MEJORA DE LA REGULACIÓN PRIMARIA DE FRECUENCIA POR PARTE DE LOS GENERADORES EÓLICOS

Trabajo de Fin de Grado

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RESUMEN

Introducción

La estabilidad de la frecuencia se refiere a la capacidad de un sistema eléctrico para mantenerse dentro de un rango aceptable a pesar de perturbaciones como la desconexión de un generador o cambios en la carga [1]. Es crucial evitar que las frecuencias bajen demasiado, ya que esto puede causar fallos mecánicos. [2]. Por ello, si las perturbaciones son graves, para limitar la caída de frecuencia, se activan esquemas de deslastre de carga por subfrecuencia Under Frequency Loading Schemes (UFLS), desconenctando demanda.

La estabilidad de la frecuencia depende en gran medida de la inercia de los generadores convencionales y de sus controles primarios de frecuencia. Por ello, los sistemas insulares son especialmente vulnerables a cualquier incidente, ya que tienen poca inercia y no están interconectados con otros sistemas. Esto se agrava con el uso de energías renovables, sobre todo la generación eólica, ya que no favorece la estabilidad de frecuencia. Los generadores eólicos están conectados a la red a través de la electrónica de potencia, lo que significa que no presentan la misma inercia de rotación que los generadores convencionales [3]. Además, al funcionar en el punto de máxima potencia Maximum Power Point Tracking (MPPT), los generadores eólicos no tienen una reserva de potencia a subir que pueden usar para la regulación primaria de la frecuencia. A medida que se usan más las energías renovables, la necesidad de garantizar la estabilidad de la frecuencia se vuelve más importante [4].Este proyecto se alinea con el Objetivo 7 de los Objetivos de Desarrollo Sostenible de la ONU [5].

Para contribuir al control de la frecuencia y la estabilidad de la frecuencia, los generadores eólicos podrían funcionar en por debajo de su máximo (deloaded, en inglés) para poder tener una reserva, sacrificando así parte de la eficiencia para favorecer la estabilidad. Esta reducción de carga se controla ajustando la velocidad del rotor o los ángulos de las palass y se activa la reserva mediante lo que se conoce como control de droop [6]. [7]. El control de droop se utiliza habitualmente para activar el control primario de frecuencia proporcionando una señal de entrada adicional que ajusta el margen de potencia y lo inyecta en la red, permitiendo que los aerogeneradores funcionen por debajo de su capacidad máxima.

Para estudiar cómo puede utilizarse un control droop, se ha desarrollado un modelo del generador eólico dentro de un sistema electrico. Se utilizan dos ecuaciones principales, basadas en el documento [8]. La primera ecuación determina la potencia de salida del generador eólico en relación con aspectos clave, como la velocidad del rotor, la velocidad del viento, el ángulo de las palas y otros parámetros.

La segunda ecuación utilizada determina la relación entre el cambio de velocidad del rotor y un desequilibrio de potencia suponiendo una respuesta muy rápida de la electrónica de potencia. En caso de desconexión de un generador, el aerogenerador, si funciona en modo deloaded, puede aumentar su velocidad para aumentar la potencia mecánica producida. La reserva puede utilizarse en caso de incidente de frecuencia.

Estas dos ecuaciones se combinan para construir un modelo del generador eólico e integrarlo en un System Frequency Dynamics Modelling System Frequency Modelling (SFD) con otros generadores convencionales. Bajo el supuesto de que la frecuencia es siempre uniforme en todo el sistema, esto permite analizar cómo reacciona un determinado sistema energético con generadores eólicos cuando se desconecta un generador. El sistmea puede estudiar en función de varias condiciones. Esto se hace con simulaciones en el dominio temporal de Matlab/SIMULINK.

Sin embargo, el control droop presentado plantea un problema. En caso de desconexión de un generador convencional, la potencia final producida por los aerogeneradores acaba siendo inferior a la necesaria. Esto puede verse en la figura 1. La curva negra representa todos los valores posibles con una velocidad de viento dada, la curva roja es la MPPT y las curvas verdes son posibles curvas deloaded.

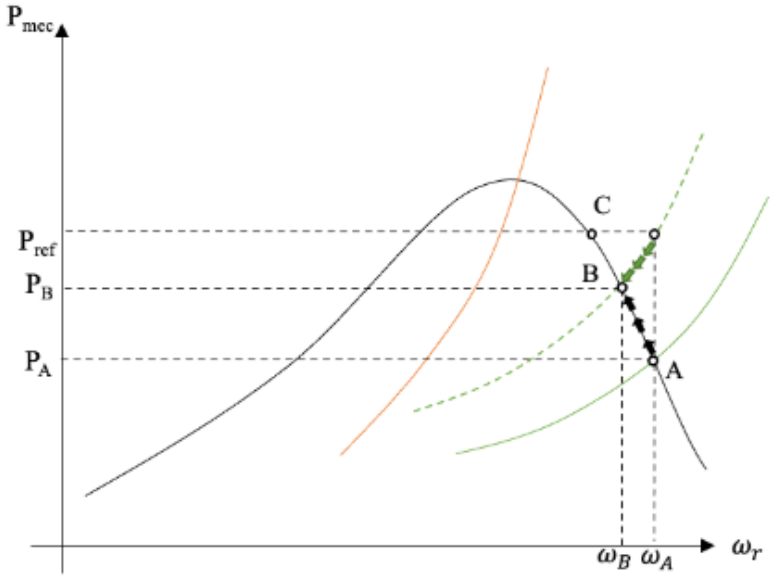

Figure 1: Potencia en función de la velocidad del rotor con control de estatismo

Al principio, los generadores eólicos funcionan en el punto A(ω_A y P_A). Si se desconecta un generador, la potencia demandada pasa a ser P_{ref} incluyendo la

contribución del control de frecuencia mediante el control por estatismo. Como hay un desequilibrio entre la potencia mecánica y la eléctrica, la velocidad del rotor empieza a cambiar siguiendo las flechas negras de la figura. Por otro lado, el control deloaded intenta que la potencia y la velocidad del rotor se mantengan a lo largo de la curva definida, como se puede ver a través de las flechas verdes. Al final, el aerogenerador se establece en el punto de equilibrio B, produciendo P_B con una velocidad del rotor de ω_B. Esto significa que el aerogenerador no ha sido capaz de producir lo que debería, $P_B < P_{ref}$. El objetivo principal de este proyecto es mejorar este control droop y analizar cómo esta mejora afecta a la reacción general del sistema cuando se desconecta una generador convencional. También se analiza el impacto de otros parámetros, como la hora del día, la potencia perdida y la velocidad del viento.

Metodología

Mejora del control frecuencia primaria basada en el droop

Una forma de tener en cuenta la disminución de potencia debida a la curva deloaded mostrada en la figura 1, es hacer que el control pida más potencia de la que realmente se desea. El control necesita aproximar cuánto se está perdiendo. Para ello, se calcula la línea tangente. El impacto de esto se ve en la figura 2.

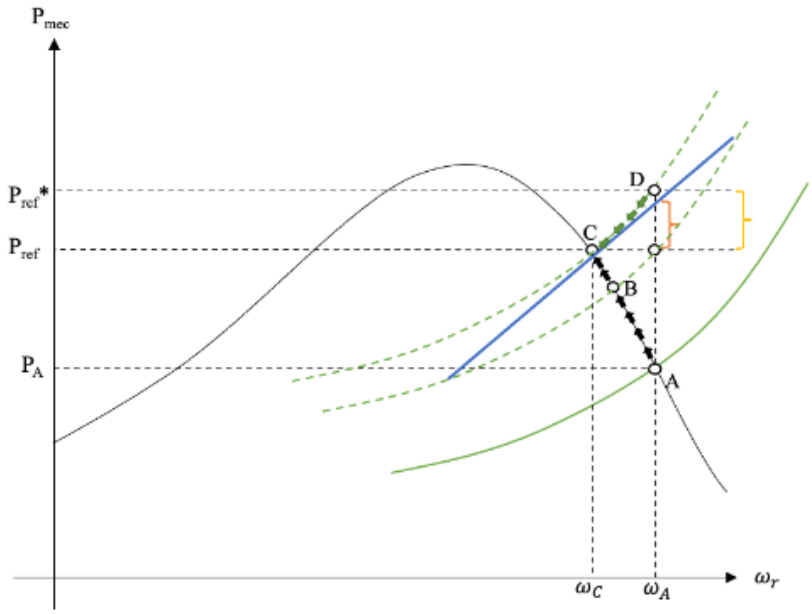

Figure 2: Potencia producida por los aerogeneradores con control de estatismo y mejora de la tangente

Antes, tras el incidente, el aerogenerador se establecía en el punto B. Ahora, gracias al cálculo de la tangente, se pide $P_{ref}*$. El punto de funcionamiento final es por tanto C, produciendo P_{ref}, lo que se deseaba. Para calcular $P_{ref} * -P_{ref}$, se multiplica la diferencia entre ω_C y ω_A por la pendiente de la tangente en el punto C. Esto es lo que se añade sobre el control de estatismo. Debido a que las diferencias en la velocidad del rotor son bastante pequeñas, la aproximación es razonablemente precisa.

Modelo Simulink Completo

Como ya se ha mencionado, se construye un modelo SFD para simular un sistema electrico. Esto se muestra en la figura 9.El "State-Space-Gen" son los generadores convencionales.

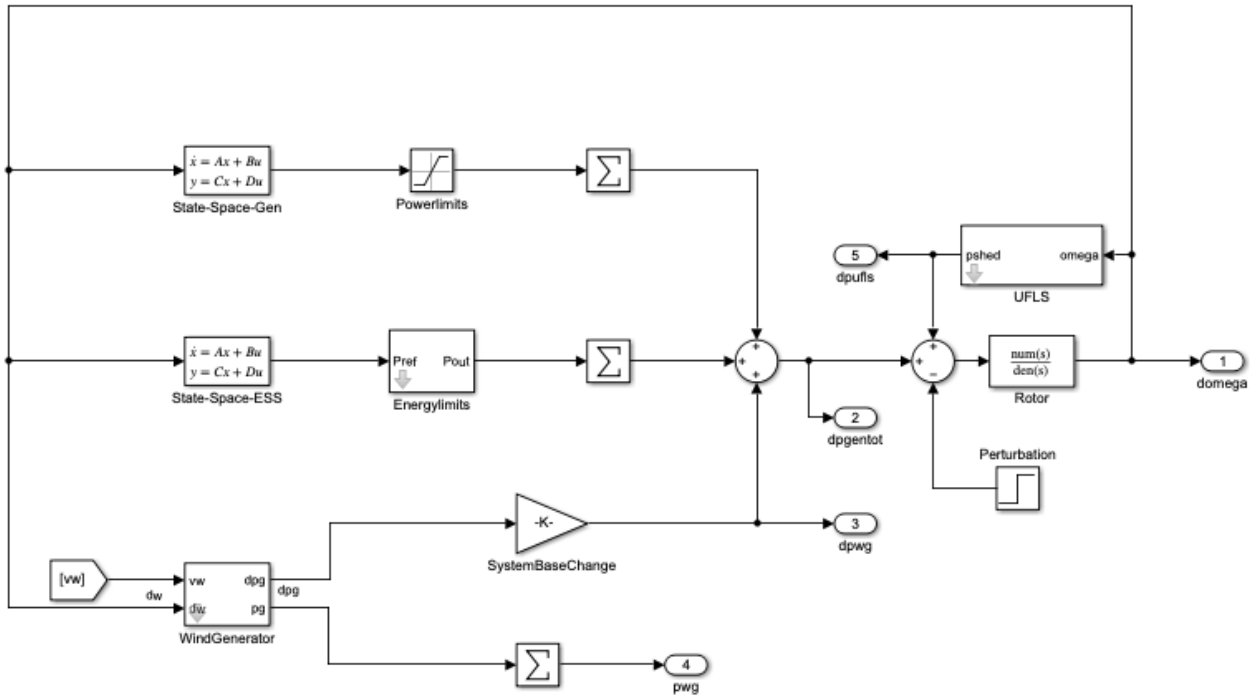

Figure 3: Modelo sistema electrico

El modelo del aerogenerador incluye las respuesta fundamental así como el control de estatismo y la mejora mediante el cálculo de la tangente también se incluyen en el modelo de la figura 3.6.

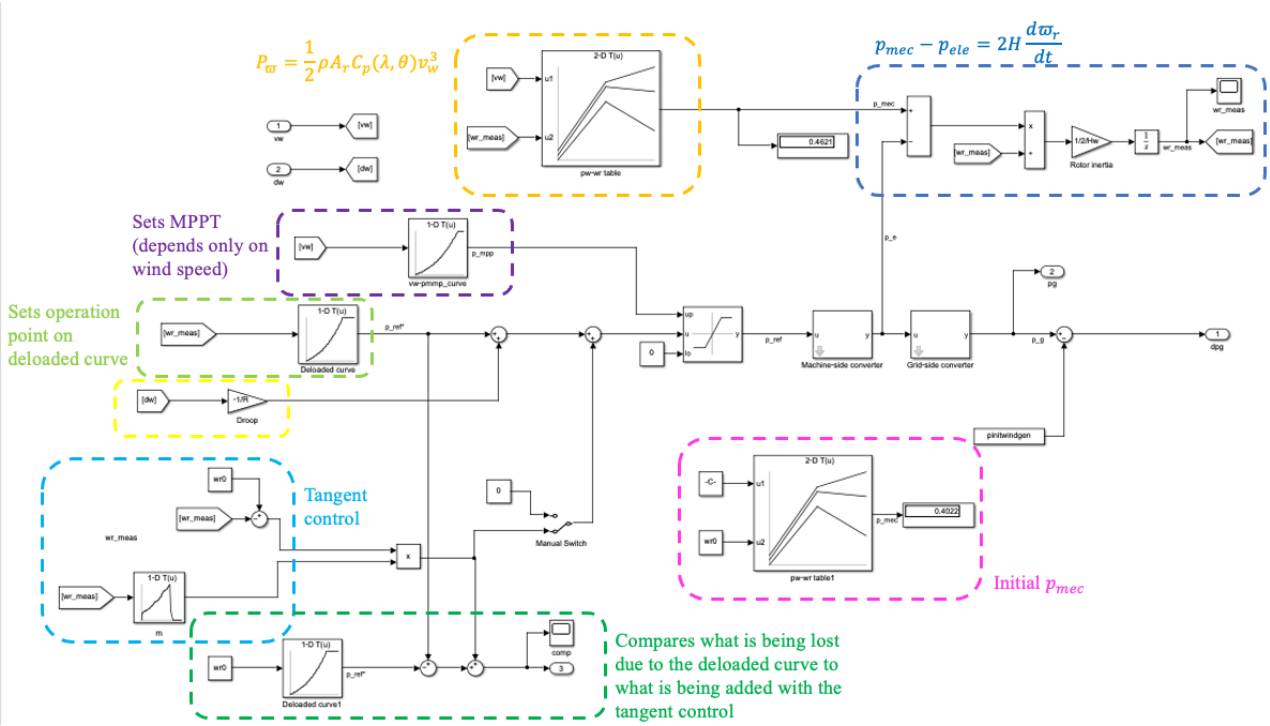

Figure 4: Modelo aerogenerador

El modelo evalúa la respuesta del sistema a la desconexión de un generador en diferentes condiciones. El procedimiento que sigue Matlab se muestra en la figura 11.

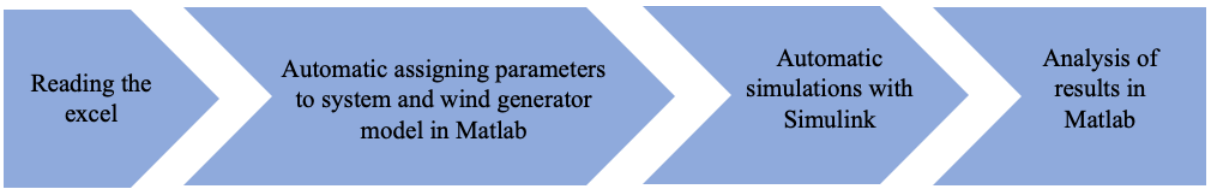

Figure 5: Procedimiento Matlab/SIMULINK

Resultados

En este proyecto se utilizaron datos de la isla de La Palma. Los parámetros que determinan el escenario concreto que se simula son la hora del día, el generador perdido, el cambio de velocidad del viento y el momento del cambio de velocidad

del viento. Los dos primeros parámetros muestran el impacto del control del estatismo y su mejora, mientras que los dos últimos proporcionan un análisis de sensibilidad en el que se comprueba la dependencia de los generadores eólicos en relación con su capacidad para proporcionar estabilidad de frecuencia.

	Control droop nuevo	Control droop original
GEN 12	0,5956	0,172
GEN 13	0,5956	0,172
GEN 15	0,8368	0,2945
GEN 17	0,832	0,3168
GEN 21	0,9793	0,5185

Table 1: Cambio en la generación de energía eólica (MW) para todos los escenarios a la 1 a.m.

	Control droop nuevo	Control droop original	Sin droop control
GEN 12	49,8989	49,883	49,8683
GEN 13	49,8989	49,883	49,8683
GEN 15	49,8477	49,8179	49,7966
GEN 17	49,8488	49,8115	49,7959
GEN 21	49,7346	49,6982	49,9570

Table 2: f_{fin} (Hz) dependiendo del generador desconectado a la 1a.m.

Las tablas 7 y 8 muestran la frecuencia final y el cambio en la potencia eólica cuando se pierde cada generador en un momento dado. Esto demuestra que el cálculo de la tangente afecta significativamente al control del estatismo, ya que los generadores eólicos pueden proporcionar el doble de reserva. No obstante, ni el control en sí ni la mejora tienen un efecto importante en el sistema global. Por un lado, la inercia de los generadores convencionales y su control de frecuencia les permite frenar la caída de la frecuencia. Por otro lado, la penetración de la generación eólica no es muy alta. Esto se ve muy claramente en la figura 12.

El efecto de los cambios de velocidad del viento se observa en las tablas 4.9, 10, 11 y 12. Aquí se suman las frecuencias máximas y mínimas, así como el UFLS activado para cada escenario (hora del día, generador perdido, etc.). Las primeras dos tablas muestran que, cuanto mayores son los cambios de velocidad del viento, menos potencia pueden producir los generadores eólicos y, por tanto, peor es el impacto para el sistema. Las últimas dos muestran que, si el viento cambia a la vez que se desconoecta el generador, el impacto va a ser peor. No obstante, esto tiene un efecto relativamente pequeño.

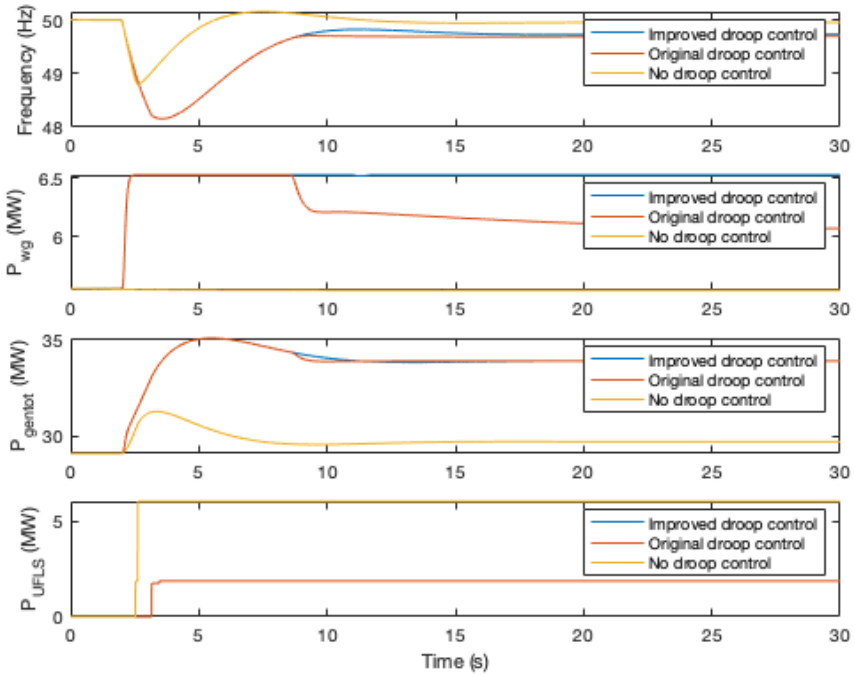

Figure 6: Simulación cuando se pierde un generador con el control nuevo, original y sin estatismo

Cambio velocidad viento	0m/s	0,5m/s	1m/s	2m/s	4m/s
Frequencia final	267,6	300,3	336,3	393,9	481,4

Table 3: Suma de f_{fin} (Hz) para todas las simulaciones con control de estatismo mejorado en función del cambio de velocidad del viento

Cambio velocidad viento	0m/s	0,5m/s	1m/s	2m/s	4m/s
UFLS	375,4	409,8	473	584,5	804,6

Table 4: Suma de d_{UFLS} (MW) para todas las simulaciones con el control de estatismo mejorado en función del cambio de velocidad del viento

Momento del cambio velocidad viento	-2s	0s	2s
Frecuencia final	593,6	614,2	570,8

Table 5: Suma de f_{fin} (Hz) para todas las simulaciones con control de estatismo mejorado en función del momento del cambio de velocidad del viento.

Momento del cambio velocidad viento	-2s	0s	2s
UFLS	872,3	930,5	844,4

Table 6: Suma de d_{UFLS} (Hz) para todas las simulaciones con el control de estatismo mejorado en función del momento del cambio de velocidad del viento.

Conclusiones

La respuesta de las simulaciones indica que la implementación de esta mejora en el control de estatismo afecta significativamente su influecia. Esto se observa claramente en la diferencia en la potencia final producida por los aerogeneradores. No obstante, el impacto tanto del control de estatismo como de su mejora en el sistema no es especialmente grande. Los aerogeneradores se saturan rápidamente, por lo que el regimen transitorio no se ve modificado por la mejora de la tangente. Además, la potencia adicional que aportan los generadores eólicos no tiene un gran impacto en la frecuencia final, ya que los generadores convencionales (con su gran inercia) son capaces de compensarlo. Como era de esperar, cuanto mayor es la pérdida del generador, mayor es el impacto. Del mismo modo, cuanto mayor sea el cambio en la velocidad del viento, peor funcionará el sistema.

Este proyecto podría mejorarse afinando los datos utilizados en el modelo y permitiendo ruido en la velocidad del viento. Además, se podría añadir un controlador del ángulo de las palas e incorporar un sistema de almacenamiento de energía a corto y largo plazo para aumentar la estabilidad de la frecuencia del sistema.

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IMPROVED PROVISION OF PRIMARY FREQUENCY CONTROL BY WIND GENERATORS

Bachelor's final project

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SUMMARY

Introduction

Frequency stability refers to a power system's ability to remain within an acceptable range despite disturbances such as generator tripping or load changes [1]. It is crucial to prevent frequencies from dropping too low, as this can cause mechanical failures. [2]. Because of this, if disturbances are severe, to limit the drop in frequency, under-frequency loading schemes UFLS are activated, however this results in partial blackouts.

Frequency stability is dominated by the conventional generator's inertia and their primary frequency controls. Island systems are therefore particularly vulnerable to any incident as they have small inertia and not interconnected. This is made worse through the use of renewable energies, notably wind generation, as it doesn't support frequency control. Wind generators are connected to the grid through power electronics, meaning they don't exhibit to the grid the same rotating inertia as conventional generators [3]. On top of that, operating at maximum power point tracking MPPT mode, wind generators cannot provide reserve power for primary frequency regulation. As the use of renewable energies becomes more widespread, the need to ensure frequency stability is highlighted [4]. This project aligns with Goal 7 of the UN Sustainable Development Goals [5].

To contribute to frequency control and stability, wind generators must operate in a deloaded mode to provide reserve power, therefore sacrificing some efficiency for stability. This deloading is controlled by adjusting rotor speed or blade pitch angles. The activation of the held back reserve is usually done by a droop control [6] [7]. Droop control is commonly used to activate primary frequency control by providing an additional input signal that adjusts the power margin and injects it into the grid, allowing wind generators to operate below their maximum capacity.

To study how a droop control can be used, a model of the wind generator within a power system is developed. Two main equations are used. The first one determines the wind generator's power output in function of key variables, such as rotor speed, wind speed blade pitch angle and other parameters. The second equation determines the relationship between the rotor's change in speed and a power imbalance. In case of a generator tripping, the wind generator, if working on a deloaded mode, can increase its speed to increase the mechanical power produced. The reserve can be utilised if there is a frequency incident.

These equations are combined to build a wind generator model and integrate it into a SFD with other conventional generators. Under the assumption that frequency is always constant throughout the system, this allows the analysis of how a

given energy system with wind generators reacts to a generator outage depending on several conditions. This is done with Matlab/SIMULINK time-domain simulations.

However, there is an issue associated with the droop control. In case of generator tripping, the final power produced by wind generators ends up being lower than what is necessary. This can be seen in figure 7. The black curve represents all possible values with a given wind speed, the red curve is the MPPT and the green curves are possible deloaded curves.

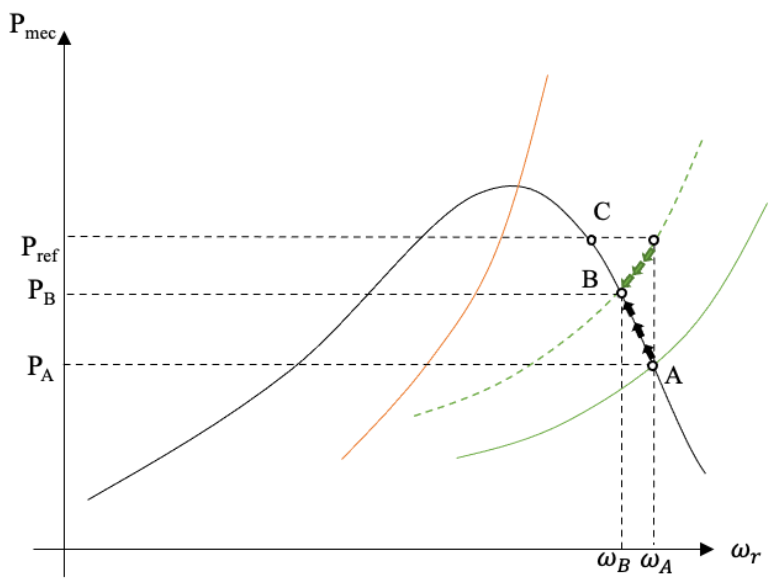

Figure 7: Power output depending on rotor speed with droop control

In the beginning, wind generators are operating at point A(ω_A and P_A). In case of a generator being disconnected, the power demanded suddenly becomes P_{ref} considering the frequency control contribution by means of the droop control, corresponding to P_e in equation **??**. As there is an imbalance between what the mechanical and electrical power, the rotor's speed begins to change following the black arrows. On the other hand, the deloaded control tries to get the power and rotor speed to stay along the curve defined, as can be seen through the green arrows. In the end, the wind generator settles at equilibrium point B, producing P_B with a rotor speed of ω_B. This means the wind generator was not able to produced what it should have, $P_B < P_{ref}$. The main objective of this project is to improve upon this droop control and analyse how this enhancement affects the system's overall reaction to generator's being disconnected. The impact of other

parameters, such as time of day, power lost, wind speed, are also analysed.

Methodology

Enhance droop-based primary frequency

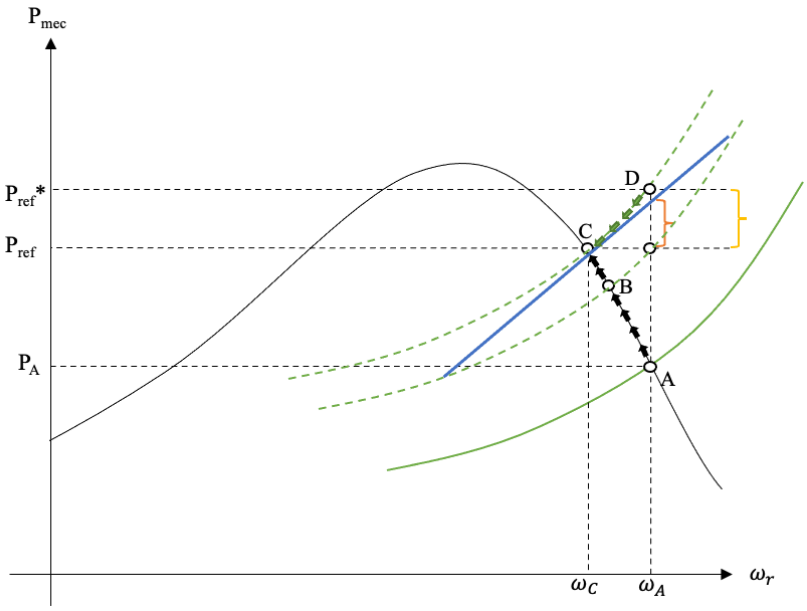

Figure 8: Power system output with droop control and tangent enhancement

One way to account for the decrease in power due to the deloaded curve shown in figure 7, is to make the control ask for more power than actually and strictly needed for frequency control. The control needs to approximate how much is being lost. To do this, the tangent line is calculated. The impact of this is seen in figure 8.

Previously after the incident the wind generator settled on point B. Now, thanks to the tangent calculation, $P_{ref}*$ is asked for. The final operating point is therefore C, producing P_{ref}, what was desired. To calculate the $P_{ref} * - P_{ref}$, the difference between ω_C and ω_A is multiplied by the slope of the tangent on point C. This is what is added on top of the droop control. Because the differences in rotor speed are quite small, the approximation is reasonably accurate.

Complete Simulink Model

As mentioned before, a SFD model is built to simulate an energy system. This is shown in figure 9.The state-space-gen are the conventional generators.

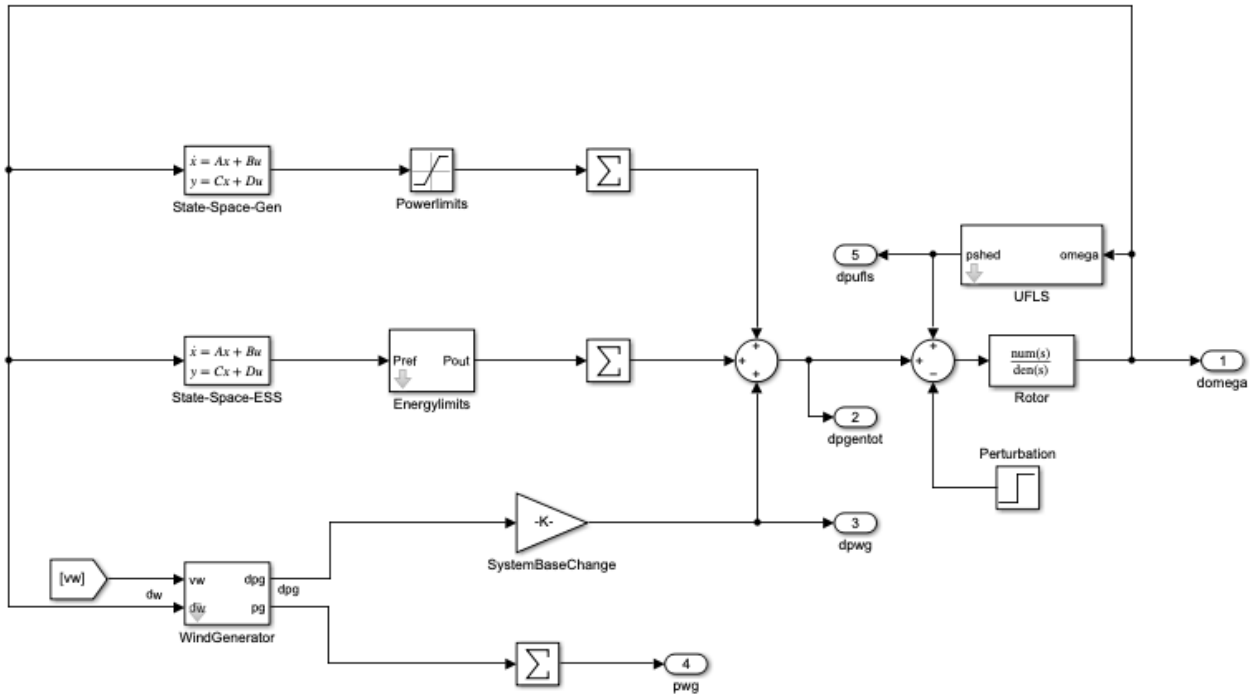

Figure 9: Powersystem model

The two equations are combined to model a wind generator. The droop control, and the enhancement using a tangent calculation, are also included into the model seen in figure 3.6.

The model evaluates the system's response to the disconnection of a generator under different conditions. The flow chart carried out by the Matlab script is shown in figure 11.

Results

Data from the island of La Palma, Spain was used in this project. The parameters that determine the particular scenario being simulated are time of day, generator lost, wind speed change and time of wind speed change. The first two parameters

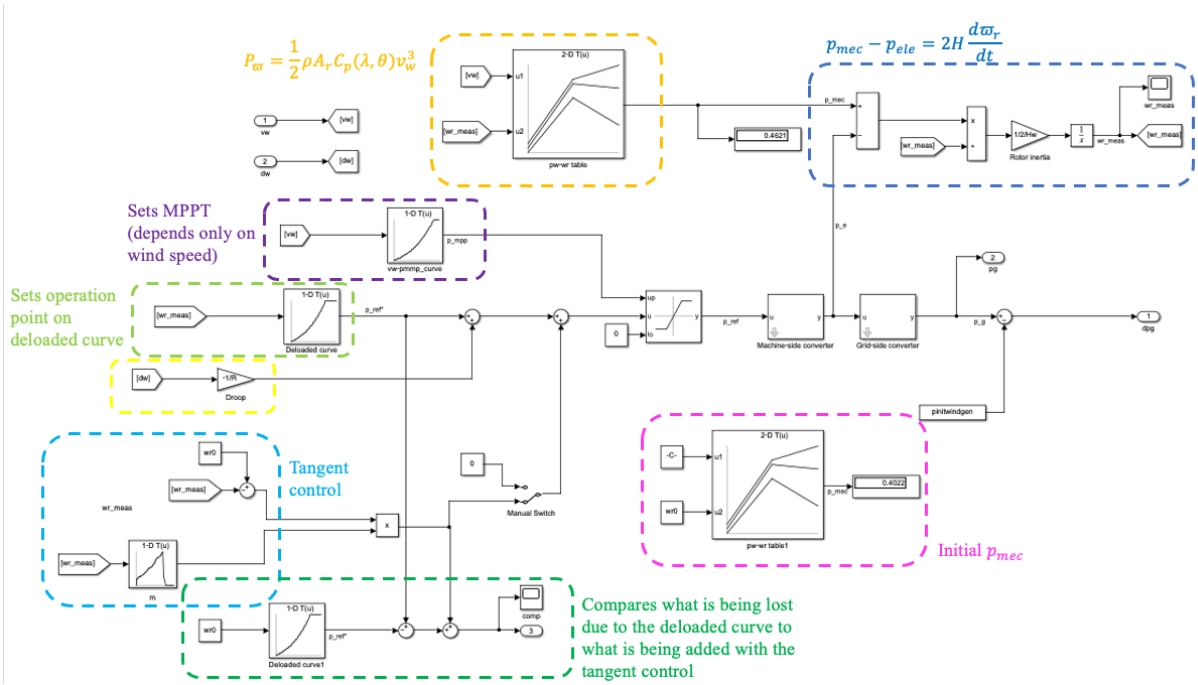

Figure 10: Wind generator model

show the impact of the droop control and its improvement whereas the last two provide a sensitivity analysis where the dependence on wind generators is tested in relation to their ability to provide frequency stability.

	New droop control	Original droop control
GEN 12	0,5956	0,172
GEN 13	0,5956	0,172
GEN 15	0,8368	0,2945
GEN 17	0,832	0,3168
GEN 21	0,9793	0,5185

Table 7: Change in wind power generation (MW) for all scenarios at 1a.m.

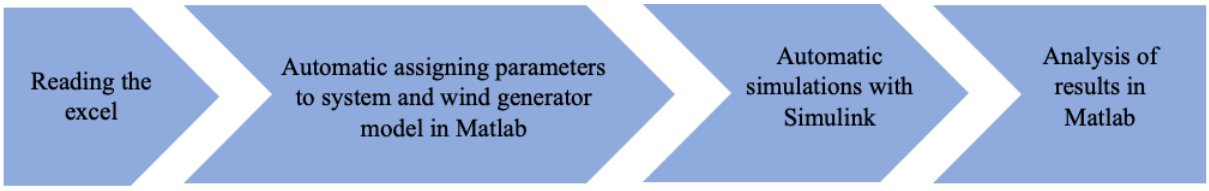

Figure 11: Matlab script flow chart

Wind speed change	0m/s	0,5m/s	1m/s	2m/s	4m/s
Final frequency	267,6	300,3	336,3	393,9	481,4

Table 9: Sum of f_{fin} (Hz) for all simulations with improved droop control depending on the wind's speed change

	New droop control	Original droop control	No droop control
GEN 12	49,8989	49,883	49,8683
GEN 13	49,8989	49,883	49,8683
GEN 15	49,8477	49,8179	49,7966
GEN 17	49,8488	49,8115	49,7959
GEN 21	49,7346	49,6982	49,9570

Table 8: f_{fin} (Hz) for all scenarios at 1a.m.

Tables 7 and 8 show the final frequency and change in wind power when each generator is lost at a given time. This shows that the tangent calculation significantly affects the droop control, as wind generators are able to provide twice as much reserve. Nonetheless, neither the control itself or the enhancement have a major effect on the overall system. The conventional generator's large inertia means they are able to provide reserve without lowering the frequency too much. This is seen very clearly in figure 12.

The effect of changing wind speeds is seen in tables 4.9, 10, 11 and 12. Here, the maximum and minimum frequencies as well as the UFLS activated are added for every scenario (time of day, generator lost etc.) The first two tables show that, the bigger the wind's speed changes, the less power wind generators can produce and therefore the worse the impact to the system. The last two show that, if the wind changes at the same time as the conventional generators are disconnected, the overall impact is worse. Nonetheless, this effect is relatively minor.

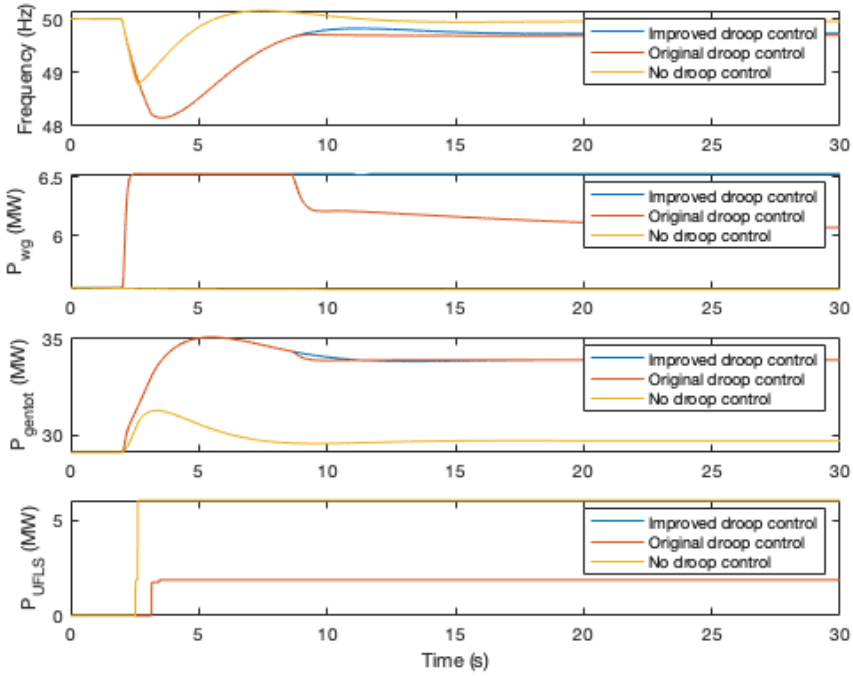

Figure 12: Simulation when a generator is lost with the new, original and no droop control

Wind speed change	0m/s	0,5m/s	1m/s	2m/s	4m/s
UFLS	375,4	409,8	473	584,5	804,6

Table 10: Sum of d_{UFLS} (MW) for all simulations with the improved droop control depending on the wind's speed change

Time of wind speed change	-2s	0s	2s
Final frequency	593,6	614,2	570,8

Table 11: Sum of f_{fin} (Hz) for all simulations with improved droop control depending on the moment of the wind's speed change

Time of wind speed change	-2s	0s	2s
UFLS	872,3	930,5	844,4

Table 12: Sum of d_{UFLS} (Hz) for all simulations with the improved droop control depending on the moment of the wind's speed change

Conclusion

The simulation responses indicate that implementing the proposed improvement into the original droop control significantly affects its influence, as seen in the difference in the final power produced by wind generators. Nonetheless,the actual impact of both the droop control and its improvement on the system was small. Wind generators saturate quickly so the transient effect is not changed by the tangent enhancement. On top of that, the additional power wind generators contribute didn't have a huge impact on the final frequency as conventional generators (with their large inertia) are able to compensate. As was expected, the greater the generator lost, the bigger the impact. Similarly, the bigger the change in the wind's speed, the worse the system will perform.

This project could be improved by fine tuning the data used in the model and allowing noise in the wind's speed. Furthermore, adding a pitch-angle controller and incorporating a short and long term energy storage system could be used to increase frequency stability in the system.

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Degree in Industrial Technologies

Bachelor's final project

Improved provision of primary frequency control by wind generators

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Abbreviations

UFLS Under Frequency Loading Schemes

ROCOF Rate of Change of Frequency

MPPT Maximum Power Point Tracking

SFD System Frequency Modelling

Chapter 1

Introduction

1.1 Frequency stability

Frequency stability can be defined as "the capacity of generators to supply the loads at acceptable frequency ranges in the case of a generator tripping" [1]. Every power system needs to ensure frequency stability so that, in case of a sudden severe change in the load or real power generation, the frequency remains as close to the nominal value as possible [2]. Low frequency, caused by a disconnection of a generator or the connection of an additional load, is especially harmful to the power system. This is seen, for example, through the fact that the blades in many gas and steam turbines exhibit a resonance frequency close to 47Hz in a 50Hz system. If the frequency descended to that level many generators would vibrate until they break. To avoid this, conventional generators have a reserve that can be used to increase total power generation.

However, if the disturbance is big enough, generator's reserve might not be enough to stabilise the system. In this case, UFLS are set in place. These measures disconnect predetermined percentages of the overall load when the frequency dips bellow a certain value (or falls faster than a certain rate) to once again bring the power offer and demand closer together. For example, in Spain (peninsula), 15% of the total load would be disconnected at 49Hz, followed by another 15% is the frequency continues to drop past 48.7Hz [3]. This is however far from a perfect solution as it entails partial blackouts, highlighting the importance of ensuring frequency stability.

Frequency is nowadays imposed by the rotating speeds of the synchronous generators. For this reason, frequency stability relies mostly on the combined inertia of all the generators [1]. Frequency dynamics can be illustrated using the following equation:

$$2H\frac{df}{dt} = p_{gen} - p_{load} \tag{1.1}$$

'H' refers to the component's inertia ($MVA * s$), f is the system's frequency (as a function of time), p_{gen} refers to the total power generated and p_{load} refers to the total power demanded by the system. As can be clearly seen, the larger the imbalance between generation and load the greater the rate of variation in frequency, and the larger the rotating inertia of the system's components, the better the frequency stability.

It is for this reason that island systems are particularly vulnerable to any incident which causes a power imbalance. Island systems are those which are not interconnected to any other power system and in which any individual generating unit presents a substantial portion of the total generation [1]. This means that these systems have a lower total rotating inertia. For example, the Spanish island of La Palma has a daily maximum load demanded of around 35MW and its generation portfolio includes 11 generators [4]. A sudden failure of any of those generators would have a much larger impact than if one of the hundreds of generators in continental Spain (producing a daily maximum of around 30 000MW and connected to the central European power system [5]) were to fail.

1.2 Wind generation

The world is currently experiencing a shift in how power is produced. As the worry for climate change increases, we are moving towards a more sustainable approach to obtaining power. Renewable energy is penetrating further into the energy market, particularly through wind [6]. An issue with this is that, unlike conventional generators, wind generators don't have the same inherent rotating inertia and therefore they can't contribute to the system's frequency stability by providing inertial response. This is because they are not connected directly to the grid. Instead, they use power electronics (particularly frequency converters [7]), meaning all potential inertia is lost. Consequently, the higher the penetration of wind generators in a system, the lower the overall inertia [8]. As can be seen in the equation 1.1 this results in a higher Rate of Change of Frequency (ROCOF) in case of a power imbalance, making UFLS more likely to be activated.

Furthermore, wind generators usually work at their maximum operation point (MPPT mode), meaning they are unable to produce more power for a given wind, the maximum is extracted. This is because, if frequency stability is not a concern, this point makes the most economic sense. It creates the most power given the current wind and generators in place. Wind generators operating at the MPPT cannot provide reserve and thus primary frequency regulation. This is illustrated in the figure 1.2. It shows the power output of a wind generator in function of

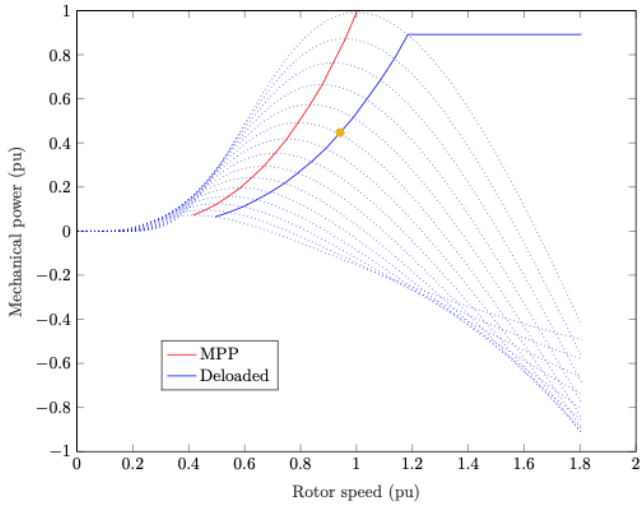

Figure 1.1: MPP and deloaded curves for different winds

the rotor speed and different wind speeds (blue lines). The red line shows the operating point of the MPPT. A wind generator working at its MPPT (the red line)can't change its power output unless the wind increases (moves to a higher blue dotted line).

To be able to contribute to the system's primary frequency control, wind generators need to work in a deloaded mode, i.e., to operate below the MPPT to have some power margin. On figure 1.2 this would mean to work along the solid blue line. It can be done through several ways, for example by changing the pitch angle or the rotor speed.

By deliberately changing the speed at which the wind turbines spin for any given wind, wind generators are able to control how much power they output and therefore provide primary power reserve to account for any possible imbalances, contributing to frequency stability. This is known as a droop control [9]. As will be seen in further sections, there are some issues with this control.

1.3 Alignment with the United Nations Sustainable Development Goals

This project aligns with Goal 7 of the UN Sustainable Development Goals [10]:

"*Ensure access to affordable, reliable, sustainable and modern energy*".

Most crucially, it addresses target 7.2:

> "*By 2030, increase substantially the share of renewable energy in the global energy mix*".

In order to have reliable access to renewable sources, it is crucial that wind generators ensure frequency stability. As mentioned in previous sections, it is not only important that renewable sources have a high penetration in an energy system, but also that they can participate in the system's frequency dynamics even if they don't have the same rotating inertia conventional generators do. This ensures UFLS don't need to be used often, making access to power more reliable.

By addressing the discrepancy between how much wind generators should produce in case of power instability and how much they actually do, wind generators can hopefully become more reliable, allowing systems to have a higher penetration of wind generators.

As highlighted by the target 7.B., this is especially relevant in island systems (and developing countries) where frequency stability is already significantly lower due to the smaller number of conventional generators:

> "*By 2030, expand infrastructure and upgrade technology for supplying modern and sustainable energy services for all in developing countries, in particular least developed countries, small island developing States, and land-locked developing countries, in accordance with their respective programs of support*"

1.4 Objectives

The main objectives of this project are:

- Improve upon the droop control used in wind generators
- Model how wind generators react in case of an imbalance between power generated and demanded
- Analyse the improvement of wind generator's response after implementing the change in the control
- Study how a system reacts to a power imbalance depending on several parameters (including time of day, power lost, wind loss and moment of wind speed change)

Chapter 2

State of the art

The section aims to provide and overview of the current literature regarding wind generation. Firstly, the basic equations that govern wind generation will be studied, followed by the existing research on the modelling of both the generators and their controls. By examining the key concepts in the field, this section intends to identify the challenges with accurately incorporating wind generation into a system's primary frequency control. It therefore establishes the basis upon which the rest of the project will be built on.

2.1 Wind generation

In this section, the current literature with respect to the modelling and control of wind generators is going to be studied. The focus will be on the provision of primary frequency regulation and how wind generators can contribute to this.

The most significant parts of a wind generator in this context are the rotor and the blades, as they are responsible for extracting the wind's energy and converting it into mechanical power. The converter and controls are also crucial, as through this the MPPT is defined. Understanding the factors that affect wind generator performance is essential to understand the impact of wind generation on the power system. For this section, paper [11] will be used.

A wind generator's power output depends on many factors as can be shown in equation 2.1:

$$P_\omega = \frac{1}{2}\rho A_r C_p(\lambda, \theta) v_\omega^3 \tag{2.1}$$

This equation shows the dependency of wind power on the rotor speed, the wind speed and the pitch angle. P_ω refers to the power extracted from the wind

[W], ρ is the air density $[kg/m^3]$, A_r is the area covered by the rotor $[m^2]$, C_p is a performance coefficient, v_w is the wind speed $[m/s]$, θ is the blade pitch angle, and λ is the tip speed ratio defined as:

$$\lambda = \frac{\omega_r R}{v_w} \tag{2.2}$$

where ω_r is the rotor speed and R is the radius. In paper [11] the performance coefficient (in the range between zero and one) is approximated numerically :

$$C_p(\lambda, \theta) = 0.73(\frac{151}{\lambda_i} - 0.58\theta - 0.002\theta^{2.14} - 13.2)e^{(-18.4/\lambda_i)} \tag{2.3}$$

with

$$\lambda_i = \frac{1}{\frac{1}{\lambda - 0.02\theta} - \frac{0.003}{\theta^3+1}} \tag{2.4}$$

This performance coefficient is meant to provide a simplified numerical approximation of the wind generator's mechanical performance. Evidently, in practice this depends on more parameters, for example the type of wind generator and its nominal power.

2.2 Primary frequency control of wind generators

As mentioned before, although wind generators have a rotating mass, for the power grid, they do not exhibit inertia since the converters and their control, in particular in the MPPT, impede a change of the wind generator's rotational speed if the wind speed does not change. For this reason, they need additional controls to be able to offer primary frequency regulation. These control mechanisms allow wind generators to adjust their power output by monitoring frequency changes. They also optimize rotor speed, and finely adjust blade pitch angles. They allow wind generators to move from the MPPT. The most common ways to adjust how much power is generated is to change the rotor speed or the pitch angle [9] [12]. As can be seen in equation 2.1 and 2.2, the power output depends on the rotor speed and angle, which is why this can be used. This paper will focus on a rotor speed control as it generally acts faster than the blade angle control [13]. On top of that, in practice, pitch angle controllers are more commonly used to protect the wind generator's blades in case of extremely high winds by acting as a brake. [14]. By moving to a non-optimal angle according to the current wind direction, the blades turn slower, thus preventing them from any damage. Similarly, by changing the speed at which the rotor turns, the amount produced can be changed.

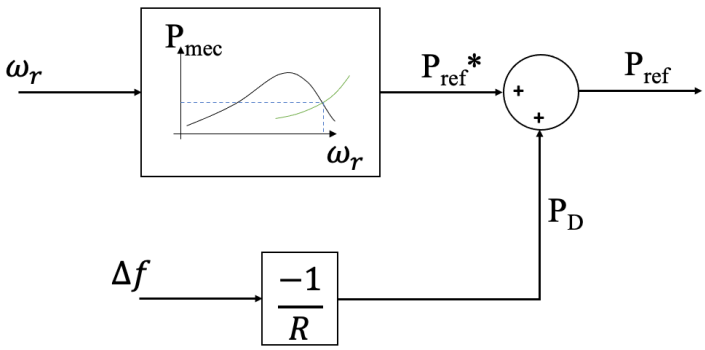

Figure 2.1: Rotor speed with an integrated frequency droop control

A droop control is typically used to activate primary frequency control. This provides an additional input signal, as can be seen in figure 2.1. This means that the power margin (the result of working on a deloaded mode) is activated and injected into the grid. Through this, the wind generator no longer works at it's maximum. [13]. As shown in the figure, it is common to provide a droop power directly proportional to the frequency deviation, but this control can be achieved in several other ways. For instance, paper [14] studies the use of a variable droop control.

Frequency stability can also be achieved by deploying the kinetic energy of the rotating masses. By using this type of control, the mechanical power reserve required to fulfill the necessary power reserve is notably diminished [15]. When doing this, wind generators use temporary overproduction to provide frequency stability. The wind turbine speed is temporarily decreased to extract the stored energy [16].

2.3 Issues of droop-based frequency control

Current models using the droop technique outlined have an error associated with them. Due to the interactions between the control and the relationship between power output and rotor speed, the real time power produced by a wind generator in case of an imbalance is actually lower than what is desired. This is best shown through a simplified graph, as seen in figure 2.2. This figure shows how a wind generator with a droop control reacts to a frequency deviation in the system. The red line shows the MPP and the solid green line represents a possible deloaded mode. The black curve represents all possible combinations of power generated and rotor speed for a given wind.

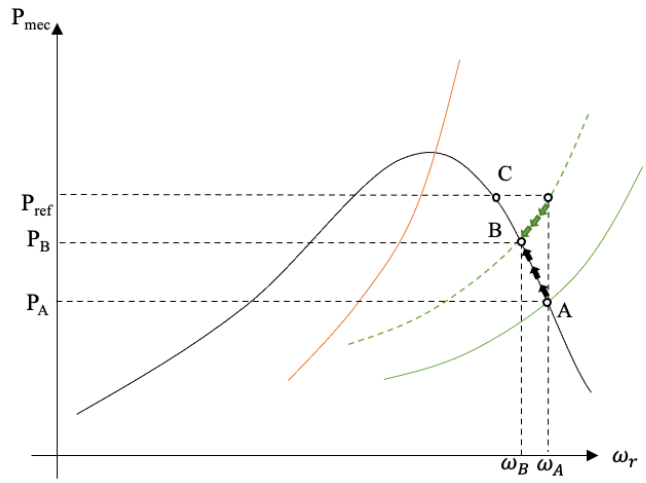

Figure 2.2: Power output depending on rotor speed

At the start of this given scenario, the wind generator is working at equilibrium point A, with a rotor speed ω_A producing P_A. The desired electrical output matches the power outputted. It can be noted that the wind generator always works on the right part of the figure, at a higher rotor speed than the one at the MPPT. Working at a slower speed would lead to an unstable system [9]. In case of an incident leading to a frequency deviation, the power demanded suddenly changes to P_{ref}. This causes a power imbalance between the electrical power (demand) and the mechanical power (produced) of the wind generator.

Right after the incident, the wind generator is working at ω_A, but now has a demanded power of P_{ref}. However, this is not a point along the black curve, meaning it is impossible to produce that power with that rotor speed (without the wind changing). Two things begin to happen simultaneously. On the one hand, the wind generator will reduce the rotor speed, always following the black curve. This is shown through the black arrows. On the other hand, the deloaded control tries to get the power and rotor speed to stay along the curve defined, as can be seen through the green arrows. In the end, the wind generator settles at equilibrium point B, producing P_B with a rotor speed of ω_B. Once again, the desired power output matches what is produced. As can be seen in the graph, this point belongs to a new deloaded curve which is represented here with the green dotted line.

The issue with this current system, and the main motivation of this project, is that as can be seen, the final power output doesn't match exactly what was desired, $P_{ref} > P_B$. This limits wind generator's ability to contribute to a system's

primary reserve, as they can't produce as much as is needed. The final frequency in the system will therefore be lower than if the power was being generated by a conventional generator, wind generators are not able to fully maintain frequency stability. For a system to have high wind generation penetration, it needs to be able to assure that if a conventional generator is ever disconnected, the system can still react properly to limit the chances of UFLS being activated. The main purpose of this project is therefore to improve upon the current controls so that, if P_{ref} is needed, P_{ref} is generated. This would mean finding a way to work at point C whilst maintaining the general structure of a rotor speed droop control.

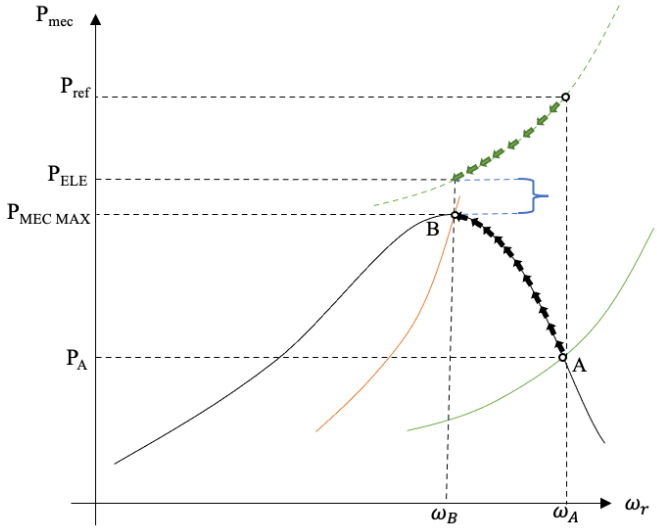

Figure 2.3: Power output depending on rotor speed 2

In case of reaching the maximum, the wind generator would produce P_{mecmax}. If the power demanded exceeds the mechanical maximum, the control limits the contribution to primary frequency in terms of the difference between P_{mecmax} and P_A. This means P_{ref} is limited to P_{mecmax}. This avoids the situation shown in figure 2.3, where there is a clear mismatch the power demanded and produced.

Chapter 3

Modelling

This chapter presents the power system model as well as the wind generator model to asses the contribution of wind generation to frequency stability in general and primary frequency control in particular.

3.1 Modelling power system

To model a power system (in this case the island of La Palma's electrical system), a SFD is used. There have been many proposed SFD models across the literature, including in [1]. These models are designed to represent interconnected generators and loads as well as their transmission network in a way that preserves the fundamental frequency characteristics of a system, particularly in terms of dynamic behaviour. It assumes uniform frequency, although in reality, uniform frequency is only observed in a steady state. [1]. The model takes into account generation and load variations, the rotational inertia of all generators, the governor- turbine response (i.e. the controls that regulate the turbine's speed and therefore output power) and the natural and artificial damping processes that help stabilize the system.

In these models, generators are represented with several generic second-order systems. These equations represent the previously mentioned inertia and turbine-governor system which, due to the nature of frequency deviation, are what mainly impacts short-term frequency dynamics. The next set of equations correspond to the ith machine in the system:

$$\begin{bmatrix} \Delta\dot{x}_{1tg,1} \\ \Delta\dot{x}_{2tg,1} \end{bmatrix} = \begin{bmatrix} 0 & 1 \\ \frac{-1}{a_{1,i}} & \frac{-a_{1,i}}{a_{2,1}} \end{bmatrix} \begin{bmatrix} \Delta x_{1tg,1} \\ \Delta x_{2tg,1} \end{bmatrix} + K_i \begin{bmatrix} 0 \\ \frac{1}{a_{2,1}} \end{bmatrix} \Delta\omega \tag{3.1}$$

$$\Delta p'_{G,i} = \begin{bmatrix} 1 - \frac{b_{2,i}}{a_{2,i}} & b_{1,i} - \frac{a_{1,i} * b_{2,i}}{a_{2,i}} \end{bmatrix} \begin{bmatrix} \Delta x_{1tg,1} \\ \Delta x_{2tg,1} \end{bmatrix} + K_i * \frac{b_{2,i}}{a_{2,i}} \Delta\omega \tag{3.2}$$

$$\Delta p_{G,i} = max(\Delta p_{i,min}, min(\Delta p_{i,max}, \Delta p'_{G,i})) \tag{3.3}$$

where $a_{1,i}$, $a_{2,i}$, $b_{1,i}$ and $b_{2,i}$ are the poles and zeros of the generic second-order system, K_i is the inverse of the droop in pu on $M_{base,i}$, $\Delta p_{i,max}$ and $\Delta p_{i,min}$ are the maximum and minimum output of the generator. It is important to note that the inclusion of maximum and minimal power outputs transforms this linear system into a non linear system. This is why a MATLAB/Simulink model is used, as a time-domain analysis is crucial in understanding the system.

Using these equations, a sample power system is represented in the following figure, taken from [1]:

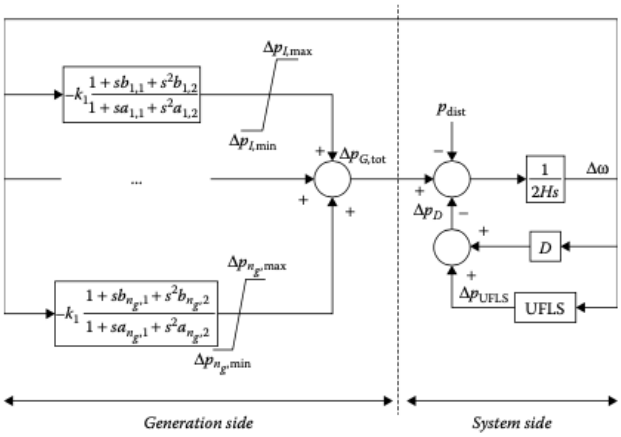

Figure 3.1: SFD model

In this figure, the two blocks on the generation side represent two possible conventional generators (as explained before, they are defined by a second-order system). The $\frac{1}{2H_i s}$ term seen on the system side corresponds to the inertia seen in equation 1.1. The operator D is the demand damping seen in the system.

In this project, to make the model simpler, there will be one single equivalent generator. This can be seen in the following Simulink system (figure 3.2). The State-Space-Gen block represents the conventional generators and the State-Space-ESS corresponds to the energy storage system however, this is not currently used. It can be noted that both of these operators are followed by limits, showing how both of these can saturate. The 'Rotor' (shown as $\frac{num(s)}{den(s)}$) is the system's equivalent inertia.

Figure 3.2 shows the complete Simulink model of the power system:

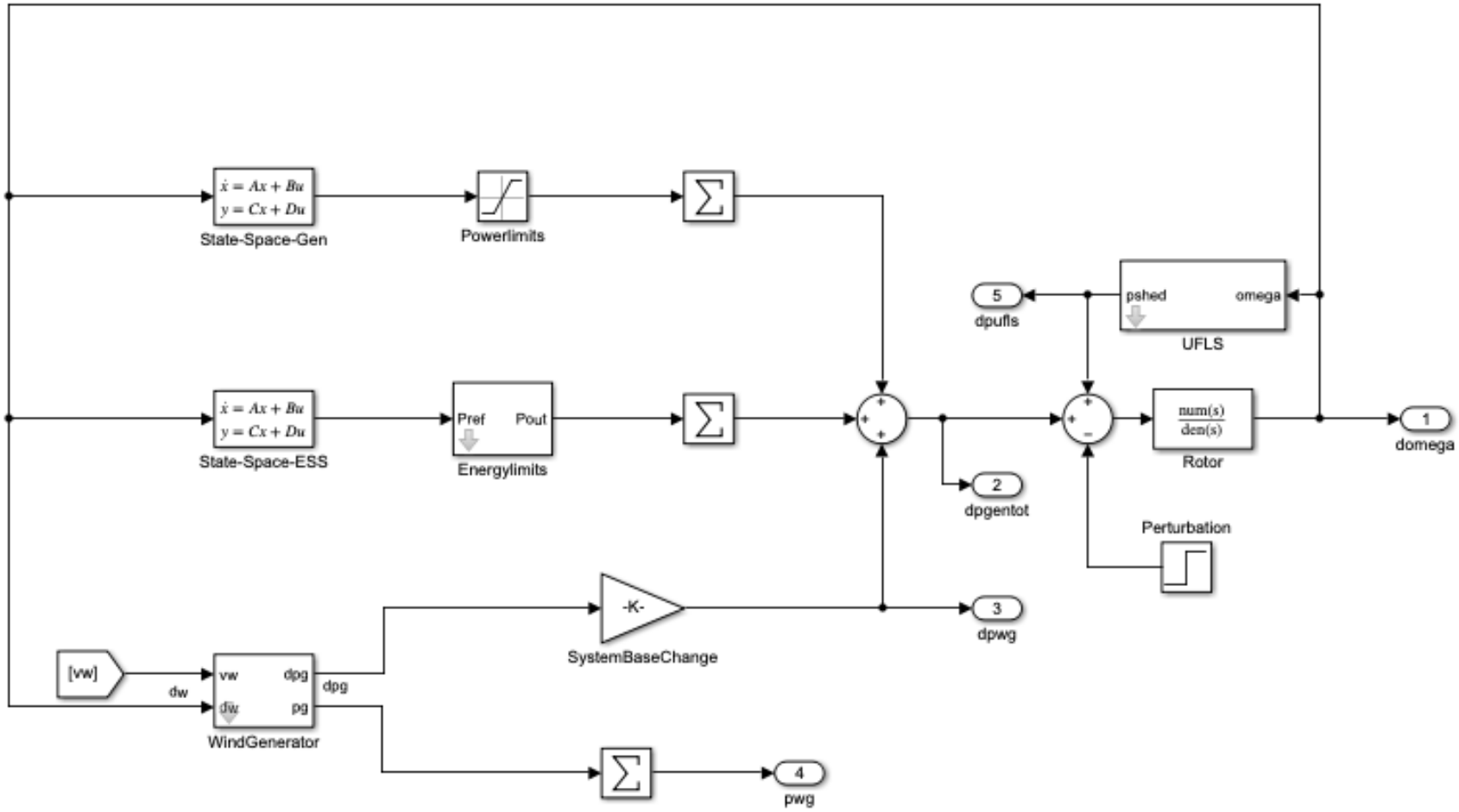

Figure 3.2: Powersystem

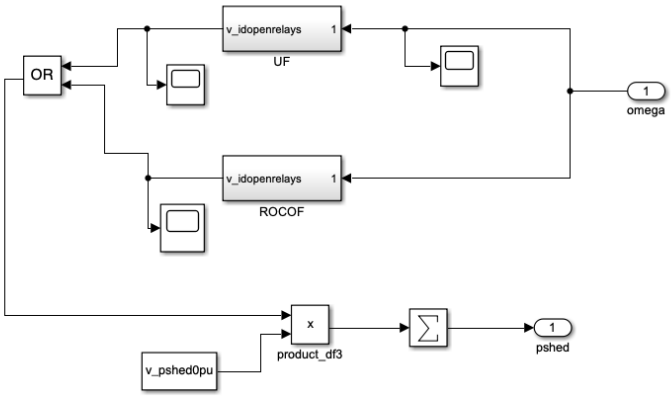

Figure 3.3: UFLS Subsystem

Figure 3.2 shows the MATLAB/Simulink diagram used for the power system in this project. Figure 3.3 shows the UFLS subsystem. This once again has two subsystems, ROCOF and UF. In this case, they are the same, the only difference is what part of the data in A.3 they take into consideration. For this reason, only one is shown in figure 3.4. The wind generator susbsystem will be analysed in further sections.

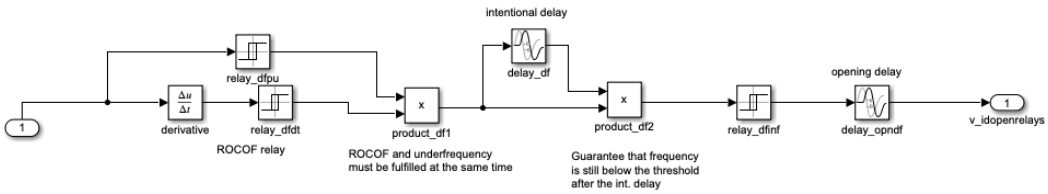

Figure 3.4: ROCOF Subsystem

3.2 Modelling wind generator

3.2.1 Model and control for MPPT and deloaded operation

To model the wind generator, two main equations are used. The first one is equation 2.1. This is used to calculate the mechanical power generated by the

wind generator as a function of set parameters, the wind's speed and the rotor's angular speed. The model uses a lookup table to determine what is being produced with the given parameters.

The other equation used is, as shown in [11]:

$$\frac{d\omega_r}{dt} = \frac{1}{2H}(T_e - T_{mec}) \tag{3.4}$$

where ω_r is the rotor's angular speed, H refers to the wind generator's rotating inertia, T_e is the electrical torque and T_{mec} is the mechanical torque generated. This equation very similar to 1.1, but instead of describing the entire electrical system's frequency and inertia, it describes the relationship between torque imbalances and the rotor's acceleration. As seen in [17], if the variations around the steady state conditions are considered small enough, the change in power is considered the same as the change in torque. This allows as to rewrite equation 3.4 as:

$$\frac{d\omega_r}{dt} = \frac{1}{2H}(T_e - T_{mec}) \approx \frac{1}{2H}(P_e - P_{mec}) \tag{3.5}$$

In this case, the electrical power P_e represents what the system is demanding at that point, whilst the mechanical power P_{mec} represents what is being produced according to equation 2.1. The discrepancy between these two values it what will cause the rotor to speed up or slow down in order to increase or decrease power output respectively. A constant rotor speed will indicate that there is no imbalance, meaning the overall frequency of the system is also constant (in a steady-state). This equation explains why the rotor's speed always has to be above the MPPT. The typical power imbalance (and the one that will be analysed in this project) happens when the system demands more than what is currently being generated because another generator has suddenly been disconnected. This makes the right part of the equation negative, $P_e < P_{mec}$, meaning the rotor's speed will tend to decrease. If the wind generator was working slower than the MPPT, by slowing down the rotor, less P_{mec} would be produced, further increasing the discrepancy between P_e and P_{mec}. In the end, the wind generator would simply slow down until it stopped [9].

As was explained in the previous chapter, in order to contribute to frequency stability, wind generators need to have an additional control that makes them operate in a deloaded mode instead of the MPPT. This provides a margin that can be used to increase power output if necessary.

In this project, the wind generators are working at 15% deloading, meaning they work at 85% of the MPPT. This value was chosen because the typical values for deloading, according to the literature, are between 10% and 20% [18], so the middle point was taken.

3.2.2 Enhance droop-based primary frequency

The main purpose of this project was to improve upon the droop control. As was shown with figure 2.2, even when working in a deloaded mode, some power reserve is still lost. One way to improve this is making the control ask for more power than what is actually needed. This means that, when the amount produced inevitably falls as it follows the deloaded curve, the total end value ends up matching what was actually desired. In order to achieve this, the control needs to approximate exactly how much power is being lost because of the deloaded curve. To do this, the tangent line to the deloaded curve is calculated.

The effect of this is once again best shown through the use of a simplified graph, as shown in figure 3.5.

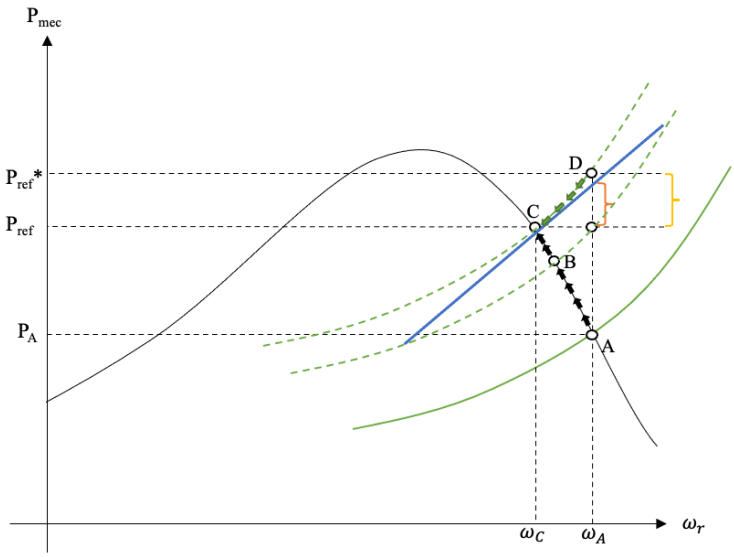

Figure 3.5: Power system output with droop control and tangent calculation

Previously, after the frequency incident, the wind generator was asked to produce P_{ref} yet, due to the interactions between the droop control and the rotor speed the wind generator settled on point B, producing P_B. Now, as shown in the figure, $P_{ref}*$ is asked, so the final operating point is C, producing P_{ref}, the desired amount. The wind generator is now working at ω_C, slower than with the previous model, where the final angular velocity was ω_B. In order to determine how much more power needs to be demanded (i.e. the difference between $P_{ref}*$ and P_{ref}) the tangent of the deloaded curve is calculated.

On the graph only one tangent line is shown to keep the diagram simple, however in practice the tangent is taken at every point on the way from A to C, following the black arrows seen on the figure. The difference from the current

rotor speed and ω_A is calculated, multiplied by the slope of the tangent and added to the previous control. In the end (what is being represented), the difference between ω_C and ω_A is multiplied by the slope of the tangent on point C, and this is what is being added on top of the droop control. This is represented by the red braces in figure 3.5. It can be observed that it is slightly different than what would be ideal (represented by the yellow braces). Although the tangent line is a good approximation, it is not perfect. Nonetheless, the differences in the rotor's speed ($\omega_C - \omega_A$) are actually quite small, making the approximation accurate. On top of that, as mentioned previously, the tangent is taken and used in the calculation at every point from A to C, not just at point A. Because the curve's slope continuously changes, this makes the calculation once again even closer to the actual value.

Overall this method should approximate the difference between $P_{ref}*$ and P_{ref} sufficiently well.

In case of reaching the MPPT the wind generator would behave the same as what is shown in the figure 2.3, it saturates. It is important to note however, that since for every case, more power is being demanded, it is more likely that all the reserve is used up and the wind generator reaches its maximum.

Similarly to the curve describing the mechanical power generated, the deloaded curve is not a continuous function but rather a lookup table. It is shown in annex A.4. For this reason, it is not possible to take the derivative of the function. Instead, it is approximated using:

$$f'(a) = \frac{f(a+h) - f(a-h)}{2h} \tag{3.6}$$

This results in a calculation for the tangent on any given point i as:

$$m_i = \frac{y_{i+1} - y_{i-1}}{x_{i+1} - x_{i-1}} \tag{3.7}$$

where m_i represents the slope. The intersection with the y-axis is calculated using:

$$b_i = y_i - m * x_i \tag{3.8}$$

. The results of these calculations are shown in annex C.1.

3.2.3 Complete Simulink model

The complete Simulink model is shown in figure 3.6:

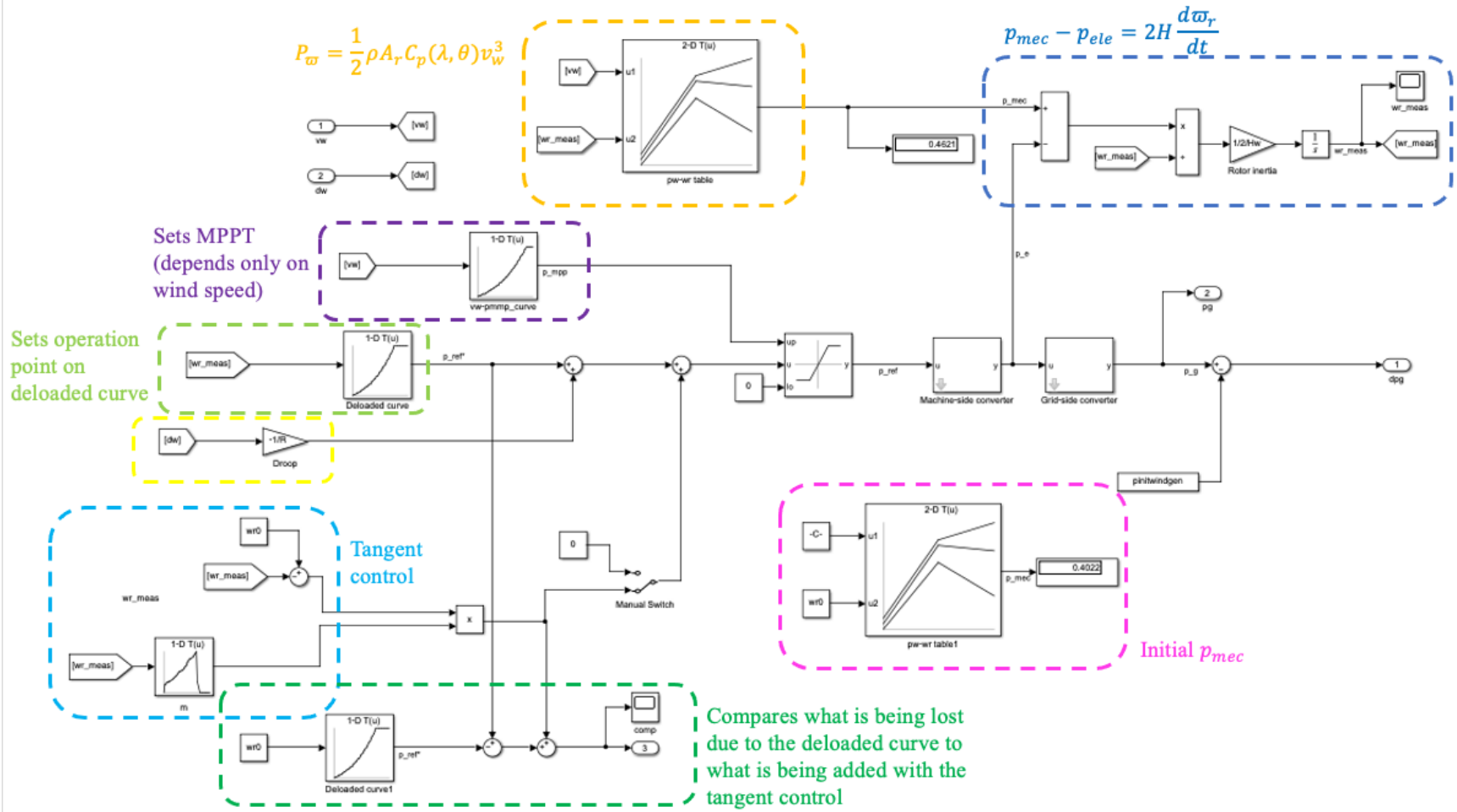

Figure 3.6: Wind generator Simulink model

The two dimensional lookup tables (*pw-wr-table*) represent the curve that would be achieved with equation 2.1, the black curve shown in figures 2.2 and 3.5. The one dimensional lookup table *vw-pmmp-curve* shows the data for the MPPT, the red curve in figures 1.2 and 2.3. The; *deloaded curve* and m table show have the data used for determining the green solid and dotted lines seen in figures 2.2, 2.3 and 3.5; and the slope at each point of these curves respectively.

As can be seen in the dotted dark green box in figure 3.6, an additional verification is carried out to ensure the approximation is accurate enough. The amount the deloaded curve decreases (measured as the power generated at w_{rmeas} minus the power generated at the original rotor speed w_{r0}) is compared to what is calculated by the tangent ($m_C * (wr_{meas} - wr0)$). It is important to note that the first subtraction doesn't correspond to the difference between P_{ref} and P_A but rather to the difference between $P_{ref}*$ and P_{ref} as the block encircled in the light green dotted lines only has data about the deloaded curve and not the wind curve (black curve on figure 3.5. Therefore, this comparison is equivalent to the difference between the red and yellow braces in figure 3.5.

Ideally, this value should be close to 0, as it would mean that whatever power being lost because of the deloaded curve, it is then being added back.

3.3 Methodology

The model evaluates the system's response to the disconnection of a generator under different conditions. Once the parameters that determine a particular scenario have been decided, the model assigns the corresponding values and simulates the situation using the Simulink systems shown previously. The values are then stored in different multidimensional arrays in Matlab that allow the analysis and visualisation of the final frequency, minimum frequency, power generated (total and by the wind generators), change in power (total and wind) and the demand shedded in the time domain to be conducted. This flow chart carried out by the Matlab script is shown in figure 3.7. The Matlab script used can be found in appendix B.1.

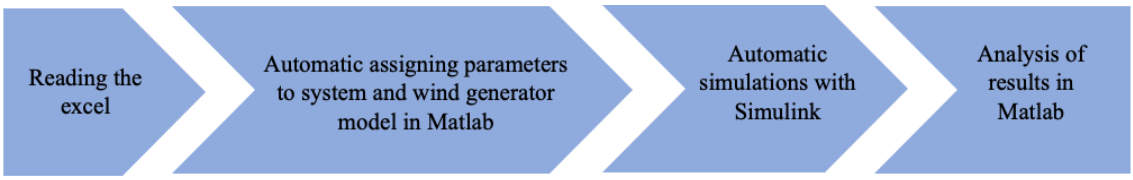

Figure 3.7: Flow chart of the Matlab script

Chapter 4

Results

In this chapter, the results of the time domain simulations are analysed. The minimum and final frequency, the power shedded will be examined and the change in wind generation.

Each scenario will feature different amounts of power being lost and different amounts of wind generation. For each case, the simulations will be conducted without any droop control, with the original and the improved control. By examining these three configurations, the impact of the droop control and its improvement can be assessed under both small and large frequency events as well as under different levels of wind generation.

Following this, simulations will be performed under changing wind speed conditions. This analysis provides crucial information about the system's response and how wind generators can provide frequency stability.

4.1 Description of the test system

4.1.1 Data

The data used for this project corresponds to the island of La Palma in the Canary Islands, Spain. The data can be divided into three sections:

- **Generation scenarios:** this data specifies the generation for every hour (1-24) of each of the 11 conventional generators. The wind generator's power output is also considered, they are lumped into one equivalent generator. Generators are numbered 11 to 22 (the last one being the wind generators).
- **Generator specifications:** this includes properties such as the inertia, the

nominal and maximum values of each generators, the zeros and poles of their second order equivalent and the radius of the blades (this is simply meant to differentiate generator 22 as it corresponds to the wind generators, eliminating of any future doubt)

- **UFLS specifications:** this includes what substations (and the percentage of the demand they represent) are disconnected depending on the low frequency arrived at, and for how long.

All of this is gathered in the tables A.1, A.2 and A.3 respectively.

In the Excel, there is also a prepared sheet for an additional section of data: **Energy Storage System (ESS) specifications:** this section is meant to have the data (such as nominal and maximal power, the poles and zeros of its two-order system equivalent) corresponding to the batteries and other storage available in the island. In this project, this sheet is left blank. However, as will be seen in further section there is still a Simulink block set into the block diagram so it can be easily utilised in the future.

The nominal value of the wind generators in this project is set to 12,5MW. The initial value Currently, the island's wind generators have a 7MW power capacity [19] [20], however, this is bound to increase rapidly in the next years. Electrical company 'Ecoener' has announced the construction of two new power plants that will increase wind generation capacity by 16,5MW [21]. On top of that, the European Union recently chose this island to make it carbon neutral and rely exclusively on renewable energy sources by 2030 [22]. For this reason, it was decided that more importance should be given to wind generation. As mentioned in other chapters, it is important to see how renewable energy can reliably provide primary frequency control, and the higher the wind penetration into the system, the easier it is to observe just how much improving the current droop control can help. However, it was decided not to go above at 12,5MW in order to keep the available data useful, and to still be able to draw meaningful conclusions about this particular island system.

In other words, the value of 12,5MW was chosen because it seemed like the maximum increase that would showcase wind generation's present and future importance whilst maintaining the original conventional generator's importance without altering their current generations schemes. Inevitably, this means in the model there is more electricity being generated than what is currently seen on the island.

The frequency incident in the model will happen after two seconds, and it will run for 30 seconds. At this point the system will have already reached a steady state and the final values can therefore be analysed.

4.1.2 Specifications

In this project, frequency stability will be studied for different scenarios, changing several parameters. This is done to properly analyse how wind generators can provide frequency stability, even in unfavourable weather conditions. For this reason, the parameters which are being analysed are:

- **Time of day:** When this is being studied, the same generator (with the same wind for every simulation) is being disconnected at different times of the day.
- **Generator lost:** This analyses the impact of disconnecting a particular generator at any given time of day (once again considering the same wind)
- **Wind speed change:** With this parameter, the impact of losing some wind around the time of the incident is studied. This truly puts wind generation to the test. Not only do they need to provide reserve, but they need to do so in a moment where their capacity to produce has been reduced. Five total cases are studied, corresponding to a 0m/s; 0.5m/s; 1m/s; 2m/s and 4m/s speed change. These values are chose because the island's average wind speed is around 25 km/h (6,9m/s) with averages in times of extreme winds of 30-50m/s (8,3-13,8 m/s) [23]. This means that a sudden drop of 4m/s would represent a change of well over 50% most of the time. Although modelling higher wind changes would not be difficult, it would no longer describe a realistic situation. On top of that, the effects of the droop control would no longer be significant as overall wind generation is reduced that significantly.
- **Time of wind speed change:** This parameter analyses the difference in response when the wind changes two seconds before, during, or two seconds after the generator being lost. It provides valuable information as the system doesn't react in the same way in every case. For example, if the wind changes at the same time, it can essentially be considered one bigger frequency incident and there will clearly be a higher ROCOF. If the wind changes before the incident, from the beginning there is less reserve in the system overall so it is more likely that more UFLS will be used, meaning there could be differences in the steady-state end point and not just the transitory.

The first two parameters are set in place to analyse what would be the most damaging situation for the system (without considering the weather). As can be seen in the data (A.1), the biggest impacts will be seen when either generator 17 or 21 is disconnected, as they produce the most. If generator 17 is lost between 1a.m. and 10a.m. over 26% of the total production is lost. In particular, at 8a.m., 32% would be lost. This will clearly have a bigger impact than if, for

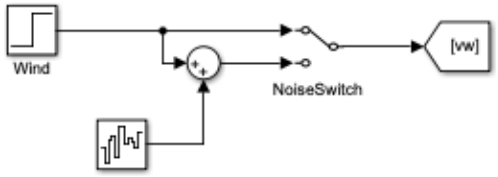

Figure 4.1: Modelling wind

example, generator 15 is disconnected at 12p.m., as it only accounts for 8,6% of total generation. Nonetheless, it is important to look holistically at all possible outcomes, as this can shed light how and when UFLS are activated, how much or how fast wind generators can provide reserve etc. It is also important to note that for many hours of the day some conventional generators are shut off (in fact, generator 16 and 19 never produce power) so disconnecting these obviously won't have an impact on the frequency.

The last two parameters provide a sensibility analysis where, as mentioned, wind generator's capacity to provide frequency regulation is put to the test. They are important to analyse because, unlike with conventional generators, the amount a wind generator can produce is highly dependant on exterior, uncontrollable factors like the weather. Therefore, not taking this into account misrepresents the uncertainty associated with replacing fossil fueled based methods of obtaining energy with wind and solar. In order to work towards a higher penetration of renewable sources it is important to account for the wind speed's ability to change rapidly and analyse stability accordingly.

The base model considers a wind speed of 9,48m/s. The change in speed imposed by the model is done through a step block as shown in figure 4.1. As can be seen, there is the possibility to include noise in the wind, making the simulations more realistic. However, this is not considered in this project as the focus is more on the final frequency and UFLS that are activated.

4.2 Validation of the tangential approximation

Before analysing the impact of improving the droop control, its accuracy will be tested. As mentioned in the previous chapter, the tangent is calculated to compensate for the decrease in power generated due to the deloaded curve (represented with the green arrows in figure 2.2).

In the case when generator 11 is lost at 1a.m., the fall in power with the original droop control due to the deloaded curve is 0,0312pu. This corresponds to the difference between P_{REF} and P_B in figure 2.2. This is shown in the figure 4.2.

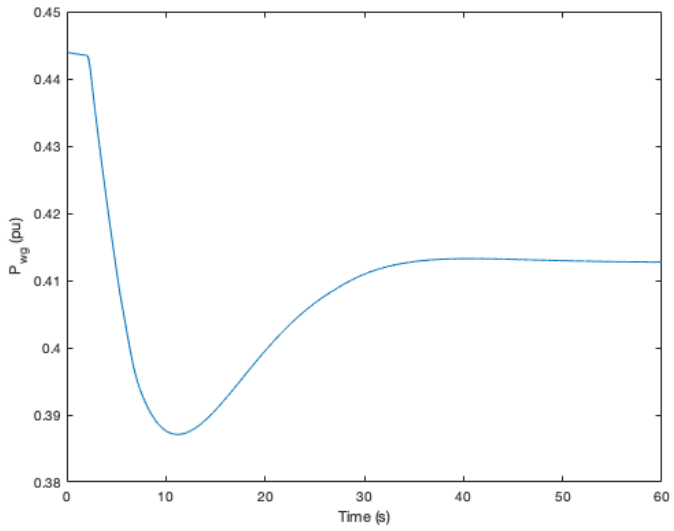

Figure 4.2: Drop in power generated due to the deloaded curve with the original droop control

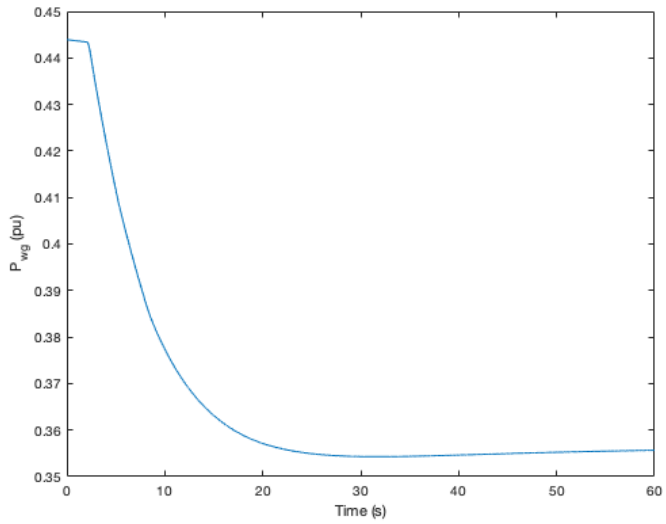

Figure 4.3: Drop in power generated due to the deloaded curve with the improved droop control

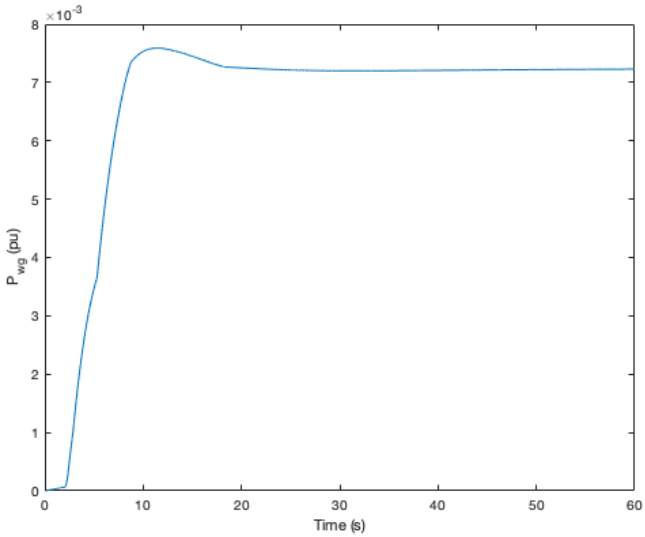

Figure 4.4: Difference between the drop due to the deloaded curve and what is added due to the tangent calculation

On the other hand, when the control is improved, the decrease in power (green arrows in figure 3.5) is 0,0883pu. The decrease is seen in figure 4.3, which shows the deloaded curve the control follows as the power generated reaches its new value after the incident over times. It shows the curve from point D to point C in figure 2.2, the yellow braces in figure 3.5. Because of the tangent calculation, the control asks for an additional 0,0955pu (red braces in figure 3.5). The difference between what the drop due to the deloaded curve and the amount calculated with the tangent is seen in figure 4.4.

Overall, this means that before, the difference between the power desired and the power obtained (between point C and B in figure 2.2) was -0,0312pu whether as now, the difference (the gap between the yellow and red braces in figure 3.5) is $0,0955 - 0,0883 = 0,0072$pu. In the end, the control manages to stay 77% closer to the desired power output (P_{ref}).

4.3 Base case

For this section, the impact of the droop control's improvement with the tangent calculation will be analysed. To do this, several scenarios will be simulated. Firstly, the impact of losing every generator individually at a given hour (1a.m.) will be determined. Secondly, the impact of losing the same generator (17) at different

times will be studied. This generator is chosen because it always has the highest proportion of overall generation (sometimes tied with generator 21).

In both of these cases, the results with no droop control, with the original droop control, and with the improved droop control will be analysed and compared.

4.3.1 Wind generator lost

In this subsection, the impact of disconnecting any particular generator at 1a.m. will be analysed. It is evident that the higher the power generated by the lost generator, the greater the impact to the system. This is clearly seen in figure 4.5 where the highest UFLS is activated when generator 17 is lost. It is interesting to note that because of this, it doesn't actually have the lowest final frequency.

Figures 4.6 and 4.7 show the same situations but when the droop control is implemented without the improvement and when there is no droop control at all, respectively.

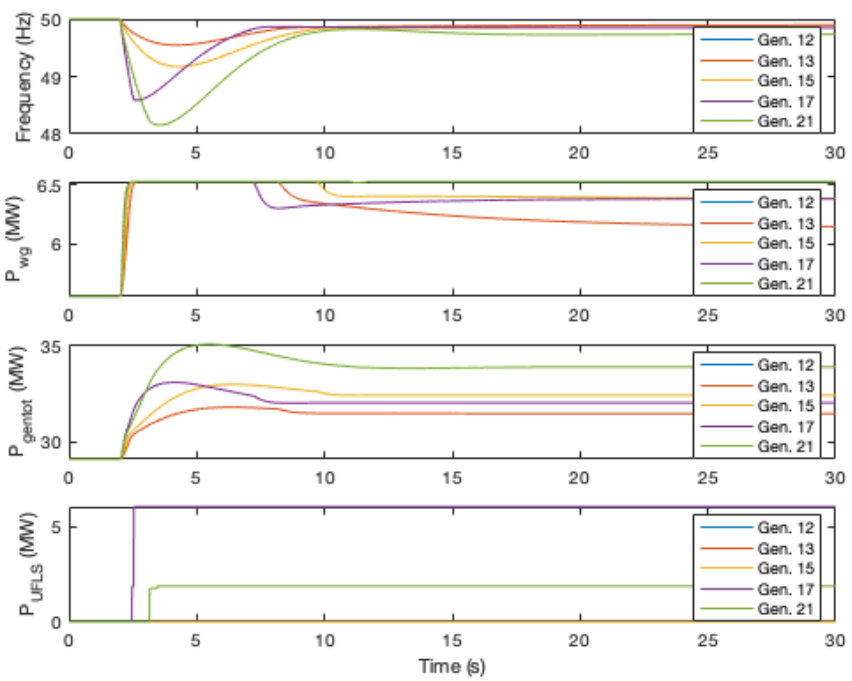

Figure 4.5: Loss of every generator individually at 1a.m. with droop control improvement

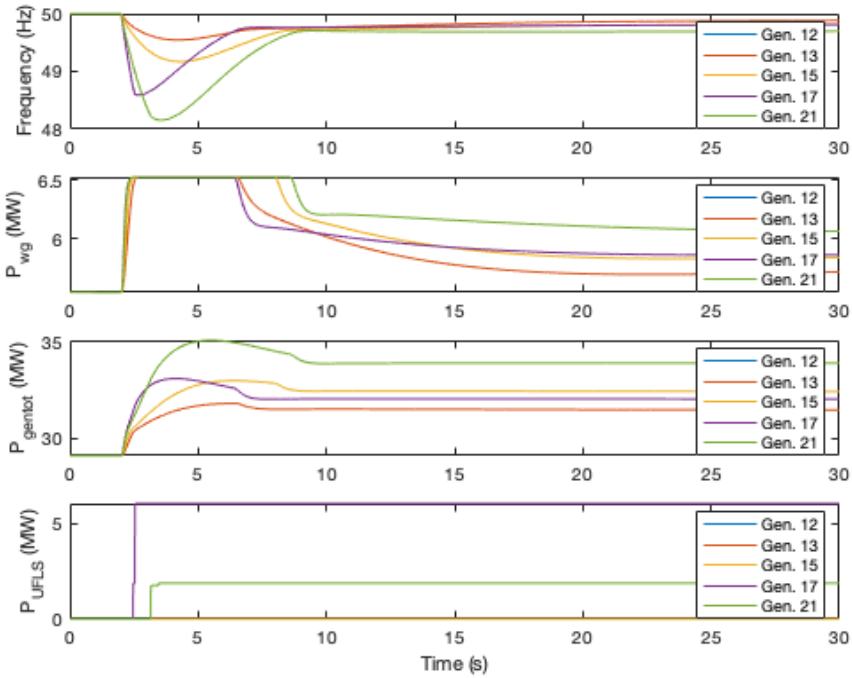

Figure 4.6: Loss of every generator individually at 1a.m. with original droop control

It is interesting to see that in figure 4.7, even though there is no control applied to the wind generators, there is a slight decrease in the power they produce. This is due to the lookup tables- if the initial conditions don't match up perfectly to one of the data points, the system moves it ever so slightly in order to get to one. The difference in these values is therefore very small: the final wind power generated is $5,53635MW$ where as the initial is $5,54909MW$, there is a difference of only $0,01274MW$. In contrast, there is a difference of $6,5285 - 5,5492 = 0,9793MW$ when generator 21 is lost with the improved droop control. The change in power produced by the wind generators is shown in table 4.4.

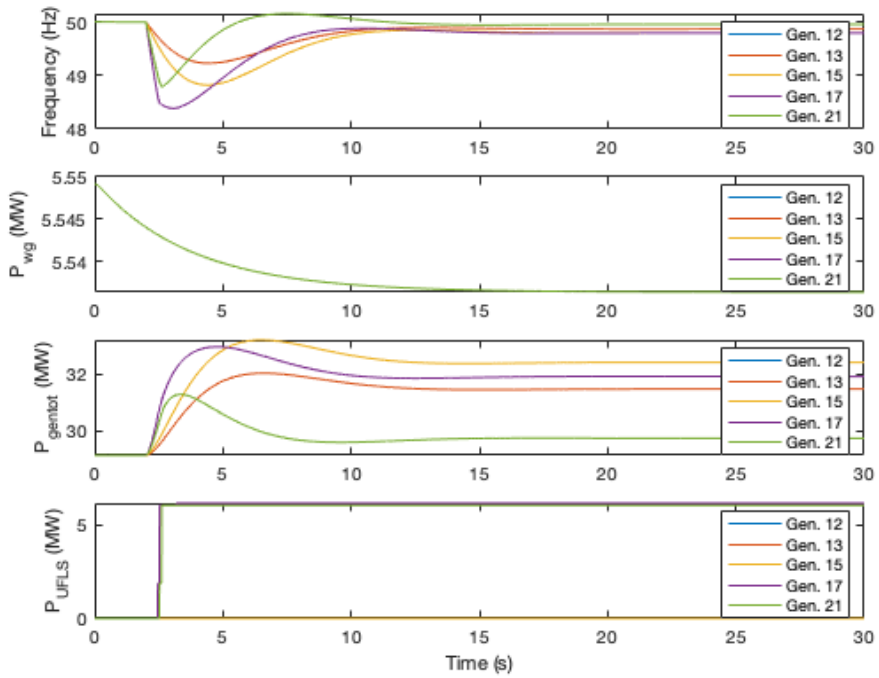

Figure 4.7: Loss of every generator individually at 1a.m. with no droop control

The results of all these scenarios are shown in tables 4.1, 4.2, 4.3 and 4.4. These display the system's final frequency f_{fin} (Hz), the minimum frequency f_{min} (Hz), the power shedded d_{UFLS} (MW) and the change in wind generation respectively.

	New droop control	Original droop control	No droop control
GEN. 12	49,8989	49,8830	49,8683
GEN. 13	49,8989	49,8830	49,8683
GEN. 15	49,8477	49,8179	49,7966
GEN. 17	49,8488	49,8115	49,7959
GEN. 21	49,7346	49,6982	49,9570

Table 4.1: f_{fin} (Hz) for all scenarios at 1a.m.

	New droop control	Original droop control	No droop control
GEN. 12	49,55	49,55	49,23
GEN. 13	49,55	49,55	49,23
GEN. 15	49,17	49,17	48,82
GEN. 17	48,59	48,59	48,39
GEN. 21	48,16	48,16	48,78

Table 4.2: f_{min} (Hz) for all scenarios at 1a.m.

	New droop control	Original droop control	No droop control
GEN. 12	0	0	0
GEN. 13	0	0	0
GEN. 15	0	0	0
GEN. 17	6,028	6,028	6,145
GEN. 21	1,864	1,864	6,028

Table 4.3: d_{UFLS} (MW) for all scenarios at 1a.m.

	New droop control	Original droop control
GEN. 12	0,5956	0,172
GEN. 13	0,5956	0,172
GEN. 15	0,8368	0,2945
GEN. 17	0,832	0,3168
GEN. 21	0,9793	0,5185

Table 4.4: Change in wind power generation (MW) for all scenarios at 1a.m.

The demand is shedded according to the UFLS data found in annex A.3. 1,864MW corresponds to the first two lines of the table, which specifies that 6% and then 0,4% of the total load of 29MW should be disconnected if the frequency reaches 48,81Hz for 0,3 and then 0,6 seconds. Similarly, 6,028MW corresponds to the first four lines of the table.

Table 4.3 shows that, for generators 12, 13, 15 and 17, the UFLS is nearly identical regardless of whether there is a droop control (original or new) or not. This allows us to compare the values in a more meaningful way, but it also shows that the droop control doesn't result in a huge difference.

From table 4.1 it can be seen that there is not a significant disparity between each scenario. Focusing on generator 17, the difference in the final frequency with the new droop control and when there is no control is only $49,8488 - 49,7959 =$

$0,0529Hz$. The limited impact of the enhanced control in this scenario can be attributed to the minimal influence of the control setting. The droop setting may be so small (with a correspondingly high gain) that the power reduction doesn't significantly affect rotor speed. This highlights the need to consider droop setting adjustments when evaluating control effectiveness.

Nonetheless, over 70% of this difference is due to the improvement in the droop control, as it accounts for an increase in $0,0373Hz$. From this it can be inferred that although the droop control in this particular scenario is not particularly impactful, implementing this improvement does change it in a meaningful way.

Table 4.2 shows that there is no difference in the minimum frequency whether the droop control is improved or not. It can be seen that in figures 4.5 and 4.6 the first few seconds of the P_{WG} graph are the same, the wind generators quickly saturate. It is not until around second 7 where wind generation goes back down, and when the differences between the improved and original droop control start being see. By this point, the minimum frequency has already been reached, explaining why there is no difference between the two scenarios.

Finally, table 4.4 shows the difference between how much wind power is produced with the new and the original droop control. The results when there is no control are not showed, as the very small difference is due to a numerical error. This is where the impact of the enhanced droop control with respect to normal droop control is most evident. In many cases, the wind generators contribute to the system's primary reserve more than doubles. Given the initial wind generation of 5,55MW, an increase of 0,832MW (and an improvement of 0,5MW with respect to the original droop control) is fairly substantial. The overall impact on the system's frequency is small, however, the difference here is quite significant. This enhanced contribution is crucial during periods of high demand or unexpected generator outages, providing greater stability and reliability to the power grid.

4.3.2 Time of day

In this subsection, the effect of loosing generator 17 at every hour of the day will be analysed. The biggest impact will be seen when this generator represented a bigger proportion of the total generation. The tables and figures shown here only have the first five hours of the day to keep them easy to interpret. The complete tables can be found in C.2, C.3, C.4 and C.5.

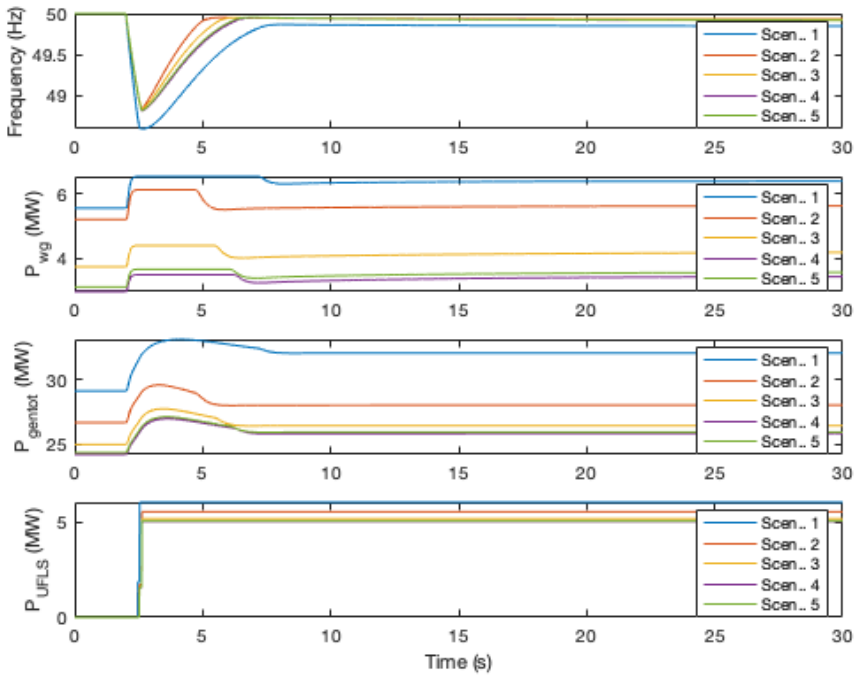

Figure 4.8: First five hours of the day when generator 17 is disconnected, with new droop control

From all three figures, it can be seen that, because it is the same generator being disconnected (with the same inertia being lost), there is generally the same shape every time, simply translated upwards or downwards depending on the proportion of the total generation it represented. Because at 1a.m. the generator produces the most power proportionally, the lowest minimum and final frequency are seen, as well as the highest demand disconnected. From this, the response of systems with different wind generator's penetration can be seen. This is important, since many countries are planning to invest more into wind energy in the near future [24]

In this case, there is also the same minimum frequency whether the droop control has been improved upon or not. Once again, this is due to the wind generators reaching the MPPT before the frequency reaches its minimum. The amount produced by the wind generators corresponds mostly to how much they were producing at the moment of the incident, not the severity of the event. The amount it increases by does depend on other criteria. This can be seen in table 4.8, where the biggest increase in wind generation by far is seen when generator 17 is lost at 1a.m., when it represented 30% of total generation. In this moment, wind generation accounted for 11,3% of the total ,less than when this generator is lost

at 4a.m. (14,6%). Once again, the difference in wind power with the original and new droop control is very significant, showing the tangent calculation considerably improved it.

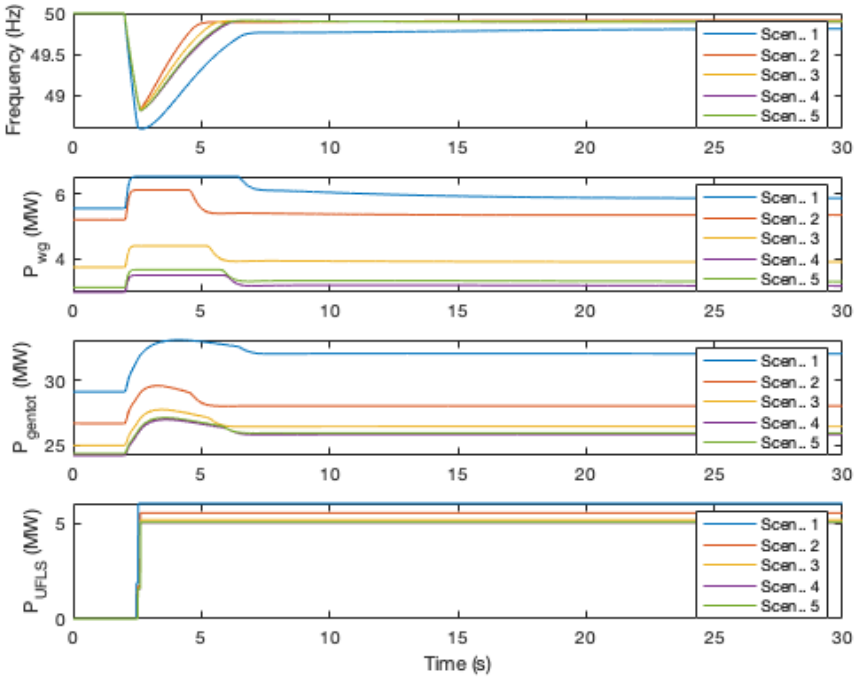

Figure 4.9: First five hours of the day when generator 17 is disconnected, with the original droop control

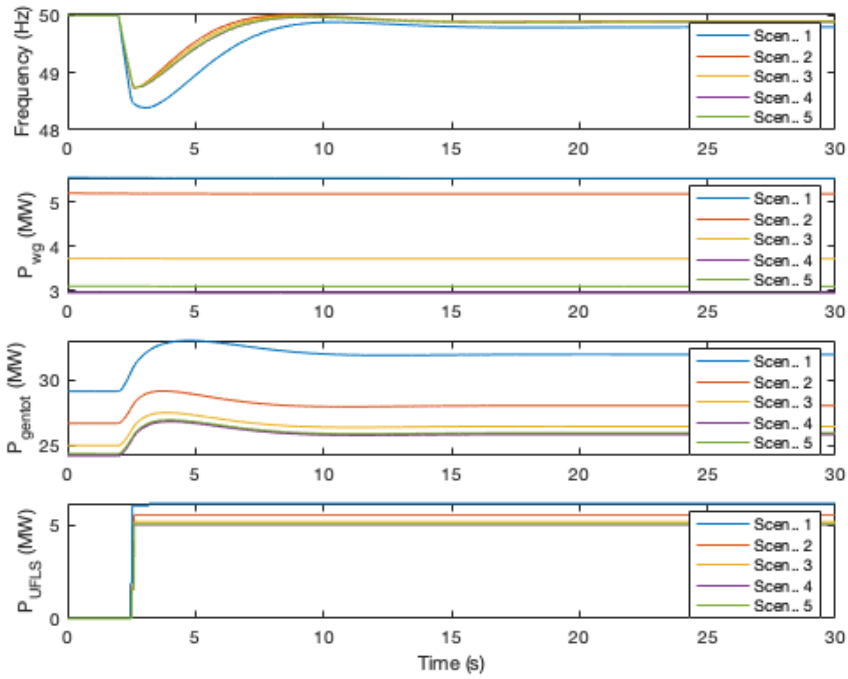

Figure 4.10: First five hours of the day when generator 17 is disconnected, with no droop control

	New droop control	Original droop control	No droop control
1	49,8488	49,8115	49,7959
2	49,9343	49,9144	49,902
3	49,9306	49,9056	49,8936
4	49,9175	49,8946	49,8822
5	49,9196	49,8966	49,8845

Table 4.5: f_{fin} (Hz) for all scenarios when generator 17 is disconnected between 1a.m. and 5a.m.

	New droop control	Original droop control	No droop control
1	48,59	48,59	48,39
2	48,83	48,83	48,73
3	48,82	48,82	48,74
4	48,81	48,81	48,74
5	48,81	48,81	48,74

Table 4.6: f_{min} (Hz) for all scenarios when generator 17 is disconnected between 1a.m. and 5a.m.

	New droop control	Original droop control	No droop control
1	6,028	6,028	6,145
2	5,524	5,524	5,524
3	5,173	5,173	5,173
4	5,015	5,015	5,015
5	5,044	5,044	5,044

Table 4.7: d_{UFLS} (MW) for all scenarios when generator 17 is disconnected between 1a.m. and 5a.m.

	New droop control	Original droop control
1	0,832	0,3168
2	0,4162	0,1443
3	0,4466	0,1611
4	0,4573	0,1871
5	0,4512	0,1812

Table 4.8: Change in wind power (MW) for all scenarios when generator 17 is disconnected between 1a.m. and 5a.m.

4.3.3 Comparison

To study more closely how the droop control affects the system's response, this section will closely compare the scenario where generator 17 is disconnected at 1a.m. The data can be seen in the first line of the tables in the previous section.

This figure shows exactly where the improvement to the droop control proves to be useful. The second subplot shows what was seen tables 4.4 and 4.8. There is a considerable difference between the final power produced by the wind generators when the droop control is improved upon versus when it isn't. Focusing on

the two scenarios with a droop control, with the original control the wind generators produce $0,33MW$ more between the beginning and end point. With the improvement, there is an increase of $0,85MW$, $0,52MW$ more than before. This represents over a 150% relative increase.

Nonetheless, the third subplot shows that the conventional generators left are able to compensate this without lowering the frequency too much, there is only a difference of $0,033Hz$ between both scenarios. In a system where the conventional generators have lower inertia (or they have been replaced with other power sources that don't have rotating inertia such as solar panels) this difference would be greater. Overall, although in this particular island the droop control's improvement didn't have a huge impact on the final frequency, it is still shown that it has the potential to increase frequency stability for other systems with very high wind energy penetration by significantly affecting how much they produce after a frequency incident.

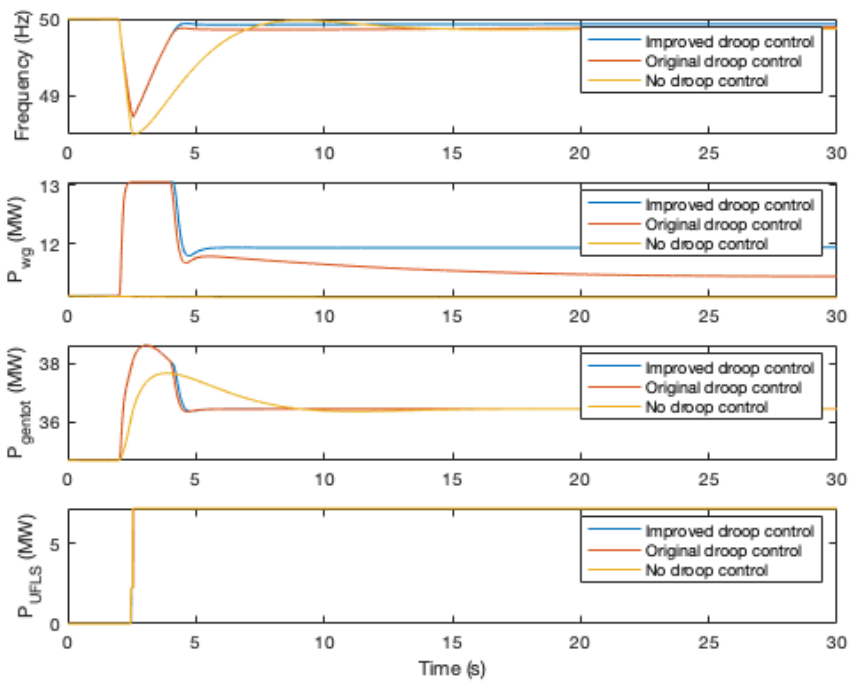

Figure 4.11: Effect of losing generator 17 at 1a.m. with no droop control and the original and new droop control

The same figure (4.12is shown for generator 21. In this case, as there is a big change in the UFLS activated when there is no control, the final frequency is

highest in this case.

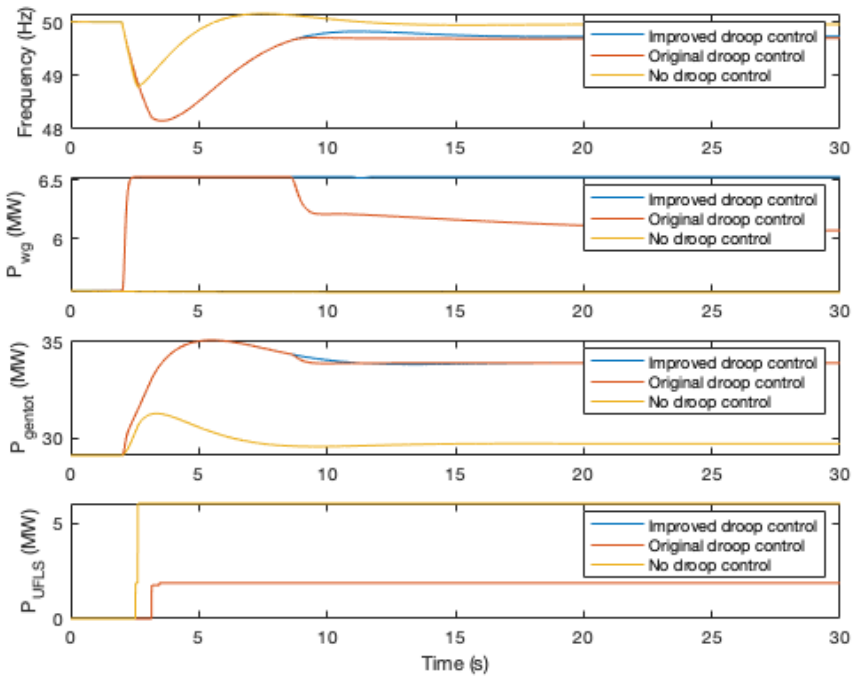

Figure 4.12: Effect of losing generator 21 at 1a.m. with no droop control and the original and new droop control

4.4 Sensitivity analysis

As mentioned before, wind generator's ability to produce power is highly dependant on the weather, so in the context of frequency stability it is important to analyse how it reacts when the wind's speed changes suddenly. A decrease in the wind reflects on the system as part of the wind generator being disconnected. They no longer produce what is needed to keep equation 1.1 at 0. The effect of the wind's speed reducing at the same time as a generator is being disconnected is shown with figure 4.13:

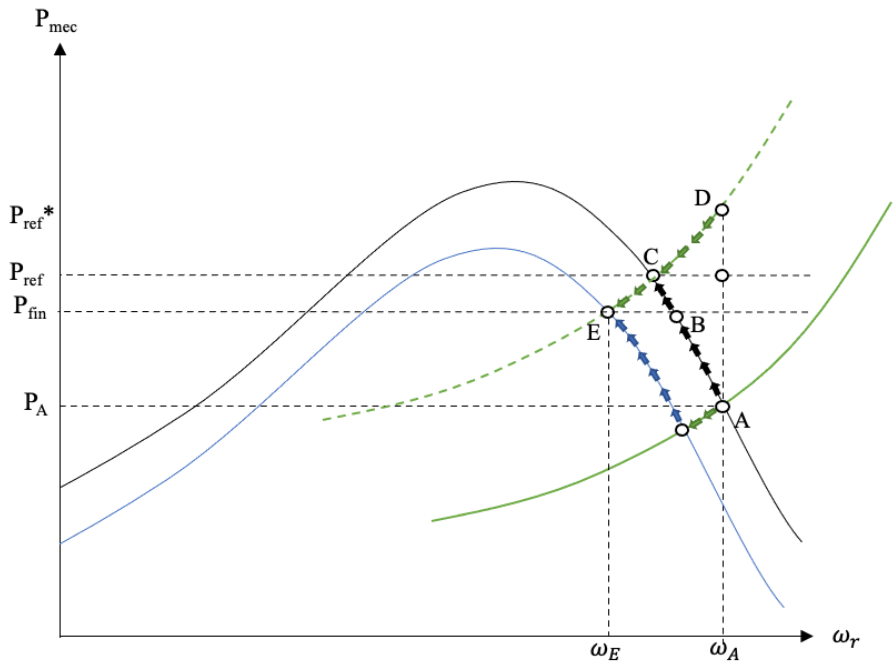

Figure 4.13: Power system with improved droop control and wind speed change

The control in this figure acts the same as in figure 3.5, however, due to the wind change, the generator no longer works along the black curve but rather along the blue curve. In this curve, for any given rotor speed, there is less power produced. Because of this, instead of ending up at point C producing the desired P_{ref}, the system ends up operating at point E, with an output of P_{fin}. The wind generator is also working at a slower pace $\omega_E < \omega_C$ and overall closer to the MPPT. This means it would take a smaller increase in power demanded to make the wind generator saturate. Evaluating the impact of this is crucial in understanding just how much wind generators can be relied upon for frequency stability.

In this section, only final and minimum frequency, and demand shedded will be analysed as the main objective is to analyse the impact of wind variations on primary frequency control. On top of that, when there is a significant change in the wind, the power produced will depend more on this than on the control.

4.4.1 Size of wind variation

Example

In this section, the impact of changing the wind's speed at same time as generator 17 is disconnected will be analysed.

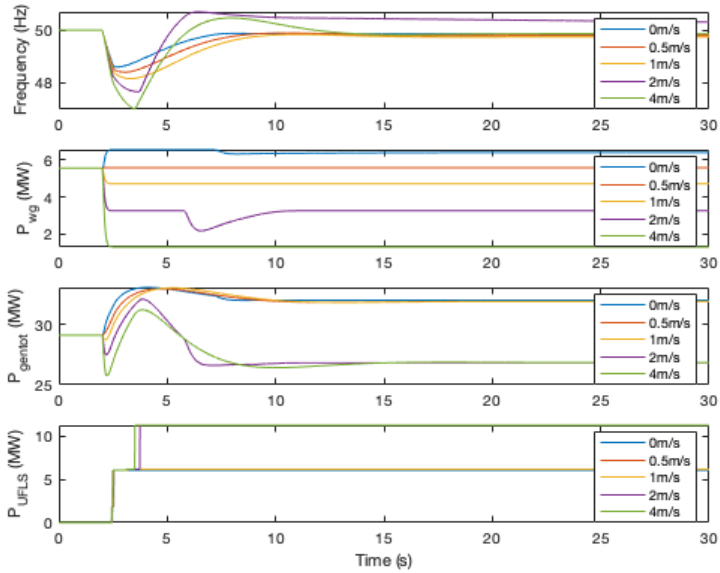

Figure 4.14: Effect of wind speed change at the same time as generator 17 disconnection with improved droop control

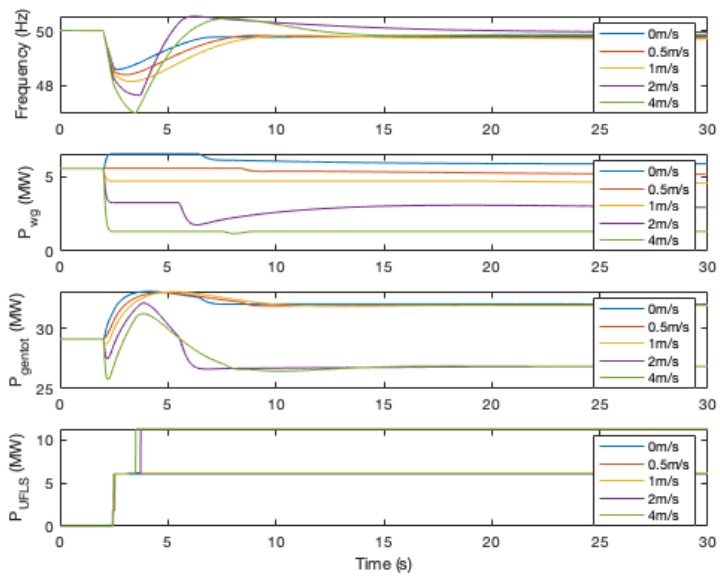

Figure 4.15: Effect of wind speed change at the same time as generator 17 disconnection with original droop control

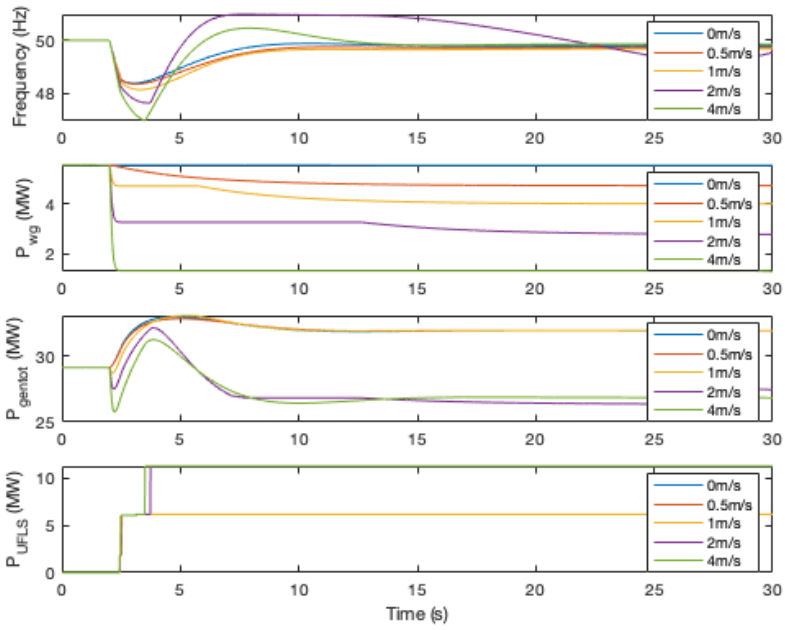

Figure 4.16: Effect of wind speed change at the same time as generator 17 disconnection with no droop control

	New droop control	Original droop control	No droop control
0m/s	49,8488	49,8115	49,7959
0,5m/s	49,7981	49,7581	49,7362
1m/s	49,7355	49,7059	49,682
2m/s	50,3019	49,9512	49,5415
4m/s	49,8574	49,8575	49,8543

Table 4.9: f_{fin} (Hz)for different wind speed changes

	New droop control	Original droop control	No droop control
0m/s	48,59	48,59	48,39
0,5m/s	48,39	48,39	48,35
1m/s	48,14	48,14	48,14
2m/s	47,65	47,65	47,65
4m/s	46,98	46,98	46,98

Table 4.10: f_{min} (Hz) for different wind speed changes

	New droop control	Original droop control	No droop control
0m/s	6,028	6,028	6,145
0,5m/s	6,145	6,145	6,145
1m/s	6,145	6,145	6,145
2m/s	11,2	11,21	11,21
4m/s	11,21	11,21	11,21

Table 4.11: d_{UFLS} (MW) for different wind speed changes

As is expected, the higher the wind speed change, the greater the impact on the system. Having a change of $2m/s$ or greater causes the system to disconnect even more load than the 6MW that had been seen previously. This shows that for the first three cases, the frequency event has the most impact on the system, but int the last two the wind has changed so much it starts to have very noticeable effects.

Simulation of all scenarios

This sections briefly summarises the combined effects of the parameter explored previously. In order to get a more complete look at the impact of it has, the sum of the deviations of the final and minimum frequency, and the UFLS for every case (loosing every generator individually at every hour, with the wind speed change at every moment) is created. This allows to take into account only one specific parameter, the change in the wind's speed.

	New droop control	Original droop control	No droop control
0m/s	267,6	267,6	299,3
0,5m/s	300,3	300,2	310,8
1m/s	336,3	336,3	226,2
2m/s	392,9	392,9	290,7
4m/s	481,4	481,1	478,2

Table 4.12: Sum of f_{min} (Hz) for all simulations depending on wind speed change for new, original and no droop control

	New droop control	Original droop control	No droop control
0m/s	38,2	43,0	44,1
0,5m/s	45,5	50,3	52,3
1m/s	51,6	54,6	59,0
2m/s	62,4	61,7	67,4
4m/s	70,5	73,0	73,2

Table 4.13: Sum of f_{fin} (Hz) for all simulations depending on wind speed change for new, original and no droop control

	New droop control	Original droop control	No droop control
0m/s	375,4	375,4	410,7
0,5m/s	409,8	409,8	432,5
1m/s	473,0	473,0	467,5
2m/s	584,5	584,5	585,9
4m/s	804,6	804,6	804,7

Table 4.14: Sum of d_{UFLS} (MW) for all simulations depending on wind speed change for new, original and no droop control

Similarly to what was seen in the previous example, the deviations of the final frequency are lower (meaning the frequency is higher) for the cases with the new droop control. The deviations in the minimum frequency and the UFLS activated are the same. The tables show once again the crucial influence of the weather on wind generator's ability to produce power, highlighting the instability of a system with a high wind penetration. Table 4.14 shows that when the wind changes by $4m/s$, there is a massive jump in the UFLS. At this point, wind generator's ability to produce power is lowered dramatically. For this reason, in the next section a wind speed of $2m/s$ will be chosen.

4.4.2 Instant of wind variation

Example

Finally, the effect of the moment at which the wind's speed change with respect to the moment generator 17 (two seconds before, at the same time and two seconds after) is disconnected will be studied. The wind speed's change will be $2m/s$. With this change, the wind's speed becomes an important parameter influencing the system. Nonetheless, it is still small enough to see the impacts of the improved droop control.

This analysis is important because each of the three scenarios reveal important information about the system. If the wind changes before, the system's resilience is shown, as it tackles the disconnection of a generator with an already reduced capacity to generate power. If the wind changes at the same time, the system essentially acts like if there was one big generator disconnected (part due to conventional part due to the wind). It shows the system's ability to deal with bigger drops in power. Finally, if the wind changes after, the importance of adequate reserves and the system's response to a frequency incident are highlighted. If the system takes a long time to recover, the overall effect will be worse as the minimum frequencies will be lower, leading to more UFLS being activated.

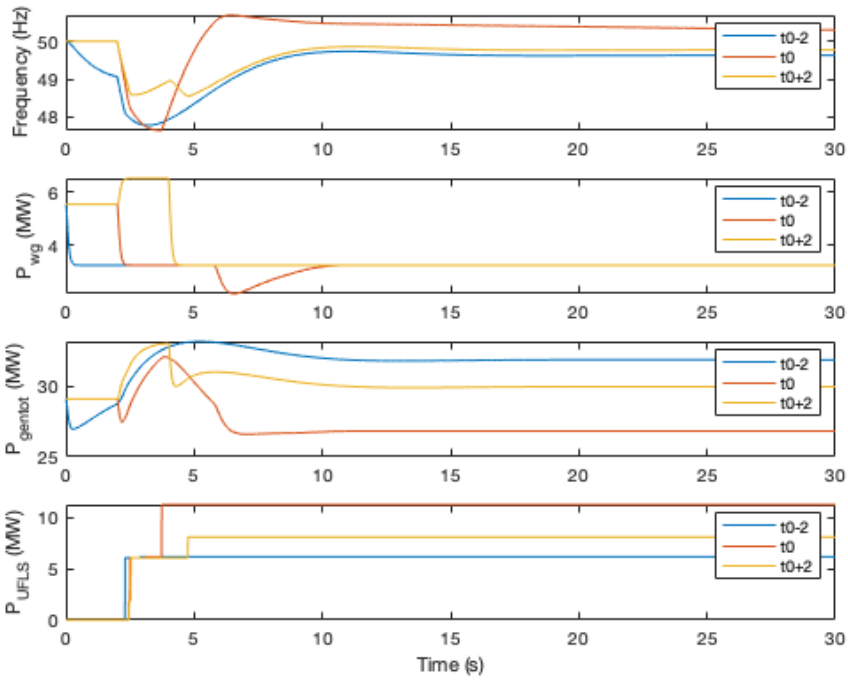

Figure 4.17: Effect of time of wind speed change with improved droop control

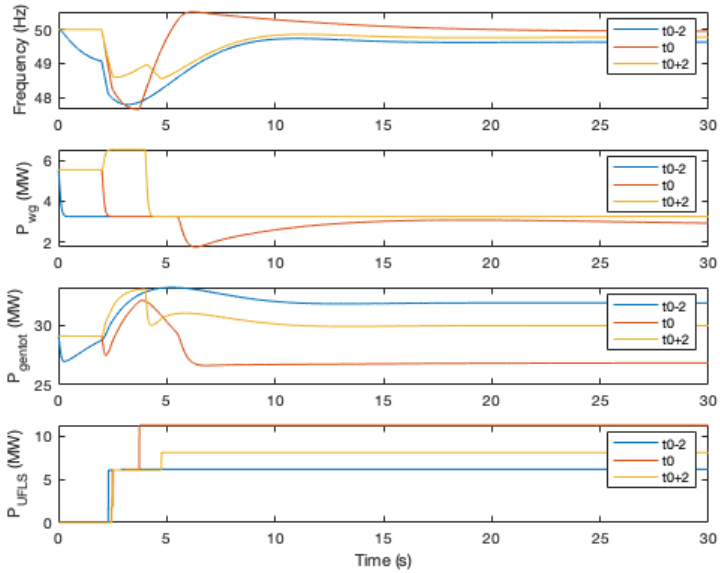

Figure 4.18: Effect of time of wind speed change with original droop control

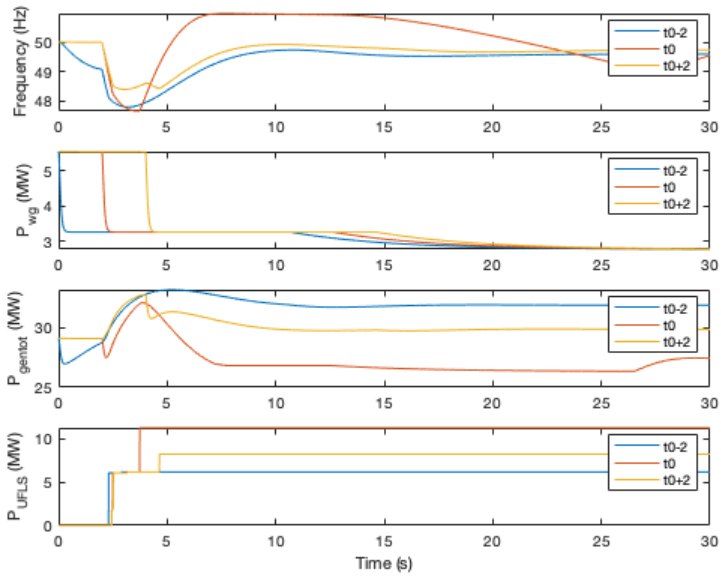

Figure 4.19: Effect of time of wind speed change with no droop control

	New droop control	Original droop control	No droop control
-2 seconds	49,6303	49,6303	49,5907
0 seconds	50,3019	49,9512	49,5415
2 seconds	49,7699	49,7699	49,735

Table 4.15: f_{fin} (Hz) for different time of wind speed change

	New droop control	Original droop control	No droop control
-2 seconds	47,78	47,78	47,78
0 seconds	47,65	47,65	47,65
2 seconds	48,54	48,54	48,39

Table 4.16: f_{min} (Hz) for different time of wind speed change

	New droop control	Original droop control	No droop control
-2 seconds	6,145	6,145	6,145
0 seconds	11,21	11,21	11,21
2 seconds	8,067	8,067	8,183

Table 4.17: d_{UFLS} (MW) for different time of wind speed change

The tables and figures show how the worst case scenario is when the wind changes at the same time as the generator is disconnected. The system is already experiencing a transition and instability due to the loss of the conventional generator. A simultaneous drop in wind speed exacerbates this by further reducing available power, making it harder to maintain frequency stability. The best case is when the wind changes before the incident. The system can tackle the loss in wind generation with the entire inertia from the conventional generators for two seconds, leading to a slightly smaller impact than when the wind changes after the incident.

Simulation of all scenarios

Similarly to the previous section, the sum of the final and minimum frequency's deviation, and the UFLS are added for every situation. This it is done in reference to the moment the wind's speed changes.

	New droop control	Original droop control	No droop control
-2 seconds	90,2	94,6	98,7
0 seconds	86,5	91,6	96,1
2 seconds	91,6	96,4	101,2

Table 4.18: Sum of f_{fin} (Hz) for all simulations depending on moment of wind speed change for new, original and no droop control

	New droop control	Original droop control	No droop control
-2 seconds	593,6	593,5	609,0
0 seconds	614,2	614,1	626,8
2 seconds	570,8	570,7	579,5

Table 4.19: Sum of f_{min} (Hz) for all simulations depending on moment of wind speed change for new, original and no droop control

	New droop control	Original droop control	No droop control
-2 seconds	872,3	872,3	895
0 seconds	930,5	930,5	950,3
2 seconds	844,4	844,4	856

Table 4.20: Sum of d_{UFLS} (MW) for all simulations depending on moment of wind speed change for new, original and no droop control

In these tables, there is a lower deviation of the final frequency with the new droop control as there is with the original (this was not necessarily seen in the example shown previously). It matches what has been seen in all the other cases studied. The minimum frequencies and UFLS are the same between these two cases. Finally, it can be noted that this doesn't actually have a massive impact on the system's response. The other factors studied have shown to make a more significant difference.

4.5 Discussion

Overall, the results show that the tangent enhancement significantly improves the droop control. This is seen in the tables showing the difference in power produced by the wind generators. Furthermore, the system's final frequency was affected more by this improvement than by simply implementing the droop control. The improved droop control had about twice the effect of to the original control. In

other words, the difference between the system with no control and the system with the improved droop control was three times greater than the difference between the original droop control and the system without any control.

Nonetheless, even though the percent increase was noticeable, the absolute difference between every case was quite small, rarely over 0,1Hz. This shows that, although the improvement does significantly affect the droop control, the control in itself isn't very important for the overall system's frequency response. The actual impact both the control and its improvement have on the system is relatively small.

The modest effect may be due to several important factors. Firstly, the system's inherent inertia may be overshadowing the incremental adjustments made by improving the droop control. This can be seen in the section on the wind speed's change. Even if the wind was changed by 1m/s (over 10% of the original amount) there was only a small difference in the final result. Working on a system with less emphasis on conventional generators, and more on renewable sources such as solar energy, could therefore highlight the wind generator's improved response to frequency events.

On top of that, the magnitude of the adjustments proved to be too small to counteract the effect of loosing a conventional generator. Even when loosing the biggest generator at one of the worst times, the increase in wind power generation between the old and new droop control was of around 0,5MW. This is only around 5% of what was lost. Finally, although the MATLAB/Simulink model is robust, it might not be able to capture all real-world complexities and interactions that would influence the control method's effectiveness.

Wind variations have an important impact on the wind generator's ability to provide to the system's primary frequency control. These changes can lead to low and inconsistent power output. It challenges the system's stability and reliability, as it highlights the dependence of wind generators on external factors. This was shown well in the situations where there was as very high change in the wind's speed. The moment at which the wind changed had an overall smaller impact, however having the wind change at the same time as the generator outage did lead to more power being shedded overall.

Chapter 5

Conclusion

5.1 Conclusions

In this project, an approach to improve the droop-based primary frequency control for wind generators was explored. To this aim, the existing droop-based control has been analyzed and improved and the proposed solution implemented then implemented by using a MATLAB/Simulink model, designed to simulate the frequency dynamics of island power systems.

The developed wind generator model including the improved droop-based control has then been applied to the island energy system of La Palma with different degrees of wind energy penetration. The dynamic behaviour of the La Palma power system to generation outages has been simulated with and without wind generation providing frequency control and for different wind generation scenarios.

The simulation results indicate that implementing this improvement into the original droop control significantly affects its influence. The impact is seen particularly well in the final power produced by wind generators in steady state after the disturbance. Nonetheless, the actual impact of both the droop control and its improvement on the system was small.

On the one hand, because the wind generators tend to saturate quickly after the frequency event (with or without the improvement to the control), there is little to no effect on the minimum frequency and the rest of the transient state. On the other, the additional power that wind generators were able to contribute to the system didn't have a massive effect on the final frequency. With the original droop control, the conventional generators were able to make up for the fact wind generators didn't produce as much as they needed to relatively easily. This was especially highlighted with the very similar curves of total power generated by the system as well as the similar UFLS that were being activated.

Despite this, the approach still gives valuable insights into potential enhancements of droop control mechanisms. It highlights the importance of fine tuning control parameters to ensure frequency stability, as, even though this improvement did not lead to huge changes, it still enhanced the wind generator's ability to contribute to the system's primary frequency control.

The different scenarios modelled also reveal a lot about the system. The greater the generator lost (or the more it contributed proportionally) the bigger the impact. As seen in the base case section in the last chapter, this was by far what dominated the system's response. It is most evident when looking at the UFLS. More often than not, the power shedded stayed the same regardless of if there was no droop control, the original or new one. It depended more on the particular generator being disconnected and at what time. This behaviour corresponds to what is expected of an island system where a single generator is responsible for so much of the total power.

In this project it was also shown that, inevitably, if the wind's speed changes close to the conventional generator being disconnected, the system will perform worse. Wind generation decreases to the point where even small changes of $0,5m/s$ have more of an impact than the control. Often, it meant there was more demand being shedded. Nonetheless, the exact moment at which the wind's speed changed didn't end up having a massive impact on the overall result. The worst case for the system was when the wind changed at the exact moment the generator was disconnected, however, except for the rare occasions where more UFLS were activated, the response was very similar.

5.2 Improvements and further research

Based on the findings of this project, there are a few potential improvements to the control and the model. These aim to enhance the effectiveness of the proposed control and to address the model's limitations. They can be divided into two main categories, firstly improvements that would lead to a more accurate model and secondly improvements that would make wind generators contribute more to frequency stability, outside of a droop control.

5.2.1 Improvements of the accuracy of the model

In this project, wind generators were lumped together (into generator 22) as a way to simplify the model. Although this is very useful, details about how they behave is lost. For example, in La Palma, there are three main wind farms, one

on the north, one on the east and one on the south of the island [19]. It could be therefore interesting to separate wind generation into three categories and model wind changes accordingly.

In connection with this, including wind noise into the model would provide a more realistic simulation of wind power generation. It would make the wind more unpredictable, therefore more true to life. Additionally its variation in speed would be smoother over time so the decrease in wind generation could be accounted for in a way where the ROCOF is smaller, leading to less UFLS.

Next, fixing the numerical problem will help avoid the discrepancies in wind generation that were seen as it decreased slightly even when there was no droop control.

Finally, balancing renewable and conventional generation could lead to a more realistic model. Instead of simply increasing the amount wind generators produce as was done in this project (which lead to there being more power generated and consumed in the model than in real life), this amount could be compensated by lowering how much the conventional generators produce. This should be done by means of an economics dispatch which determines which generator produces how much to cover the overall demand at lowest costs.

5.2.2 Improvements to frequency stability

Although making the current model better would lead to more realistic simulations, there are also a few things that can be done outside the droop control to increase frequency stability in regards to wind generation.

Firstly, the wind generators could incorporate other controls, notably a pitch angle controller. Along with the rotor speed, it is one of the main controls that is currently being studied. This would increase the responsiveness and efficiency of the generators, regulate power output and provide an addition parameter that can be adjusted and therefore optimised for the current situation.

Linked to this, it would be interesting to study the economical effect of the droop control has and to determine what the optimal deloading should be, depending for example on the current available reserve and demand. Although this might limit wind controllers impact of frequency stability (if at some point a very low deloading mode is best) it would make this model (which most of time leads to not using wind generators to its maximum) cheaper and therefore easier to implement.

Incorporating energy storage systems (which the model is prepared for) could be explored to analyse the impact of short and long term energy storage in the system. Due to their high variability, there are moments where wind generators could

produce more than what is needed. Producing and then storing that surplus can be another way to ensure frequency stability as it is a way of building up reserve. This could be particularly relevant for cases when a generator is disconnected and the wind changes as the effects of this reserve would not be affected like with a droop control. Overall, it could lead to a slightly lower dependency on the current weather, making wind generators more reliable.

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Appendix A

Data

	11	12	13	14	15	16	17	18	19	20	21	22
1	0,00	2,35	2,35	0,00	3,30	0,00	8,94	0,00	0,00	0,00	6,63	1,110
2	0,00	2,35	2,35	0,00	3,30	0,00	6,86	0,00	0,00	0,00	6,63	1,040
3	0,00	2,35	2,35	0,00	3,30	0,00	6,63	0,00	0,00	0,00	6,63	0,746
4	0,00	2,35	2,35	0,00	3,30	0,00	6,63	0,00	0,00	0,00	6,63	0,593
5	0,00	2,35	2,35	0,00	3,30	0,00	6,63	0,00	0,00	0,00	6,63	0,621
6	0,00	2,35	2,35	0,00	3,30	0,00	6,63	0,00	0,00	0,00	6,63	0,818
7	0,00	2,35	2,35	0,00	3,30	0,00	8,63	0,00	0,00	0,00	6,63	0,745
8	2,35	2,35	2,35	0,00	3,30	0,00	9,38	0,00	0,00	0,00	6,63	0,747
9	2,35	2,35	2,35	2,82	3,30	0,00	10,86	0,00	0,00	0,00	6,63	0,699
10	2,35	2,35	2,35	2,82	3,30	0,00	8,82	0,00	0,00	6,63	6,63	0,488
11	2,35	2,35	2,35	2,82	3,30	0,00	10,08	0,00	0,00	6,63	6,63	0,374
12	2,35	2,35	2,35	2,82	3,30	0,00	9,38	0,00	0,00	6,63	6,63	0,346
13	2,35	2,35	2,35	2,82	3,30	0,00	9,46	0,00	0,00	6,63	6,63	0,328
14	2,35	2,35	2,35	2,82	3,30	0,00	10,04	0,00	0,00	6,63	6,63	0,298
15	2,35	2,35	2,35	2,82	3,30	0,00	9,01	0,00	0,00	6,63	6,63	0,281
16	2,35	2,35	2,35	0,00	3,30	0,00	9,53	0,00	0,00	6,63	6,63	0,303
17	2,35	2,35	2,35	0,00	3,30	0,00	8,21	0,00	0,00	6,63	6,63	0,322
18	2,35	2,35	2,35	0,00	3,30	0,00	8,26	0,00	0,00	6,63	6,63	0,353
19	2,35	2,35	2,35	0,00	3,30	0,00	10,32	0,00	0,00	6,63	6,63	0,353
20	2,60	2,60	2,60	0,00	5,78	0,00	11,20	0,00	0,00	6,63	6,63	0,415
21	2,60	2,60	2,60	0,00	5,89	0,00	11,20	0,00	0,00	6,63	6,63	0,619
22	2,35	2,35	2,35	0,00	4,23	0,00	11,20	0,00	0,00	6,63	6,63	0,818
23	2,35	2,35	2,35	0,00	3,30	0,00	7,71	0,00	0,00	6,63	6,63	0,903
24	2,35	2,35	2,35	0,00	0,00	0,00	6,63	0,00	0,00	6,63	6,63	0,829

Table A.1: Generation Scenarios

Bus	11	12	13	14	15	16	17	18	19	20	21	22
k (on MBASE, =1/R)	20,00	20,00	20,00	20,00	20,00	20,00	20,00	21,25	20,00	20,00	20,00	20
H (s) (on MBASE)	1,75	1,75	1,75	1,73	2,16	1,88	2,10	6,50	2,10	2,10	2,10	5
MBASE (MVA)	5,4	5,4	5,4	6,3	9,4	9,6	15,75	26,82	14,5	14,5	14,5	2,5
Pmax (MW)	4	4	4	4,5	7	7	12	22,8	12	12	12	2,5
Pmin (MW)	2,5	2,5	2,5	3	3,5	3,5	7	0	7	7	7	0,00
B1	1,82	1,82	1,82	1,80	3,16	2,05	3,21	0,83	3,21	3,21	3,21	0
B2	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0
A1	17,31	17,31	17,31	17,11	25,03	18,88	25,32	5,20	25,32	25,32	25,32	0,05
A2	0,79	0,79	0,79	0,85	9,80	1,68	9,70	3,40	9,70	9,70	9,70	0
WG rotor diameter (m)	0	0	0	0	0	0	0	0	0	0	0	84

Table A.2: Generator specifications

Type	Substation	Frequ (Hz)	ROCOF (Hz/s)	Int. delay (s)	Open. delay (s)	load (
uf	2101	48,81		0,30	0,20	6,00
uf	2102	48,81		0,60	0,20	0,40
uf	3101	48,66		1	0,2	10,5
uf	3102	48,66		1,5	0,2	3,8
uf	2103	48,66		2	0,2	7
uf	1101	48,00		0,80	0,20	17,40
uf	1111	48,00		1,50	0,20	8,70
uf	3103	47,00		1,80	0,20	12,30
uf	3104	47,00		2,10	0,20	11,50
uf	1102	47		2,4	0,2	2,2
uf	1112	47		2,4	0,2	7,8
rocof	2101	49,5	-1,8	0,1	0,2	6
rocof	21020	49,5	-1,8	0,1	0,2	0,4
rocof	3101	49,3	-1,8	0,1	0,2	10,5
rocof	3102	49,3	-1,8	0,1	0,2	3,8

Table A.3: UFLS specifications

wr	p
0,46	0,07
0,47	0,07
0,49	0,08
0,51	0,09
0,53	0,10
0,55	0,11
0,56	0,12
0,58	0,14
0,60	0,15
0,62	0,16
0,64	0,18
0,66	0,19
0,67	0,21
0,69	0,23
0,71	0,25
0,73	0,27
0,75	0,29
0,76	0,31
0,78	0,33
0,80	0,35
0,82	0,38
0,84	0,41
0,86	0,43
0,87	0,46
0,89	0,49
0,91	0,52
0,93	0,55
0,95	0,59
0,96	0,62
0,98	0,66
1,00	0,69
1,02	0,73
1,04	0,77
1,05	0,81
1,07	0,86
1,09	0,90
1,14	0,90
1,19	0,90
1,24	0,90
1,28	0,90
1,32 6	10,90

Table A.4: Deloaded curve

Appendix B

Code

B.1 main

```
    function [m_t,m_W,m_Pgentot,m_Pufls,m_Pwg] =
       main_rundynamicsimulation

%
   ----------------------------------------------------------------------

% User-defined values
%
   ----------------------------------------------------------------------


xlsfilename = 'LaPalmaInputData_noESS_withoutFCUC.xls';

deload = 0.15;         % pu of deloading
iswgctrl = 1;         % wg controls (1) or not (0)
   frequency
correctionWG = '0';  % wg corrects with tangent (0) or
   not (1)

tsimulation      = 60;
t0               = 2;

v_varvw        = 0; % [0, 0.5, 1, 2, 4]; % wind speed
   variation around inital one (m/s)
v_tvarvw       = t0; % [t0-2, t0, t0+2]; % instant of
```

```
   wind speed variation

nscenarios      = 1; % up to which scenario to simulate

%
   ----------------------------------------------------------------

% Predefined values
%
   ----------------------------------------------------------------


warning off

str_uftype      = 'uf';
str_rocoftype   = 'rocof';

fbase           = 50;

powersystemdl = 'Powersystem.slx';

%
   ----------------------------------------------------------------

% Read input data
%
   ----------------------------------------------------------------


disp('Reading data...');

load_system('Powersystem');

set_param('Powersystem/WindGenerator/Manual Switch', 'sw
   ', correctionWG);
[~, c_sheets] = xlsfinfo(xlsfilename);

% read generator dynamic model data
```

```
m_gendata       = xlsread(xlsfilename,c_sheets{1});

 % read generation scenarios
m_Pgenscenarios = xlsread(xlsfilename,c_sheets{3});
m_Pgenscenarios = m_Pgenscenarios(2:end,2:end);      %
   delete first row and column

% correct max and min generation output
ngen = size(m_gendata,2);
for igen = 1:ngen
    v_idxcommitted = find(m_Pgenscenarios(:,igen)>0);
    m_gendata(6,igen) = min([m_Pgenscenarios(
       v_idxcommitted,igen);m_gendata(6,igen)]); % pmax
    m_gendata(5,igen) = max([m_Pgenscenarios(
       v_idxcommitted,igen);m_gendata(5,igen)]); % pmin
end

% get wg parameters
idxwg = find(m_gendata(11,:)>0); % wg is the one with
   non-zero diameter entry
if ~iswgctrl
   m_gendata(2,idxwg) = 1e-12; % no wg droop
end
v_wgdata = m_gendata(:,idxwg);

% read ufls parameters
[m_uflsparam,c_uflsID] = xlsread(xlsfilename,c_sheets
   {4});
[m_ufparam , m_rocofparam, v_pshed0] = ...
    fun_prepareuflsformat4simulinkformat(m_uflsparam,
       c_uflsID, str_uftype, str_rocoftype);

v_dfufpu = (m_ufparam(:,1)-fbase)/fbase;
v_tintuf = m_ufparam(:,3);
v_topnuf = m_ufparam(:,4);

v_dfrocofpu = (m_rocofparam(:,1)-fbase)/fbase;
v_dfdtrocofpu = m_rocofparam(:,2)/fbase;
v_tintrocof = m_rocofparam(:,3);
v_topnrocof = m_rocofparam(:,4);
```

```
%
   ----------------------------------------------------------------

% Simulate all possible single generating unit outages
%
   ----------------------------------------------------------------


disp('Simulation start...');

% separte wg from other generators and modify generation
    scenarios
v_Pwg          = m_Pgenscenarios(:, size(m_Pgenscenarios
   ,2));
m_Pgenscenarios = m_Pgenscenarios(1:end,1:end-1);      %
    delete last column

% just take the first nscenarios
m_Pgenscenarios  = m_Pgenscenarios(1:nscenarios,:);
v_Pwg           = v_Pwg(1:nscenarios);

nvarvw          = length(v_varvw);
ntvarvw         = length(v_tvarvw);


% set fixed simulation block paramters
set_param([powersystemdl(1:end-4) '/UFLS'],'v_dfufpu',['
   [' sprintf('%f ',v_dfufpu) ']'],...
    'v_tintuf',['[' sprintf('%f ',v_tintuf) ']','
       v_topnuf',['[' sprintf('%f ',v_topnuf) ']'],...
    'v_dfrocofpu',['[' sprintf('%f ',v_dfrocofpu) ']','
       v_dfdtrocofpu',['[' sprintf('%f ',v_dfdtrocofpu)
       ']'],...
    'v_tintrocof',['[' sprintf('%f ',v_tintrocof) ']','
       v_topnrocof',['[' sprintf('%f ',v_topnrocof) ']'
       ]); % set UFLS parameters

[v_pwdel, v_wrdel, v_vw] = fun_setfixwgparameters(
   powersystemdl(1:end-4), v_wgdata, deload); % set fix
```

```
   WG parameters

set_param([powersystemdl(1:end-4) '/Perturbation'],'time
   ',['[' sprintf('%f',t0) ']'],'Sampletime','0'); % set
    perturbation parameters

set_param(powersystemdl(1:end-4),'StopTime',sprintf('%f'
   ,tsimulation),'OutputOption','SpecifiedOutputTimes','
   OutputTimes',['0:0.01:',sprintf('%f',tsimulation)]);

% simulate each scenario
ngenscenarios = size(m_Pgenscenarios,1);
for igenscenario = ngenscenarios:-1:1

    fprintf('Scenario: %i\n', igenscenario);

    Pinitwg = v_Pwg(igenscenario); % in MW

    [~, vw0] = fun_setvarwgparameters(powersystemdl(1:
       end-4), Pinitwg, v_wgdata, v_pwdel, v_wrdel, v_vw
       );

    % get generation scenario
    v_Pgenscenario = m_Pgenscenarios(igenscenario,:); %
       generation of each unit in MW
    Pdem = sum(v_Pgenscenario) + Pinitwg; % demand = sum
        of generation (in MW)

    % get online units
    v_igenonline = find(v_Pgenscenario>0); % a unit is
       online if its generation > 0 MW
    ngenonline = length(v_igenonline);

    % simulate every single generator outage
    for igenonline = ngenonline:-1:1

        % remaining units
        v_iremgenonline = v_igenonline;
        v_iremgenonline(igenonline) = []; % take out the
            lost generator
```

```
ngen = length(v_iremgenonline);

% set model parameters
Sbase = fun_setsimulinkblockparameters(
   powersystemdl(1:end-4),ngen,m_gendata, ...
     v_wgdata,v_Pgenscenario,v_igenonline,
        igenonline,v_iremgenonline); %v_pshed0MW

v_pshed0MW = v_pshed0/100*Pdem;
v_pshed0pu = v_pshed0MW/Sbase;

% set UFLS parameters (step size only)
set_param([powersystemdl(1:end-4) '/UFLS'],'
   v_pshed0pu',['[' sprintf('%f ',v_pshed0pu) ']
   ']);

for ivarvw = nvarvw:-1:1

    % initialise the change in wind speed
    set_param([powersystemdl(1:end-4) '/Wind'],'
       After',['[' sprintf('%f',vw0-v_varvw(
       ivarvw)) ']']);


    for itvarvw = ntvarvw:-1:1

        % initialise the time of the wind speed
           change
        set_param([powersystemdl(1:end-4) '/Wind
           '],'time',['[' sprintf('%f',v_tvarvw(
           itvarvw)) ']']);
                    % antes pon a sprintf('%f
                       ',t0+v_tvarvw(itvarvw))

        % simulate it and store results
        [m_t(:,igenscenario, igenonline, ivarvw,
            itvarvw), ~, ...
            m_w(:,igenscenario, igenonline,
               ivarvw, itvarvw), ...
            v_dpgentot, ...
```

```
                    v_dpw, ...
                    v_pwg, ...
                    v_dpufls] = sim(powersystemdl);

                m_Pgentot(:,igenscenario, igenonline,
                   ivarvw, itvarvw)=Pdem + v_dpgentot *
                   Sbase;
                m_dPwg(:,igenscenario, igenonline,
                   ivarvw, itvarvw)=v_dpw * Sbase;
                m_Pwg(:,igenscenario, igenonline, ivarvw
                   , itvarvw)=v_pwg * v_wgdata(5);
                m_Pufls(:,igenscenario, igenonline,
                   ivarvw, itvarvw)= v_dpufls* Sbase;
            end
        end
    end
end


%change from pu units to MWs
%m_Pgentot     =     Sbase * m_dpgentot;
%m_Pufls       =     Sbase * m_dpufls;
%m_Pwg         =     v_wgdata(5) * m_pwg;
m_W           =     fbase + fbase * m_w;


disp('Simulation stops.');

%
   ----------------------------------------------------------------------

%TABLAS LATEX
%
   ----------------------------------------------------------------------



[v_sum_pufls_varvw, v_sum_delta_fss_varvw,
   v_sum_delta_fmin_varvw, v_sum_pufls_tvarvw,
   v_sum_delta_fss_tvarvw, v_sum_delta_fmin_tvarvw] =
```

```
   fun_sums(m_Pufls, m_W, fbase, igenscenario,
   igenonline, ivarvw, itvarvw, ngenscenarios,
   ngenonline, nvarvw, ntvarvw, v_varvw, v_tvarvw,
   tsimulation, t0);

%
   ----------------------------------------------------------------

% Show a result - Example
%
   ----------------------------------------------------------------


% all outages for scenario 1- cada curva es lo que pasa
   si quito un
% generador a la 1 de la ma ana, no cambia el viento

igenonline = 4;
igenscenario = 1;
ivarvw = 1;
itvarvw = 1;

% all outages for the same scenario, no wind variation
fun_graphonline(ngenonline, igenscenario, ivarvw,
   itvarvw, m_Pgentot, m_Pufls, m_Pwg, m_W, m_t)

% all scenarios (hours) removing the same CG every time,
    no wind variation
fun_graphscenarios(ngenscenarios, igenonline, ivarvw,
   itvarvw, m_Pgentot, m_Pufls, m_Pwg, m_W, m_t)

% all wind variations hapenning at the same time,
   removing the same CG at
% the same scenario (hour)
fun_graphvarvw(nvarvw, igenonline, igenscenario, itvarvw
   , m_Pgentot, m_Pufls, m_Pwg, m_W, m_t)

ivarvw = 5;

% all moments of the same wind variation, removing the
```

```
   same CG at the same
% scenario (hour)
fun_graphtvarvw(ntvarvw, igenonline, igenscenario,
   ivarvw, m_Pgentot, m_Pufls, m_Pwg, m_W, m_t)

%{
%comp
T = readtable('LaPalmaInputData_noESS_withoutFCUC.xls','
   Sheet','GenerationScenarios');
T(1:11,1:13)
disp(T)
T1 = readtable('LaPalmaInputData_noESS_withoutFCUC.xls
   ','Sheet','GeneratorParameters');
T1(1:11,1:13)
disp(T1)
%}
```

B.2 Function: sums

```
    function [v_sum_pufls_varvw, v_sum_delta_fss_varvw,
       v_sum_delta_fmin_varvw, v_sum_pufls_tvarvw,
       v_sum_delta_fss_tvarvw, v_sum_delta_fmin_tvarvw]
       = fun_sums(m_Pufls, m_W, fbase, igenscenario,
       igenonline, ivarvw, itvarvw, ngenscenarios,
       ngenonline, nvarvw, ntvarvw, v_varvw, v_tvarvw,
       tsimulation, t0);

v_sum_pufls_varvw        = zeros(1,5);
v_sum_delta_fss_varvw    = zeros(1,5);
v_sum_delta_fmin_varvw   = zeros(1,5);

v_sum_pufls_tvarvw       = zeros(1,3);
v_sum_delta_fss_tvarvw   = zeros(1,3);
v_sum_delta_fmin_tvarvw  = zeros(1,3);

% Define the index mappings for v_varvw and v_tvarvw
varvw_indices = [0, 0.5, 1, 2, 4];
tvarvw_indices = [t0-2, t0, t0+2];
```

```
% Loop through scenarios and units
for igenscenario = ngenscenarios:-1:1
    for igenonline = 1:ngenonline

        for ivarvw = 1:nvarvw
            varvw_index = find(varvw_indices == v_varvw(
               ivarvw));

            for itvarvw = 1:ntvarvw
                tvarvw_index = find(tvarvw_indices ==
                   v_tvarvw(itvarvw));

                % Update varvw sums
                v_sum_pufls_varvw(varvw_index) =
                   v_sum_pufls_varvw(varvw_index) +
                   m_Pufls(tsimulation * 100,
                   igenscenario, igenonline, ivarvw,
                   itvarvw);
                v_sum_delta_fss_varvw(varvw_index) =
                   v_sum_delta_fss_varvw(varvw_index) -
                   m_W(tsimulation * 100, igenscenario,
                   igenonline, ivarvw, itvarvw) + fbase;
                v_sum_delta_fmin_varvw(varvw_index) =
                   v_sum_delta_fmin_varvw(varvw_index) -
                    min(m_W(:, igenscenario, igenonline,
                    ivarvw, itvarvw)) + fbase;

                % Update tvarvw sums
                v_sum_pufls_tvarvw(tvarvw_index) =
                   v_sum_pufls_tvarvw(tvarvw_index) +
                   m_Pufls(tsimulation * 100,
                   igenscenario, igenonline, ivarvw,
                   itvarvw);
                v_sum_delta_fss_tvarvw(tvarvw_index) =
                   v_sum_delta_fss_tvarvw(tvarvw_index)
                   - m_W(tsimulation * 100, igenscenario
                   , igenonline, ivarvw, itvarvw) +
                   fbase;
                v_sum_delta_fmin_tvarvw(tvarvw_index) =
                   v_sum_delta_fmin_tvarvw(tvarvw_index)
```

```
                    - min(m_W(:, igenscenario,
                    igenonline, ivarvw, itvarvw)) + fbase
                    ;
            end
        end
    end
end


%dependiendo de cuanTo cambia el viento
latexTable = sprintf('\\begin{table}[ht]\n');
latexTable = [latexTable, sprintf(' \\centering\n')];
latexTable = [latexTable, sprintf(' \\caption{Sums of
   the shed power, final and maximum deviations from the
    base frequency from all simulations, depending on
   the wind speed change.}\n')];
latexTable = [latexTable, sprintf('\\begin{tabular}{
   cccccc}\n')];
latexTable = [latexTable, sprintf('\\\\')];
latexTable = [latexTable, sprintf('\\hline\n')];
latexTable = [latexTable, sprintf('%s&%s&%s&%s&%s&%s
   \\\\\n','','0$m/s$', '0.5 $m/s$', '1 $m/s$','2 $m/s$'
   ,'4 $m/s$')];

latexTable = [latexTable, sprintf('%s & %.1f & %.1f &
   %.1f & %.1f & %.1f\\\\\n', ' $\Sigma P_{ufls}$',
   v_sum_pufls_varvw(1), v_sum_pufls_varvw(2),
   v_sum_pufls_varvw(3),v_sum_pufls_varvw(4),
   v_sum_pufls_varvw(5))];
latexTable = [latexTable, sprintf('%s & %.1f & %.1f &
   %.1f & %.1f & %.1f\\\\\n', '$\Sigma \Delta f_{ss}$',
   v_sum_delta_fss_varvw(1), v_sum_delta_fss_varvw(2),
   v_sum_delta_fss_varvw(3),v_sum_delta_fss_varvw(4),
   v_sum_delta_fss_varvw(5))];
latexTable = [latexTable, sprintf('%s & %.1f & %.1f &
   %.1f & %.1f & %.1f\\\\\n', '$\Sigma \Delta f_{min}$',
    v_sum_delta_fmin_varvw(1), v_sum_delta_fmin_varvw(2)
   , v_sum_delta_fmin_varvw(3),v_sum_delta_fmin_varvw(4)
   ,v_sum_delta_fmin_varvw(5))];
```

```
latexTable = [latexTable, sprintf('\\hline\n')];
latexTable = [latexTable, sprintf('\\end{tabular}\n')];
latexTable = [latexTable, sprintf('  \\label{tb:
   sums_delta_vw}\n')];
latexTable = [latexTable, sprintf('\\end{table}')];
disp(latexTable);

%dependiendo de cuanDo cambia el viento
latexTable = sprintf('\\begin{table}[ht]\n');
latexTable = [latexTable, sprintf(' \\centering\n')];
latexTable = [latexTable, sprintf(' \\caption{Sums of
   the shed power, final and maximum deviations from the
    base frequency from all simulations, depending on
   the time of the wind speed change.}\n')];latexTable =
    [latexTable, sprintf('\\begin{tabular}{cccc}\n')];
latexTable = [latexTable, sprintf('\\\\')];
latexTable = [latexTable, sprintf('\\hline\n')];
latexTable = [latexTable, sprintf('%s&%s&%s&%s\\\\\n','
   ,'-2 $s$', '0 $s$', '+2 $s$')];

latexTable = [latexTable, sprintf('%s & %.1f & %.1f &
   %.1f \\\\\n', '$\Sigma P_{ufls}$', v_sum_pufls_tvarvw
   (1), v_sum_pufls_tvarvw(2), v_sum_pufls_tvarvw(3))];
latexTable = [latexTable, sprintf(' %s & %.1f & %.1f &
   %.1f \\\\\n', '$\Sigma \Delta f_{ss}$',
   v_sum_delta_fss_tvarvw(1), v_sum_delta_fss_tvarvw(2),
    v_sum_delta_fss_tvarvw(3))];
latexTable = [latexTable, sprintf(' %s & %.1f & %.1f &
   %.1f \\\\\n', '$\Sigma \Delta f_{min}$',
   v_sum_delta_fmin_tvarvw(1), v_sum_delta_fmin_tvarvw
   (2), v_sum_delta_fmin_tvarvw(3))];

latexTable = [latexTable, sprintf('\\hline\n')];
latexTable = [latexTable, sprintf('\\end{tabular}\n')];
latexTable = [latexTable, sprintf('  \\label{tb:
   sums_delta_vw}\n')];
latexTable = [latexTable, sprintf('\\end{table}')];
disp(latexTable);
```

B.3 Function: set variable wind generator parameters

```
    function [pinit, vw0] = fun_setvarwgparameters(
       powersystemdl, Pinit, v_wgdata, v_pwdel, v_wrdel,
        v_vw)

% Setting up parameters
Pmax = v_wgdata(5); % Pn = Pmax
[vw0, wr0, pinit] = fun_getinitialwgop(v_pwdel, v_wrdel,
    v_vw, Pinit, Pmax);

% set simulink model parameters
set_param([powersystemdl '/WindGenerator'], '
   pinitwindgen', ...
    sprintf('%f',pinit),'wr0',sprintf('%f',wr0));

% initialise initial wind speed
set_param([powersystemdl '/Wind'], 'Before',['[' sprintf
   ('%f',vw0) ']']);
```

B.4 Function: set simulink block parameters

```
    function Sbase = fun_setsimulinkblockparameters(
       powersystemdl,ngen,m_gendata, ...
    v_wgdata,v_genscenario,v_igenonline,igenonline,
       v_iremgenonline) % v_pshed0MW

% Prepares and sets the parameters of the blocks of the
   Simulink model.

v_pinit = v_genscenario(v_iremgenonline); % the initial
   power for the

% base power to convert everything in pu on system basis
v_Mbase = m_gendata(4,v_iremgenonline);
Sbase = 8*sum(v_Mbase);
```

```
% lost amount of power
plostpu = v_genscenario(v_igenonline(igenonline))/Sbase;

% get dynamic parameters of remaining units
v_h = m_gendata(3,v_iremgenonline); % pu on generator
   rating basis
heq = v_h*v_Mbase(:)/Sbase;
close all

v_kpugenrating = m_gendata(2,v_iremgenonline); % pu on
   generator rating basis
v_kgpu = v_kpugenrating.*v_Mbase/Sbase;

v_bg1 = m_gendata(7,v_iremgenonline);
v_bg2 = m_gendata(8,v_iremgenonline);
v_ag1 = m_gendata(9,v_iremgenonline);
v_ag2 = m_gendata(10,v_iremgenonline);

[m_Ag,m_Bg,m_Cg,m_Dg] = fun_getstatespace(ngen,v_kgpu,
   v_bg1,v_bg2,v_ag1,v_ag2);
v_dpgmaxpu = (m_gendata(5,v_iremgenonline)-v_pinit)/
   Sbase;
v_dpgminpu = (m_gendata(6,v_iremgenonline)-v_pinit)/
   Sbase;

% set rotor parameters
set_param([powersystemdl,'/Rotor'],'Numerator', '[0 1]',
   'Denominator', ['[2*', sprintf('%f',heq), ' 0]']);

% set generator state space parameters
set_param([powersystemdl,'/State-Space-Gen'],'A',mat2str
   (m_Ag),'B',mat2str(m_Bg),'C',mat2str(m_Cg),'D',
   mat2str(m_Dg));

% set generator power limits
set_param([powersystemdl '/Powerlimits'],'UpperLimit',['
   [' sprintf('%f ',v_dpgmaxpu) ']'],'LowerLimit',['['
   sprintf('%f ',v_dpgminpu) ']']);

% set perturbation parameters (plost only)
```

```
set_param([powersystemdl '/Perturbation'],'After',['['
   sprintf('%f',plostpu) ']'],'Before','0');

% set system base change parameters for wg (System base
   only, where the system base is the sum of the Mbase's
    of the CG)
set_param([powersystemdl '/SystemBaseChange'],'Gain',['[
   ' sprintf('%f',v_wgdata(5)) '/' sprintf('%f',Sbase) '
   ']']);
```

B.5 Function: set fix wind generator parameters

```
    function [v_pwdel, v_wrdel, v_vw] =
       fun_setfixwgparameters(powersystemdl, v_wgdata,
       deload)

% This function sets up the parameters of the WG and
   inserts them into the
% Powersystem simulink model.

% Setting up parameters
Rwg = 1/v_wgdata(2);
Hwg = v_wgdata(3);
Tc1 = v_wgdata(9); % small eqivalent converter time
   constant
Tc2 = Tc1; % small eqivalent converter time constant

% getting wind power curve
[m_pw,v_wr,v_pwmpp,v_wrmpp,v_pwdel,v_wrdel,v_vw] =
   fun_getwindpowercurve(deload, 0);

% Set predefined WG parameters on Simulink model
set_param([powersystemdl '/WindGenerator'],'R',sprintf('
   %f',Rwg),'Hw',sprintf('%f',Hwg),...
     'Tc1',sprintf('%f',Tc1),'Tc2',sprintf('%f',Tc2), ...
     'v_vw',['[' sprintf('%f ',v_vw) ']'],'v_wr',['['
        sprintf('%f ',v_wr) ']'],'m_pw',mat2str(m_pw), ...
     'v_wrdel',['[' sprintf('%f ',v_wrdel) ']'],'v_pwdel'
        ,['[' sprintf('%f ',v_pwdel) ']'],...
```

```
    'v_wrmpp',['[' sprintf('%f ',v_wrmpp) ']'],'v_pwmpp'
       ,['[' sprintf('%f ',v_pwmpp) ']']);
```

B.6 Function: prepare UFLS format for Simulink

```
    function [m_ufparam, m_rocofparam, v_pshed0, ...
    v_idxuf,v_idxrocofonly,v_idxrocofcmn] =
       fun_prepareuflsformat4simulinkformat(m_uflsparam,
        c_uflsID, str_uftype, str_rocoftype)
% retrieve sheddable load (in % of demand)
v_pshed0 = m_uflsparam(:,end);

% retrieve and separate uf and rocof stages
c_relaytype = c_uflsID(2:end,1);
v_idxuf = find(strcmp(str_uftype,c_relaytype)); % get uf
    stages
v_idxrocof = find(strcmp(str_rocoftype,c_relaytype)); %
   get rocof stages
nufstages = length(v_idxuf);
nrocofstages = length(v_idxrocof);
nstages =  nufstages + nrocofstages; % efective number
   of stages

% retrieve uf and rocof stage IDs (substation bus
   numbers) and get common
% stages
v_ufID = m_uflsparam(v_idxuf,1); % get uf ID: nufstages
   x 1 vector
v_rocofID = m_uflsparam(v_idxrocof,1); % get rocof ID:
   nrocofstages x 1 vector
[v_IDcmn,v_idxcmnIDuf,v_idxcmnIDrocof] = intersect(
   v_ufID,v_rocofID); % get common stages (both uf and
   rocof)

% create two parameter sets of equal dimensions: 1 for
   uf stages (without rocof stages), 1 for
% rocof stages (without uf stages)
m_ufparam = zeros(nstages,5); % m_ufparam and
   m_rocofparam same size
```

```
m_rocofparam = zeros(nstages,5);

% assign uf parameters to uf stages only
m_ufparam(v_idxuf,:) = m_uflsparam(v_idxuf,2:end);

% assign rocof parameters to rocof stages
v_idxrocofcmn = v_idxcmnIDrocof + nufstages;
v_idxrocofonly = setdiff(v_idxrocof,v_idxrocof(
   v_idxcmnIDrocof)); % pure rocof stages
m_rocofparam(v_idxcmnIDuf,:) = m_uflsparam(v_idxrocofcmn
   ,2:end); % rocof stages common to uf stages
m_rocofparam(v_idxrocofonly,:) = m_uflsparam(
   v_idxrocofonly,2:end); % pure rocof stages

v_pshed0(v_idxrocofcmn) = 0; % set pshed at those rocof
   stages common to uf stages to zero (just to be sure)
```

B.7 Function: get wind power curve

```
    function [m_pw,v_wr,v_pwmpp,v_wrmpp,v_pwdel,v_wrdel,
       v_vw] = fun_getwindpowercurve(deload, v_beta)

% This function computes the power-speed curves (MPP and
    deloaded operation
% modes) for wind generation.
% The power-speed curve of a 1.5 MW wind generator is
   used for this
% purpose. The resulting curve must be appropriately
   scaled.
%
% Input:    angle of attack (beta), wind speed (v_vw),
   initial Power
%           (pinitwindgen), nominal P (Pn), rotor
   diameter
% Output:   wind power, (pw); rotor speed, (wr); MPP
   power, (pwmpp); MPP rotor
%           speed, (wrmpp); deloaded power, (pwdel);
   deloaded rotor speed,
%           (wrdel)
```

```
rho = 1.275;     % air density
v_Wr = 0:0.005:5; % rotor speed range (rad/s)
v_vw     = 5:0.2:13; % wind speeds (m/s)
% Rb = diameter/2; % blade radius (m)
Rb = 31.2; % m
v_cp = [0.73/0.990891, 151, 0.58, 0.002, 2.14, 13.2,
   18.4, -0.02, -0.003]; % performance coefficients
Pn = 1.5; % MW

Aw = Rb^2*pi; % surface

nvw = length(v_vw);
nwr = length(v_Wr);

m_pw     = zeros(nvw,nwr);
for iw = nvw:-1:1 % for every wind speed:
    vw = v_vw(iw);
    lambda = v_Wr*Rb./vw;
    delta = (1./(lambda+v_cp(8).*v_beta)-v_cp(9)./(1+
       v_beta.^3));
    Cp = v_cp(1)*(v_cp(2).*delta-v_cp(3).*v_beta-v_cp(4)
       .*v_beta.^v_cp(5)-v_cp(6)).*exp(-v_cp(7).*delta);
    m_pw(iw,:) = Cp*rho/2*Aw*vw.^3/(Pn*1e6); % per unit
       mechanical power
end

% [m_VW,m_WR] = meshgrid(v_Wr,v_vw);
% m_LAMBDA = m_WR*Rb./m_VW;
%     m_DELTA = (1./(m_LAMBDA+v_cp(8).*v_beta)-v_cp(9)
   ./(1+v_beta.^3));
%     m_CP = v_cp(1)*(v_cp(2).*m_DELTA-v_cp(3).*v_beta-
   v_cp(4).*v_beta.^v_cp(5)-v_cp(6)).*exp(-v_cp(7).*
   m_DELTA);
%     m_PW = m_CP.*rho/2*Aw.*m_VW.^3/(Pn*1e6); % per
   unit mechanical power

[v_pwmpp,v_iwrmpp] = max(m_pw,[],2); % MPP
v_pwmpp(v_pwmpp>1) = 1;
```

```
v_pwdel = (1-deload) * v_pwmpp; % deloaded


ipwmppn = find(v_pwmpp<=1,1,'last');     % nominal power
   (1 pu)
Wrn = v_Wr(v_iwrmpp(ipwmppn));           % nominal speed
v_wr = v_Wr/Wrn;

v_Wrmpp = v_Wr(v_iwrmpp);

v_iwrdel= zeros(1,nvw);
for iw = nvw:-1:1
    % it takes the right half of the curve after the MPP
        point corresponding to that
    % particular wind speed

    [~,v_iwrdel(iw)] = min(abs(m_pw(iw,v_iwrmpp(iw):end)
        - v_pwdel(iw)));
    v_Wrdel(iw)      = v_Wr(v_iwrmpp(iw)+v_iwrdel(iw));
       % gives the corresponding wr
end

% % we add a few "deloaded" points so that, when the
   wind speed becomes higher
% % than the maximum specified one, the maximum power
   has been reached
% for i_extra_vw = 1:5
%     v_pwdel(nvw+i_extra_vw) = v_pwdel(nvw);
%     v_Wrdel(nvw+i_extra_vw) = v_Wrdel(nvw) +
   i_extra_vw * (v_Wr(nwr)-v_Wrdel(nvw))/5;
%
%     v_pwmpp(nvw+i_extra_vw) = v_pwmpp(nvw);
%     v_Wrmpp(nvw+i_extra_vw) = v_Wrmpp(nvw) +
   i_extra_vw * (v_Wr(nwr)-v_Wrmpp(nvw))/5;
% end

v_wrmpp = v_Wrmpp/Wrn;  % speed corresponding to MPP
v_wrdel = v_Wrdel/Wrn;  % speed corresponding to
   deloaded operation points
```

```
if ~nargout
    % TO DRAW FIGURE WR-PW CURVE:
    figure(2);
    title('MPP and Deloaded operation')
    plot(v_wr,m_pw',':b','HandleVisibility','off');hold
       on;
    plot(v_wrmpp,v_pwmpp,'-r');hold on;
    plot(v_wrdel,v_pwdel,'-g');hold on;
    legend('MPP','Deloaded');hold on;
    %plot(wr0,pinit,'*', 'linewidth',4,'HandleVisibility
       ','off');hold on;

    plot(v_wr,m_pw',':b', 'HandleVisibility','off');hold
        on;
    xlabel('Rotor speed (pu)')
    ylabel('Mechanical power (pu)')
    hold off;
    sgt = sgtitle('Power-speed curve', 'interpreter','
       latex');
    sgt.FontSize = 18;
end
```

B.8 Function: get state space

```
    function [m_A,m_B,m_C,m_D] = fun_getstatespace(n,
       v_kpu,v_b1,v_b2,v_a1,v_a2)

% This function computes the state space representation
   matrices A, B, C, D
% given the canonical transfer function form
%
% Each unit is represented by a generic 2nd order
   transfer
% function: P(s) = kpu*(1 + b1*s + b2*s^2)/(1 + a1*s +
   a2*s^2)
%
% A = [0 1; -1/a2 -a1/a2]
% B = [0; 1/a2]
% C = kpu*[(1 - b2/a2) (b1 - b2*a1/a2)]
```

```
% D = kpu*b2/a2

m_A = zeros(2*n,2*n);
m_B = zeros(2*n,1);
m_C = zeros(n,2*n);
m_D = zeros(n,1);

for i = n:-1:1
   if v_a2(i)>0
      m_A(2*(i-1)+1:2*i,2*(i-1)+1:2*i) = [0 1; -1/v_a2(i
         ) -v_a1(i)/v_a2(i)];
      m_B(2*i,:) = 1/v_a2(i);
      m_C(i,2*(i-1)+1:2*i) = [(-v_kpu(i)-v_kpu(i)*v_b2(i
         )/v_a2(i)) (-v_kpu(i)*v_b1(i)-v_kpu(i)*v_b2(i)*
         v_a1(i)/v_a2(i))];
      m_D(i,:) = v_kpu(i)*v_b2(i)/v_a2(i);
   else % if a2 = 0 (1st order transfer function)
      m_A(2*(i-1)+1:2*i,2*(i-1)+1:2*i) = [0 0; 0 -1/v_a1
         (i)];
      m_B(2*i,:) = 1/v_a1(i);
      m_C(i,2*(i-1)+1:2*i) = [0 (-v_kpu(i)+v_b1(i)*v_kpu
         (i)/v_a1(i))];
      m_D(i,:) = -v_kpu(i)*v_b1(i)/v_a1(i);
   end
end
```

B.9 Function: get initial values

```
    function [vw0, wr0, pinit] = fun_getinitialwgop(
       v_pwdel, v_wrdel, v_vw, Pinit, Pn)

pinit = Pinit/Pn;

% find closest deloaded value that corresponds to
   pinitwindgen
i_pinitwindgen_lower  = find(v_pwdel <= pinit,1,'last');
i_pinitwindgen_higher = find(v_pwdel > pinit,1,'first');

% find closest rotor speed value that corresponds to Wr0
```

```
wr0_lower   = v_wrdel(i_pinitwindgen_lower);
wr0_higher  = v_wrdel(i_pinitwindgen_higher);

% interpolate
wr0 = wr0_lower + ...
    (wr0_higher-wr0_lower)*(pinit-v_pwdel(
       i_pinitwindgen_lower))/(v_pwdel(
       i_pinitwindgen_higher)-v_pwdel(
       i_pinitwindgen_lower));


% interpolate to find initial wind speed
vw0 = v_vw(i_pinitwindgen_lower) + ...
    (v_vw(i_pinitwindgen_higher)-v_vw(
       i_pinitwindgen_lower))*(pinit-v_pwdel(
       i_pinitwindgen_lower))/(v_pwdel(
       i_pinitwindgen_higher)-v_pwdel(
       i_pinitwindgen_lower));
```

B.10 Function: graphs

There are four total functions for graphing different scenarions: one in terms of what generator has been disconnected, one in terms of the time of day, one in terms of the wind speed's change and one in terms of the time the wind's speed changes. They follow a very similar format, so only one will be shown:

```
    function fun_graphscenarios(ngenscenarios,
       igenonline, ivarvw, itvarvw, m_Pgentot, m_Pufls,
       m_Pwg, m_W, m_t)


figure(2)
labels = cellstr(num2str((1:ngenscenarios)', 'Scen.. %d'
   ));
subplot(4,1,1)
plot(squeeze(m_t(:,:,igenonline,ivarvw,itvarvw)),squeeze
   (m_W(:,:,igenonline,ivarvw,itvarvw)));
ylabel('Frequency (Hz)')
legend(labels);
subplot(4,1,2)
```

```
plot(squeeze(m_t(:,:,igenonline,ivarvw,itvarvw)),squeeze
   (m_Pwg(:,:,igenonline,ivarvw,itvarvw)));
ylabel('P_{wg} (MW)')
legend(labels);
subplot(4,1,3)
plot(squeeze(m_t(:,:,igenonline,ivarvw,itvarvw)),squeeze
   (m_Pgentot(:,:,igenonline,ivarvw,itvarvw)));
ylabel('P_{gentot} (MW)')
legend(labels);
subplot(4,1,4)
plot(squeeze(m_t(:,:,igenonline,ivarvw,itvarvw)),squeeze
   (m_Pufls(:,:,igenonline,ivarvw,itvarvw)));
xlabel('Time (s)')
ylabel('P_{UFLS} (MW)')
legend(labels);
```

Appendix C

Results

m	b
0	0
0,461904111	-0,145481318
0,498101352	-0,162971642
0,56118711	-0,194379386
0,601968977	-0,216028783
0,614871879	-0,222695632
0,656531716	-0,24580678
0,699584768	-0,270478784
0,743996722	-0,296743163
0,789700861	-0,324608457
0,83680271	-0,3541871
0,885346664	-0,385560754
0,935229197	-0,418712946
0,986395673	-0,453655357
1,038983745	-0,490529769
1,145044504	-0,566372654
1,202993532	-0,610057641
1,204939081	-0,61101951
1,262935038	-0,655836588
1,322433481	-0,702903655
1,383280973	-0,752153411
1,445376315	-0,803549085
1,50882369	-0,857224882
1,573731082	-0,913323345
1,640031689	-0,971840842
1,707616238	-1,032728419
1,86114132	-1,173083772
1,934918863	-1,243768223
1,91872695	-1,227507491
1,991722668	-1,298492668
2,066109381	-1,372192381
2,141943944	-1,448713944
2,219232345	-1,528117955
2,29774621	-1,610219507
2,377533738	-1,69511136
0,618507855	0,191957567
0	0,9
0	0,9
0	0,9
0	0,9
0	0,9

Table C.1: Tangent calculation results

	New droop control	Original droop control	No droop control
1	49,8488	49,8115	49,7959
2	49,9343	49,9144	49,902
3	49,9306	49,9056	49,8936
4	49,9175	49,8946	49,8822
5	49,9196	49,8966	49,8845
6	49,9308	49,9108	49,8988
7	49,8264	49,7997	49,7858
8	49,8566	49,8354	49,8203
9	49,8974	49,8827	49,8723
10	49,9144	49,9049	49,8989
11	49,9109	49,9039	49,8988
12	49,9100	49,9038	49,8989
13	49,9094	49,9036	49,8989
14	49,9085	49,9032	49,8988
15	49,9079	49,9031	49,8989
16	49,8746	49,8717	49,8633
17	49,8753	49,8701	49,8633
18	49,8764	49,8702	49,8634
19	49,8764	49,8702	49,8634
20	49,8759	49,8673	49,8572
21	49,8808	49,8665	49,8551
22	49,8481	49,8255	49,8091
23	49,8884	49,8745	49,8631
24	49,7819	49,7606	49,7404

Table C.2: f_{fin} for all scenarios when generator 17 is disconnected

	New droop control	Original droop control	No droop control
1	48,59	48,59	48,39
2	48,83	48,83	48,73
3	48,82	48,82	48,74
4	48,81	48,81	48,74
5	48,81	48,81	48,74
6	48,83	48,83	48,74
7	48,55	48,55	48,38
8	49,17	49,17	48,97
9	49,42	49,42	49,26
10	49,5	49,5	49,41
11	49,48	49,48	49,41
12	49,48	49,48	49,41
13	49,47	49,47	49,41
14	49,47	49,47	49,41
15	49,46	49,46	49,41
16	49,27	49,27	49,21
17	49,28	49,28	49,21
18	49,28	49,28	49,21
19	49,28	49,28	49,21
20	48,68	48,68	48,63
21	48,69	49,69	48,61
22	49,15	49,15	48,96
23	49,40	49,40	49,21
24	48,38	48,38	48,23

Table C.3: f_{min} for all scenarios when generator 17 is disconnected

	New droop control	Original droop control	No droop control
1	6,028	6,028	6,145
2	5,524	5,524	5,524
3	5,173	5,173	5,173
4	5,015	5,015	5,015
5	5,044	5,044	5,044
6	5,247	5,247	5,247
7	5,586	5,586	5,694
8	0	0	0
9	0	0	0
10	0	0	0
11	0	0	0
12	0	0	0
13	0	0	0
14	0	0	0
15	0	0	0
16	0	0	0
17	0	0	0
18	0	0	0
19	0	0	0
20	2,406	2,406	2,406
21	2,474	2,474	2,474
22	0	0	0
23	0	0	0
24	1,99	1,99	1,99

Table C.4: d_{UFLS} for all scenarios when generator 17 is disconnected

	New droop control	Original droop control
1	0,832	0,3168
2	0,4162	0,1443
3	0,4466	0,1611
4	0,4573	0,1871
5	0,4512	0,1812
6	0,4107	0,1551
7	0,6571	0,3512
8	0,6594	0,2803
9	0,5657	0,1964
10	0,4305	0,1601
11	0,3299	0,1686
12	0,3055	0,1718
13	0,2893	10,1759
14	0,2631	0,1779
15	0,2479	0,1791
16	0,2675	0,2518
17	0,2838	0,2469
18	0,3116	0,2419
19	0,3116	0,2419
20	0,3665	0,2701
21	0,546	0,255
22	0,7217	0,3004
23	0,6242	0,2054
24	0,7311	0,4181

Table C.5: Change in wind generation (MW) for all scenarios when generator 17 is disconnected