Modelling the NPCC System with 12.5% Wind Penetration

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***Abstract*—This research investigates the effect of wind penetration on the frequency response demonstrated by the NPCC system. The frequency response of the system is entirely dependent on the regulating unit models that were also developed as part of this research. The simulations run on the NPCC system with wind penetration suggest that the wind turbine generator model needs to be developed further, and that the NPCC system may not be able to support high levels of wind penetration in its current state.**

***Keywords*—frequency response, wind generation, modelling, NPCC, AGC, DFIG, WTG**

I. Nomenclature

ACE – Area Control Error
AGC – Automatic Generation Control
B – Frequency Bias Factor
D – Damping Factor
DFIG – Doubly Fed Induction Generator
I – Integral
NERC – North American Electric Reliability Corporation
NPCC – Northeast Power Coordinating Council
PI – Proportional-Integral
PU – Per Unit
R – Speed Regulation or Governor Droop Characteristic
UDM – User Defined Model
WTG – Wind Turbine Generator
ΔP_{Tie} – Change in tie-line power flow
Δf – Change in system frequency

II. Introduction

To fully understand the goals and methods of this research, one must know a little about power systems, power system control, and wind generation. From this understand of power system control and wind turbine, models of regulating units and wind turbine generators were built. These models were then tested to determine whether or not they were built correctly. Once both types of model had been verified, they were added to the NPCC system, which was simulated for several scenarios.

III. Power System Control Background

An effective control system must be aware of the scheduled values for the system it controls. The control system must compare these values to the real-time system in order to determine when control actions need to be taken to steer the system back to a scheduled behavior.

A. Load Frequency Control

In power systems, each area or balancing authority has a control center responsible for meeting its demanded load and maintaining system integrity [1]. Error based frequency controllers compare scheduled and actual values of tie-line power flow between areas and system frequency to create an Area Control Error (ACE) signal. Using either an integral (I) or proportional-integral (PI) controller, the accumulation of error is tracked. The controller then tells regulating units in the system to adjust generation in an attempt to force the accumulated error to zero.

1) Balancing Authorities: A balancing authority is an area in a power system, comprised of any number of generation and load buses, but not necessarily a continuous piece of land. Balancing authorities are responsible for meeting their load demand (including expected losses and generation transfers). The required generation can come from generators located in the balancing authority, power can be purchased from other balancing authorities, or a mix of both sources can be used [1].

Most balancing authorities use a central control center to implement automatic generation control (AGC) through specific generators in the area, called regulating units. These control centers monitor all tie-line power flow and compare it to the scheduled power flow. This data is then added to the scaled deviation in system frequency to create the instantaneous ACE.

2) Area Control Error: The area control error is the distance between an areas actual and scheduled tie-line power flow added to a scaled error in system frequency [1][2].

$$ACE = \Delta P_{Tie} + B\Delta f \tag{1}$$

ΔP_{Tie} represents the tie-line flow error, and Δf represents the frequency deviation of the system. The constant B indicates how the generation and load profiles change with a change in frequency [2]. B, the frequency bias factor, is given by the following equations:

$$B = \frac{1}{R} + D \tag{2}$$

$$\frac{1}{R} = \frac{\Delta P_{Gen}}{\Delta f} \tag{3}$$

$\frac{1}{R}$ is the inverse speed regulation characteristic, also known as governor droop in generators, and it represents how generation responds to a frequency change. D, the damping factor,

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represents how the load profile changes with frequency [2]. For the NPCC system used in this research, the damping factor is negligible, hence:

$$ACE = \Delta P_{Tie} + \frac{1}{R}\Delta f \tag{4}$$

The North American Electric Reliability Corporation (NERC) has many standards related to ACE, including those that dictate that B should be updated every month and that ACE should cross 0 at least once every 10 minutes [2][3]. The first standard helps to ensure that B reflects the system as accurately as possible. Because ACE cannot possibly be zero in the constantly changing, dynamic power grid, the second standard is to prevent excessive accumulated error on either side of 0. The requirement of ACE to cross zero often is also intended to force positive and negative error to balance each other out over time. For example, an hour of the system being at 58.98 Hz, any clock keeping time based on the grid frequency will lose 1.2 seconds. If the error then reverses for an hour, and frequency is 60.02 Hz, the clock will gain those 1.2 seconds back in another hour [3].

B. System Inertia

Inertia is a very important characteristic in power systems. The amount of inertia in a system directly impacts the severity of the initial frequency deviation due to a disturbance [3]. Inertia is a naturally occurring feature of traditional synchronous generators. Due to the nature of the law of conservation of energy, when there is a disturbance in an interconnected power system (i.e. a change in energy balance), the kinetic energy stored in the generators rotating masses is naturally recruited to restore that balance [1].

IV. Wind Generation Theory

A wind turbine generator (WTG) offers clean and free power generation. This has led to extensive development of WTG technology. Naturally, there have been many different versions of the WTG and they can be categorized as either horizontal or vertical axis turbines [4]. Vertical axis turbines have the advantages of easy maintenance and low construction cost, but they are less efficient than horizontal axis turbines. Hence, this research was based around the 3-blade, horizontal axis WTG.

The power captured by a wind turbine is largely based on the wind speed, and there are a few very important wind speeds to be aware of [4]. The cut-in speed, at which the WTG can begin to rotate and capture power, is generally around 3.5 m/s. The rated speed, where the WTG is producing the maximum possible power, is generally between 11 and 17 m/s. The cut-out speed, where the turbine must be stopped to avoid damage to the WTG is usually any speed greater than 17 m/s. Within these limits, the potential power can be represented by the following equation.

$$P_{wind} = \frac{1}{2}\rho\pi R^2 V_{wind}^3 \tag{5}$$

Wind speed, however, is not the only factor effecting the power captured by the turbine. The blade pitch is also significant. It is also obvious that the WTG is not perfectly efficient, so the actual captured power must be scaled. This observation yields the following equation [4]:

$$P_m = \frac{1}{2}\rho\pi R^2 V_{wind}^3 C_p(\lambda, \beta) \tag{6}$$

The new power coefficient term is always between 0 and 1, and should be expected to be between 0.4 and 0.5 for the selected type of WTG [5]. It is calculated using the following equation:

$$C_p(\lambda, \beta) = 0.22\left[\frac{116}{\lambda_i} - 0.4\beta - 5\right] e^{-\frac{12.5}{\lambda_i}} \tag{7}$$

Since blade pitch factors into how much power is being captured, it makes sense to control it. The blade pitch is only changed from 0 for wind speeds between the rated speed and cut-out speed. This allows the WTG to produce its maximum power by acting as if the wind speed is less than it actually is.

At this point, the design of wind generators can be split even further. There are many architectures of the electric generator piece of a WTG. Each of these architectures can be classified as either a fixed- or variable-speed turbine system [4]. In terms of frequency control, a variable-speed turbine is the best option as they offer an adjustable power output and a built-in way of controlling the reactive power generated. Other advantages of variable-speed turbines include better efficiency than fixed turbines, and high quality power generation [4].

A. Doubly Fed Induction Generator

One of the leading types of variable-speed WTGs is the Doubly Fed Induction Generator (DFIG) and was thus used to insert wind into the NPCC system. A DFIG WTG can be modelled roughly as is shown in Figure 1.

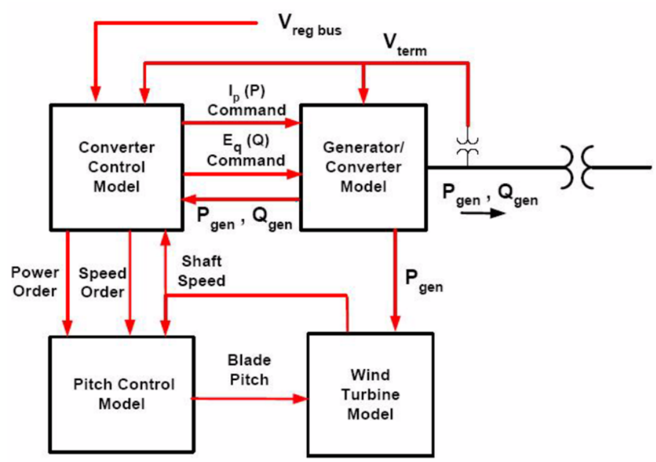

Fig. 1. Basic DFIG Model

The model consists of four major blocks [5], the first of which is the Wind Turbine Model. This block is responsible for generating a value for the mechanical power produced by the WTG given wind speed and blade pitch. The second block, the Pitch Control Model, is responsible for telling the first block what blade pitch to use based on wind speed and power needed. The Converter Control Model is responsible for telling the Pitch Control Model what amount of power is needed, and telling the Generator/Convertor Model how to split the captured mechanical power into active and reactive power. The Generator/Convertor Model is tasked with converting the mechanical power to the specified active and reactive power, and then injecting this asynchronous power into the grid.

B. WTGs and Frequency Response

The basic WTG detracts from overall system frequency response. This comes from a lack of both inertia and reserve generation capacity in WTGs. Because WTGs are always operating at their maximum power output for the current wind speed, they cannot contribute to governor or AGC response that calls for either an increase or decrease in generation [6]. Also, because a WTG is an asynchronous generator, the inertia of the generator is hidden from the grid. In the event of a disturbance, this absence of inertia causes the initial frequency change to be more severe. This phenomenon can be seen in Figure 2, where the inertial response is lessened as the system becomes more penetrated by wind generation.

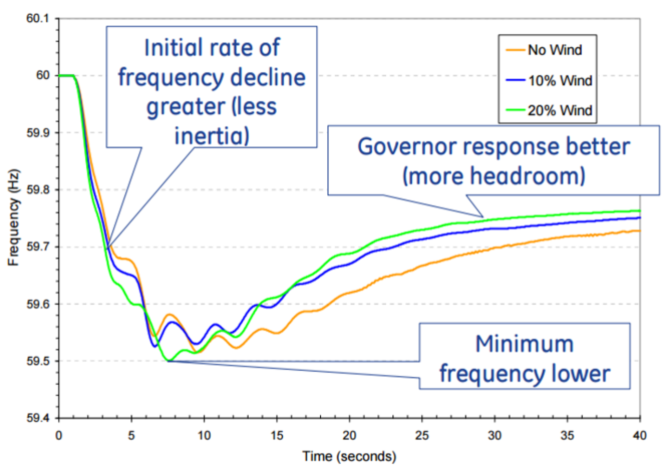

Fig. 2. The effect of wind generation on system inertia

V. Finding NPCC Characteristics

An important piece of this research was the User-Defined AGC models. For these models to work properly, accurate measurements of each areas scheduled tie-line flow and frequency bias were needed. Using DSATools TSAT program, the scheduled tie-line flow for each area was found using the following procedure:

1) Make sure there is no AGC connected to the system.
2) Add all tie-lines in the NPCC system to the Monitor Data, taking note of the areas each line is connected to.
3) Create a no fault contingency and run the scenario.
4) Record the constant power flow on each tie-line.
5) Add the power flow on all tie lines connected to an area, taking into account that positive flow is power leaving an area, to get the total scheduled power flow for each area.

The resulting scheduled values for tie-line power flow can be found in Table 1.

In order to find the inverse of the speed regulation characteristic for each area, the following procedure was used:

1) Make sure there is no AGC connected to the system.
2) Add all generators in the pertinent area to the Monitor Data.
3) Create a contingency of mild severity and run the scenario.
4) Record the initial and final values of every generators active power output.
5) Record the initial and final value of the system frequency, using any generators Generator Speed as the representative system frequency.
6) Add all of the initial output power. Add all of the final output power. Find the absolute difference between the total initial, and total final power. This is equal to (Delta Pgen).
7) Find Δf (the absolute difference between the initial and final system frequency).
8) Divide ΔP_{Gen} by Δf to get $\frac{1}{R}$.

To verify that the results were correct, three different contingencies were run: an 80% load shed at bus 127, a generator disconnect at bus 137, and a 40% load shed at bus 120 along with a 40% load shed at bus 127. The calculated $\frac{1}{R}$ values for each area can be found in Table 1.

Area	$P_{Tie,sched}$	$\frac{1}{R}$
NEPOOL	-152.688	3157.587
NYISO	-163.135	6649.542
IESO	-143.872	2449.872
MISO	0.029	2287.126
PJM	467.143	3664.026

TABLE I. Area Control Characteristics

VI. User Defined Models

DSATools UDM Editor was used to create models for regulating units and WTGS to be used in the NPCC system.

A. Regulating Units

Each of the five areas inside the NPCC system was given a regulating unit. Each regulating unit model was constructed in the same way. The UDM Simplified Thermal or Hydraulic Turbine Governor Model 1 template was used as the starting point. This template was then modified by removing the Dt connection and INV R block, changing TR to 20.0, removing the limits on T1, changing the T2 parameter in the T1 block to 10.0, and changing the T1 and T2 parameters in the T2T3 block to 6.0. The actual tie line power flow was monitored by adding a Remote Branch Active Power block for each tie line connected to the regulating units area. Because the Remote Branch Active Power block monitors power in per unit (PU), and the scheduled power flow was found in MW, the monitoring blocks were all given a gain of 100.0 to transform the power flow from PU to MW. These Remote Branch Active Power blocks were all connected to a Summation block to give the total tie line flow for the area. The difference of the actual and scheduled tie line flow was calculated by adding the scheduled value as a Constant Value and connecting it to another Summation block through a Gain With Limits block (with a gain of 1.0 and no limits). The difference in system frequency was then brought in with a Generator Speed Deviation block with a gain of 60 to transform it from PU to Hz. It was then run through a Gain With Limits block, with gain being equal to the areas inverse speed regulation characteristic and no limits imposed. The resulting signal was then added to the difference in tie line power via another Summation, the resulting signal represented ACE. The ACE signal was then transformed back to PU, using a Gain With Limits block with gain equal to the inverse of the regulating units base MVA. This PU ACE signal was then run through a Proportional Plus Integral With Limits (Dynamic) block with K set to -0.01, T set to 0, and no limits. Finally, this AGC signal was run through a Digital Controller block (with T equal to 4.0, b1 equal to 1.0, and everything else equal to 0) and connected to the first Summation block of the governor template to force AGC to act every 4 seconds instead of constantly.

B. WTGs

The process of creating WTG models in the UDM Editor was much simpler than creating regulating units. The Generic Type 3 Wind Generator Model template was already very close to the finished WTG model. The Srate and Prate variables inside the CONV block were changed to match the corresponding characteristics of the traditional generator that the WTG would be replacing in the NPCC system. Then the WINPOWER block was changed. ICP was set to 0, then Kb was set to 56.6, Kap to 0.00159, Kturb to 1.0, Prating to 1.0, and Vw0 to 12.0 as per the UDM Manuals suggestions for a 1.5 MW DFIG unit. Next the Constant Value 1.0 connected to the WINPOWER block was replaced with a Lookup Table that stored the wind profile. The Simulation Time was added to the Lookup Table as input u1, and a Constant Value of 0.0 was used for input u2.

VII. AGC Case Study

In order to make sure that the AGC being enacted by the user defined regulating units was correcting the system in an acceptable manner, two disturbances were simulated on the NPCC System: an 80% Load Shed at Bus 127, and a Generator Disconnect at Bus 137.

A. Load Shed

The system behaved as follows after a load shed 100 seconds into a 600 second simulation:

Figure 3 depicts the system frequency spiking after the load shed, and then gradually returning to 60 Hz over a time period of about 5 minutes. Figure 4 shows the tie line power flow for each area change at the time of the disturbance, then follow return to their scheduled values as the frequency did.

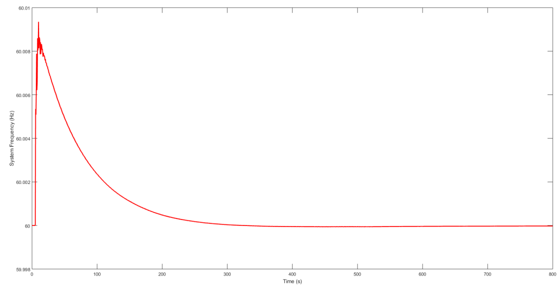

Fig. 3. Shed 80% Load at Bus 127

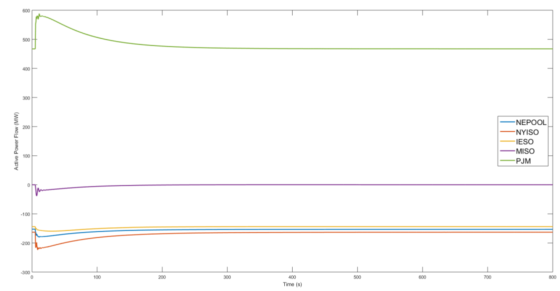

Fig. 4. Tie Line Flow After Load Shed

B. Generator Disconnect

The system behaved as follows after a generator disconnection 100 seconds into a 600 second simulation:

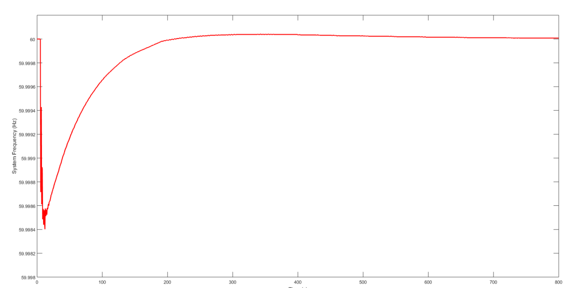

Fig. 5. Disconnect Generator at Bus 137

Figure 5 shows the system frequency drop at the time of the disturbance and then gradually return to the scheduled value of 60 Hz. In Figure 6, the tie line power in each area can be seen doing the same.

VIII. Wind Penetration Case Study

With AGC working correctly, it was time to investigate the effect of adding the DFIG models to the NPCC system. Due to the limited amount of time there was to research this, very few possible scenarios were able to be considered. Due to the geographic separation of the generators that were replaced

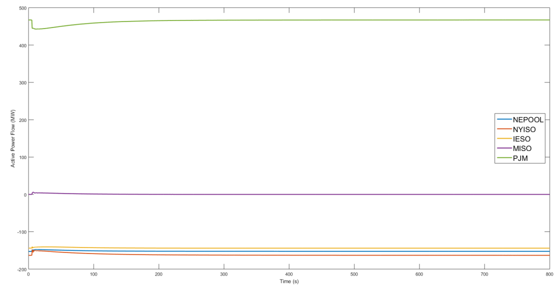

Fig. 6. Tie Line Flow After Generation Loss

by WTGs, it is very unlikely that all six turbines would face the same wind profile. However, for simplicity, each tested scenario assumes that all six WTGs are experiencing the same wind. The first scenario tested assumed a sustained drop in wind speed from 12 m/s to 11 m/s starting at 10 seconds into the simulation and subjected the system to no disturbance.

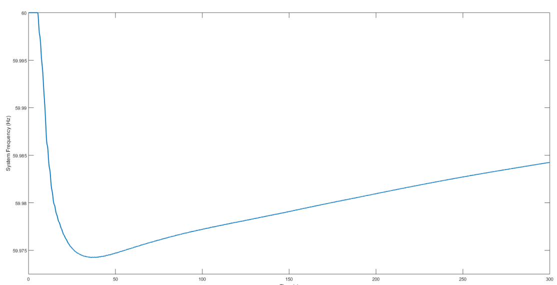

Fig. 7. Sustained Change in Wind with No Disturbance

Figure 7 shows the system frequency trying to return to 60 Hz when AGC is present. However, the response is not adequate because the time it takes to return the frequency to its scheduled value is much longer than 5 minutes.

The next scenario assumes the same wind profile, but subjects the system to the same generation loss as in II-B.

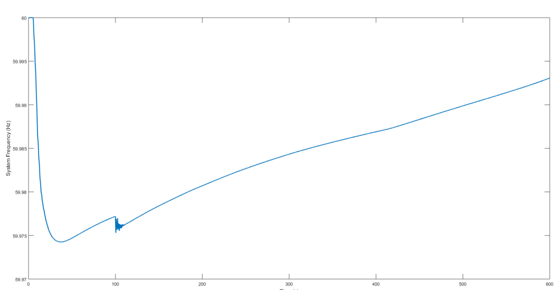

Fig. 8. Sustained Change in Wind with Generation Loss at Bus 137

The same trend that is in Figure 7 is present in Figure 8, but with a slight disruption at the time of the disturbance. This response is unacceptable for the same reasons as the first case.

The final scenario assumes a constantly varying wind profile with no disturbance to the system.

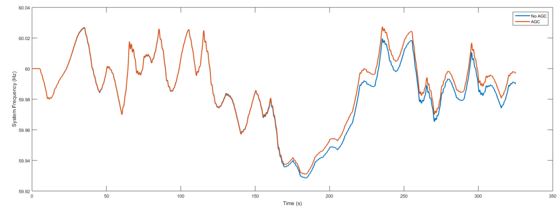

Fig. 9. Constantly Varying Wind Speed

Figure 9 shows how the system frequency changes with constantly varying wind profile. Every disturbance that was simulated alongside this wind profile resulted in a system failure. This suggests that in their current state the wind turbine models are not useful for simulation with the NPCC system.

IX. Future Work

As discussed, the WTG models may not be developed enough to be useful in simulating the NPCC system. The models could be improved by adding any of the following functions: emulated inertia, droop control, and deloading control. Each of these functions would give the WTGs a way to contribute to frequency control, whether it be short term inertial response, via emulated inertia or droop control, or governor and AGC response, via deloading control [6].

X. Conclusion

An understanding of power systems and wind generation was key to comprehending and analyzing the results of the simulation run on the NPCC system during this research. The models for regulating units and wind turbine generators were tested and determined to function as expected. These models were then added to the NPCC system together, and tested with a few different scenarios. The results of these simulations suggest that the wind turbine models require more development before they accurately reflect current technology. This development needs to occur before concluding whether or not the NPCC system is compatible with a high level of wind penetration.

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