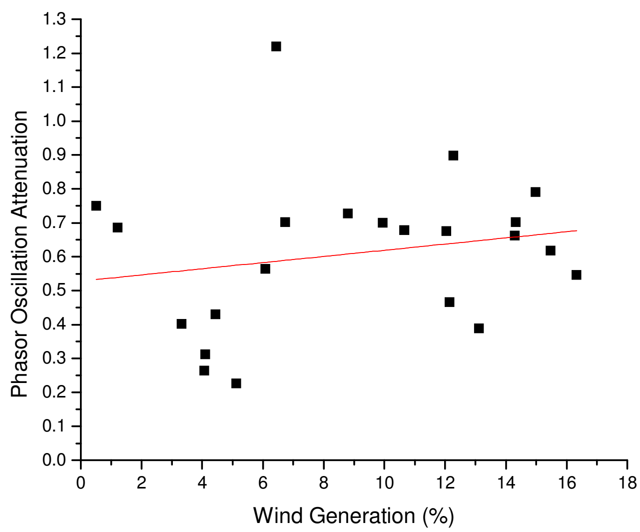



Fig. 12. α vs. Wind Generation (% of Demand)

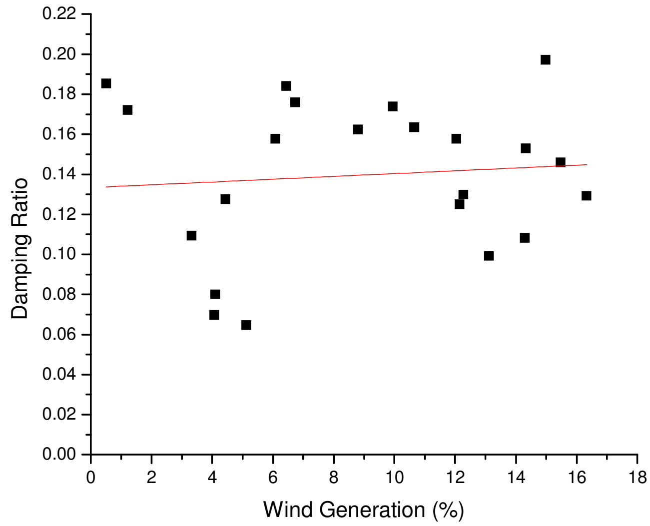



Fig. 13. ζ vs. Wind Generation (% of Demand)

As seen in Fig. 12 there is not a strong correlation between the amount of wind generation on the grid and the phasor oscillation attenuation, α. Similarly in Fig. 13 there is not a visible correlation between wind generation and the damping ratio, $\zeta$. There is no clear trend and given a low $R^2$ value the data is quite random and does not seem to follow a trend strongly. Since the determination of $\alpha$ (and thus $\zeta$) was subjective, the values that were strongly considered to be legitimate were noted. These values are marked with an * in Appendix A, and the resulting simulated oscillation fits are shown in Appendix B. Appendix B shows that most of the extracted values of $\alpha$ are correct. In order to understand the situation better data points not strongly considered to be legitimate were removed. The results are shown in Fig. 14 and Fig. 15.

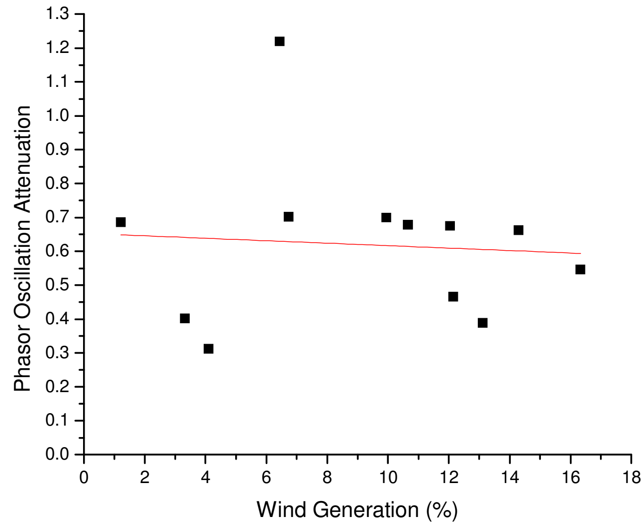



Fig. 14. α vs. Wind Generation (% of Demand)

(Decidedly Legitimate Measurements)

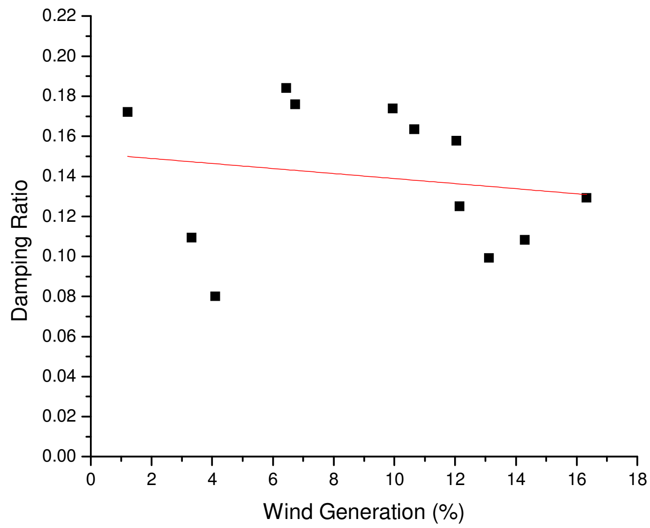



Fig. 15. $\zeta$ vs. Wind Generation (% of Demand)

(Decidedly Legitimate Measurements)

After removing possibly bad data and fitting a linear function, the slope becomes negative with small $R^2$ values in both Fig. 14 and Fig. 15. This presents the case that wind generation is having little effect on $\zeta$; however, it seems that an increase in wind generation may be leading to a general decrease in $\zeta$. The lack of effect of wind generation on $\zeta$ may be explained by looking at (6) and noting the multi-machine behavior in [2]. Since the system $D$ is a determining factor for $\alpha$ as well as the system $M$, $D$ would need to stay relatively constant for an effect of $M$ on $\alpha$ to be noticed. Since the system $D$ depends on both $M$ and $D$ of each generator and the pre and post generator configurations are unknown, the system $D$ (and thus $\zeta$) could consist of a wide-range of values. The method used to extract the attenuation is also not perfect. As can be seen in

Appendix B it is difficult to measure $\alpha$ when the oscillations are not oscillating around a straight line and at a non-constant frequency. Further study into a more exacting method of extracting $\alpha$ may lead to more decisive results.

**FREQUENCY DROPS**

Measured values for both the frequency drops are shown in Appendix A.

The total frequency drop versus the amount of power lost during the unit trip (as a percentage of the total generation) is shown in Fig. 16 along with points designated by the amount of wind power being produced as a percentage of demand.

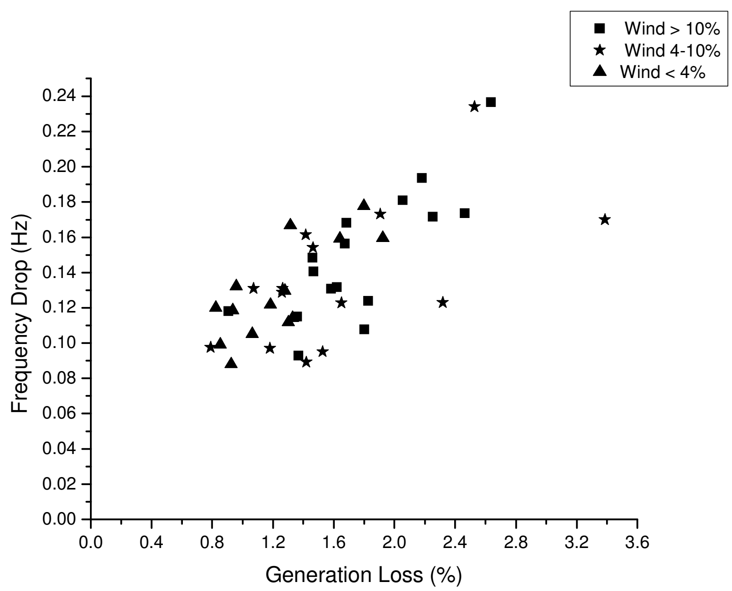



Fig. 16. Frequency Drop vs. Generation Lost Sorted By Amount of Wind Generation (% of Demand)

As can be seen in Fig. 16 as the amount of generation lost during the unit increases, the total frequency drop also increases. This follows from basic power systems analysis and can be seen analytically using (2). Theoretically the frequency drop and generation loss should have a linear relationship with an intercept at zero.

In order to study the effect any wind generation had on the frequency drop, linear functions were fitted to each wind level without any specific intercept and are shown in Fig. 17. In Fig. 18 intercepts of 0 were used.

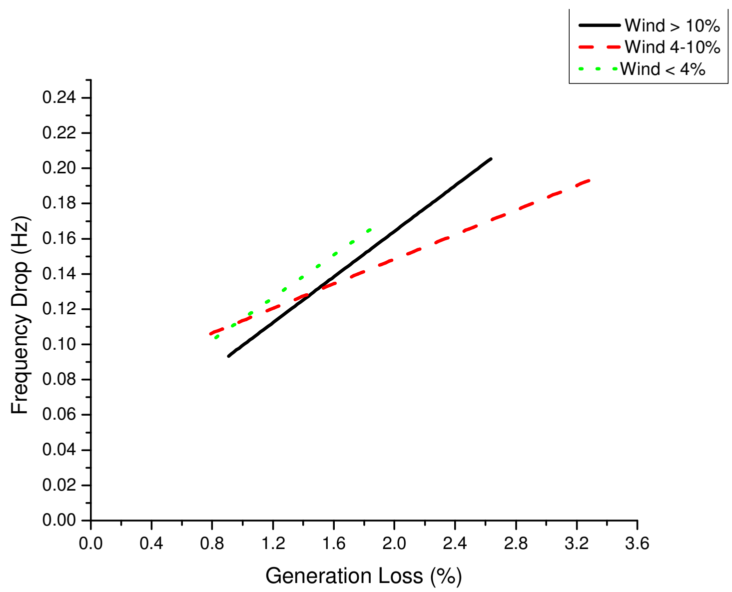



Fig. 17. Fitted Lines to Fig. 16 (No set offsets)

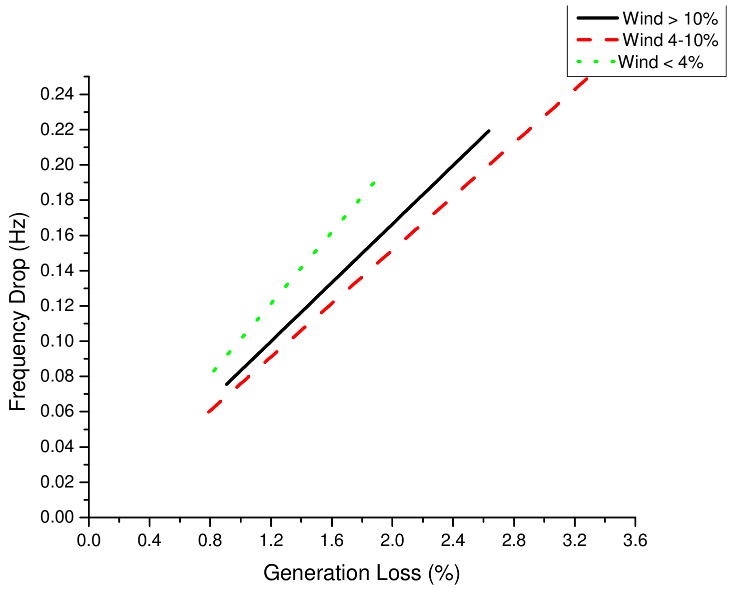



Fig. 18. Fitted Lines to Fig. 16 (Offsets set to 0)

In Fig. 17 the adjusted $R^2$ values are 0.59853, 0.30795, and 0.57232 from high wind to low wind. In Fig. 18 the adjusted $R^2$ values are 0.97519, 0.90481, and 0.97059 from high wind to low wind. Since the fitting is still acceptable using an intercept of zero and using no set offset still results in an offset close to zero, further graphs with intercepts set to zero will be used for analytical purposes.

As can be seen in Fig. 17 and Fig. 18 a high amount of wind generation leads to relatively smaller frequency drops when compared to the unit trips with low wind generation; however, with “medium” wind generation the frequency drops are smaller when compared to unit trips in both “high” and “low” wind generation. If the unit trips occurring in “medium” wind generation are disregarded assuming that the results occur in a “grey” area, Fig. 18 predicts that an increase in wind generation on the ERCOT grid leads to relatively smaller drops in frequency. In Fig. 19 and 20 the “medium” wind generation results are removed and only extremes are examined with wind above 12% and below 3%.

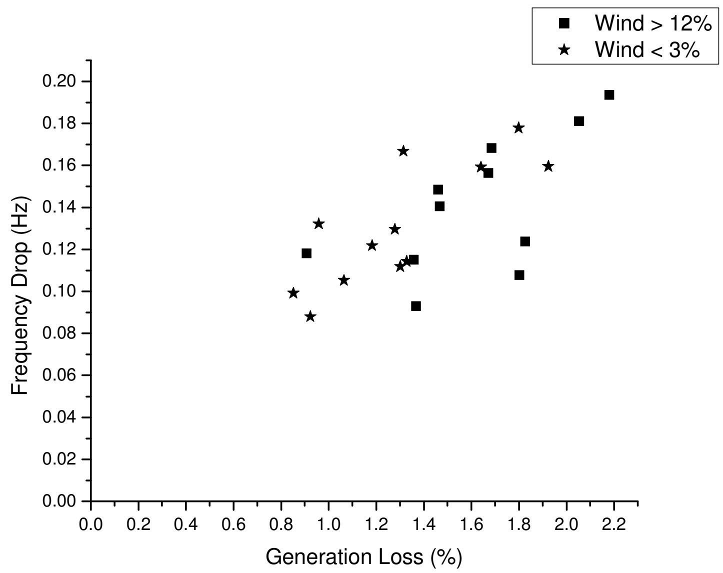



Fig. 19. Frequency Drop vs. Generation Lost Sorted By Amount of Wind Generation (Wind > 12% & < 3%) (% of Demand)

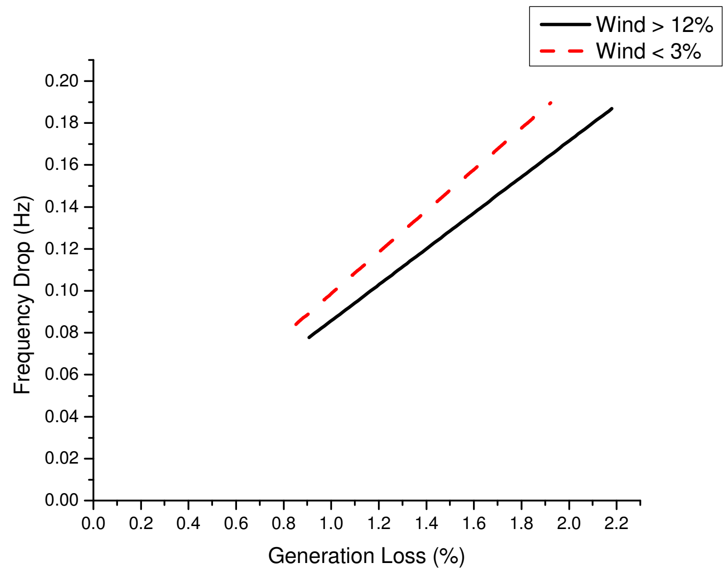



Fig. 20. Fitted Lines to Fig. 19 (Offsets set to 0)

As can be seen in Fig. 20 the same situation has not changed from Fig. 18. The adjusted $R^2$ values of 0.3506 and 0.60999 from high wind to low wind are similar to Fig. 17, and the adjusted $R^2$ values with the zero offset were also similarly above 0.94. In this case, an increase in wind power on the ERCOT grid leads to relatively smaller frequency drops.

One final case was examined using the most extreme cases of wind power on the grid. The results are shown in Fig. 21 and Fig. 22.

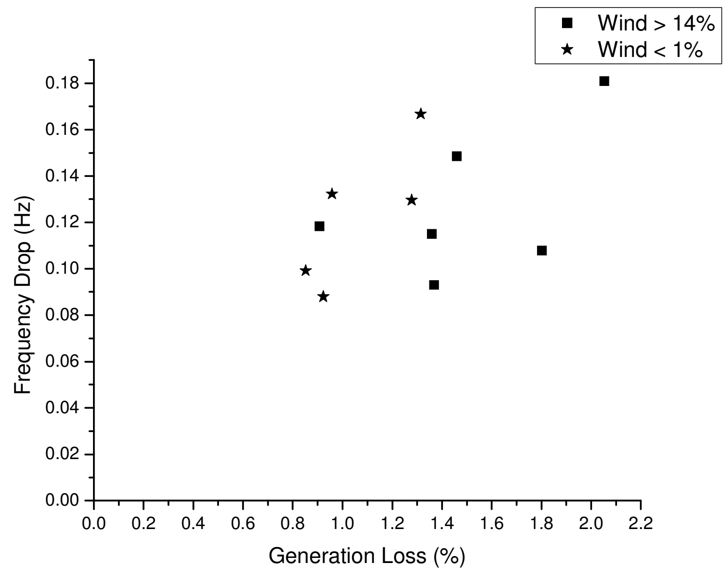



Fig. 21. Frequency Drop vs. Generation Lost Sorted By Amount of Wind Generation

(Wind > 14% & < 1%) (% of Demand)

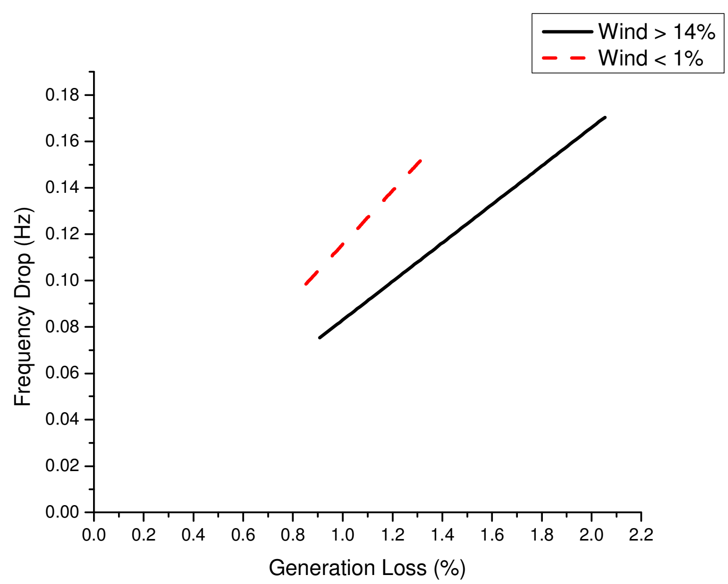



Fig. 22. Fitted Lines to Fig. 21 (Offsets set to 0)

As can be seen in Fig. 21 the same situation has again not changed from Fig. 18. The adjusted $R^2$ values of 0.1223 and 0.5264 from high wind to low wind are similar to Fig. 17; however, the high wind case shows a poor fit probably due to the small number of data points. The adjusted $R^2$ values with the zero offset were also similarly above 0.94. In this case an increase in wind power on the ERCOT grid still leads to smaller frequency drops.

If the results from Fig. 11 are taken into consideration, and removing the outlier events from Fig. 8 and Fig. 10, a large change in the wind generation may lead to an increase frequency drop magnitude; however, this is not the case as shown in Fig. 23 where the outlier data points (eight in total) are removed. This means that even though in general as $f_d$ increases and the frequency drop magnitude increases, when unit trip magnitude is taken into account the result is reversed.

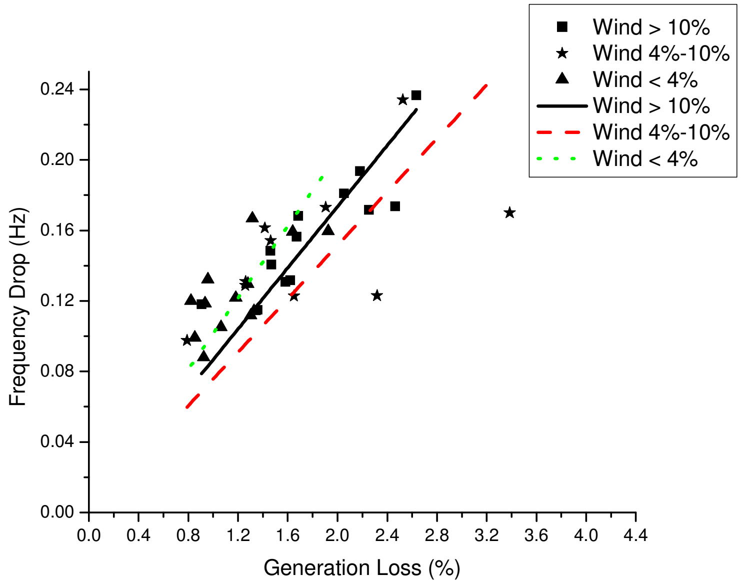



Fig. 23. Frequency Drop vs. Generation Loss (% of Demand)

(No Outliers)

The data shown in Fig. 16 through Fig. 23 shows that at any level, an increase in wind generation on ERCOT seems to be leading to a reduction in the frequency drop magnitude. Since little wind generation (0-16%) is occurring during the unit trips in this study other factors may have the same or greater effect on the frequency drop as wind generation. The spinning reserves on the grid can have a large effect on the frequency drop as shown in [1]. In [3] it is stated that if the wind turbines are fixed speed generators connected directly to the grid that they will have little effect on the system inertia when compared to a system with no wind generation. It is also unknown which generators are operating at what level of capacity and which generator was isolated for the unit trip; therefore, the multi-machine case shown in [2] could result in a wide range of system inertia constants. Furthermore, since frequency drops for unit trips of equal value were not analyzed the results may be uncertain. If the aforementioned occurrences are minimized, the results show that an increase in wind generation (beyond 4%) on ERCOT leads to greater frequency stability; however, this result is not definitive.

## SUMMARY

Fig. 9 shows wind generation on ERCOT is affecting the damped natural frequency, $f_d$, as an increase in wind generation leads to an increase in $f_d$. It then follows that an increase in wind generation is leading to a decrease in system inertia. The increase in $f_d$ also seems to lead to an increase in the frequency drop; however, when the magnitude of unit trips occurring is taken into account the increase in $f_d$ is not affecting the frequency drop. In the case of $\alpha$ and $\zeta$, wind generation seems to be having only a small effect. After removing possibly bad data Fig. 15 shows an increase in wind generation may be leading to a general decrease in the damping ratio. Many factors can explain the lack of correlation in wind generation to frequency drop and damping. The factors include pre and post unit trip generator arrangements, amount of spinning reserves, and the percentage of wind generation that is not strongly coupled to the grid.

[1] Machowski, Jan, Janusz W. Bialek, and James R. Bumby. *Power System Dynamics: Stability and Control* , 2d ed. West Sussex, United Kingdom: John Wiley & Sons, Ltd., 2008. Pg335-381.

[2] Bergen, Arthur R., and Vijay Vital. *Power System Analysis,* 2d ed. Upper Saddle River, New Jersey: Prentice-Hall Inc. 2000. Pg556-563.

[3] Mullane, Alan, and Mark O'Malley. "The Inertial Response of Induction-Machine-Based Wind Turbines," IEEE Transactions on Power Systems, vol. 20, no. 3, pp. 1496-1503, August 2005.

# Chapter Five: Conclusion

Renewable energy is increasingly becoming a greater percentage of the world's electric power supply and wind turbines represent a large majority of both existing and new renewable energy sources. Wind turbines operate in a different manner then conventional generation methods (large synchronous generators) such as the availability of power/energy at any given moment as well as the way in which the generators are coupled to the grid. Since certain types of wind turbine generators (Variable speed DFIGs and SGs) are coupled to the grid through ac/dc/ac converters the frequency of the generator can be almost completely decoupled from the grid's frequency. This also means that the wind turbine may provide little or no inertia to the system inertia $M$.

A lower inertia on the grid can lead to stability issues if it becomes low enough during grid disturbances such as unit trips. As the amount of wind generation on the grid increases, the need for empirical evidence of the impact (or lack thereof) of wind turbines on the grid transient stability increases as well. This lowered stability can be studied by looking at both the phase angle and the grid power frequency during unit trips. Through theoretical analysis as well as previous analytical studies, an increase in wind generation may lead to an increase in the amplitude of frequency variations, an increase in the phasor oscillation frequency, and possibly an increase in the phasor oscillation attenuation.

For this study data was collected from two sources. Frequency data was taken from a data logger in San Angelo, TX where it recorded data during large frequency swings. Phasor data was taken from a server located on the University of Texas at Austin campus which synchronously logged data from PMUs located in both east and west Texas.

Fig. 8 and Fig. 9 show that wind generation is having a noticeable effect on $f_d$; however, many outliers exist that could not be explained. As the amount of wind generation increased on the grid the phasor oscillation frequency also slightly increased. This also means that the increase in wind generation on ERCOT is leading to reduced system inertia.

Fig. 12 and Fig. 13 show that wind generation is having little effect on $\alpha$ and $\zeta$. While a linear function can be fitted to the data, the fit is a very poor and the data is still scattered. After removing possibly bad data the result is showing that an increase in wind generation may be leading to a reduction in the damping ratio; however, the method with which $\alpha$ was determined may not be adequate and more exacting methods may be needed before a conclusion is reached.

Fig. 16 through Fig. 22 shows a result opposite to what [2], [3], and [4] predict. As the amount of wind generation on the ERCOT grid increases the frequency drop becomes smaller for any unit trip magnitude. When correlating the damped natural frequency, $f_d$, to the frequency drop and removing outliers, an increase in $f_d$ leads to a larger magnitude of frequency drop; however, after considering the magnitude of the unit trip and removing the same outliers wind generation was still leading to a reduction in the magnitude of frequency drops. In [1] it is shown that spinning reserves can have a large effect on frequency drop. Also since exact unit trips during different levels of wind generations were not examined and the grid generator configuration was unknown the results cannot be definitive.

After looking at the results as whole it can be determined that the wind generation is having an effect on the grid. An increase in wind generation is leading to a reduction in system inertia. An increase in wind generation also may be leading to a reduction in damping and frequency drop magnitude; however, several other factors besides wind generation may be present. Spinning reserves, the unit trip location, generator configuration and the type of wind turbine operating could all have a large effect on the grid dynamics following a unit trip.

[1] Machowski, Jan, Janusz W. Bialek, and James R. Bumby. *Power System Dynamics: Stability and Control* , 2d ed. West Sussex, United Kingdom: John Wiley & Sons, Ltd., 2008. Pg335-381.

[2] Mullane, Alan, and Mark O'Malley. "The Inertial Response of Induction-Machine-Based Wind Turbines," IEEE Transactions on Power Systems, vol. 20, no. 3, pp. 1496-1503, August 2005.

[3] Doherty, Ronan, Alan Mullane, Gillian Nolan, Daniel Burke, Alexander Bryson, and Mark O'Malley. "An Assessment of the Impact of Wind Generation on System Frequency Control," IEEE Transactions on Power Systems, vol. 25, no. 1, pp. 452-460, February 2010.

[4] Lalor, Gillian, Alan Mullane, and Mark O'Malley. "Frequency Control and Wind Turbine Technologies," IEEE Transactions on Power Systems, vol. 20, no. 4, pp. 1905-1913, November 2005.

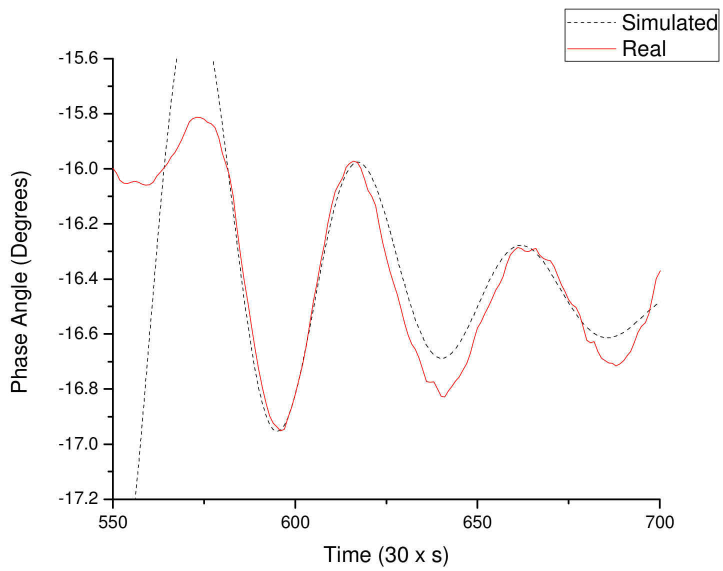
# Appendix A: Data

| Event # | Date/Time CST | Freq. Drop | % Wind Gen | % Gen Lost | $f_d$ (Hz) | $f_0$ (Hz) |
|---|---|---|---|---|---|---|
| 1 | 10/30/09 21:23 | 0.181 | 16.33 | 2.05 | 0.66667 | 0.6681 |
| 2 | 4/19/2009 1:49 | 0.1182 | 15.47 | 0.91 | 0.66667 | 0.6685 |
| 3 | 4/23/2009 1:07 | 0.1484 | 14.98 | 1.46 | 0.625 | 0.6282 |
| 4 | 4/5/2009 7:09 | 0.1078 | 14.32 | 1.80 | 0.72202 | 0.7242 |
| 5 | 10/26/09 4:56 | 0.093 | 14.30 | 1.37 | 0.96759 | 0.969 |
| 6 | 4/26/2009 2:43 | 0.115 | 14.21 | 1.36 | - | - |
| 7 | 4/15/2009 16:47 | 0.1682 | 13.11 | 1.68 | 0.6192 | 0.62 |
| 8 | 3/26/2009 7:54 | 0.1238 | 12.28 | 1.83 | 1.09111 | 1.0934 |
| 9 | 3/27/2009 9:54 | 0.1406 | 12.21 | 1.47 | 0.6192 | - |
| 10 | 3/29/2009 19:40 | 0.1936 | 12.15 | 2.18 | 0.58824 | 0.5894 |
| 11 | 4/9/2009 7:10 | 0.1564 | 12.04 | 1.67 | 0.6734 | 0.6755 |
| 12 | 4/26/2009 11:24 | 0.1308 | 11.75 | 1.58 | - | - |
| 13 | 2/8/2009 23:36 | 0.1316 | 11.21 | 1.62 | - | - |
| 14 | 2/9/2009 10:41 | 0.2366 | 10.90 | 2.63 | - | - |
| 15 | 5/18/2009 3:20 | 0.1736 | 10.66 | 2.46 | 0.65147 | 0.6537 |
| 16 | 2/23/2009 16:43 | 0.1716 | 10.38 | 2.25 | - | - |
| 17 | 10/12/09 2:27 | 0.17 | 9.95 | 3.39 | 0.63091 | 0.6334 |
| 18 | 11/23/09 9:51 | 0.234 | 8.79 | 2.53 | 0.70423 | 0.7066 |
| 19 | 10/11/09 18:06 | 0.123 | 7.19 | 2.32 | - | - |
| 20 | 5/11/2009 5:41 | 0.097 | 6.95 | 1.18 | 0.81301 | - |
| 21 | 5/4/2009 22:09 | 0.1542 | 6.74 | 1.46 | 0.625 | 0.6275 |
| 22 | 9/14/2009 15:00 | 0.131 | 6.45 | 1.07 | 1.03627 | 1.0408 |
| 23 | 5/19/2009 18:20 | 0.1228 | 6.08 | 1.65 | 0.5618 | 0.5636 |
| 24 | 5/11/2009 12:46 | 0.0892 | 5.65 | 1.42 | 0.7326 | - |
| 25 | 11/3/09 4:18 | 0.131 | 5.62 | 1.26 | 0.5988 | - |
| 26 | 8/16/2009 21:18 | - | 5.12 | 1.01 | 0.55556 | 0.5558 |
| 27 | 9/16/2009 20:12 | 0.0952 | 4.72 | 1.53 | 0.95238 | - |
| 28 | 7/2/2009 16:58 | 0.049 | 4.44 | 1.02 | 0.53191 | 0.533 |
| 29 | 6/20/2009 19:49 | 0.1614 | 4.27 | 1.42 | - | - |
| 30 | 5/3/2009 9:49 | 0.1732 | 4.11 | 1.91 | 0.61728 | 0.6178 |
| 31 | 3/9/2009 22:38 | 0.1288 | 4.07 | 1.26 | 0.6006 | 0.601 |
| 32 | 6/16/2009 16:51 | 0.1186 | 3.34 | 0.94 | - | - |
| 33 | 5/3/2009 16:39 | 0.12 | 3.32 | 0.82 | 0.5814 | 0.5823 |
| 34 | 5/19/2009 14:36 | 0.1218 | 2.97 | 1.18 | - | - |
| 35 | 7/20/2009 7:08 | 0.1118 | 2.60 | 1.30 | - | - |
| 36 | 4/17/2009 15:01 | 0.1778 | 2.29 | 1.80 | 1.05263 | - |
| 37 | 2/14/2009 20:17 | 0.1592 | 1.99 | 1.64 | - | - |
| 38 | 6/26/2009 9:11 | 0.1142 | 1.24 | 1.33 | 0.56022 | - |
| 39 | 5/25/2009 16:21 | 0.1052 | 1.24 | 1.06 | 0.65359 | - |
| 40 | 4/7/2009 4:55 | 0.1596 | 1.21 | 1.92 | 0.625 | 0.6274 |
| 41 | 7/20/2009 16:14 | 0.088 | 0.89 | 0.92 | - | - |
| 42 | 9/5/2009 14:38 | 0.0992 | 0.76 | 0.85 | 0.63898 | - |
| 43 | 7/7/2009 11:59 | 0.1296 | 0.53 | 1.28 | - | - |
| 44 | 8/27/2009 16:22 | 0.1668 | 0.51 | 1.31 | 0.63291 | 0.6357 |
| 45 | 8/27/2009 17:05 | 0.1322 | 0.41 | 0.96 | - | - |

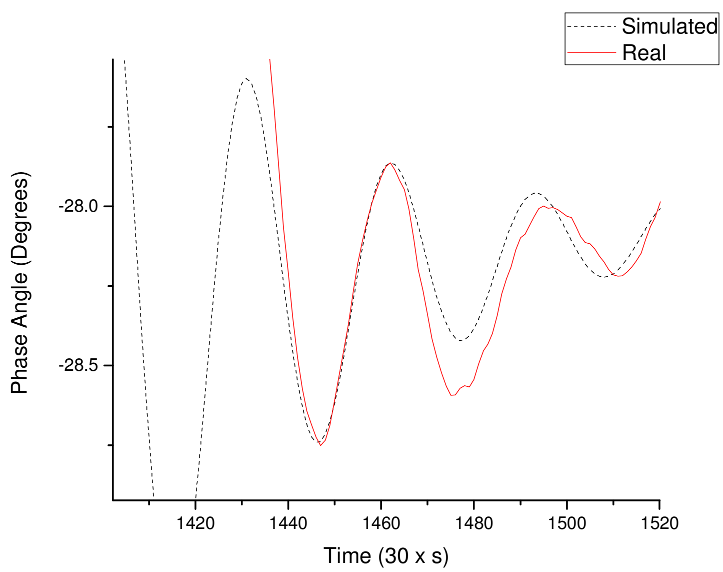
| Event # | α | ζ | Max δ | PMU | Reference | Notes |
|---|---|---|---|---|---|---|
| 1 | 0.546* | 0.129 | 0.527 | McDonald | Austin | - |
| 2 | 0.618 | 0.146 | 0.327 | Austin | McDonald | - |
| 3 | 0.79 | 0.197 | 0.632 | Austin | McDonald | - |
| 4 | 0.702 | 0.153 | 1.102 | McDonald | Boerne | - |
| 5 | 0.662* | 0.108 | 0.411 | Austin | McDonald | - |
| 6 | - | - | - | - | - | - |
| 7 | 0.388* | 0.099 | 0.751 | McDonald | Austin | - |
| 8 | 0.898 | 0.13 | 0.267 | ? | ? | - |
| 9 | - | - | 0.316 | ? | ? | - |
| 10 | 0.466* | 0.125 | 1.325 | ? | ? | - |
| 11 | 0.676* | 0.158 | 1.215 | Mcdonald | Austin | - |
| 12 | - | - | - | - | - | - |
| 13 | - | - | - | - | - | - |
| 14 | - | - | - | - | - | - |
| 15 | 0.678 | 0.163 | 0.983 | Mcdonald | Austin | - |
| 16 | - | - | - | - | - | - |
| 17 | 0.7 | 0.174 | 1.149 | McDonald | Austin | - |
| 18 | 0.728 | 0.162 | 0.662 | McDonald | Austin | - |
| 19 | - | - | - | McDonald | Austin | - |
| 20 | - | - | 0.367 | Austin | McDonald | - |
| 21 | 0.702* | 0.176 | 0.925 | McDonald | Austin | - |
| 22 | 1.22* | 0.184 | 1.065 | Austin | Houston | - |
| 23 | 0.564 | 0.158 | 2.403 | McDonald | Austin | - |
| 24 | - | - | 0.089 | Houston | Austin | - |
| 25 | - | - | 0.387 | Austin | McDonald | - |
| 26 | 0.226 | 0.065 | 0.899 | McDonald | Houston | Double Freq. Drop |
| 27 | - | - | 0.902 | Austin | Houston | - |
| 28 | 0.43 | 0.128 | 0.753 | McDonald | Austin | Unusual Freq. Drop |
| 29 | - | - | - | - | - | - |
| 30 | 0.312* | 0.08 | 1.007 | McDonald | Austin | - |
| 31 | 0.264 | 0.07 | 0.98 | ? | ? | - |
| 32 | - | - |  | Austin | Houston | - |
| 33 | 0.402* | 0.109 | 0.689 | McDonald | Austin | - |
| 34 | - | - | - | McDonald | Austin | - |
| 35 | - | - | - | - | - | - |
| 36 | - | - | 0.694 | Austin | McDonald | - |
| 37 | - | - | - | - | - | - |
| 38 | - | - | 1.453 | Houston | McDonald | - |
| 39 | - | - | 0.153 | Houston | Austin | - |
| 40 | 0.686* | 0.172 | 1.39 | McDonald | Boerne | - |
| 41 | - | - | - | Houston | McDonald | - |
| 42 | - | - | 0.208 | Austin | Boerne | - |
| 43 | - | - | - | Houston | Austin | - |
| 44 | 0.75 | 0.185 | 1.531 | Houston | Austin | - |
| 45 | - | - | - | - | - | - |

# Appendix B: Phasor Oscillation Fitting

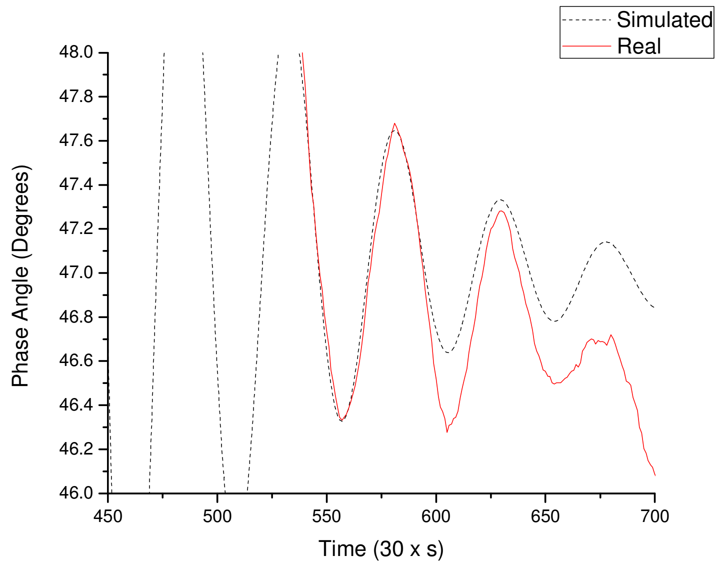
Event 1:



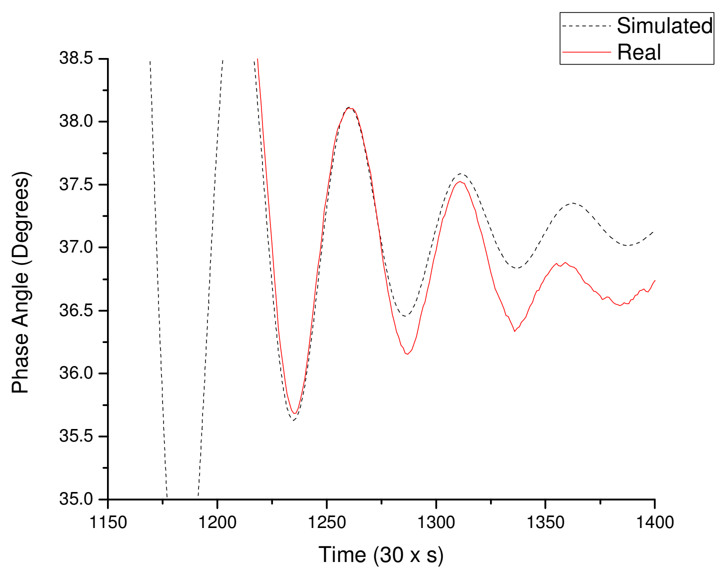

Event 5:



Event 7:




Event 10:



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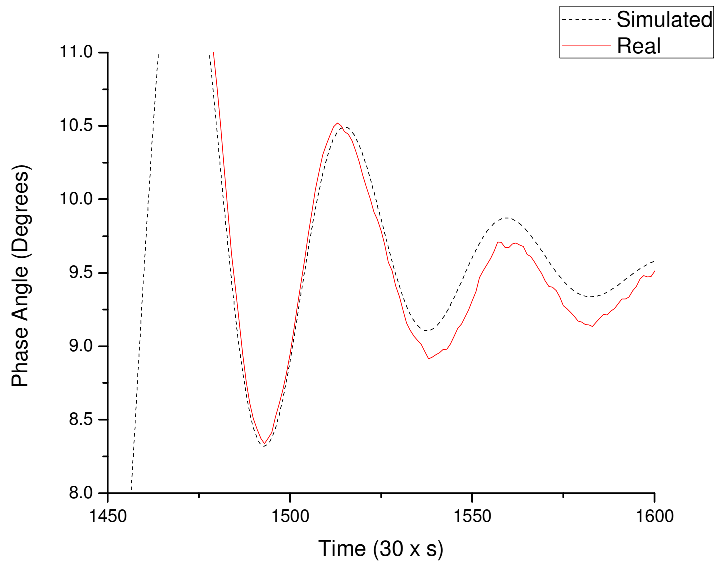


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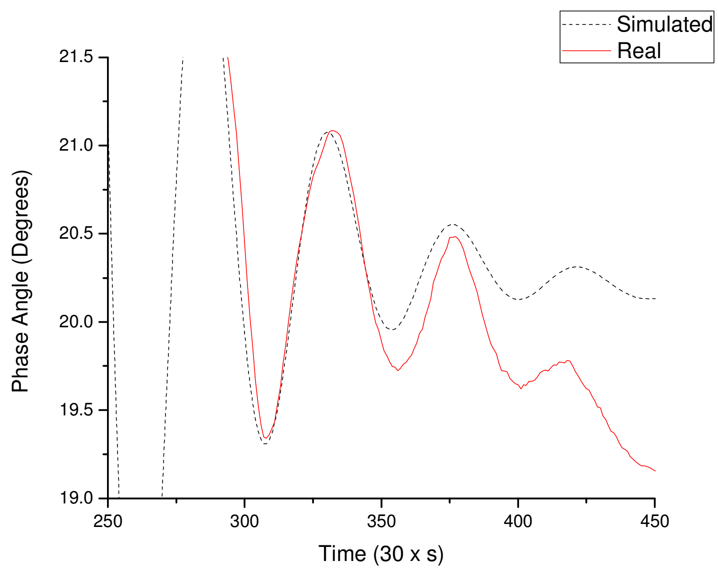

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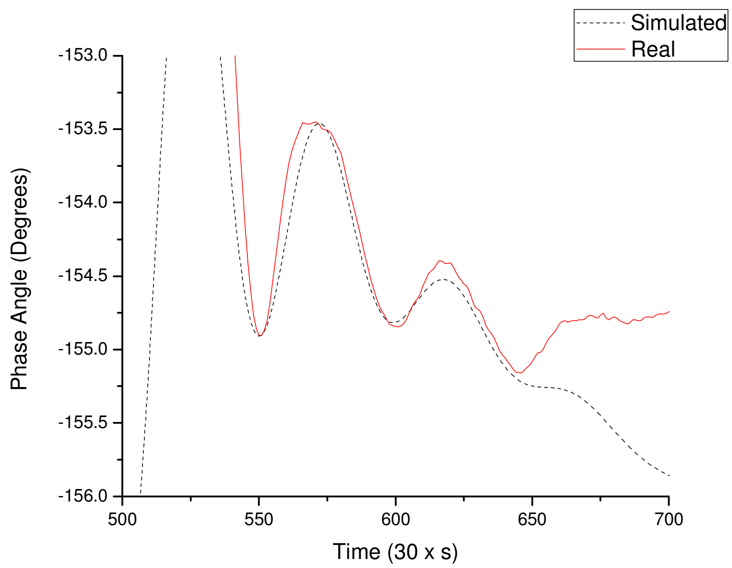


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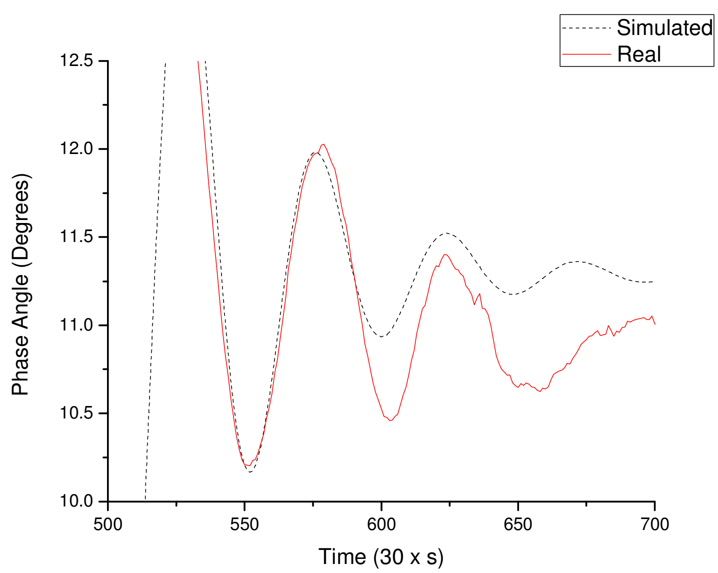

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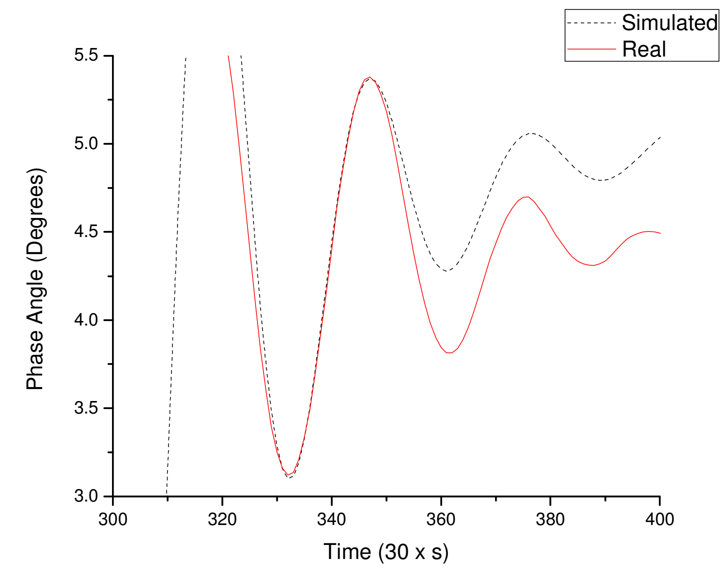


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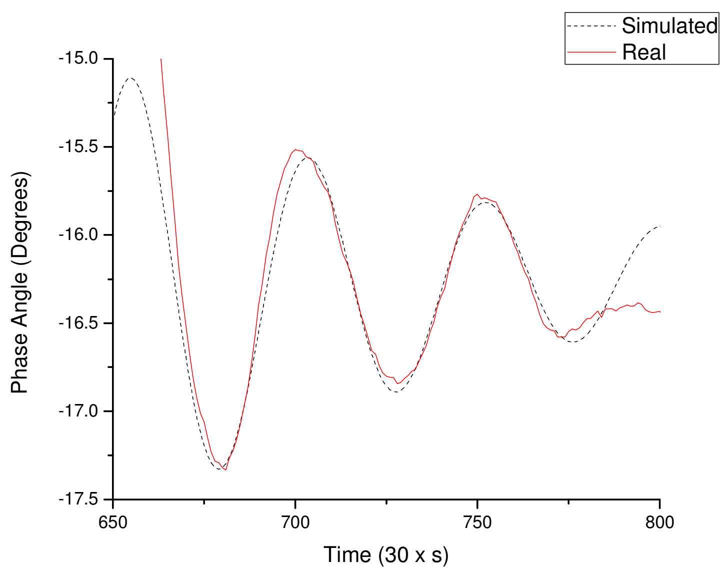

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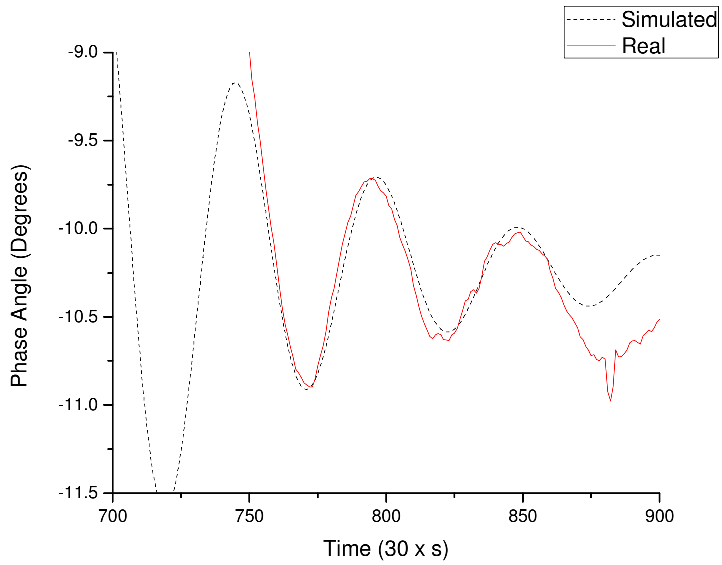


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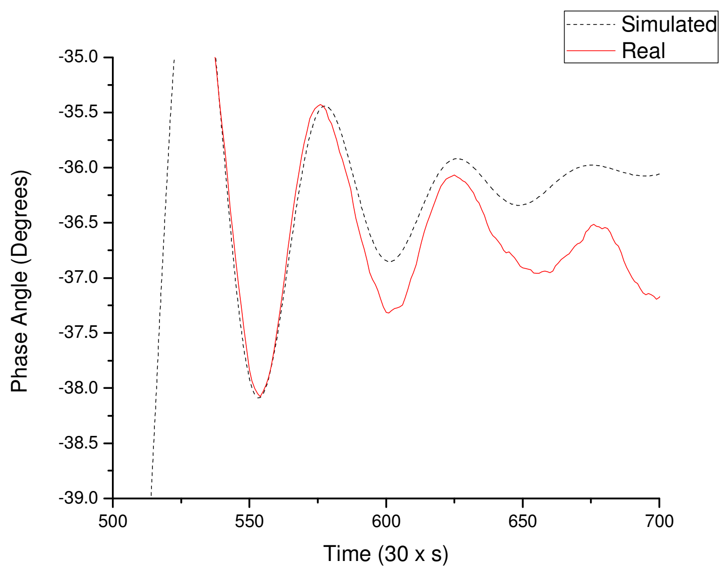

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# Vita

Will Lovelace received his B.S. from the University of North Dakota located in Grand Forks, ND. He is currently working towards his M.S. in electrical engineering at the University of Texas at Austin with research focused on transient stability of the power grid and wind turbines.

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This thesis was typed by Will Lovelace.