Mitigating the erosion of transient stability margins in Great Britain through novel wind farm control techniques.

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Abstract

The predominant North-to-South active power flow across the border between Scotland and England has historically been limited by system stability considerations. As the penetration of variable-speed wind power plants in Great Britain grows (reducing the generation share of traditional synchronous generation), it is imperative that stability limits, operational flexibility, efficiency and system security are not unduly eroded as a result. The studies reported in this thesis illustrate the impacts on critical fault clearing times and active power transfer limits through this North-South corridor, known as the B6 boundary, in the presence of increasing penetrations of wind power generation on the GB transmission system. By focussing on the transient behaviour of a representative reduced test system following a three-phase short-circuit fault occurring on one of the two double-circuits constituting the B6 boundary, the impacts on the transient stability margins are qualitatively identified. There is a pressing necessity for new wind farms to be able to mitigate, as much as possible,

their own negative impacts on system stability margins. The transient stability improvement achieved by tailoring the low voltage ride-through reactive power control response of wind farms is first investigated, and a novel control technique is then presented which can significantly mitigate the erosion of the transient stability performance of power systems, in the presence of increasing amounts of wind power, by tailoring the immediate post-fault active power recovery ramp-rates of the wind power plants around the system. The impacts of these control techniques on critical fault clearing times and power transfer limits are investigated. In particular, it has been found that the use of slower active power recovery from wind farms located in exporting regions when a short circuit fault occurs on the export corridor will provide significant benefits for both of these metrics, while a faster active power recovery in importing regions will provide a similar transient stability benefit. However, it is also shown that there are potential detrimental effects for system frequency stability. In addition, important impacts of wind farm settings in respect of low voltage ride through are revealed whereby the LVRT controls can act to erode stability margins if careful consideration of their settings is not taken. Assuming a future power system with high levels of centralised observability and controllability (or decentralised co-operative control systems), it may be possible to continually "dispatch" the reactive power gains and active power recovery ramp rates discussed in this thesis to match the current system setpoint and to seek an optimal transient response to a range of credible contingencies.

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I cannot remember the books I've read any more than the meals I have eaten; even so, they have made me.

– (possibly) Ralph Waldo Emerson

When men know not what to do, they ought not to do they know not what.

– Samuel Moody

You are not singular in your suspicions that you know but little.

– John Adams

For Elizabeth and her wee sister . . .

Contents

List of Abbreviations

Abbreviation	Full Name
AGC	Automatic Generation Control
AVR	Automatic Voltage Regulator
CCT	Critical [Fault] Clearing Time
DER	Distributed Energy Resource(s)
DFIG	Doubly-Fed Induction Generator
DSM	Demand-side Management
E&W	England and Wales
FACTS	Flexible AC Transmission System
FES	Flywheel Energy Storage
FRC	Fully-Rated Converter
FSIG	Fixed Speed Induction Generator
LFC	Load Frequency Control
GB	Great Britain
HVAC	High Voltage Alternating Current

Abbreviation	Full Name
HVDC	High Voltage Direct Current
LVRT	Low Voltage Ride-Through
NS	Northern Scotland
PF	Power Factor
PMSG	Permanent Magnet Synchronous Generator
PMU	Phasor Measurement Unit
PV	Photovoltaic
SG	Synchronous Generator
SI	Synthetic Inertia
SS	Southern Scotland
STATCOM	Static [Synchronous] Compensator
SVC	Static VAR Compensator
RoCoF	Rate of Change of Frequency
UFLS	Under-frequency Load Shedding
VDFD	Voltage Dip [Induced] Frequency Dip
VSC	Voltage Source Converter
VSWT	Variable Speed Wind Turbine
WTG	Wind Turbine Generator

Nomenclature

Script	Description	Unit
E_k	Kinetic energy	(J)
J	Inertia	$(kg \cdot m^2)$
H	Generator normalised inertia constant	(s)
$p.u$	Per-unit quantity	–
ω	Angular Speed	$(rad \cdot s^{-1})$
ω_{syn}	Synchronous angular speed	$(rad \cdot s^{-1})$
S	Nominal generator rating	(MVA)
δ	Power angle	(rad)
p_m	Generator mechanical power input	(W)
p_E	Generator electrical power output	(W)
p_a	Generator net accelerating power	(W)
ΔP	Change in power	(W)
f	Grid frequency	(Hz)

List of Figures

List of Papers

- K. Johnstone, R.M. Tumilty, K.R.W. Bell, and C.D. Booth, "Transient stability assessment of the GB transmission system with high penetrations of wind power," 13th International Workshop on Large-scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Berlin, Germany, November 2014.
- K. Johnstone, K.R.W. Bell, and C.D. Booth, "Post-fault active power ramp rates of DFIGs for transient stability enhancement in Great Britain," 14th International Workshop on Large-scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Brussels, Belgium, October 2015.
- K. Johnstone, K.R.W. Bell, and C.D. Booth, "The impact of post-fault active power recovery ramp rates of wind turbines on transient stability in Great Britain," EWEA Conference, Paris, France, November 2015.

CHAPTER 1

Introduction

1.1 Introduction

THE electricity transmission industry in many countries finds itself in a state of change which is unprecedented since such transmission systems were first designed and built in the first half of the last century. The combination of legal obligations on governments to cut fossil fuel use and their corresponding emissions (the current UN emissions targets from the 2015 Paris agreement to limit anthropogenic climate change to less than 2 degrees Celsius and for global emissions to peak as soon as possible [7]; the GB target of 80% reduction in greenhouse gas emissions by 2050), predicted requirements for renewable technologies to cut greenhouse gas emissions to a sustainable level (84% low carbon capacity in the 2040 GB network according to National

Grid's 2016 "Gone Green" future energy scenario [8]), and a growing public desire to source its electrical energy from sustainable and renewable resources has resulted in the growth and expansion of wind power (among other renewable technologies) which can be seen in markets around the world today.

Wind power generation technology has enjoyed rapid worldwide growth in recent years [9, 10] due to the relative maturity of the technology and falling cost of energy and, as a result of this increasing penetration, dramatic changes are expected in the way in which electricity transmission grids are planned, analysed and operated in the coming decades. As an example, Scotland successfully reached a 2015 target of generating the equivalent of 50 per cent of its total energy from green sources, ahead of the goal of producing 100 per cent of electricity need from renewables by 2020 [11]. On 7th August 2016, Scotland was able to produce enough electricity from wind power to effectively cover their electricity needs for the entire day [12]. Meanwhile, the EU's "Large Combustion Plant Directive" will cause many coal plants to be closed in Great Britain (in Scotland and in the Midlands and North of England) within the next decade (the LCPD was superseded by the Industrial Emissions Directive as of 1st January 2016). According to the GB system operator National Grid in 2016: "The potential future increase in renewable generation in Scotland is against a backdrop of recent closures or reduced capacity of conventional generation at Longannet, Cockenzie, Fife and Peterhead. This represents a 4.7 GW reduction in conventional generation plant in Scotland operating within the wholesale market since 2010" [13].

Along with the rapid expansion of highly distributed, small- and large-scale renewable energy sources comes the major challenge of having to integrate them, quickly and efficiently, into electricity transmission and distribution systems, along with markets, which were not originally designed to handle them. Transmission system owners and operators must now change how they plan and operate their networks in a future in which many of the standard practices will no longer apply. For instance, the increased penetration of renewable resources (including high numbers of variable-speed converter-interfaced wind power plants, as well as a rapidly growing share of solar photovoltaics, wave/tidal technology and batteries) will tend to reduce, and may one day supersede the dominance of large synchronous generators powered by steam turbines. Such large power stations were traditionally placed in locations which were relatively close to large demand centres such as cities and industrial areas and existed in relatively small numbers. The meshed transmission system would facilitate the flows of electrical power between power stations and cities over fairly short distances and electrical power would be mostly consumed in close proximity to where it was generated.

In contrast to this, with the growth of wind power (both onshore and offshore) there is an increasing tendency for power plants to be located more diffusely and farther from the main load centres in the network. Not only are the wind farms generally located far away from major load centres, but they are increasingly becoming "embedded" within distribution networks rather than at transmission level and therefore connected at lower voltage levels. The same is true for solar photovoltaic (PV) generation, which can have a similar impact on grid dynamic performance to modern wind turbines, with increasing numbers of people choosing to become "pro-sumers" (producers/consumers) of electrical power by installing roof-top PV panels. The placement within distribution networks of large renewable electricity generators such as wind farms and PV carries with it new challenges to grid planners and operators as traditional power flow magnitudes and directions (i.e. from high voltage transmission networks into low voltage distribution networks) may be consistently reversed, and limitations on the availability of reactive power support from such generation, to support the operation at transmission level, may become problematic.

The intermittent nature of the wind as a resource also provides new challenges to grid operators – increasingly so as wind farms continue to replace traditional synchronous generation. Whereas some conventional generators may be re-dispatched and their outputs continually changed in order to maintain a balance between generation and demand and to ensure that transmission assets such as lines and transformers are not overloaded, the same cannot be said for wind farms. Wind farms tend to be given priority over conventional plants to generate the maximum power available whenever the wind is blowing sufficiently strongly [14], as their marginal cost of energy and their direct environmental impact is low in comparison to fossil fuel burning alternatives. This means that the exact amount of power being fed into the grid by the wind farms cannot be predicted with complete accuracy as the wind speeds experienced at a wind farm site can fluctuate greatly over all timescales. This effect can be mitigated to some degree by having a wide geographical dispersion of wind generation across the grid, where the local variations in wind speed are more averaged out, but the twin problems of intermittency and predictability remain important to system operators.

Each of these expected changes to power systems around the globe will have an impact on their dynamic behaviour in response to system faults and normal day-to-day fluctuations in demand. A key challenge to grid operators in the coming years will be to form a deeper understanding of these dynamic impacts of high volumes of converter-interfaced generation, both from a transient and steady-state perspective. The work reported in this thesis aims to examine the dynamic behaviour of the GB transmission system to onerous transient short-circuit faults and the resulting changes to that behaviour that can be expected as a result of increased wind power penetration levels. The extent of the resulting changes to transient stability margins will be qualitatively assessed and explained in the context of the unique case of the Great Britain transmission system, and the suitability of novel operational techniques will be assessed based on the ability to successfully mitigate the negative impacts on transient stability margins.

The thesis will outline some of the key technical background information with respect to power system operation and stability in Chapter 2 and then follow this with descriptions of traditional methods of mitigating transient stability issues in Chapter 3. Chapter 4 will then describe the simulation methodology and the results of simulations relating to the transient stability behaviour of the GB power system, specifically the problems relating to the reduction in system inertia levels and the replacement of synchronous generation with wind power plants. Chapter 5 then describes a method which aims to show the use of fast-acting control of reactive power injections from wind farms in order to mitigate these transient stability issues through supporting the system voltage profile. This is followed by Chapter 6 in which novel research is carried out on the potential transient stability implications of manipulating the post-fault active power recovery rate of wind power plants in order to mitigate their original negative impact on transient stability margins as a result of their inherent lack of inertial response. The trade-off that exists between such transient stability considerations and longer-term frequency stability of the GB system is also examined. The thesis will therefore show the potential control advantages that may be provided to grid operators in future network scenarios where large amounts of synchronous generation have been displaced by converter-based generation, such as variable-speed wind turbines or solar PV installations. Chapter 7 will conclude the thesis and provide recommendations for future work on the subject.

1.2 Main Research Questions

- What are the impacts of increased wind power penetration, and a corresponding reduction in traditional synchronous generation, on transient stability margins in the Great Britain electricity transmission system?
- What are the key factors that influence any such changes in the transient stability margins of the system in the presence of wind power?
- Can the wind farms themselves provide any transient stability benefits, either by improving stability margins further where they are improved, or by partially mitigating any erosion of transient stability margins where they are eroded, through tailoring the wind farms' own control system response?

1.3 Contributions to Knowledge

The main contributions to knowledge provided by the work carried out in this thesis are as follows:

- Simulation and assessment of the first swing stability impacts resulting from the replacement of synchronous generation with wind farms, in the context of the electricity transmission system of Great Britain;
- Exposition of the transient stability impacts of wind farms' low voltage ride-through (LVRT) behaviour in GB, in particular the sensitivity of network stability to different LVRT settings and threshold values of controller parameters;
- An investigation of the potential first swing (transient) stability benefits to be provided by tailoring the immediate post-fault reactive power injections as a result of the LVRT reactive power controller gains implemented in the wind farm control systems;
- An investigation of the potential first swing (transient) stability benefits to be provided by slowing or curtailing the active power recovery rate of wind farms, particularly in exporting network areas, and a description of the potential trade-off with frequency stability.

CHAPTER 2

Technical Background

The following chapter first provides an overview of the key technical definitions and concepts which underpin traditional power system operability, with a focus on those areas which are most relevant to the work carried out in this thesis (namely the issues of increasing wind power penetration). The discussion is then devoted to the study of power system stability, including particular detail on the phenomena of transient stability and the changes in the GB power system which are expected to impact on the behaviour of the system in response to transient short-circuit faults on the main transmission system boundary between Scotland and England.

2.1 Power System Operation

2.1.1 Frequency Control

It is the obligation of the TSO (transmission system operator) of an interconnected power system to continually maintain the AC frequency and voltage within acceptable limits, in order to maintain successful operation of connected devices and security of supply. The majority of the world's power systems (including Great Britain) maintain a nominal utility frequency of 50 Hz, while, for example, 60 Hz has become the standard in North America. The utility frequency is a function of the mechanical rotational speed of all of the connected synchronous generators and of the instantaneous balance between total generation and demand; a surplus of active power generation with respect to overall system demand will cause the frequency to rise and a deficit of generation will result in the frequency value falling. The rate at which the frequency changes during an imbalance event is predominantly a function of the system inertia, which will be discussed in a later section.

The system utility frequency can be thought of as either a local or system-wide parameter, depending on the relevant time scale and phenomena for which it is being considered. The effect of any imbalance between overall generation and demand on the system will have an impact on the AC frequency measured at all other points on the system over a study period of tens of milliseconds. However, when fast acting dynamic phenomena is observed, there will be small variations in the spot frequency observed at different parts of the synchronous area (i.e. slightly different rotational speeds of two interconnected synchronous generators). Deviations from the nominal value of system frequency are undesirable, as electrical devices are designed to accept electrical power with properties (i.e. frequency, voltage) which are set within tight, acceptable limits.

The control of grid frequency within tight tolerances is an important obligation placed on transmission system operators, as the failure to do so can result in poor operation of customer equipment, tripping of system generators or, in the worst cases, in collapse of significant portions of the power system through cascading failures.

In Great Britain the Security and Quality of Supply Standard (SQSS) [15] specifies the obligations for frequency regulation. The grid frequency should be maintained at a nominal value of 50 Hz, with statutory limits of ± 0.5 Hz (1%) during normal grid operation. Abnormal events such as a loss of generation of 1800 MW (the largest allowable instantaneous loss) may result in a frequency deviation beyond these statutory limits but this is allowable as long as the frequency is restored to within the statutory limits within one minute of the fault.

National Grid's own internal operating limits are ±0.2 Hz (0.4%) for generation loss of up to 300 MW [16] and a maximum frequency deviation of -0.8 Hz during abnormal events [17]. Failure to maintain a system frequency within acceptable boundaries may lead to malfunctions in consumer and industrial electrical devices and machines, which is of course unacceptable from the point of view of the end user.

Primary Frequency Response (Droop Control)

Traditional synchronous generators each contribute to the regulation of system frequency by employing governor controllers with a "droop" characteristic. The generator quickly responds to small deviations in rotor speed by increasing or decreasing the steam intake to the turbine and therefore the mechanical power. By monitoring the grid-side electrical frequency (or synchronous machine rotor speed), the control system is able to tailor the mechanical power input to the generator, for example by regulating the amount of steam driving the turbine and therefore the prime mover.

A typical "droop" characteristic of 5% is employed in the control logic of synchronous generators, meaning, for example, that a negative deviation of the measured system frequency of 5% would actuate a 100% rise in the power output of the machine [3]. The droop controller "requests" additional mechanical power through the turbine prime mover which is proportional to the error between the rotor speed and a speed reference set-point. For example, when a drop in grid-side frequency occurs the generator rotor speed will drop in proportion to the electrical frequency drop. This produces an error between the rotor speed set-point and the actual rotor speed. This error signal can then be used by as the control signal to request more mechanical power to the turbine in order to support the grid frequency. This simple linear relationship between the speed (frequency) of the rotor and the electrical power output (see Fig. 2.1) ensures that all the machines set to governor control mode in the synchronous area contribute towards the re-balancing of frequency with an active power contribution which is in proportion to their relative size and rating.

According to National Grid: "All large power stations connected to the

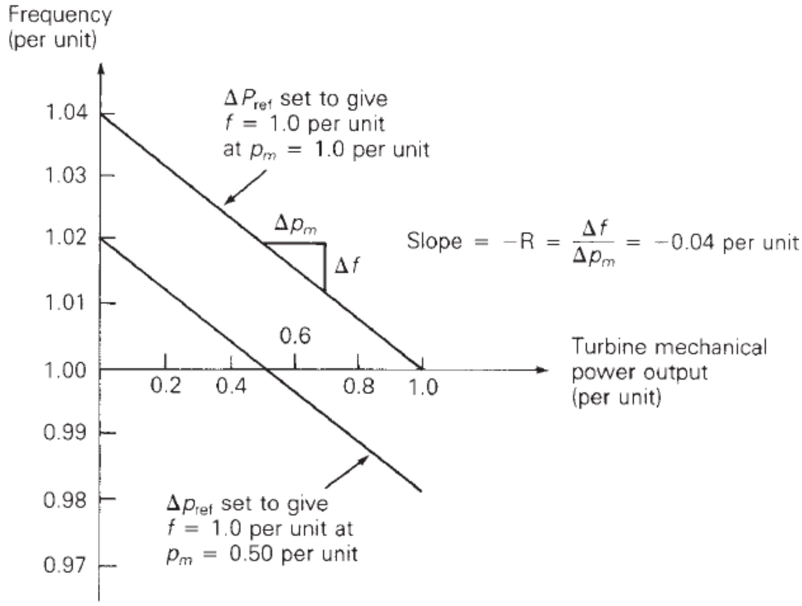


Figure 2.1: Steady-state frequency–power relation for a turbine-governor [1]

transmission network are obliged to have this capability." (The definition of "large" depends on which transmission owner's network the power station is located in.) [18]. This de-centralised droop control is normally sufficient to ensure a steady frequency for small generation/demand imbalances which are experienced continually throughout the day. It achieves balance in the power system over short timescales (seconds to minutes), however on longer timescales (morning and evening demand peaks) and when large imbalances are likely to occur (e.g. immediately following a popular televised sporting event or a solar eclipse), more comprehensive operations must be undertaken to establish generation/demand balance, either manually by the TSO dispatching additional generation assets or automatically through other control loops.

Secondary Frequency Response

This generation control scheme is normally referred to as Load Frequency Control (LFC) or Automatic Generation Control (AGC). When a fault (such as a short circuit and subsequent tripping of a generator) occurs on the system, it can result in a very large, instantaneous imbalance between generation and load. When a large imbalance is experienced in the system the droop control may only act to arrest the frequency fall or rise to a new steady-state value which is not equal to the nominal value of 50 or 60 Hz. Such unforeseen events cannot be managed by the system operator in the same way as normal day-to-day demand fluctuations, which typically happen gradually and with a reasonable amount of predictability. During the short time windows following faults, it is highly advantageous that the network has some amount of automated control in order to restore the power system to an equilibrium operating point – maintaining system frequency stability and security of supply to consumers.

In a large interconnected power system such as that of Continental Europe, LFC-based secondary frequency control is used in order to restore the power system frequency to its nominal value. In addition to this, the LFC also acts to maintain scheduled power flows between each of the different "control areas" (normally corresponding to countries) which comprise the whole synchronous area. This ensures that each of the control areas are responsible for re-balancing the system in response to an imbalance event originating within their own control area. In contrast to this, the GB system operates as a single synchronous area comprising a single control area. This means that there is no need for the secondary frequency control to include the automatic geographic

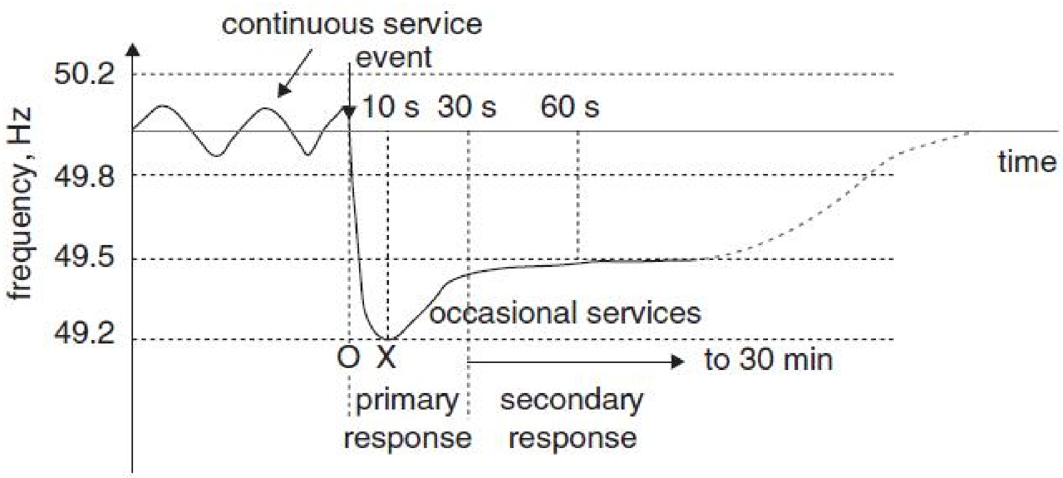


Figure 2.2: Frequency Service Quality Control [2]

re-balancing of power. Therefore, the role of secondary frequency control is taken up as a manual operation by National Grid, where the system is continually monitored by a human operator who is responsible for scheduling and dispatching the reserves necessary for re-balancing in the event of an imbalance event [19, 20].

Figure 2.2 shows the network frequency response after a typical fault, where some amount of generation has been tripped out of the grid. At the instant of the fault the frequency rapidly drops at a rate (slope) which is determined by the total inertia of the remaining electrical machines on the system. The higher the value of inertia provided by connected synchronous generation, the shallower the slope. Automatic controllers and/or transmission system operators then perform the relevant actions to regulate the system frequency in two distinct stages, discussed previously and known as primary and secondary response. The objective of primary response is to arrest the frequency drop within the first 10 seconds, which is performed through fast-acting governor droop control and potentially also fast load shedding.

Subsequently, the role of secondary response is to restore frequency to pre-fault levels over the time window of 30 seconds to 30 minutes post-fault through ramping of connected generation, the introduction of standby generating plant and the steady reconnection of system loads. National Grid maintains their own two definitions of Frequency Response: Dynamic and Non Dynamic Response: "Dynamic Frequency Response [droop] is a continuously provided service used to manage the normal second by second changes on the system. While Non Dynamic Frequency Response [manual secondary] is usually a discrete service triggered at a defined frequency deviation" [21]. Large pumped hydro schemes are often used to inject active power to the grid in these instances, a service which is known as "standing reserve".

2.1.2 Flexible Demand

Traditionally, power system operators have carried the burden of balancing generation and load on a minute-by-minute basis – taking for granted that the demand cannot be effectively controlled. Demand for electricity varies in time (and is uncertain) and large-scale, cost-effective storage of electrical energy is not yet available. This has meant that generation must be scheduled to match demand. However, in the continued absence of large-scale energy storage, it should conceptually be possible to modify, at least to some extent, demand to match generation. Moreover, the variability of the available renewable generation arguably makes that the better option, if it can be delivered reliably and doesn't unduly impact on users' use of electricity.

Energy demand management (including demand-side management (DSM) and demand-side response (DSR)) is the term given to the modification of consumer behaviour in order to tailor electricity demand to meet available generation. By encouraging consumers to use electricity at off-peak times, through financial incentives and education, it aims to reduce the total cost of energy by flattening out demand peaks and therefore reduce the requirement for expensive peaking plant.

A variation of this technique and a promising area of development is that of automatic demand-side response, which could be utilised as part of the solution to the reduced inertia and frequency response problems. An example of automatic DSR would be the widespread use of consumer electronics, such as fridges, which can automatically switch off in the event of a perceived under-frequency event. The combined effect of many thousands of consumer devices going off-line in the moments following the loss of a large generator would greatly help the network frequency response [22]. The control algorithms in such devices could then randomly bring themselves back online over the course of the following hour or so, once the system frequency has been stabilised.

2.1.3 Line Limits

A key task for power systems operators in their efforts to deliver power in a safe and secure manner is to ensure that power lines never encounter situations where their power flows are above certain limits. These limits may be thermal (maximum allowable current through the line), voltage (maximum allowable voltage drop along the line) or stability (the maximum allowable angular separation between distant generators).

For a given transmission line, the lowest power flow corresponding to one of these three limits will set the maximum allowable transfer through the line. In the case of thermal limits, each line in the system will (depending on the line type and several other factors) have a set power flow limit dictated by the amount of allowable thermal expansion through conductor heating and therefore the distance to earth when the line sags. Depending on the length and physical properties of a given transmission line, a power flow limit may also be set based on the voltage drop which is seen along the length of the line. Maintaining a grid voltage profile which is as close as possible to pre-selected voltage setpoints is a key objective in maintaining grid stability and therefore security. Finally, a power flow limit may be set on a given transmission line based on the expected voltage angle difference (and therefore synchronous generator rotor angles) which will be seen across the line. Operating synchronous generators at excessively high rotor angles with respect to the rotation of their stator magnetic field acts to erode the angular stability margins of the generators and hence the power system. When operating at a high rotor angle, the synchronous generator is more vulnerable to instability (discussed in further detail in a later section) as a result of disturbances on the system, which would be harmless if the generator was operating at a lower steady-state rotor angle.

It is the obligation of the transmission system operator to ensure that these line limits are respected at all times. This includes scenarios which may involve planned and unplanned outages, or other credible fault conditions on the network. Line limits may act to constrain the geographical distribution, and therefore the types of generation which can be online and generating power at a given instant in time. In order to ensure the most efficient use of generation resources, including, most importantly, the zero-marginal-cost generation from renewable energy sources, it is imperative that system operators are able to raise line limits to as high a level as possible. The work carried out in this thesis is intended to provide evidence that wind farm control techniques can be used to raise stability-constrained power flow limits within Great Britain in future high wind generation scenarios.

In the future power system, rather than stipulating static limits to power flows, etc. it may become possible for the system operator to have a more dynamic view of power system operational limits. In order to achieve this, the system operator would require a view of the operating condition of the network at all times (not a snapshot a ten minute intervals, as occurs today) and must be able to dynamically alter the operational limits, meaning that the grid could be operated at points which were much closer to the true instantaneous limits (such as voltage angle separation or power flow along a line) and therefore operate the grid in a more efficient manner. Guo, et. al [23] have identified the possibility of replacing the static power flow limits currently used in Great Britain with a dynamic limit based on the real-time angular separation between the exporting and importing regions of the system.

2.1.4 FACTS Devices

Many different devices and control strategies are employed throughout power systems in order to control the flows of active and reactive power. The control of active power flows through the network is a key factor in power system operation, as line thermal (current) limits must always be respected in order to avoid faults associated with over-heating of conductors and the breakdown of insulation (hence causing short-circuits). The management of reactive power flows is also an important control objective, as the network voltage profile is maintained through the manipulation of reactive power. Flexible AC Transmission System (FACTS) devices can be utilised as a method for such control and they will be discussed in more detail in Chapter 3.

2.1.5 Power Quality

For power system operators, it is crucially important that the power delivered to customers should meet a minimum standard of quality. Power quality can be described as the degree of fluctuation in the frequency or voltage of the AC waveform observed at some point in the grid. It has been identified that the increasing use of wind power generation (and other renewable sources) in power systems may have a significant and often detrimental effect on the quality of the power delivered to customers, particularly where high penetrations of wind power are integrated in low-inertia grids [24].

According to [25], wind turbines can have a detrimental effect on grid power quality including, for example, flicker, harmonic distortion, voltage imbalance, voltage sag and voltage swells. Variable-speed wind turbines can introduce harmonic distortion through the rapid switching found in their power converters. More generally, wind turbines have a negative impact on grid power quality, particularly when they are connected to weak portions of the grid. Power quality issues in the presence of wind power, though important, are not a key focus of this project.

2.2 The Low Inertia Problem

2.2.1 Power System Inertia

Inertia is one of several key factors which determines overall power system stability and can be thought of in two distinct, but equally important ways:

1. The "overall inertia" – i.e. the sum of all the system inertia connected to the power system at a given time.
2. The "distribution of inertia" – i.e. the relative sizes of, and distances between, the main centres of inertia (or a single generator with respect to the rest of the system).

The overall loss of inertia is the key component in considerations of frequency stability. For example, RoCoF protection settings must be continually managed to avoid spurious trips, as the "normal" RoCoF levels experienced in a reducing-inertia environment tend to rise over time. As National Grid have pointed out, "[The] increase of loss risk from 1320 to 1800 MW could increase RoCoF risk to above threshold level (0.125 Hz/s) of RoCoF protection" [26] – meaning that under the new largest-loss-of-infeed contingency, further reductions in inertia will prove problematic in considerations of RoCoF relay setting. The change in expected RoCoF scenarios will also affect other control and protection systems such as the operation of under-frequency load shedding (where a portion of network demand is disconnected to mitigate low frequency) and the use of synthetic inertia (where wind turbines provide an emulated inertial response to mitigate low network frequency). Meanwhile, the geographical distribution of inertia (the changes in how the inertia is distributed between parts of the synchronous area) is more important in terms of transient stability. These are related phenomena but can be thought of as distinct problems.

Overall Inertia

Firstly, the overall inertia of a power system acts to slow down drops or rises in frequency caused by the imbalance between total generation and load. Traditional power systems contain a degree of inherent inertia (resistance to change in speed), which is proportional to the sum of all of the rotating masses directly electro-mechanically coupled to the power system. Provided stability is maintained and they remain synchronised with the rest of the power system, traditional synchronous machines that are connected to the grid are bound to rotate at a speed which is dictated by the system frequency, and hence their physical rotational inertia is also directly linked to the electrical frequency.

To determine whether an electrical machine is able to contribute an “inertial response” in the event of a grid-side disturbance, one must identify whether any change in network frequency is reflected in the generator by a change in electromagnetic torque, which manifests itself as a change in rotational speed of the turbine rotor [27]. The inertial response of a generator occurs before frequency regulation controllers have time to react, as it is an instantaneous injection/absorption of active power caused by the natural electro-mechanical coupling response of a generator to grid-side conditions [28] and the principle of conservation of energy.

Inertia can be expressed in terms of the internal kinetic energy of the rotating mass, which is stored in the rotor as the mass accelerates and released as it decelerates.

$$E_k = \frac{1}{2}J\omega^2 \tag{2.1}$$

The stored kinetic energy within a turbine rotor can be expressed as shown in Equation 2.1, where E_k is the rotor kinetic energy, J is the rotor moment of inertia around its centre and ω is the rotational speed of the rotor in $rad \cdot s^{-1}$. In the dynamic analysis of power systems, the inertia constant H is conventionally used as an indicator of the inertial response of any synchronous generator connected to the grid. It corresponds to "the time, in seconds, that it would take to replace [the] stored energy when operating at rated mechanical speed and rated apparent power output" [29].

$$H = \frac{E_k}{S} = \frac{J\omega^2}{2S} \tag{2.2}$$

where S is the machine rating in MVA. Typical inertia constants for conventional generators lie in the 2–9 s range [30], while the combined rotor/generator of wind turbines are similar at 2–6 s [31], without taking into account the lack of direct coupling between the electrical and mechanical systems as a consequence of the power electronic converter interface. This indicates that a promising area of wind turbine design will be in developing controllers which allow access to this inertia (and hence kinetic energy) during faults, a technique known as Synthetic Inertia which will be discussed further in Chapter 3.

The introduction of increasing amounts of converter-interfaced generation (such as variable-speed wind turbines and photovoltaic solar power) causes a net drop in the total power system inertia. This has been identified as a major area of concern for transmission system operators, particularly in smaller power systems such as those of Great Britain and Ireland, due to their relatively low existing inertia and the fact that a typical fault represents a larger proportion of generation lost than that on a larger system [32]. The low inertia problem is exacerbated during periods where low demand coincides with high renewable power production. During these periods there will be very low amounts of inertia available as fewer synchronous generators are connected to the grid. A large system disturbance, or loss of infeed, during such scenarios may therefore be considered critical to frequency or transient stability.

The continued growth in wind penetration in power systems will cause changes in the type and quantity of active power reserve which is needed in order to address the inherent unpredictability of wind speed and hence wind power output. It is likely that this reserve will however come in the form of conventional generation – which does add inertia to the system – and therefore the system inertia will never be completely eroded, according to [33]. It is still up for debate what proportion of this reserve should be spinning or standing given the rapid improvements in weather forecasting and the limits to how much power might be lost (or gained) in a short space of time, for example as a result of geographically dispersed, and therefore uncorrelated, wind power across the system.

Urdal, et al. [34] highlighted the scale of the emerging problem regarding loss of system inertia in the GB transmission system. They stated that in accordance with National Grid's "Gone Green" scenario, a five-fold reduction in overall grid inertia is expected by 2030. This grid-wide effect, coupled with increasingly isolated synchronous generation in the northern part of Scotland, will lead to reduced stability margins in the system unless the effects are appropriately mitigated.

According to [28], hypothetical grids in the far future may contain absolutely no synchronous generation and therefore no natural inertia. In this case, some of the inertial response must be contributed by the power converters of the non-synchronous generation. Inertial response could also be provided by energy storage systems or by deloading the generation equipment. Chapter 3 will cover each of these strategies in more detail. Coordinated control between devices and changes to grid codes will be required to ensure security of the future grid at all times.

As mentioned previously, an important relationship exists between the grid inertia and the rate of change of frequency (RoCoF) experienced during a given network disturbance:

$$\frac{d\Delta f}{dt}|_{t=0^*} = \frac{f^0 P_k}{2\sum_{i=1,i\neq k}^{N} H_i S_i} \tag{2.3}$$

where Δf is the deviation of the frequency f from its nominal value f^0, 0^* is the moment just after disconnection of the load/generation, P_k is the lost generation/load (the machine carrying the index k), and H_i and S_i are the inertial constant and apparent power rating of the synchronous machine i, with

i ranging from 1 to N.

Equation 2.3 [35] shows a key relationship concerning the initial rate of change of system frequency (RoCoF) in the wake of a system fault. This is a useful indicator of stability as excessive values of RoCoF tend to be indicative of systems with little inherent inertia. It can be seen that the rate of change of frequency is proportional to the power discrepancy between generation and demand (P_k) and inversely proportional to the inertia constant (H) and power rating (S) of the generator(s) that remain connected to the system after the disturbance. A key part of the problem is highlighted here as power systems are growing increasingly larger (in terms of generation capacity), however the drop in inertia is occurring at a much quicker rate and therefore dominating in networks with increasing penetrations of wind power generation. According to studies performed in [32], the increase in post-fault RoCoF is similar with both fixed-speed (FSIG) or variable-speed (DFIG) wind turbines and the maximum value of RoCoF is sensitive to wind penetration.

As the rate of change of frequency following a given fault increases, this means that there is less allowable time for controllers (such as steam turbine governors), and protection systems in the grid to perform the relevant actions in order to stabilise the system. It is therefore critical that future networks maintain some form of inertial response, whether it is natural or synthetic, in order to minimise the system frequency's sensitivity to load imbalance, therefore minimizing the RoCoF in such an event. At present, many generators connected at lower voltage levels are equipped with "loss of mains" protection which is based on local RoCoF signals. Their function is to trip off the generation equipment in the event that a high value of RoCoF is detected, as this is likely to have occurred as a result of a disconnection between the local system and the bulk power system. Generation of power while operating in such an "islanded" mode is unsafe to equipment and personnel, and therefore the RoCoF protection is set to trip off the generator. The disconnection of many small, distributed generators as a consequence of high RoCOF experienced at their grid connection point will act to further exacerbate the frequency issue and result in a cascading failure within the power system. As higher levels of RoCoF are to be expected in a converter-dominated power system, it is important that these protection systems are diligently managed, perhaps by raising the acceptable level of RoCoF before the generation asset is tripped in order to avoid ever more frequent spurious disconnections from the grid.

According to [32], during summer scenarios (lower demand) there is a higher likelihood of excessively high RoCoF. In the event of a system fault under such conditions there will be a reduction in stability margins due to the decreased total system inertia resulting from fewer synchronous generators on the system. This can lead to more generators tripping through their RoCoF protection, further exacerbating the original frequency dip [28].

[36] argues that "voltage-dip induced frequency drop", where a cluster of wind farms (or other sources of generation) will significantly reduce their active power output in the event of a low grid voltage profile, is the "most problematic of the RoCoF issues". This problem can be mitigated through the expansion of fault-ride through capability, including reactive power control from the wind farms and fast active power recovery in the immediate post-fault condition. As will be discussed in later chapters, the fast recovery of active power from wind may prove beneficial in relation to mitigating frequency stability

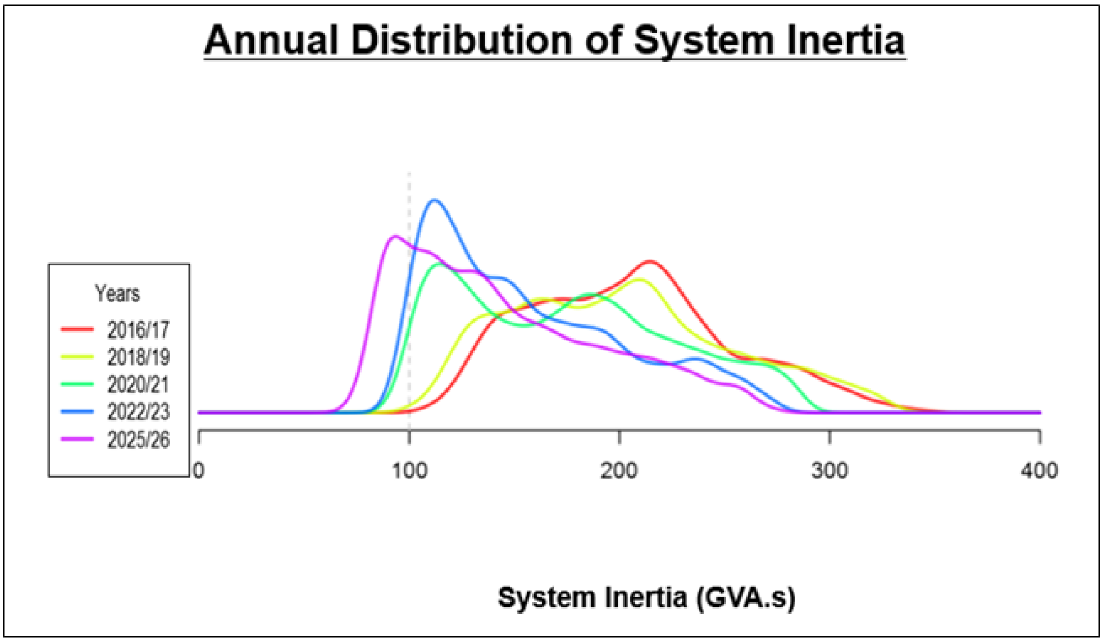


Figure 2.3: Projected probability density function of GB system inertia over an annual cycle.

issues, however there are opportunities to use slower active power recovery ramps to deliver transient stability benefits and such trade-offs must be managed by transmission system operators to ensure overall stability is adequately maintained.

Figure 2.3 shows projections by National Grid (the GB system operator) of the annual distribution of total system inertia (in GVA.s) expected over the next decade [37]. As can be seen from the figure, there will be a dramatic tendency for a growing part of the year to have a very low amount of synchronous inertia connected to the power system. This means that over a growing number of hours through the year there will be a high risk of system insecurity to possible loss-of-infeed events if there are no mitigation measures undertaken to address the erosion of system inertia.

Figure 2.4 shows the sensitivity of experienced RoCoF in the GB power

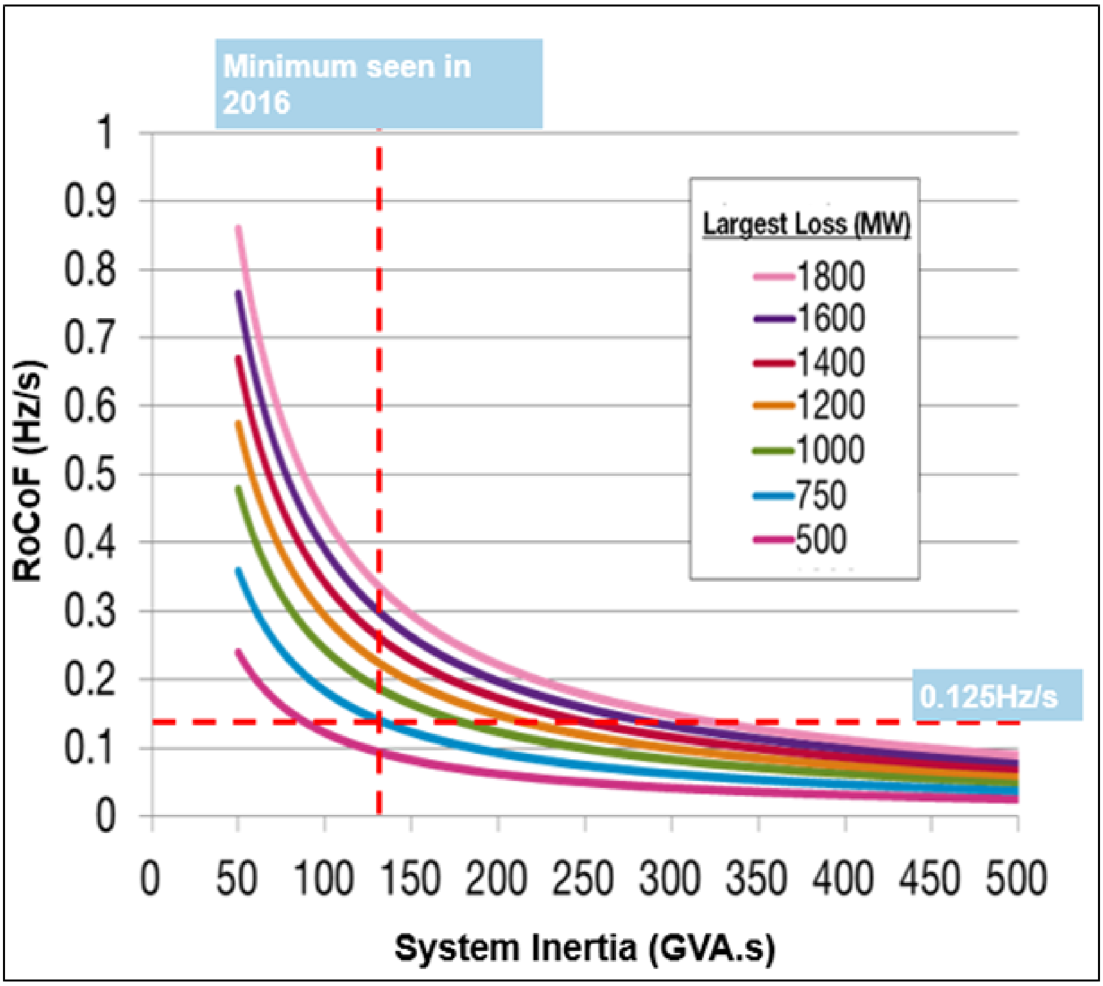


Figure 2.4: RoCoF experienced in GB for a range of inertia and loss of infeed events.

system to the amount of system inertia online, for increasing loss-of-infeed events. It shows that for the present-day loss-of-infeed limit (1800 MW), and the minimum level of inertia already experienced in 2016, that there is a risk of RoCoF values of around 0.35 Hz/s. This exceeds the present-day RoCoF-based loss-of-mains protection settings for distributed generation. A presentation [37] given by Fiona Williams (National Grid Technical Policy) explains that the RoCoF withstand limit for generation units must be raised to over 0.5

Hz/s (measured over 500 ms) by 2025. Owing to the lack of standardization that this project is beginning to address, it has been noted in [38] that there is potential for two or more distributed generators connected in the same location to react differently to the same event, even with the same “settings”, due to slight differences in the RoCoF algorithms used in their respective protection devices.

Distribution of Inertia

While the total grid inertia is the dominant factor in longer-term frequency stability studies, another crucial aspect of the system inertia is the way in which the inertia that exists on the system is distributed. When considering the transient stability of the system (which will be discussed in more detail in the following section) the nature of how the inertia of the system is spread around the system, as well as the location of the fault within this distributed inertia background, may have a large impact on how the system responds to large disturbances.

As will be seen, an important aspect of maintaining transient stability is the electrical distance between the synchronous generators within the system. In order for them to maintain synchronism with one another, the relative voltage angle differences in the steady-state must remain low enough that for all credible contingencies the angle difference does not exceed certain limits in the first rotor swings during the transient fault period. In situations where a single, isolated synchronous generator is located within a region that is dominated by converter-interfaced generation and is electrically distant from a set of more interconnected synchronous machines, these generators will become more susceptible to transient instability.

As well as changes in generation, as the nature of industry throughout the country moves further away from heavy manufacturing, there will also be a corresponding change in the types of loads that are connected to the electricity transmission system. Historically heavy manufacturing has made use of large electrical motors, the number of which looks set to decline. Such motors are also sources of inertia to the system, therefore the reduction in their numbers or any change in their distribution around the system will have an impact on the stability behaviour of the transmission system in the future.

Synthetic/Virtual Inertia

Historically the synchronous generators have been the only generation sources which have been able to maintain a steady grid voltage and provide synchronising torque in the system. Alternatively, the converter-based generation does not provide the same "grid forming" characteristic, instead acting as "grid following", meaning that they operate by synchronising their synthesised AC voltage waveform with the waveform measured at their connection point with the grid. As the proportion of generation in power systems that is delivered from synchronous machines is reduced steadily by the increased penetration of converter-based generation, it will become increasingly important that at least some of the non-synchronous generation is capable of providing the system with reliable and steady voltage waveforms, in the same "grid forming" manner as the synchronous machines. Future converter-interfaced generation and storage may be expected to provide a control service which aims to emulate an active power response which is the same or better than equivalently sized conventional synchronous generation [39].

Real-time Inertia Estimation

In future power systems which are dominated by converter-based generation, it may become useful (or entirely necessary) for system operators to have a real-time view of how much inertia exists on the system at a given moment in time. The total amount and the geographical distribution of the system inertia will have large impacts on the response of system variables to both fast-acting transients and longer term frequency dynamics. The inertia of the power system will change depending on several factors, including the instantaneous demand, the proportion of that demand which is being met by converter-based generation, the proportion of demand which is being met by international tie-lines and the dynamic characteristics of the generation and load which are connected to the network at a given moment.

If grid operators are able in a future power system to estimate the amount of inertia present on the network, and are therefore able to anticipate any need to procure additional inertial response on a range of time scales, then this would have a positive impact on the security and quality of electricity supply to customers. Two different methods may be considered as possible ways to estimate the amount of inertia which is available on the grid. Firstly, the frequent "polling" of generators which are connected to the network, which report their available inertial response on a moment-by-moment basis. The polling method relies on the operator having complete visibility of all generation (and load) which is currently providing an inertial response to the system. This includes all of the synchronous generation, synchronous motors and any converter-interfaced generation capable of providing an inertia-like active power response to grid frequency fluctuations. Secondly, the use of Phasor Measurement Units (PMU) to monitor fluctuations in power system variables, such as voltage phase angles, in response to a known generation imbalance. The PMU-based technique depends on the power system operator (their algorithm) having access to data at very short time resolution, allowing the operator to monitor the deviations which occur in the system in response to a known generation/load imbalance. This technique shows promise in theory, but in reality the ability to widely and accurately monitor system variables, and the lack of precise knowledge of the magnitude of imbalance events may prove a challenge for the deployment of such inertia monitoring/estimation techniques. [40, 41, 20].

As will be discussed subsequently, the overall inertia is useful as a guide to the slower frequency response of the system to imbalances. However, the precise geographical distribution of the system inertia is the dominant factor for consideration during faster acting dynamics, such as maintaining transient stability in the wake of short-circuit faults on important transmission boundaries. Future developments which could accurately measure or predict the geographical distribution of inertia throughout the system could be a key enabler for the transient stability improvement techniques discussed later in this thesis.

2.3 Power System Stability

Broadly speaking, engineering can be thought of as the practice of ensuring stability, operational consistency and predictability in the behaviour of physical systems. In terms of electrical power systems, an important design criteria is that the system should be able to maintain a stable operation both in the steady state and in the wake of any "credible" contingency condition. The power system stability problem comprises a combination of several different behaviours – each of which must be managed carefully and in harmony with one another – which manifest themselves in different ways and over a range of time scales. These are defined in [42] and are discussed in this section.

In order to reliably provide power and ensure the safe operation of both generators and loads, a power system must operate in a stable manner. "Power system stability refers to the ability of synchronous machines to move from one steady-state operating point following a disturbance to another steady-state operating point, without losing synchronism"[1]. This is characterised by the continued synchronous operation of all of the connected synchronous machines, i.e. they should all remain operating in parallel and at the same speed, dictated by the system frequency.

After a disturbance has occurred (such as the tripping of a system generator or a fault on, and subsequent loss of, a line) and while the system is tending towards either a new equilibrium state or a loss of synchronism, this is referred to as the "transient period". The system behaviour during this time is called the "system dynamic performance" and is of great interest to power system designers and operators. In GB, an important criterion for system security is that the synchronous generators maintain synchronism at the end of the

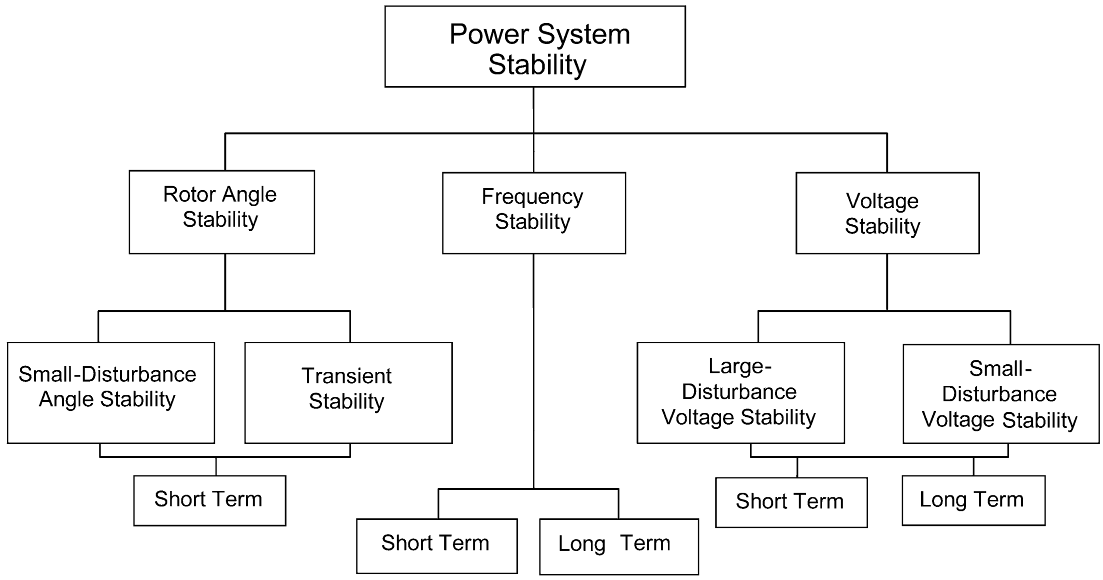


Figure 2.5: Classification of power system stability [3].

transient period following "the secured event of a fault outage" of "a double circuit overhead line on the supergrid" [15]. If the oscillatory response of the power fluctuations in the network are damped and settle to a new equilibrium point within a finite time (i.e. they are bounded), then the system is said to be stable – otherwise the system is unstable.

Power system stability can be split up into three distinct areas: frequency stability, rotor angle stability and voltage stability, shown in Figure 2.5. These phenomena will be discussed in the following sections.

2.3.1 Frequency Stability

As discussed previously, the regulation of frequency in power systems is one of the most important aspects of grid operation. Frequency stability is the study of how well the power system frequency can be maintained within acceptable limits in the wake of unplanned imbalances between load and generation, for instance the loss of the largest generator or other power infeed to the power system. In order to achieve acceptable frequency stability, the power system must contain enough spinning reserve and inertial response that statutory frequency limits and RoCoF limits are not breached. This is more of a problem in smaller power systems, such as Ireland or Great Britain (which have inherently low inertia and cannot readily draw on large power reserves) than for large interconnected systems like mainland Europe. The larger the power system, generally the larger the loss of generation required to result in the same magnitude of frequency deviation.

The frequency nadir (lowest point reached) can be used as a measure of system frequency stability in the event of a loss of generation or other fault [43]. According to [32], the frequency nadir is considerably lower in a scenario where Doubly-Fed Induction Generators (DFIGs) are the dominant form of wind generation over Fixed-speed Induction Generators (FSIGs), given the same fault. The paper also concludes that increasing DFIG wind on the system will require increased availability of frequency response to maintain the frequency nadir above a given threshold value. New frequency regulation methods may be required due to the increased penetration of wind power. Reference [28] argues that the entire methodology for frequency control must be reassessed in a future where there are reduced levels of, or virtually no natural inertia.

National Grid System Operability Framework 2015 [44] mentions the increasing need for frequency response services. The analysis carried out by National Grid shows a need for new services for frequency management, as the frequency response requirement will rise by 30-40% by 2020.

2.3.2 Rotor Angle Stability

Transient Stability

"Transient stability is the ability of the power system to maintain synchronism when subjected to a severe transient disturbance such as a fault on transmission facilities, loss of generation, or loss of a large load." [3]. When a large disturbance occurs on the network, such as a three-phase-to-earth short-circuit fault which is subsequently "cleared" by quickly isolating and removing the faulted transmission component through circuit breaker action, a combination of several factors can contribute to transient instability. Transient instability manifests itself in the excessive accelerations of synchronous machine rotors during the "fault-on" period, the resulting high rotor angle deviations and finally through highly undesirable pole-slipping rotor behaviour. Transient stability is therefore mainly concerned with maintaining the balance between mechanical power in, and electrical power out of the synchronous generators on the system, and if unavoidable imbalances do occur, keeping such imbalances short in duration. Modern protection technology currently sets a lower limit on the duration of the fault-on period to somewhere in the region of 80 to 100 ms, so further improvements in transient stability margins must now be found through means other than fault duration reduction. With high penetrations of wind power in future power systems, there is an opportunity to utilise the wind turbine capabilities for transient stability improvement.

Equation (2.4) illustrates several critical aspects affecting transient stability. It shows that the power flow through a section of network (or from a particular synchronous generator to the bulk power system) is proportional to the magnitudes of the two end voltages (E) and also to the sine of the voltage angle difference between the two points. It is clear from this expression the importance of maintaining an acceptable grid voltage profile (as close to the rated voltage value as possible) in order to maximise active power output from the synchronous generator terminals. A low voltage profile leads to a reduced power output capability for the synchronous generators and therefore, through conservation of energy, increased acceleration of the generator rotors throughout the disturbance event (given constant mechanical power input from the turbine). The provision of reactive power from generators and other grid devices is instrumental in maintaining an adequate voltage profile, both during steady-state and extreme contingency conditions.

$$P = \frac{E_1 E_2}{X} sin(\theta_1 - \theta_2) \tag{2.4}$$

Another key aspect affecting system transient stability is the need to maintain low levels of transmission system reactance (X) between exporting and importing regions. Large values of inductive reactance from transmission lines and other components impose a limit on the power transfer capability of the transmission corridor or machine in question in the pre-fault steady state and lead to high relative pre-fault rotor angles. These high rotor angles act to erode the transient stability by reducing the margins for rotor accelerations during the fault-on period. In the period following a fault (when a portion of the network has been switched out by protection systems), the system reactance between the two points will have instantaneously increased and therefore the maximum power transfer is reduced – limiting the export of active power from the generators in the exporting region and causing their rotors to tend towards a new, higher rotor angle for the same mechanical power input. This causes the post-fault stability margin to decrease.

The swing equation (2.5) is the governing second-order differential equation which determines the dynamic behaviour exhibited by synchronous machine rotors in transient stability studies. It is derived from Newton's laws of motion in a rotational reference frame and describes how the synchronous machine rotor accelerates in the presence of an imbalance in the powers of the electrical and mechanical systems:

$$\frac{2H}{\omega_{syn}}\omega_{p.u}(t)\frac{d^2\delta(t)}{dt^2} = p_{mp.u}(t) - p_{ep.u}(t) = p_{ap.u}(t) \tag{2.5}$$

The equal area criterion (Figure 2.6) is a useful graphical representation of the transient stability of a single generator in the event of a system fault and is applicable for a single generator connected to an infinite bus, or for a two-generator system. It shows the power angle curve of the synchronous generator, and through simple integration and graphical analysis it is possible to determine whether the machine(s) will maintain synchronism in the wake

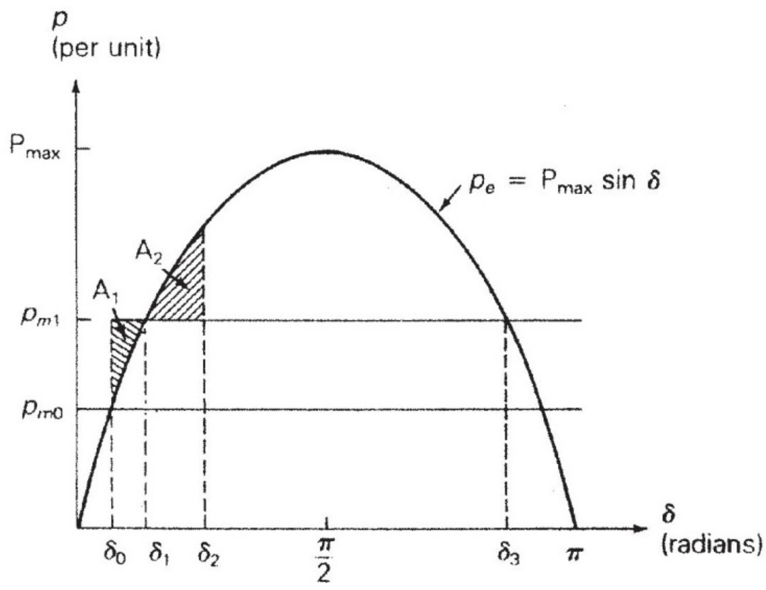


Figure 2.6: Graphical example of the Equal Area Criterion [1].

of a system fault.

In this illustrative case, the initial equilibrium operating condition of the machine was at $p_{m0} = p_e$ and the power angle was at δ_0, where p_m is the mechanical input power to the generator and p_e is the electrical power output. As described by the Swing Equation (2.5), when these two values are equal there is no net accelerating power and the generator rotor neither accelerates nor decelerates, hence the generator is turning at a constant speed: the synchronous speed.

There is then a disturbance in the form of a step change in the mechanical input power, which becomes p_{m1}, while the load demand—and therefore the electrical power out—remains at the initial value, p_e. The rotor then absorbs the excess energy in the form of rotational kinetic energy by accelerating towards a new equilibrium power (and rotor) angle of δ_1. Due to the inertia of the rotor mass there is then an overshoot beyond the new equilibrium point, after which, due to the domination of electrical torque relative to mechanical torque, the rotor begins to decelerate until it comes to rotor angle δ_2, and finally the direction rotor reverses (with respect to a synchronously rotating reference frame). The rotor then oscillates around the new equilibrium power angle δ_1, where the mechanical power p_{m1} is equal to the electrical output power p_e.

A short-circuit fault causes a voltage dip to propagate outward throughout the system from the fault location, with the magnitude of the dip decreasing as the distance from the fault increases. This has the effect, as discussed previously, of limiting the amount of electrical energy that the synchronous generators in the affected area are able to export and, given constant mechanical input power over the short time scale of transient behaviour, causes acceleration of their rotors due to a loss of synchronising torque. This acceleration then leads to an advancement of the rotor angles in the exporting region with respect to that of the importing region. Upon clearance of the fault through tripping of the faulted line, the voltage profile of the network must recover to acceptable levels within a short enough time frame to allow the generators which have accelerated during the fault to export the excess kinetic energy gained during the fault period in the form of electrical energy. The restoration of voltage has been historically, for the most part, performed through the action of automatic voltage regulators (AVR) associated with conventional generators. Transient stability is maintained when the synchronous machines in the system all return to a new steady state operating condition, without irreversible long-term drifts or oscillations in power flows and rotor angles.

The replacement of conventional thermal generation with wind power plants consisting of variable-speed turbines alters the power system operation in several significant ways. The key grid changes which must be diligently managed include:

- The reduction of overall grid inertia and changes to the geographical distribution of the system inertia.
- The loss of important grid controllers associated with conventional plant (including AVR, power system stabiliser (PSS) and governor action).
- The relocation of generation to more remote areas with respect to the large demand centres, and the associated higher impedances through which the power must flow.
- The increasing isolation of some synchronous power plants with respect to the bulk power system as other local conventional plants are replaced by wind power.

Each of these effects may act to reduce the stability of the system to transient faults and therefore must be mitigated through either passive (long-term system planning) or active (short-term control) means. In this thesis, a transient fault is applied to a key transmission boundary in the system and time domain simulations are carried out and analysed to demonstrate the impacts that wind power plants may have on transient stability margins of the GB system, with a focus on the stability improvement as a result of reduced active power ramp rates from wind power plants immediately following the fault.

As wind power penetration at transmission level has increased substantially in the last decade, it has become an important grid code requirement for modern wind power plants to provide support in the event of faults. Previously, while wind penetration was low with respect to total demand and was predominantly connected at distribution level, wind power plants were allowed to disconnect entirely from the grid in the event of large faults. However, so-called “Fault Ride-Through” requirements have become increasingly demanding and widespread within grid codes worldwide. During a transient event (where the terminal voltage of the wind power plant has been reduced), the wind power plants must now not only remain connected, but must also be equipped to produce transient injections of reactive power to support the local grid voltage. In order for a wind turbine to provide high levels of reactive power to the system during a fault, while honouring the turbine and converter’s MVA rating, there will be a corresponding drop in the active power output from the wind turbine.

If the turbines happen to be within an exporting region (in this case located in Scotland) then this drop in active power output is expected to be beneficial to the transient stability of the synchronous machines in the exporting region and therefore the stability of the entire system. In effect, by dropping their active power output the wind turbines allow a greater proportion of the neighbouring synchronous machines’ power to feed the loads in the exporting region. This has the beneficial effect of slowing the accumulation of kinetic energy in the synchronous machine rotors and therefore retards their acceleration in much the same way as through the provision of reactive power by the wind power plants described previously.

A promising area of research around this concept is to quantify the level of benefit in terms of transient stability which can be gained through tailoring the rate of recovery of the active power from the wind power plants in the exporting region. Currently the grid code in Great Britain states that all wind power park modules must recover 90% of their pre-fault active power within 1 second of fault clearance [45]. The recovery ramp-rate varies between grid codes, is a condition which can be easily met by modern wind turbines, and is in place in order for wind turbines to contribute positively to the frequency stability of the system. It is expected, however, that by using a lower ramp-rate – for example 50% per second – there is an opportunity to gain significant advantages in terms of transient stability following a large grid disturbance, but this may come at the expense of frequency support from the wind power plants (e.g. "Synthetic Inertia" [46]).

When considering a single synchronous generator connected to a large network, several factors affect the transient response (and therefore the transient stability) of the generator to a fault [3]:

(a) How heavily the generator is loaded.

The loading of a particular generator (the proportion of its maximum active power that it is currently generating) is proportional to the physical angle of the rotor with respect to the rotating magnetic field in the generator stator coils. The difference between these angles is known as the power angle of the generator. In the steady-state condition, the higher this angle then the lower the margin for rotor angle drift during a transient fault which is allowable before the machine becomes transiently unstable. Maintaining a relatively low machine power angle during steady-state operation therefore aids in maintaining transient stability margins in the system for transmission system short-circuit faults.

(b) The generator output during the fault. This depends on the fault location and type.

The transient stability of a generator during a fault can be thought of in terms of the ability of the generator to export as much of the kinetic energy in its rotating parts as possible. When a short-circuit fault occurs in close proximity to the generator in question, the terminal voltage experienced by the machine will be depressed to a value which might mean that the generator cannot release its full kinetic energy to the system, causing acceleration of the rotor and an increase in the rotor angle during the fault period. The type of fault is also important here as a single or double phase fault will still allow unfaulted phases to export their full or near-full power capability and therefore the rotor acceleration and swings are not as drastic in these conditions.

(c) The fault-clearing time.

The amount of time that a short-circuit fault is active on the system, as discussed previously. For a particular fault type and generator dispatch, a longer fault time before clearance will bring the generator closer to transient instability.

(d) The post-fault transmission system reactance.

When a transient short-circuit event has been cleared through the removal from service of a transmission circuit, the post-fault impedance of the system through which power is flowing will be altered. The reactance value of the transmission corridor at this point is important since the resulting decrease in power transfer capability means that the kinetic energy gained in the fault-on period cannot be fully exported back to the system. It is therefore advantageous for there to be fast auto-reclosure of circuit breakers which, if the fault has been extinguished and is not permanent, can ensure that the post-fault reactance is the same as pre-fault and the power export capability of the generator is not hindered.

(e) The generator reactance.

A lower reactance increases the peak power and reduces the initial rotor angle. The lower the steady-state relative rotor angle, the farther the generator is operating from the transient rotor angle limit. For the same short-circuit transient fault, a generator operating at the lower steady-state rotor angle will have a higher stability margin since its rotor will have to advance farther during the fault-on period.

(f) The generator inertia.

The higher the inertia, the slower the rate of change in angle. This reduces the kinetic energy gained during fault; i.e., area A1 is reduced in the equal area equation discussed previously. The generator inertia generally acts to slow down any physical dynamics in the generator.

(g) The generator internal voltage magnitude (E').

This depends on the field excitation in the generator. High speed exciters may be able to maintain a high internal voltage magnitude during a fault which aids in the overall power export capacity of the generator during transient short-circuit events and hence improve the transient response.

(h) The "system" bus voltage magnitude (E_B).

This represents the receiving end of a transmission line through which the generator in question is transporting power. In an infinite bus test system this will normally be held at 1.0 p.u., however in real-world scenarios the distant system voltage may be significantly lowered for instance due to a fault in the system.

Small-signal Stability

Small-signal stability is the ability of the power system to maintain synchronism when subjected to disturbances of a much lesser severity than those considered for transient stability. The power system is small-signal stable if any normal day-to-day power fluctuation (due to normal changes in load or generation) does not lead to a loss of synchronism. The two forms of small-signal instability are: (1) steady rotor angle increase due to a lack of synchronizing torque, or (2) oscillatory rotor angle deviations due to a lack of damping torque. Together, these make up the forces that act upon a synchronous generator rotor and act to maintain synchronism between each of the other connected machines. A simple analogue of these forces is the example of a spring-mass-damper system which is perturbed by a force or released from a non-equilibrium position. The synchronizing torque is that component of the electro-mechanical force which acts in phase with the rotor angle deviation from equilibrium (thus acting like the spring in a simple spring-mass-damper system). The damping torque is that component of the electro-mechanical force which acts in phase with the rotor speed deviation (thus acting like the damper).

In general, where automatic voltage regulators exist on the grid, the small-signal problem is concerned with the lack of damping torque. For the system to be stable, it must be able to damp out system oscillations and therefore avoid ever-increasing rotor swings which would lead to loss of synchronism between machines. In some cases, Power System Stabilisers (PSS) are installed in the excitation controllers of synchronous machines in order to mitigate the small-signal stability problems which are brought on by the presence of AVRs.

According to [47], the addition of increasing amounts of wind power has the potential to change the amount of system damping, and therefore will affect the small-signal stability of the grid. The system damping is affected in four critical ways: (1) The dynamic modes of the system are altered through the displacement of conventional plant by wind plants, (2) Power path flows are changed through the introduction of wind power, affecting the synchronizing forces, (3) Wind plants may displace conventional power plants which were fitted with power system stabilisers (PSS), and (4) Wind power plants' controls may interact with the damping torque of any nearby synchronous generators.

Reference [48] concludes that the introduction of wind power plants tends to improve the system damping when a group of machines is oscillating relative to a large system and when there are inter-area oscillations, however the impact on intra-area oscillation was not significant. The paper attributes this to several factors including stronger coupling between the reduced number of synchronous generators and the de-coupling of DFIG turbine rotors from grid power oscillations.

[43] asserts that system damping is reduced with high wind penetrations and rotor angle oscillations are exacerbated when grid faults occur in locations which are close to wind farms. The paper recommends that DFIGs which are in networks with high wind penetration levels should be fitted with supplementary inertial response control loops and system damping capability. However, Reference [49] asserts that if transient stability is maintained after a distur-

bance, DFIGs can provide adequate system damping.

According to [50] the use of fixed-speed induction generators (FSIGs) may improve the damping of inter-area oscillations, while variable-speed doubly-fed induction generators (DFIGs) may actually erode some of the damping capability of the grid to such oscillations. FSIGs are however widely known to be detrimental to the grid voltage stability, an area where DFIG wind turbines have a significant advantage. The paper concludes that an optimal mix of FSIG and DFIG technology should be sought in order to utilise the advantages of each wind turbine type.

According to [4], a negative consequence of automatic voltage regulators (AVR), which are found in synchronous generators and have a primary function of maintaining terminal voltage, is that they tend to decrease the natural damping of power system oscillations. Dynamic instability can result from poorly tuned AVRs in the power system. The cause of the possible instability is the difference in response times between mechanical and electric systems, which are orders of magnitude different. Another controller known as a power system stabiliser (PSS) can be introduced to offset this effect and provide positive damping of oscillatory behaviour.

2.3.3 Voltage Stability

Voltage stability is the ability of a power system to maintain steady and acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance [3]. Voltage instability occurs when the demand for reactive power on the grid cannot be met by the connected generation or other reactive power sources. Under these circumstances, a disturbance in the grid may lead to a progressive and uncontrollable drop in grid voltages throughout the network.

Since the voltage stability of a system is reliant on the appropriate control of reactive power, the addition of FACTS devices (see Chapter 3) can be used to help improve the voltage stability. When fixed-speed wind turbines are aggregated into wind farms, reactive power compensation equipment such as static synchronous compensators (STATCOMs) and static var compensators (SVCs) are used at the point of connection to the grid to control reactive power and therefore support the grid voltage.

According to [25], in order for generators to contribute to voltage stability through nodal voltage control, their reactive power output must be controllable. Fixed-speed wind turbines using squirrel-cage induction generators require a supply of reactive power in order to magnetise their rotor, and are therefore incapable of reactive power control. Reference [33] asserts that fixed-speed wind turbine generators are widely known to have a negative impact on dynamic voltage stability. However, variable-speed wind turbines are able to control their reactive power and they can therefore successfully support the grid voltage. [51] asserts that with appropriate controllers installed, variable-speed wind turbines are capable of mitigating voltage stability problems in power systems.

According to [52], although traditionally voltage stability and transient rotor angle stability were historically treated as separate issues, with the current trend of replacement of synchronous generators with their corresponding AVR voltage control, this can no longer be seen as the case. Transient rotor angle stability and voltage stability are becoming more closely interlinked, and therefore must be studied in conjunction with one another in a holistic manner. For this reason, it is important that voltage considerations be thought of as an integral part of the transient stability studies undertaken in this project.

2.4 Faults and Protection Systems

2.4.1 Short Circuit Faults

Power networks are large, complex systems which are always vulnerable to a broad range of disturbances, of which transient short-circuit faults are a very common form. A short circuit is an unplanned direct connection between a part of the electrical circuit and earth, or an earthed structure. Short circuit faults affect power system stability by resulting in temporary restrictions on power transfers through depressed system voltages and altered system impedances and can take several forms, such as phase-phase faults or flashovers to earth (e.g. foliage or other structures coming into contact with a line, insulation degradation, or structural failure of a transmission tower or pole). In simple terms, when a synchronous generator is subject to a transient fault in the local network its electrical power output capability is temporarily restricted (although the current supplied to the fault will normally increase significantly while the voltage is reduced). In this event there will exist a surplus of mechanical energy being supplied to the machine rotor when compared with the electrical energy output and acceleration of the rotor will subsequently occur.

During the fault (when the voltage drops), the power transfer capability of the network will fall and hence there will generally be an imbalance between generation and load, though the extent will depend on the nature of the load. The fault is generally cleared quickly enough (allowing a recovery of the voltage) for frequency stability not to become a problem as a direct result of the short circuit. However, if the short circuit were to result in a loss of generation or load, then frequency stability issues might arise. In addition, it would always be beneficial to check the possibility of first swing (transient) instability affecting one or more generating units and the subsequent damping of power system oscillations.

In the study of power system stability, it is important to predict the behaviour of the generators and other equipment when the system is subjected to several different fault types and durations. Although single-phase-to-ground or phase-to-phase faults occur more frequently in a typical power system, the most important faults for transient stability studies are three-phase-to-ground due to their relative severity. While a single-phase-to-ground fault, for example, may cause rotor angle swings and many other unwanted effects, power is still able to be transferred through the remaining phases and the system may not be severely affected at the whole-system level [1]. In contrast, a three-phase-to-ground fault taking place on a key transmission line will cause large imbalances in power between regions of the grid, leading to very severe dynamic behaviour such as large transient rotor angle swings and hence potential damage to generators. It is for this reason that the studies carried out in the project focus on the effects of large, transient, three-phase-to-ground faults over unbalanced or asymmetrical transmission line faults.

2.4.2 Loss of Generation Fault

In addition to short-circuit line faults, other dynamic events in the system can have an impact on the transient behaviour of the synchronous machines. For example, in the event of a loss of infeed (through an unplanned generator outage, or a loss of interconnection to another synchronous grid) there will be an imbalance between the instantaneous generation and demand in the system. As discussed previously, such an imbalance will have a direct impact on the system frequency (nominally 50 Hz in Great Britain). The system is designed and operated in such a manner that the loss of the single largest infeed of power (Normal 1320 MW, Infrequent 1800 MW [15]) should not result in a frequency excursion in excess of the statutory limits of ± 0.5 Hz set by the system operator.

It is important to note that due to the large negative disturbance in the voltage profile of the network, the subsequent increase in transmission system reactance and resulting power transfer capability reduction (from removal of the faulted circuit through protection action), the most onerous fault condition for transient stability is that of a short-circuit on a major tie-line. The loss of generation fault, though important from a frequency stability perspective, does not affect the network in the same manner as a short circuit / loss of line fault. For this reason, the loss of generation fault is not considered within the scope of the analysis within this thesis. It is important, however, that long-term frequency stability implications are considered when any of the transient stability mitigation techniques discussed in this thesis are implemented in future power systems operations.

2.4.3 Fault Duration

The duration through which a section of power system is subject to a short-circuit fault before the faulted component is cleared is crucial to the stability of the system. Depending on the network configuration, generation mix, fault location and many other factors, the time taken to clear faulted equipment and re-route power flows may lead to either the network regaining a stable operating condition or a loss of synchronism between synchronous machines and therefore system instability. For a given operational condition and fault, the longest time which a faulted portion of the network can remain connected before being cleared is called the "critical clearing time".

It is conventional in transient stability studies involving wind power to assume that the wind speed experienced by the turbines remains constant throughout the transient period, as the duration of the simulated faults will generally be of a much smaller magnitude than fluctuations in wind power [53].

Critical Clearing Time

The "critical clearing time" is the amount of time through which a section of power system can exist in a faulted condition before system stability is compromised [1]. The entire system is said to be unstable if one or more synchronous machines connected to the network lose synchronism and become unstable (known as pole slipping behaviour) [15]. As long as the fault is cleared within this time window, the system will remain stable and return to a new equilibrium operating point, some time after the disturbance is terminated. As a result, CCT is often used as a metric in the assessment of system stability – with higher CCT values indicating a more stable system in transient stability studies.

Critical clearing times are used to determine the settings for protection systems on the network. Physical limitations are present on protection devices such as large circuit breakers, which take a finite amount of time to break the electricity flow. As a result of this limitation, the critical clearing times required with much reduced system inertia may not be physically possible – causing a dramatic problem to network stability. In real-world operation, the system operator would restrict power flows in order that the critical fault clearing time of all credible faults would be satisfied by the existing limits of the protection equipment.

2.4.4 Fault Level

Fault level is the term given to the magnitude of the currents present in a network in the event of a fault. Fault level is a function of several factors, including the type of generation on the network, the location of the fault relative to the generators, the impedances of the transmission lines and the network topology (i.e. the extent to which the system is meshed). In the case of a short circuit on a transmission line, the impedance of the local circuit tends towards a very low value and as a result the current level increases significantly in the immediate vicinity of the fault. The limiting factor to the level of "overcurrent" is the Thevenin equivalent impedance of the remainder of the circuit. The overcurrent can lead to permanent damage to transmission lines as they heat up and sag, and might also exceed the capability of the circuit breakers to interrupt such a large current.

A consequence of increased converter-interfaced generation on a power system is a large drop in the magnitude of such fault current levels, since the converters are only rated to a certain power output. This will have a significant impact on protection systems' ability to adequately detect and clear faults in future.

2.4.5 Protection Systems

Any reduction in the value of the overall power system inertia – and the associated increase in RoCoF values for a given generation/load imbalance – has the potential to affect the operation and performance of power system protection systems and hence the operability of the power system as a whole. It is expected that the changing landscape regarding the type and distribution of sources of power infeed will require recalibration or redesign of many protection devices on the network in the coming years.

Many generator protection systems utilise controllers which are sensitive to the rate of change of grid frequency at the point of connection with the bulk power system. A problem then arises in the form of cascading loss of generation – where synchronous machines begin disconnecting as a result of their own protection systems following a fault – resulting in an exacerbation of the original frequency response problem. Already in Ireland the grid operators have felt pressure to recalibrate the allowable RoCoF magnitudes which are taken as a control signal for the automatic tripping of distributed generation in order to minimise such cascading outages. It has been decided by Northern Ireland Electricity Networks that the distribution grid code should be updated to require generators to remain connected through events where a RoCoF of 1 Hz/s is experienced over a 500 ms measurement window [54]. A similar approach has been investigated for implementation in Great Britain. It will be an important development in distributed generation technology that future devices are able to remain connected during high-RoCoF situations as the grid inertia continues to erode in the coming years.

In the event of a grid fault, large fault currents will be present on the system. Such currents are potentially damaging to power electronic converters and other transmission assets and as such there are protection systems in place to save these assets from the effects of large current magnitudes and therefore excessive losses and heating. Overcurrent relays are found most commonly at the distribution level and may rely on the concept of electromagnetic induction which, in event of a large line current, causes a revolving disc to initiate a switching action which breaks the electrical circuit and protects the line [55]. They can also take the form of fuse or a microprocessor-based relay and may also include a magnitude-dependent delay.

RoCoF relays may provide protection to generators during periods of high rates of frequency excursion. This limits the accelerations and transient currents experienced by the machines and therefore saves the assets from damage in the event of grid faults. As the magnitude of the natural inertia available on the grid to resist high RoCoF decreases in the coming years, such protection schemes may be in need of either redesign or at least reconfiguration to keep up with the change and ensure proper protection operation.

RoCoF relays are generally deployed as "loss of mains" protection on generators which are connected at distribution level. A key factor in distribution system protection is the ability to identify when a disconnection has occurred between the bulk power system and some section of the distribution system which is able to maintain operation as an electrical "island" (i.e. it contains electrical power demand and sources of generation capable of meeting that demand). Due to the growth in distribution-level renewable energy systems, in the event where a section of distribution system has become electrically isolated from the transmission system it is increasingly likely that the islanded system will remain energised by the distributed energy resources (DER). This causes an unsafe condition for workers to attempt to diagnose and repair the fault condition [56]. Other reasons to avoid islanded operation include unsynchronised subsequent closure attempts; the island operating in an unearthed condition; voltage rises/falls; and any subsequent short circuits not being detected due to unearthed operation or low fault levels [57].

Loss-of-mains detection is incorporated into the protection systems of the DERs in order to avoid such unsafe situations. The protection is based on the principle that it is likely that the isolated section of network will be operating in an unbalanced condition, i.e. instantaneous generation and load do not match. Therefore, when the network section has been isolated from the bulk power system, there will be an instantaneous and rapid change in the frequency experienced in the isolated network. The rate of change of the frequency experienced in this part of the network will generally exceed values typically experienced while the power system is intact. The DERs are therefore commonly equipped with protection systems that measure RoCoF and, when its value exceeds a pre-set threshold for a given period of time, are programmed to disconnect the DER from the network. This guarantees that the DER does not contribute power to the isolated part of the network – de-energising the lines and allowing workers to fix the faulted section of network.

According to [58], RoCoF relays on 50 Hz grids are generally set to trip anywhere between 0.1 and 1 Hz/s, depending on the inertia and size of the grid in question. Studies in Ireland have recognised that RoCoF relay settings should be increased [36, 59] in order to account for the decrease in total system inertia due to high penetration of wind power and other non-synchronous generation, a recommendation which has since been implemented by the TSO (RoCoF relay settings may need to reach as high as 2.0 Hz/s in some predicted future generator protection systems). It is vital that any RoCoF relays in future power systems are configured in a manner that ensures that innocuous, non-loss-of-mains events are not wrongly identified by the protection as loss-of-mains. Such spurious tripping would only serve to exacerbate the under-frequency situation and may cause highly unstable frequency regulation and therefore collapse of the power system.

2.5 Wind vs. Conventional Generation

There are four relevant and key differences between wind power and conventional power, each of which can affect the stability of the system in unique ways. These will be discussed in turn in this section.

2.5.1 Difference 1: Generator Location

Historically, electrical power has been generated predominantly in large scale conventional thermal power plants. These plants were constructed in locations which were commonly proximate to large demand centres (reducing transmission losses and therefore costs) and as near as possible to the natural resource of coal or gas (in order to reduce the cost of transportation). This situation is changing in a drastic way with the development of wind power, as the areas with the highest wind power resource tend to be found far from areas with the greatest demand for electrical power. For example, in Great Britain the majority of the demand for electrical power is situated in the south of England while the areas of greatest wind power resource are to be found in northern Scotland.

As a result of this mismatch it is extremely common that wind power is connected to inherently weaker portions of the transmission system. A transient fault in such regions only has a local effect on voltage, however the torsional drivetrain oscillations and resulting power fluctuations can be observed globally [60]. The existing GB national electricity transmission system was designed in such a manner that the exploitation of wind power may be severely hindered unless continued grid re-design and reinforcement is carried out in the coming years. Such grid reinforcements as the Western HVDC Link as well as re-conductoring and the installation of series compensation across the B6 boundary have already been installed and show that system owners and operators are attuned to the problem.

According to [33], the critical clearing time for faults can be severely reduced when wind power is introduced into a power system, particularly when the wind fleet is focused on a small geographical area. This is thought to be a result of the highly modified power flows. CCT is a key indicator of power system stability and a reduction in CCT generally signifies erosion of stability margins.

2.5.2 Difference 2: Generator Types

Generators are responsible for the conversion of mechanical power into electrical power. This conversion is performed in all generators through the interactions of magnetic fields on the stator and rotor in the airgap between them. This section gives a brief overview of the two key generator technologies – synchronous and asynchronous – and how they are used in conventional thermal power plants and wind turbines.

There is a significant difference in the types of generating technology used in the wind turbine industry when compared with the conventional thermal power plants. Conventional power plants use synchronous generators and run at constant speed using governor controllers, while modern wind turbines use either variable-speed induction (DFIG) or permanent magnet synchronous (FRC) generators and are capable of generating electricity through a large rotor speed envelope. Each generator type has its own characteristics in terms of control and its own dynamic response with respect to the power system. The understanding of these controls and dynamics is a key factor in power system stability studies.

As more and more wind power comes online, it is increasingly important for the wind turbine fleet to perform the same duties as the existing synchronous generation in the form of inertial response, frequency control (primary and secondary) and voltage (reactive power) control [61]. According to [62], "For wind power generators to contribute to the security of a power system, they must have the ability to contribute to both the voltage and frequency control in stabilising the power system following a disturbance, they must be able to ramp up or down to avoid insecure power system operation, they must be able to ride through disturbances emanating from the power system, they must be able to avoid excess fault levels while still contributing to fault identification and clearance, and they should be able to operate in island mode when the supply from the grid is lost".

2.5.3 Difference 3: Lower Voltage Level

The majority of onshore wind farms in future energy scenarios are connected to the grid at lower voltage levels than conventional thermal power plants. While coal and nuclear plants are connected directly to the transmission system at high voltages (> 110 kV), wind farms are more likely to feed in to the grid at subtransmission (110 kV, 66 kV) or even distribution (20 kV, 10 kV) voltage levels.

According to [33], transient stability is negatively affected by the integration of wind generation into subtransmission and distribution systems. This is caused by the limited reactive power contribution from the generators due to reactive losses at these voltage levels.

[63] states that the voltage level at which a wind farm is connected has very little effect on the speed and voltage of the existing synchronous generators in the event of a system fault. However, there is still a small detrimental effect when the wind farm voltage is lower than transmission level.

According to [64], as of 2015 around 10 GW of embedded generation was connected in Great Britain. Going forward, National Grid expects that by 2050 50% of all electricity generation could be connected at distribution voltage levels [65]. With the longer protection clearing times found in distribution systems, distributed generation traditionally relied on other large, conventional, transmission connected generators for maintaining stability. This was acceptable as long as the overall share of generation from distribution systems was low, but they must now become active participants in maintaining system stability as they become a larger contributor to the overall energy mix.

2.5.4 Difference 4: Intermittency/Predictability

Due to the intermittent nature of wind generation the uncertainty surrounding available power is high when compared to conventional plant which has a power output which is 100% controllable. The unpredictable nature of the wind resource has an effect in terms of system inertia. As the inertia of a turbine is a function of its instantaneous rotational kinetic energy, the amount of inertial response which is available to the grid at any moment can fluctuate greatly in a variable-speed wind turbine as wind speeds (hence rotor speeds) change constantly. This is in contrast to conventional plant whose rotational speed is directly coupled to the grid, giving virtually constant inertial response [28].

According to [25], it is expected that reserve capacity may have to increase as a result of the uncertainty of wind. The variable power output from wind farms may therefore lead to increased operating costs for the power system [66]. This is of particular concern when there are high penetrations of wind power on the grid.

2.6 Conventional Generators

Conventional thermal power plants use synchronous generators to convert the rotational mechanical power provided by the prime mover (typically a steam turbine) into three-phase AC electrical power. They can reach power ratings up to 1500 MW [67]. Large synchronous generators typically use a constant rotating magnetic field which can be produced in the rotor through DC excitation of the rotor windings the exciter can take the form of a small DC generator mounted to the same shaft as the main generator, by the use of permanent magnets, or can be fed through power electronic rectifiers supplied by the AC system. The field is then rotated by the prime mover at the synchronous speed, or at some fraction of the synchronous speed, depending on the number of poles in the machine. Equation 2.6 gives the relationship between the rotor speed, the number of poles in the machine and the frequency of the AC grid voltage waveform:

$$\omega_{msyn} = \frac{2}{P} \times \omega_{syn} \tag{2.6}$$

where ω_{msyn} = the mechanical rotational speed of the rotor [rad/s], P = the number of poles on the synchronous generator rotor and ω_{syn} = the electrical frequency of the grid voltage waveform [rad/s] (314.16 rad/s for a 50 Hz power system).

AC voltages (and therefore currents) are induced in the three-phase stator windings, known as the armature. The voltage produced in the armature is dependent on the rotational speed of the rotor, the number of poles and the magnitude of the excitation current (hence the magnetic field strength) in the rotor windings. The field excitation of a large synchronous generator is important as it must maintain a stable machine terminal voltage and also it must respond quickly to any sudden grid-side load changes in order to maintain system stability. An automatic voltage regulator (AVR) may be used in the control logic of the generator, which maintains the machine terminal voltage at the desired level through manipulation of the field excitation current.

The important point to note in terms of system stability is that synchronous machines react dynamically to changes in the grid electrical frequency as seen by the armature terminals. In the event of a grid fault, the system frequency will deviate at a rate determined by the total inertia on the system at that moment. The conventional synchronous generators therefore must accelerate or decelerate in order to maintain synchronism with the AC terminal currents and voltages. Owing to the generator's own inertia and internal dynamics, this may result in electro-mechanical oscillations which, unless appropriately damped, can lead to machine instability (loss of synchronism with the grid) or, in the extreme cases, physical damage to the generator.

The industry appears to be tending towards a reduction in generator inertias and an increase in generator transient reactances [1]. These developments will mean that there will be a heavier dependence on generator excitation systems to regulate grid voltage and therefore to ensure grid stability.

2.6.1 Automatic Voltage Regulators

As well as the primary objective of the conversion of mechanical power into electrical power, the other major role that synchronous generation has traditionally played has been that of regulating the voltage of the transmission system to which the generator is connected. The control of dynamic reactive power exchange with the grid at the point of connection, and therefore control of grid voltage, is achieved through the excitation system within the synchronous generator. By regulating the internal voltage within the machine (the excitation voltage), the synchronous generator is able to provide either positive or negative reactive power exchange with the grid. This has the effect of regulating the magnitude of the voltage waveform at the connection point. As has been discussed earlier, maintaining transient stability is heavily dependent on the regulation of grid voltages to a near-nominal level as a reduced voltage profile will result in synchronous machines being unable to export electrical power to their full potential, resulting in high rotor accelerations. The displacement of synchronous generators and their AVRs with increasing penetrations of converter-interfaced generation means that the control of grid voltage is becoming a real concern for network operators. It is becoming increasingly important for wind turbine manufacturers to ensure that their wind turbines are capable of replicating or exceeding the voltage control capabilities of the replaced synchronous generation in order to ensure adequate levels of voltage stability in the power system.

2.6.2 Power System Stabilisers

Power system stabilisers (PSS) are commonly included in the excitation controllers of conventional generators in power systems. Their function is to provide positive damping of low frequency, inter-area power oscillations on the power system and therefore they have an important role to play in the mitigation of small-signal instability. They come in a several variants, the difference between them being the measured signal (rotor speed deviation, accelerating power or grid frequency deviation [3]) and their control logic adds an additional signal to the excitation voltage reference in order to provide damping of power oscillations through terminal voltage control of the machine.

The Power System Stabiliser is a highly tuned feedback system that takes inputs from the governor, AVR, and the power system and coordinates their reaction rather than having them act independently. Unlike traditional synchronous generators, commercial wind turbines are not currently required to have the capability to provide power system stabilisation as part of their control system.

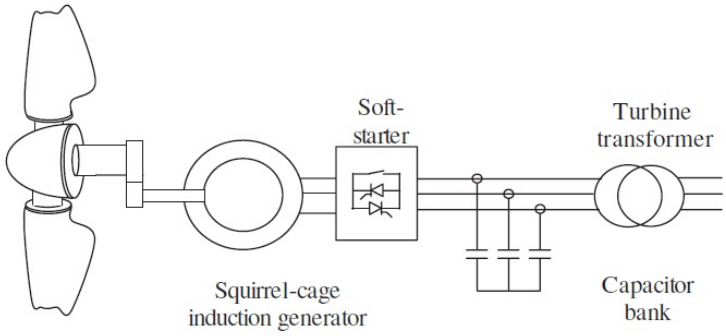


Figure 2.7: Schematic of an FSIG wind turbine [4].

2.7 Wind Generators

Wind turbine generators are categorised into two main types—fixed speed and variable speed [68]. The worldwide growth in wind power capacity has coincided with the growth of variable-speed wind turbines as a proportion of the wind power fleet.

2.7.1 Fixed Speed Wind Turbines

FSIG (Squirrel-cage Induction Generator)

During the initial growth period of wind power, generators were of the fixed-speed variety. This means that the turbine rotor is bound by the grid frequency to rotate around a single speed throughout the entire operational envelope. These turbines typically utilise a squirrel-cage induction generator with a nominal slip of 1%–2% [69]. Therefore, any change in the electrical frequency of the grid will be reflected by a corresponding change of speed in the rotor.

Assuming that the mechanical power input to the generator remains constant (a reasonable assumption on the short time scales dealt with in transient studies [47]) and the grid frequency drops, then there will be a greater demand for electrical power from the generator to the grid which cannot be met by the mechanical power input. The shortfall is instead satisfied by converting some portion of the rotational kinetic energy of the machine rotor into electrical energy. As can be seen in the equation for kinetic energy (Equation 2.1), since the moment of inertia of the machine is a constant, the only variable which can change is the rotor speed, which must reduce.

The coupling of grid frequency and generator rotor speed means that there is an inherent inertial response from the generator to any grid-side frequency perturbation — acting to reduce the rate of change of system frequency. Since some slip (relative motion between the stator and rotor) must be present in the generator in order to take advantage of electromagnetic induction, the generator speed is not technically "fixed", however a speed fluctuation of only 1%–2% from the grid synchronous frequency allows us to categorise the generators as fixed-speed.

According to [32], for a given fault condition there is no significant difference in the maximum frequency deviation when synchronous generators are replaced with FSIGs. This is due to the inherent natural inertial response of the FSIG and the similar inertia constants of the technologies.

Induction machines require a supply of reactive power in order to energise their rotor and build up a magnetic field [4]. Soft-starter units, comprised of an anti-parallel thyristor unit, are used to supply the rotor with reactive current in order to avoid excessive voltage dips in the local network as a result of the high initial magnetizing current requirement. Squirrel-cage induction generators can become unstable under low voltage conditions as a drop in the

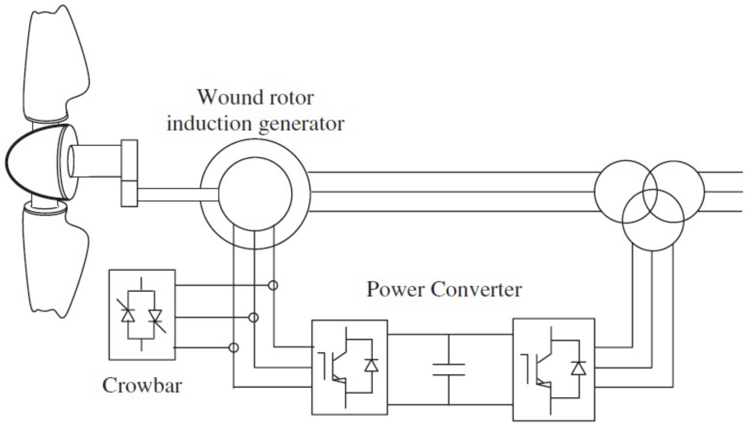


Figure 2.8: Schematic of a DFIG wind turbine [4].

terminal voltage (typically caused by a grid fault), leads to an unusually large rotor slip, which in turn requires more reactive power supply from the grid—furthering the voltage dip on the grid side. This problem can be alleviated by disconnecting the turbine, integrating a pitch controller, equipping a controllable reactive power source (e.g. STATCOM or SVC) or improving stability through changing mechanical or electrical parameters [70].Reference [60] argues that a high penetration of fixed speed wind turbines in the grid leads to large power fluctuations and hence large frequency fluctuations.

2.7.2 Variable Speed Wind Turbines

DFIG (Doubly-fed Induction Generator)

The most popular topology for modern-day MW-scale wind turbines is the DFIG (doubly-fed induction generator) concept, which at the time of writing constitutes around a 60% share of current global wind power [71, 72]. This allows the wind turbine to operate with variable rotational speed in order to capture optimal power at below-rated wind speeds, as well as offering an increase in power quality [73] and reduced mechanical loads. DFIG wind turbines also provide the capability for decoupled control of active and reactive power. Therefore, when equipped with full fault ride-through capability, they are able to contribute positively to the transient and voltage stability of the grid in the moments following a fault through reactive power support.

The DFIG concept uses a wound-rotor induction generator with slip rings to supply/extract current to/from the rotor windings. Variable speed operation is achieved by supplying the rotor with a controllable voltage at slip frequency [4].

A DFIG can supply electrical power to the grid through both its rotor and stator, while the rotor may also absorb power from the grid. This is dependent on the rotational speed of the prime mover. If the generator is spinning below the grid synchronous speed then the rotor will absorb power and if the rotor speed is greater than the synchronous speed the rotor windings will supply power to the grid.

Power electronics provide the interface between the generator rotor and the grid. By converting the variable-frequency AC waveform to DC through a rectifier and then synthesizing a new AC waveform through an inverter, the turbine or wind farm is able to provide an appropriate alternating current to the grid at the desired nominal system frequency. Only a portion of the DFIG power flows through the converters - meaning they can be rated lower and are therefore cheaper and smaller than other power converter systems. Power losses are also lower as a result [51].

The transient behaviour of a DFIG wind turbine depends mainly on the control strategy employed by the power converter [43]. According to [74], using DFIGs over squirrel-cage induction generators (FSIG) can improve transient stability due to their reduced reactive power demand during fault ride-through operation.

In contrast to the traditional synchronous generator, modern variable-speed DFIG generators provide effectively no contribution to the total system inertia [75]. As a consequence, when a system fault occurs there is a greater likelihood that the power system will become unstable as synchronous generators' rotor angles become too large during the first swing. When the rotor accelerations of the synchronous machines on the system become too great, additional generation (frequency response) must be brought on very quickly and the critical clearing time for a fault must also be reduced in order to maintain system stability – leading to a potentially costly redesign of system protection systems and changes to grid codes. In order to provide some form of inertial response from a DFIG wind generator, supplemental control loops can be employed.

According to [70], the transient and dynamic stability of wind farms with power electronic converters is generally superior to conventional generation. While [76] concluded that DFIG wind turbines, when introduced to a conventional thermal power system, tend to improve stability during small grid disturbances while eroding stability for larger, transient disturbances.

FRC (Fully Rated Converter)

Variable-speed can also be achieved through the use of an FRC generator. In this case, all of the electrical power which flows to the grid does so through the AC/DC/AC power converter and therefore there is no speed coupling

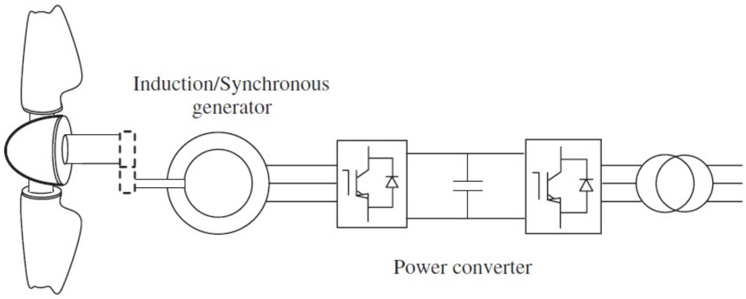


Figure 2.9: Schematic of an FRC wind turbine [4].

or natural inertial response from such turbines [77]. FRC wind turbines may employ wound-rotor, induction or permanent magnet synchronous generators (PMSG) as their means of power generation. PMSG-based wind turbines are now achieving significant market share as their cost steadily reduces. As they become more popular, it is important that their operation and dynamic behaviour is well researched and understood.

2.7.3 Simulated Wind Turbine Models

The wind turbine models used in the studies carried out in this work are generic International Electrotechnical Commission (IEC) models provided in the templates library of DIgSILENT PowerFactory. These models allow the user to manipulate many of the control settings available to real-world wind farm operators and are initially configured with a set of sample a parameters, which were kept unchanged except for those parameters under test in the studies presented here. According to the PowerFactory User Manual [78]: "The models which are available in PowerFactory as templates are configured with a set of sample parameters. The user has to adjust these parameters (i.e. power rating, voltage level, reactive power limits and all parameters of the dynamic models) to represent a specific WTG of a specific manufacturer!"

2.7.4 Limiting Factors for Wind Penetration

An important driver for governments to be able to achieve their legally binding targets for emissions reductions is their ability to utilise as much of their potential renewable energy resources as possible. It is therefore extremely important that the grid owners and operators are able to address any technical barriers which will act to limit these renewable resources, some of which will be discussed in this section.

A potential limitation to the penetration of renewable power sources while adhering to current grid control practices is the associated loss of automatic load-frequency control. Currently, each of the synchronous generator units online throughout the system must be capable of participating actively in frequency control through their governor action, though only a proportion of these are contracted through the relevant ancillary services mechanism to provide the service at any one time. When the governor control senses a downward deviation in grid frequency (measured by monitoring the rotational speed of the generator rotor), then the controller issues a command to produce more steam and therefore more mechanical power into the turbine. This action is performed by each of the synchronous generators in the system and acts to contain the frequency drop. In contrast, renewable energy sources are presently not required to provide such load-frequency control. In future power systems with large penetrations of wind and PV generation, it is imperative that their control systems are configured in such a way that they too participate in balancing of grid frequency. This will require turbines to be run at some below-rated operational point, or alternatively for some portion of each wind farm or PV installation to be connected only when required for frequency support. Market mechanisms may be required for wind farms to contribute to frequency control by de-rating their power output [79]. The extent to which renewable generation will be required to participate in frequency containment and restoration following a loss-of-generation event is expected to grow significantly in the coming decades and must be diligently managed by network operators to ensure stable and economical operation. It might become imperative that future wind farms (as well as other non-synchronous generation) be required through grid codes to participate not only in primary frequency control (droop) but also to be counted as potential reserves for secondary frequency control in synchronous areas which employ such control systems.

There may also be grid code requirements for wind farms in particular to provide "Synthetic Inertia" – i.e. fast-acting active power control which aims to emulate the natural inertial response of synchronous machines in order to slow down the frequency dynamics in the event of a fault. Such control mechanisms could also be provided on the demand side, so it will be the job of network operators and researchers to decide on the optimal mix between generation-side and demand-side frequency and inertial control in the future power system, taking into consideration the economics as well as the technical capabilities of the respective technologies.

These problems could also be mitigated by demand control in the smart grid, e.g. by the switching of large amounts of demand in the grid from fridges and air conditioners. It is important that such methods are investigated in order to fully utilise variable generation such as wind, where the instantaneous generation capability is less predictable than traditional power sources. Allowing operators more visibility and controllability on the demand side may also act to flatten out the demand peaks, and move a lot of demand temporally to line up with periods of high renewables output. The potential to treat demand as a flexible resource that can be used by the operator for balancing and control will be a growing area of research and development.

It is possible in future scenarios of low inertia and high renewable power generation, that grid operators will have to relax the acceptable limits on frequency deviations from nominal for a given contingency. However, in the short-term, National Grid is tending to constrain the input into the system of the largest infeed, rather than trying to change the generation dispatch more generally in order to provide more inertia. The problem is currently exacerbated by the inability to curtail output from distributed generation. With low levels of synchronous generators with load-frequency control and renewables not providing frequency control, the current frequency limits might be breeched more regularly. If this is not possible, then limits might have to be put in place that keep the instantaneous non-synchronous generation (wind, PV, interconnectors) below a certain percentage, as done in Ireland [80], or alternatively that there be a mandatory minimum of synchronous generation remaining online at all times to provide inertia and frequency control. This is clearly undesirable in future scenarios where the reduction of conventional electrical power generation from fossil fuels is a priority to governments.

2.8 Power System Analysis

2.8.1 Steady-state Analysis

A crucial prerequisite to the simulation of power system stability studies is to find a steady-state load flow solution for the network. This provides the initial condition for a time-domain simulation in terms of the voltage magnitudes and angles at each node on the system, and the tap ratios for OLTC (On-Load Tap Changer) transformers. The load flow (or power flow) study involves the use of numerical methods for a given generation mix, network topography and demand characteristic, and is used to determine the following four key steady state variables in the power system (within an acceptable tolerance):

- The voltage magnitude and the phase angle of the voltage waveform at each network bus, with respect to a chosen reference.
- The active and reactive powers injected (or absorbed) at each network bus.

By determining each of the above variables for all nodes (buses) in the system, it is possible to put together a picture of the real and reactive power flows through each of the lines in the network, as well as the reactive power produced/absorbed by each generator and load. This steady-state analysis is a key aspect of system planning as it allows engineers to ensure that line current limits are not being exceeded within the network during normal operation. As power transmission lines are designed to carry a certain maximum current capacity, any excess current over and above this limit may jeopardise the integrity of the grid by causing the line to sag excessively – leading to the possibility of flash-over faults to ground. Excessive currents (and therefore temperatures) in transformers or underground cables may also cause, at best, accelerated ageing of the insulation or, at worst, breakdown of the insulation – also leading to faults.

As well as being used to determine steady-state parameters for a given network, load flow studies are also a crucial aspect in the design of future grid expansion and modifications, as it is highly important to have an understanding of the changes in power flows which will result when the grid topology and generation mix are altered.

The first step in a typical load flow simulation is typically to assign a reference or “slack” bus and to determine the nature of each of the other network buses. The slack bus must have a generator attached (preferably of large capacity and with a central location) and is then taken as the per-unit voltage magnitude and angle reference (conventionally with voltage = 1 p.u at 0 degrees). Other buses in the system are designated as either load (PQ) or generator (PV) buses, based on which variables are known for each bus. Therefore:

- For a slack bus, the voltage magnitude and phase angle are known. The real and reactive power provided/absorbed by the slack bus is not required to be solved by the network equations. The net power at the slack bus can fluctuate to “take up the slack” and address the losses of the network in order to ensure a balanced condition between generation and demand.

- For a load (PQ) bus, the quantities of real and reactive power injected (or absorbed) are known.

- For a generator (PV) bus the quantity of real power and the magnitude of the bus voltage are known (since most generators regulate their active power and terminal voltage at a set level).

In a typical load-flow study, the majority of buses will be load (PQ) buses and the remainder will be generator (PV) buses. The load flow study is then used to determine each of the unknown variables in the system. Since a power network is inherently non-linear, an iterative numerical analysis is used which aims to determine each of the unknown quantities to within a given tolerance.

The power flow equations are numerically taxing for large multi-bus power systems, therefore it is not practical for the load flow analysis to be carried out by hand. Instead, with the rise of computational power in the last half century, it is now possible to carry out load flow analyses on large inter-connected power systems in a relatively short time.

The network equations must be solved iteratively through one of several numerical methods, the most widely used of which are the Newton-Raphson and Gauss-Seidel methods. The equations are generated through the use of matrices which describe the system in terms of voltages (V), currents (I) and admittances (Y). The admittance matrix is populated using known impedance values (admittance is the reciprocal of impedance) for the lines in the network. A variation of Ohm's law ($I = YV$) is then used to set up the simultaneous equations in matrix form. The network can be represented by a one-line diagram to facilitate the population of the admittance (Y_{bus}) matrix. The admittance matrix is preferred over the impedance matrix as it is much more sparsely populated (it contains many more zeros) than the impedance matrix, resulting in much lower numerical complexity and therefore less processing power and time is required to generate a solution to the network equations. A satisfactory solution to the network load flow then allows the initial conditions to be determined for a step-by-step time domain simulation, as will be discussed in the next section.

2.8.2 Dynamic Analysis

Once a steady-state load flow has been achieved in the test system, the dynamic response can then be analysed by subjecting the system to a disturbance. Such disturbances can range from small fluctuations in load or generation, up to large contingencies such as the loss of a generating unit or a three-phase-to-earth short circuit fault on a transmission line.

The analysis of power system dynamics is based on one of two main techniques: time-domain analysis and state-space analysis. Time-domain analyses are conducted in the study of transient stability while state-space representations are used to find the eigenvalues and eigenvectors of the system in small-signal stability studies. In either case, information regarding the dynamic response of the system to a given disturbance is obtained through the solution of many first-order differential equations which describe the system for a given time step. In the case of small-signal stability analyses, since the perturbation of the system from equilibrium is relatively small, the non-linear functions which describe the system behaviour may be linearised around the operating point in question. In the case of transient stability studies, the study period is short enough that the assumption of constant mechanical power from wind generators is valid during the study window, due to the much longer time constants associated with changes in point wind speed at wind turbines when compared with the rotor dynamics of synchronous generators under study.

The power system is designed to successfully maintain operation by supplying loads with power for a given set of contingencies. The selection of a useful and realistic (i.e., credible) set of "secured" contingencies and grid operating points is a crucial stage in dynamic studies. In the case of transient studies, once a selection of studies have been identified for analysis the time-domain system response to the given events can be plotted. The time series results for rotor angles (relative to a pre-selected reference generator), voltages and active/reactive power can then be analysed to determine whether or not the system's transient response is satisfactory.

As discussed previously, an unsatisfactory outcome in a transient stability study would be time-domain responses that show synchronous generator rotor angles that exhibit irreversible drift from one another and/or unacceptable damping, as well as non-compliant post-fault grid voltages.

2.9 Transient Stability in Great Britain

The transmission system of Great Britain can be simplified down to three distinct areas – England & Wales, Southern Scotland and Northern Scotland – which represent each of the three transmission system owner areas in GB. There is a predominant North-South power flow through the transmission corridor connecting Scotland and England (two double-circuit overhead lines referred to as the B6 boundary [81]), which is presently limited by transient stability considerations [82]. When the corridor is in a highly-loaded state and is subjected to a large disturbance, such as the loss of a critical transmission line, the large initial rotor angle difference between the Scottish synchronous generators and those in England & Wales may lead to unstable behaviour, even for faults with a short clearing time or high fault impedance. This behaviour is manifested in the form of irreversible rotor angle deviations and pole-slipping of one or more synchronous generators and their subsequent disconnection from the grid.

As it is expected that there will be significant wind power resources situated in northern areas of Great Britain in the coming years, it is imperative that the use of such resources is not unduly curtailed by transient stability constraints. A key aim for system owners and operators is to be able to utilise the full thermal capacity of their transmission assets wherever possible. Provided the means of increasing stability limits are not excessively expensive, this represents a scenario with minimal restrictions on generators and therefore optimally efficient grid operation.

Work has been completed by the relevant transmission system owners to deliver series compensation devices on the B6 boundary [83], effectively bringing Scotland electrically "closer" to England by reducing the boundary reactance, hence mitigating the stability constraint to some extent. The future development of high voltage direct current (HVDC) power transmission, in parallel with the existing HVAC system, may also prove beneficial from a stability standpoint [84]. However, such developments can only improve the situation to a certain extent, before other mitigation methods must then be used, including advanced control of wind power plants and novel methods for dispatching reactive power.

Although such an event is rare, it is a requirement in the GB transmission system that the loss of any double-circuit overhead line (such as those of B6) does not result in transient instability and therefore a loss of supply to customers [15].

2.10 Experiences from other TSOs

In Ireland the system operator [59], and others [80, 85], have recommended the fastest possible post-fault recovery rate of wind turbine active power to the pre-fault value. This is motivated by concerns that frequency will be unduly affected in the event of transient short-circuit faults in a system with rapidly diminishing inertial resources and high wind penetration. As will be analysed in this thesis, there may be circumstances in which a slower active power recovery may be desirable from the perspective of transient stability. At very high penetrations of wind power it might prove problematic as the temporary dip in active power from wind farms could lead to what might be called a "voltage dip induced frequency dip" (VDFD) [85], which will also be investigated in a later chapter.

The Australian Energy Market Operator (AEMO) conducted studies [86] in 2013 that showed the potential changes in transient stability constrained power flows as a result of several possible future scenarios, where wind power has replaced synchronous generators around the network. Their analysis concluded that the transient stability impacts of replacing synchronous generation with wind would have to be analysed on a case-by-case basis. This is due to the complex interaction between the geographical spread of the wind, the fault locations and types, the fault ride-through behaviour of the wind turbines, the inertia constants of the replaced machines and the remaining machines (and their locations with respect to one another and the fault). They indicated the possibility that the replacement of synchronous generation with wind power is likely in some cases to reduce the available power flow limits around the system. For example, the power flows from the Victoria region into the New

South Wales region are likely to be negatively affected by wind penetration in Victoria, and they attribute this mainly to the reduction of inertia levels in Victoria (a similar situation to that found in Scotland with respect to England & Wales, through the B6 boundary in the GB power system).

Studies were conducted by Samarasinghe and Ancell [87] on a simplified model of the New Zealand power system. They concluded that the impact of wind power plants on transient stability cannot be generalised and must therefore be assessed on a case-by-case basis. They highlight that the addition of wind generation had a minor effect on stability, however it was the displacement of conventional generators and their associated controllers which contributes most significantly to the change in stability margins. It follows therefore that in order to maintain stability margins when wind replaces significant portions of conventional generation, the wind power plants (and/or other grid connected equipment - such as loads or energy storage) must attempt to emulate some or all of the grid control capabilities of the replaced synchronous machines. These capabilities include inertial response, power system stabilisation and fast acting reactive power (voltage) control.

CHAPTER 3

Methods for Mitigating Transient Instability

As the physical characteristics and operational techniques of power systems evolve, it is inevitable that there will be resulting changes in key system behaviours. In particular, the removal of traditional sources of inertia and the changing geographic distribution of this inertia, as well as the replacement of older control systems with new types of control, will cause new problems to arise. Transient stability issues are highlighted in this thesis as a key concern in such future scenarios.

There are several traditional methods of system design and control which are known to give improvements in the transient stability margins of power systems. Depending on the power system in question, some particular combination of these methods may prove useful in order to mitigate any negative impacts on transient stability margins which come about as a result of the changing landscape of generation and demand in the future power system. In this section, each of these traditional methods will be discussed.

Glover, et. al. [1] compiled a list of traditional methods for improving transient stability:

- 1. Improved steady-state stability
  - a. Higher system voltage levels
  - b. Additional transmission lines
  - c. Smaller transmission-line series reactances
  - d. Smaller transformer leakage reactances
  - e. Series capacitive transmission-line compensation
  - f. Static var compensators / flexible ac transmission systems (FACTS)
- 2. High-speed fault clearing
- 3. High-speed reclosure of circuit breakers
- 4. Single-pole switching
- 5. Larger machine inertia, lower transient reactance
- 6. Fast responding, high-gain exciters
- 7. Fast valving
- 8. Braking resistors

Several of these measures relate directly to the discussion on transient stability given in Chapter 2, while some should be elaborated upon in more detail as they pertain to the particular case of the GB transmission system and are discussed in this section.

3.1 Improved steady-state stability

3.1.1 Grid Reinforcement

Increased levels of wind power, PV and small-scale generation and decommissioning of conventional plant will result in significant changes in typical transmission system power flows. This can have the effect of either improving, creating or simply moving bottlenecks. With more and more wind power coming online in northern areas of GB (farther from load centres), where the transmission system is relatively weak at present, the need has been recognised to reinforce both this area of the grid and other key transmission corridors (such as B6) in order for the full potential of wind power to be fully utilised. An example is the Beauly-Denny line built in order to transfer more power south from Northern Scotland. The 400 kV circuits have been made operational as of 20 November 2015 and will serve to reduce transmission constraints in the coming years. The addition of new transmission capacity (i.e., new lines and a more meshed system) improves transient stability behaviour by allowing synchronous generators in the accelerating region to export more active power during and directly following transmission faults. This reduces the rotor accelerations (swings) and therefore improves transient stability margins. However, when compared with the novel control methods discussed previously for mitigation of transient stability problems, grid reinforcement is a much more costly, lengthy and politically difficult process. Therefore, large-scale grid reinforcement should not be seen as a high priority method for mitigating transient stability constraints in the GB transmission system at present, and low-cost gains in stability improvement (e.g., through controller design) should be used to their full potential before physical grid reinforcement is considered.

3.1.2 Series Compensation

The B6 corridor has long been considered a bottleneck in the National Electricity Transmission System (NETS) of Great Britain. When the work reported in this thesis was started the interconnection was limited to power flows of approximately 3.5 GW, which is far below the thermal capacity of the lines themselves – estimated at approximately 4.5 GW [64]. This constraint is due to angular stability concerns and mitigating these concerns will allow the full use of the thermal limit and therefore the optimal use of transmission assets.

One part of the solution is to utilise Series Compensation Capacitors on the B6 boundary. By implementing these devices, there is an effective reduction in the "electrical distance", i.e., the series reactance of the corridor. This has the effect of increasing the steady-state power flow for a given angular separation between the sending end (Scotland) and the receiving end (England & Wales), or reducing the angular separation for a given power flow, thus providing a larger stability margin. The major drawback of the use of series compensation is the tendency for it to introduce sub-synchronous resonance [88].

3.1.3 High Voltage Direct Current (HVDC) Transmission

Modern electricity transmission systems are almost exclusively comprised of three-phase alternating current (AC) lines. Following the "War of the Currents", AC was crowned the winning transmission technology, mainly due to its efficiency gains as a result of being able to step up the voltage using transformers and hence step down current – resulting in smaller power losses (I^2R). Despite AC becoming more and more prevalent following the war of currents, DC transmission still has some significant benefits and can play an important part in the efficient and safe operation of power networks.

High-Voltage Direct Current (HVDC) transmission is a technology which can be used in place of High-Voltage Alternating Current (HVAC) for the bulk transfer of electricity from point-to-point over long distances. While an HVAC transmission system may require lower capital investment when compared to HVDC (transformers vs. converter stations, for example), after a certain transmission distance HVDC becomes more economical due to the lower resistive losses associated with the technology and significantly less cable material use.

Benefits of HVDC

DC transmission makes more efficient use of the cable cross-section over AC due to the lack of a phenomenon called the skin effect. The skin effect takes place in cables when electricity is transmitted using alternating current and results in the majority of the electron flow in the conductor to occur in the outer portion of the cable cross-section. The higher the frequency of the alternating current, the more pronounced the skin effect. The skin effect does not occur with DC transmission, and therefore HVDC makes more economical use of the conductor material and thinner conducting material can be used, which can significantly bring down conductor costs.

Since the DC converter stations at either end of the HVDC line are able to convert AC at any frequency and voltage level into a controlled DC voltage, and vice-versa, HVDC allows bulk power transfer between two otherwise incompatible synchronous AC regions. This provides an important advantage over AC transmission – where the connection of two AC regions with differing nominal grid frequency would not be possible. The HVDC connection can also act to isolate one AC network from the negative effects generated by faults on another AC network, while being able to control the direction and magnitude of power flows between such areas to provide support to the faulted network.

HVDC may also be more desirable than AC transmission in cases where power is being generated in remote locations which are far away from major demand centres. This may become an important use of HVDC in future as more and more wind power generation is being installed in offshore environments, for example in the North Sea, while the main demand centres of the GB system will continue to be concentrated in the south of England. The economical benefits of HVDC over HVAC are enhanced in undersea applications.

3.1.4 HVDC in the GB Context

Although HVDC connections already exist and provide connections to Ireland, France and the Netherlands, the technology will also be utilised in future to support the GB transmission system in the form of embedded "bootstraps". The Western HVDC link now connects the Scottish Power network at Hunterston in western Scotland to the National Grid network Deeside in north Wales, while the Eastern HVDC link to connect the SSE network at Peterhead in north-eastern Scotland to a connection point in the National Grid network in north-west England is currently in the planning stage. A shorter, lower capacity

HVDC link is now operational across the Moray Firth in northern Scotland.

This network reinforcement will allow greater North-South power flows than have been possible through the existing HVAC boundary transmission lines, in order to reduce the curtailment of wind generation in Scotland and will provide stability improvements for the entire GB transmission system. In contrast with the majority of HVDC installations, which are used as interconnectors between two separate synchronous systems, the HVDC links proposed for Great Britain will exist within a single synchronous grid. The control implications and the possible effects on power system stability are relatively unknown.

3.2 FACTS (Flexible AC Transmission System) Devices

One of the basic methods for controlling the operation of a power system is to alter the reactance (and hence the electrical distance) of one or more transmission lines. The IEEE has defined FACTS as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer quality" [89]. The basic principle of FACTS devices is to introduce either series or shunt "compensation" in the form of capacitive or inductive elements. By altering the effective reactive impedance of certain lines, the power transfer capability and stability margins of the system can be improved. Examples of FACTS devices include:

- Static VAR compensator (SVC)

- Static synchronous compensator (STATCOM)

3.2.1 SVC

A static VAR compensator (SVC) is another form of reactive power compensation device which can be used either at the point of connection of a highly inductive load (industrial motor applications tend to have high lagging power factors), or in the transmission system itself to maintain a suitable voltage profile and improve stability. The SVC's key components are thyristor controlled reactors (TCR) and thyristor switched capacitors. By utilising correct switching logic, the power factor at the coupling point to the grid can be tailored accurately in order to mitigate leading or lagging power factors on the grid – improving power transfer capability and stability and minimising power losses.

3.2.2 STATCOM

A STATCOM device may be installed on a section of the power system in order to mitigate poor power factor and/or enhance voltage regulation. Commonly, STATCOM devices are implemented primarily to improve grid voltage stability. A STATCOM is based on voltage source converter (VSC)-based technology, and represents a voltage source behind a reactive element. The reactive power support provided by the STATCOM is dependant on the amplitude of the voltage source. If the voltage of the VSC is higher than the AC voltage at the point of connection, the STATCOM generates reactive current. Conversely, when the amplitude of the voltage source is lower, it absorbs reactive power.

The fast switching times provided by the IGBT (Insulated Gate Bipolar Transistor) switches mean that the response time of a STATCOM can also be very short, which is beneficial to stability. The STATCOM also provides better reactive power support at low AC voltages than an SVC, since the reactive power from a STATCOM decreases linearly with the AC voltage (as the current can be maintained at the rated value even down to low AC voltage).

3.3 Synchronous Condenser

As well as power-electronic equipped devices such as those detailed above, another technique for power factor correction is the use of a device known as a synchronous condenser. The synchronous condenser operates in much the same way as a synchronous motor with no shaft load attached. The field excitation is regulated by a control system in order to alter the reactive power absorbed or generated by the device, in order that it can therefore provide the same reactive power support capability as a synchronous generator or motor without simultaneously generating or absorbing active power. Synchronous condensers also have the added advantage of providing some "natural" inertial response from their rotating mass and the ability to provide transient current capability (e.g. when there are short circuit faults on the network) which is similar to synchronous generators and greater than that provided by converters. Promising research has been conducted into the usefulness of Synchronous Condensers to mitigate the reduction in transient stability margins [90]. Denmark and Tasmania both intend to make use of synchronous condensers in the future to mitigate some problems associated with high non-synchronous penetration: Denmark with synchronous condensers fitted with flywheels and Tasmania to use hydro-style generators with high inertia constants. Inertia values of 7.84 MW.s/MVA have been obtained from hydro generators with vertical shafts [91].

3.4 Wind Farm Control for Transient Stability

In order for wind farms to contribute in any way to the general improvement of stability margins in the power system, it is first necessary to ensure that the wind farms are able to maintain a grid connection throughout some of the most onerous faults that are likely to occur in the network. This capability is known as either Fault Ride-Through (FRT) or Low Voltage Ride-Through (LVRT), and is described in this section.

3.4.1 Low Voltage Ride-Through Capability

In recent years, as a consequence of expected high levels of growth in global wind penetrations, Low Voltage Ride-Through (LVRT) requirements have been introduced in many grid codes. During a grid disturbance, a low voltage profile may propagate through the system. In the past, wind farms were able to disconnect from the grid during such scenarios, however now they must not only stay connected but also contribute to the overall stability of the system.

Figure 3.1 shows an example of an LVRT requirement present in various grid codes, with the GB requirement emphasised in bold.

From Figure 3.1, it can be seen that there is an allowable voltage-time characteristic, above which the generating unit must remain connected to the grid to provide support. In an event where the wind farm experiences a voltage-time profile which falls beneath the characteristic line, it is allowed to discon-

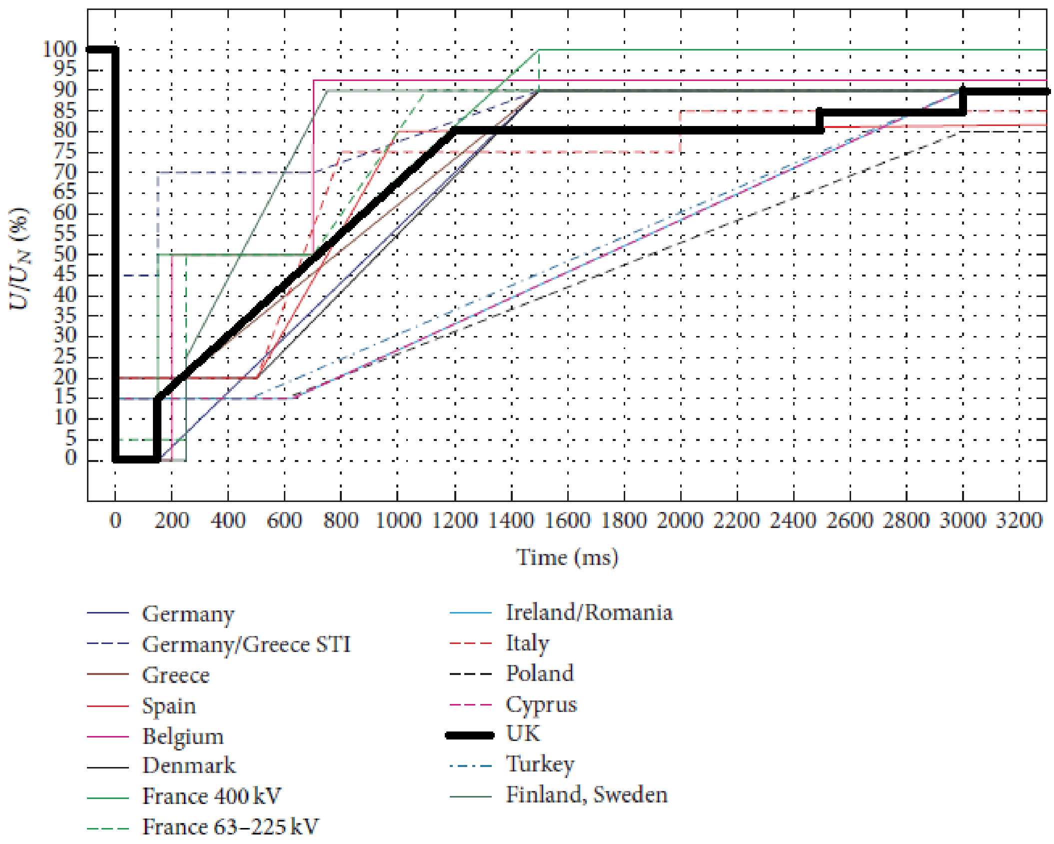


Figure 3.1: LVRT requirements in various grid codes [5].

nect from the grid. It can also be seen that the LVRT requirements can vary a great deal between different grid codes, and that the requirements of a given grid are very specific to the individual characteristics of each power system.

The studies carried out in this thesis concern the tailoring of certain aspects of LVRT control which may lead to improvements in the transient stability behaviour of the GB transmission system in response to extreme network faults. There follows a brief description of these parameters to introduce their functions before investigations in later chapters:

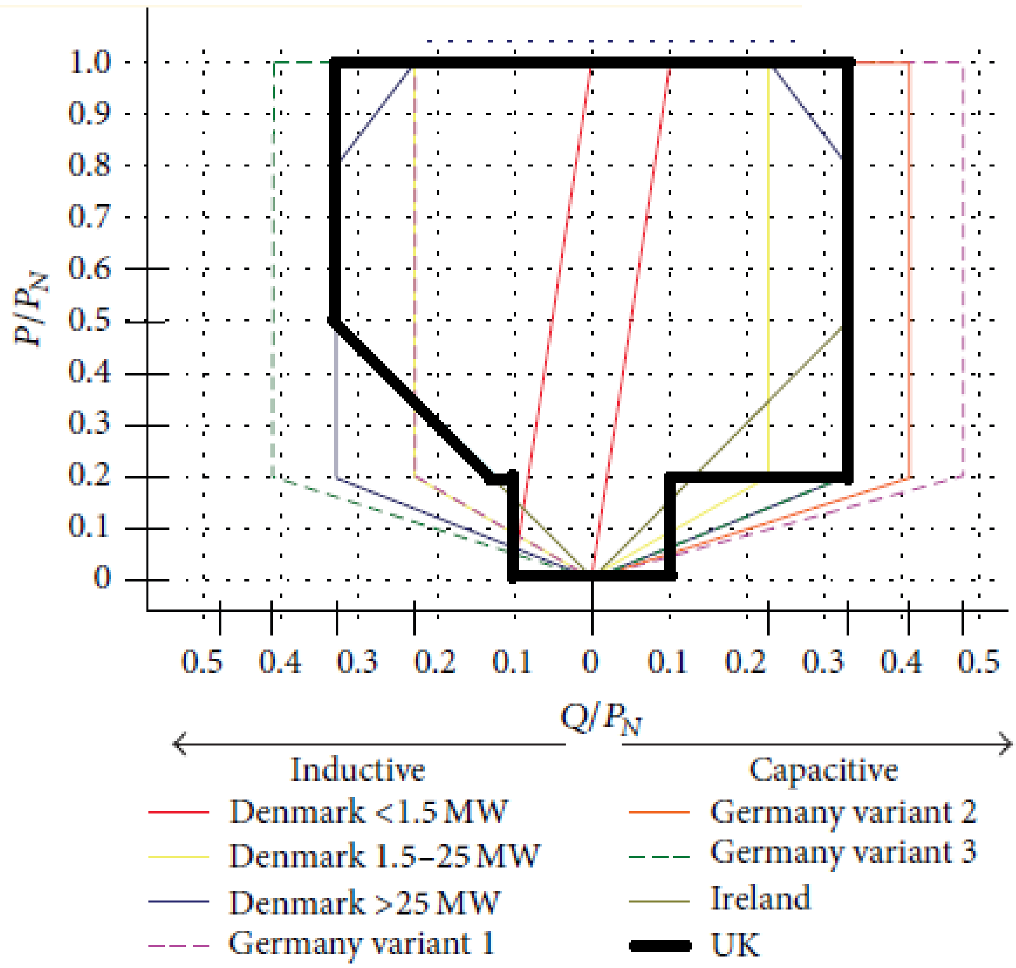


Figure 3.2: Reactive power requirements of various grid codes [5].

Reactive Power

During a transient fault, it is desirable for wind turbines to provide reactive power to the system in order to support the voltage profile. This translates to an increase in transient stability as the maintenance of grid voltage allows the synchronous machines in the vicinity to better export their active power and therefore retard the acceleration of their rotors during and immediately following the fault-on period.

Figure 3.2 shows the reactive power requirements present in various grid codes, with the GB requirement emphasised in bold. As with the LVRT requirements described above, it can be seen that there is a broad range of reactive power capability requirements between each of the grid codes. Simulations testing the effects of reactive power control on transient stability margins are presented in Chapter 5.

Vittal, et al. [92] have highlighted the importance of ensuring that wind turbines provide similar grid control capabilities to synchronous generators, focussing on the contribution of wind power plant reactive power support through terminal voltage control. They also made clear the increasingly close relationship between voltage stability and rotor angle stability in networks where increasing penetration of wind generation are replacing synchronous generators.

[79] discusses the possibility of delivering reactive power control from wind generators distributed throughout the power system, while not generating active power. This would have a significant advantage over synchronous generation, which must be running and synchronised with the grid in order to provide reactive power and therefore suppose grid voltage. According to [93], wind farms often will have more relaxed reactive power capability requirements in grid codes than similarly-sized conventional generators.

Active Power Ramp Rates

In order for a wind turbine to provide high levels of reactive power to the system during a fault, while honouring the turbine and converter's MVA rating, there will be a corresponding drop in the active power output from the wind turbine. If the turbines happen to be within an exporting region (in this case located in Scotland) then this drop in active power output is also beneficial to the transient stability of the synchronous machines in the exporting region and therefore the stability of the entire system. In effect, by dropping their active power output the wind turbines allow a greater proportion of the synchronous machines' power to feed the loads in the exporting region. This has the beneficial effect of slowing the accumulation of kinetic energy in the synchronous machine rotors and therefore retards their acceleration in much the same way as through the provision of reactive power by the wind farms described previously.

A promising area of research around this concept is to quantify the level of benefit in terms of transient stability which can be gained through tailoring the rate of recovery of the active power from the wind farms in the exporting region. Currently the Grid Code states that all wind power park modules must recover 90% of their pre-fault active power within 1 second of fault clearance [45]. This is a condition which can be easily met by modern wind turbines, and is in place in order for wind turbines to contribute positively to the frequency stability of the system.

It is expected however that by lowering this limit, there is an opportunity to gain significant advantages in terms of transient stability following a large grid disturbance, at the expense of frequency support from the wind farms.

Mitra, et al. [94] developed a DFIG control method which would improve the transient stability margins of nearby synchronous generators by manipulating the post-fault active power injection of the wind turbines based on local frequency measurements. The work was carried out using standard IEEE test systems and showed that manipulation of wind turbine active power in the immediate post-fault period is a viable method for improving the transient stability margins of nearby synchronous generators.

3.4.2 Synthetic Inertia

A proposed solution to the reduced inertia problem is known as "synthetic inertia". Through novel control strategies it is possible to simulate the effects of inertia [95, 96, 97] in a DFIG wind turbine by providing the network with additional power output in the critical moments following a fault - therefore reducing the magnitude of the discrepancy between generation and load and aiding frequency support. Commercially available synthetic inertia controllers include General Electric's WindINERTIA^{TM} and ENERCON's Inertia Emulation [29].

By implementing a control loop which monitors the grid-side frequency and controls the generator reaction torque, it is possible to extract a certain amount of the kinetic energy stored in the large rotating mass of the turbine rotor in order to provide fast frequency support. However, unlike "natural" inertia which acts instantaneously, due to the delay associated with the controller which means that the frequency support does not act instantaneously, synthetic inertia may therefore be unable to aid the transient stability response in exactly the same manner as directly-connected synchronous machines. Therefore, the initial high RoCoF may not be entirely mitigated, however the use of the technique can achieve a significant reduction in the magnitude of the maximum frequency excursion. According to the studies conducted in [95], the use of such a control strategy is able to consistently contain maximum frequency excursions to below one third of the value of those found in studies with wind turbines without such control.

According to [28], the inertial response from conventional plant is always proportional to the RoCoF. However, wind turbines may have the advantage that their inertial response could be independent of the magnitude of the RoCoF — theoretically this means that wind turbines may be able to provide greater frequency response than conventional plant. There may also be additional benefits to be found in the wind turbine's ability to dynamically control the inertial response to the grid — something which conventional power plants cannot achieve.

The inertial response provided by a synthetic inertia controller implemented in a DFIG is given in equation 3.1: (from [29]).

$$\Delta p = 2H_{syn} f_{sys} \frac{d f_{sys}}{dt} \tag{3.1}$$

Limitations of Synthetic Inertia

- In order to use this type of control strategy to effectively control the frequency after a transient event, there must be a significant number of wind turbines with such controllers connected to the grid.
- In extracting the kinetic energy from the rotor, its speed must be decreased and the turbine (or wind farm) will therefore not be operating at its optimum tip-speed ratio – leading to inefficiency in the minutes

following a fault and overall reduced power output which must be compensated for by bringing online other forms of generation or shedding load.

- According to [36] “The very high RoCoF value can occur before the emulated inertial control is activated. Emulated inertia could be useful in mitigating frequency nadirs that occur during a system event, but it is not the same as the synchronous inertial response provided by synchronous machines.” [98] concurs that there is little chance of utilising synthetic inertia to mitigate first-swing stability issues due to the relatively lengthy timescales (around 1 second) required for full deployment of the emulated inertial response.

- The magnitude of the available active power (inertial) response from the wind will not be a constant quantity, as it will be a function of the rotational speed of the wind turbine at a specific moment in time, which varies with the local wind speed. This adds complexity to the operator’s calculations for how much inertial response is really available on the system at any given time [99].

3.5 Other Transient Stability Improvement Strategies

3.5.1 Dynamic braking resistors

In the event of a power imbalance where the mechanical power provided by a turbine shaft is greater than the generator electrical output power, an acceleration of the rotor will occur. In order to limit this acceleration for a given power imbalance (for example, after a grid fault), resistive elements can be switched in to the generator stator circuits, providing a pathway for the excess energy to be dissipated. This approach is intended to provide damping of power system oscillations and improve the transient stability of synchronous generators by reducing accelerations during grid faults, but size and cost implications appear to have limited the technology to academic discussion until now.

[100] found through experimental study that the use of braking resistors, with and without integration of other power system stabilising technologies, can help to increase stability margins of conventional generators during and after a range of fault types and investigated the implementation of controllers for such technology.

3.5.2 Flywheel Energy Storage (FES)

A method of providing system inertia and primary frequency support is through the use of flywheels [101, 102] and other energy storage technology. A flywheel is an energy storage device in the form of a large, heavy, spinning disc (or cylinder) which is connected to an integrated motor/generator through a shaft. An abundance of electrical energy on the system to which the device is connected results in motor action and acceleration of the wheel. Conversely, a lack of electrical power in the grid results in generator action, which causes the flywheel to decelerate and kinetic energy to be extracted from the wheel. The deceleration of the flywheel and the associated energy extraction during an under-frequency event provides a valuable feed of power into the system, reducing the discrepancy between generation and load.

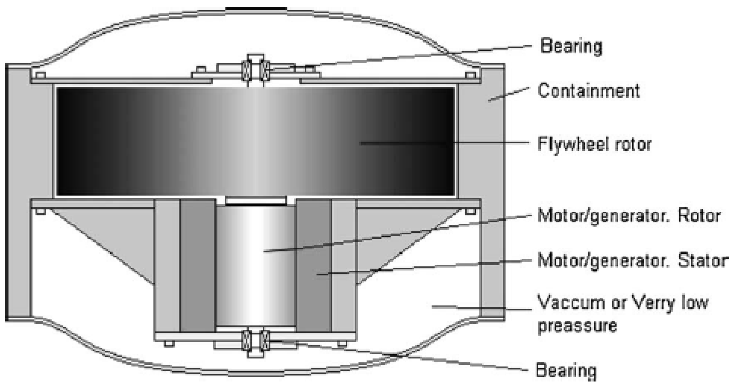


Figure 3.3: Typical Flywheel Energy Storage (FES) system [6].

Meanwhile, the flywheel acts in the same way as a traditional synchronous generator by providing a certain amount of inertia to the system – acting to slow down the rate of change of frequency. Flywheel energy storage (FES) has been highlighted as a promising development area for the above reasons and also to help provide back-up for the inherent intermittency of wind generation. The placement of flywheels within power systems is a current area of research [103].

Similarly, other methods of energy storage on the system (such as batteries, electric vehicles, superconducting magnetic energy storage, hydrogen, etc.) may be used to provide either inertial or primary frequency response on a power system. The challenge has so far been to develop these technologies at a scale which would be useful and cost-effective as a means of grid operational support. In a future grid where a combination of the technologies mentioned are used, the coordinated control of such devices, and the generation online, is a prerequisite. As is the case with existing generation and stability enhancing technology, each of the components must be controlled with due respect to the behaviours of every other system component, in order to maintain a stable and controllable system.

CHAPTER 4

Impacts of Wind Power on Transient Stability

This chapter aims to provide an illustration of the transient stability behaviour of the GB system and the extent of the problems encountered as a result of increased wind power penetrations. This will include studies of the sensitivity of transient stability margins to the geographical inertia distribution of the synchronous generation and a comparison to cases where wind power penetration (and the associated reduction in the size of synchronous generation) is responsible for the removal and relative geographical redistribution of inertia around the system. A comparison will also be made between the transient responses the system experiences when the wind farm is operated in different reactive power control modes and particular transient stability issues which can arise through the use of these different modes.

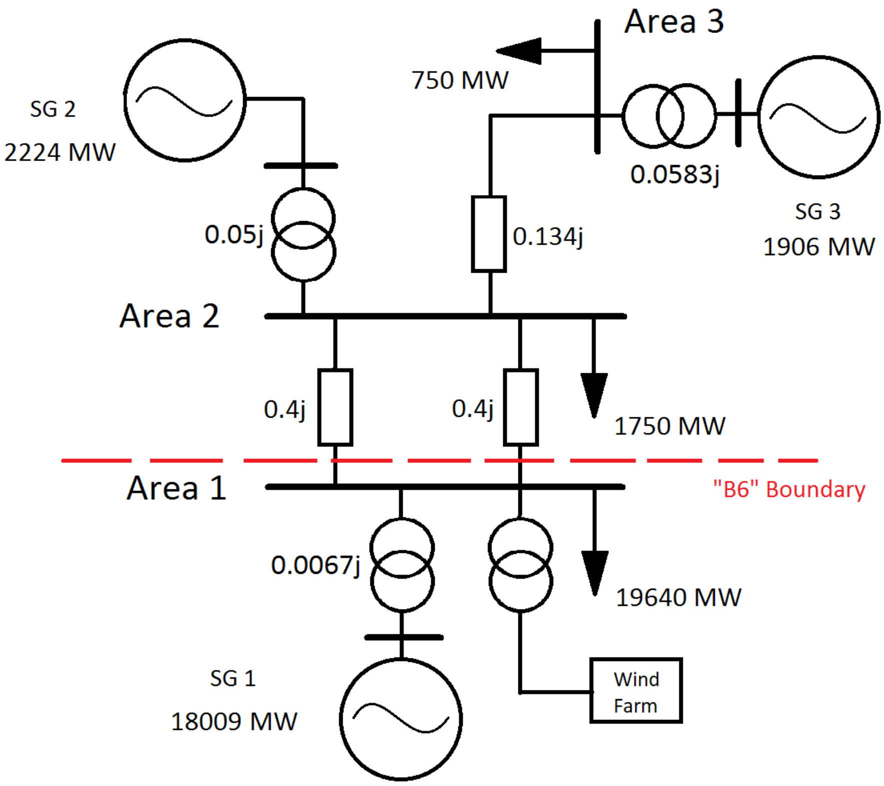


Figure 4.1: Representative GB network with CCT base case dispatch. Impedances in per unit on 1000 MVA base.

4.1 Representative GB Dynamic Model

A test system was built using DIgSILENT PowerFactory which was based on [104] and [105], and first developed in 2006 to approximate the GB system at that time. These earlier versions of the test system were intended to produce results representative of GB from the perspective of small-signal stability. The slightly modified version of the test system for this study is intended to broadly replicate the GB system's transient behaviour following a three-phase fault on one of the two double circuits of the representing the B6 boundary, by including an additional demand centre located in the Northern Scotland area.

The test system (Fig. 4.1) consists of three generation areas, which roughly represent each of the three transmission system owner areas of the GB system. Area 1 represents the England and Wales (E&W) network, Area 2 represents the southern part of Scotland (SS) and Area 3 represents the northern part of Scotland (NS). Area 3 is connected to Area 1 through Area 2, broadly replicating the grid topology of the GB transmission system. A wind farm is shown integrated in Area 1 in this schematic, which is connected in each area in turn for in the studies carried out in later sections. A graphic of the power system as modelled in DIgSILENT PowerFactory can be found in the Appendix to this thesis. The generation in each area is initially modelled as a single synchronous generator (SG), equipped with generic IEEE governor (TGOV1), AVR (IEEET1) and PSS (STAB1). Three loads are included in the test system, one in each area, representing the active power demand of England/Wales (19640 MW), Southern Scotland (1750 MW) and Northern Scotland (750 MW). The relative levels of generation and demand between the three areas is representative of the real GB transmission system [81]. The demand centres are modelled as static (constant impedance) loads.

4.2 Stability Assessment Methodology

In order to assess the impact of wind power plants on the transient stability of the GB system, a fully synchronous base case was first analysed to provide a baseline for comparison. Generic models of wind power plants available within PowerFactory – consisting of 2.0 MW rated FRC wind turbines (developed by the IEC and described in [106]) – were then added to each of the three test system areas in turn and the impact on the critical clearing time and boundary power transfer limit was assessed with respect to the fully synchronous base case.

4.2.1 Calculating Critical Clearing Time (CCT) and B6 Boundary Flow Limits

The critical clearing time of a given fault and power dispatch scenario is the longest acceptable time for which the fault can be active on the system before protective action is taken to avoid transient instability. Any clearing time below this value will result in stability being maintained and synchronous machine rotors returning to a new steady-state post-fault condition. Conversely, if the fault is not cleared within this time there will be transient instability in the system, manifested by pole slipping of one or more synchronous generator rotors. The use of this metric for transient stability assessment is common as it can be clearly stated that any reduction in CCT for a given fault is a corresponding reduction in the transient stability margins of the system to that fault [3], [107]. For the CCT impact assessments, a constant pre-fault power dispatch of 1400 MW across the B6 transmission boundary was selected and the clearing time of the fault was then varied using an interval halving algorithm to find the last stable clearing time (CCT) for each wind penetration scenario in turn. Details of the base case power flow can be found in Appendix A. The interval halving algorithm was configured to find the CCT to an accuracy of 0.2 ms. The simulation time for every study in this thesis was 30 seconds. This was chosen as the study time in order that any first swing issues could be assessed and an initial indication of damping of oscillations gained without dependency on the modelling of slower dynamics such as responses of wind farms to changing wind conditions and changes to transformer tap positions driven by automatic voltage control.

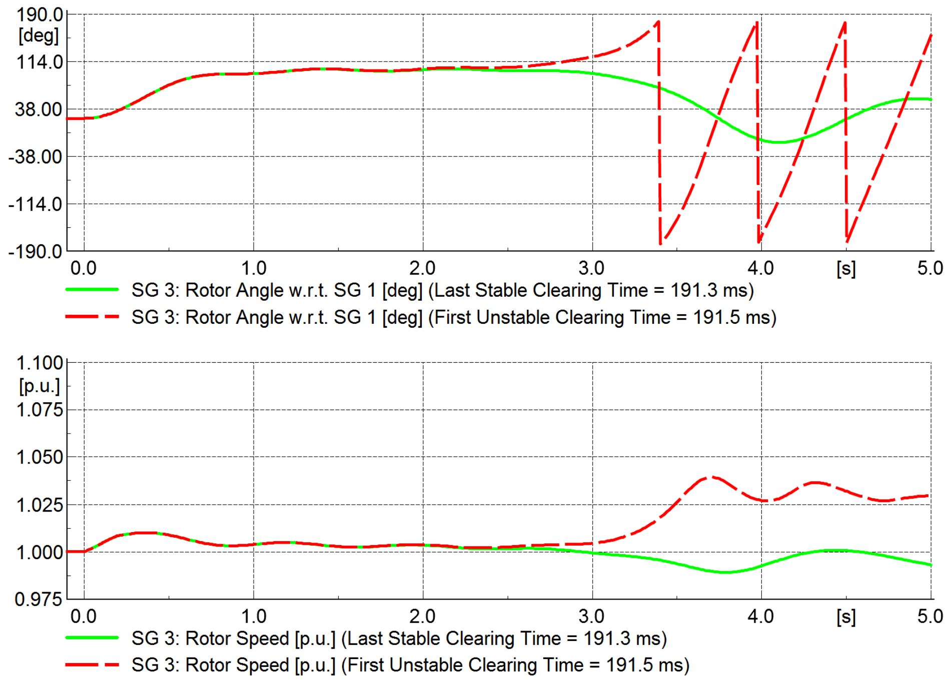
As well as the impact on the critical fault clearing time, a second metric was also used to measure the impact on transient stability margins to provide confidence in the efficacy of the methods employed in the work. While maintaining a constant ratio of active power output between Area 2 and Area 3, a similar interval-halving algorithm to that used for CCT was used to find the North-South power flow at which a three-phase fault (located half-way along the transmission corridor) with 80 ms line clearance provided a transiently unstable response from the system. The interval halving algorithm was configured to find the B6 Limit to an accuracy of 0.1 MW. As with the CCT study, the criterion for monitoring transient instability was observed pole slipping in any of the synchronous generators on the network. The synchronous generator in Area 1 was chosen as the reference (swing) generator in the simulations. This means that the active and reactive power dispatch of this generator are automatically regulated by the DIgSILENT power flow to provide system balancing in the pre-fault steady state and that the dynamic rotor angles of the other generators were measured with respect to that of synchronous generator 1. This is justifiable as the relative inertia and system strength of the England and Wales network is extremely high when compared with those of the Scottish areas and therefore it is expected that the transient rotor swings will be more severe for the Scottish generator rotors, the trajectories of which will be plotted against time in this work. The total North-South pre-fault active power flow through the transmission corridor was monitored in each case to find the last steady-state power flow for which transient stability is maintained following the application of the fault and subsequent clearance of the line through circuit breaker action after 80 ms. This provided a baseline against which the subsequent scenarios, which included wind power plants, could be compared in order to assess the impact made by the wind plants on the transient stability constrained boundary power transfer limit.

4.2.2 Fully Synchronous Base Case

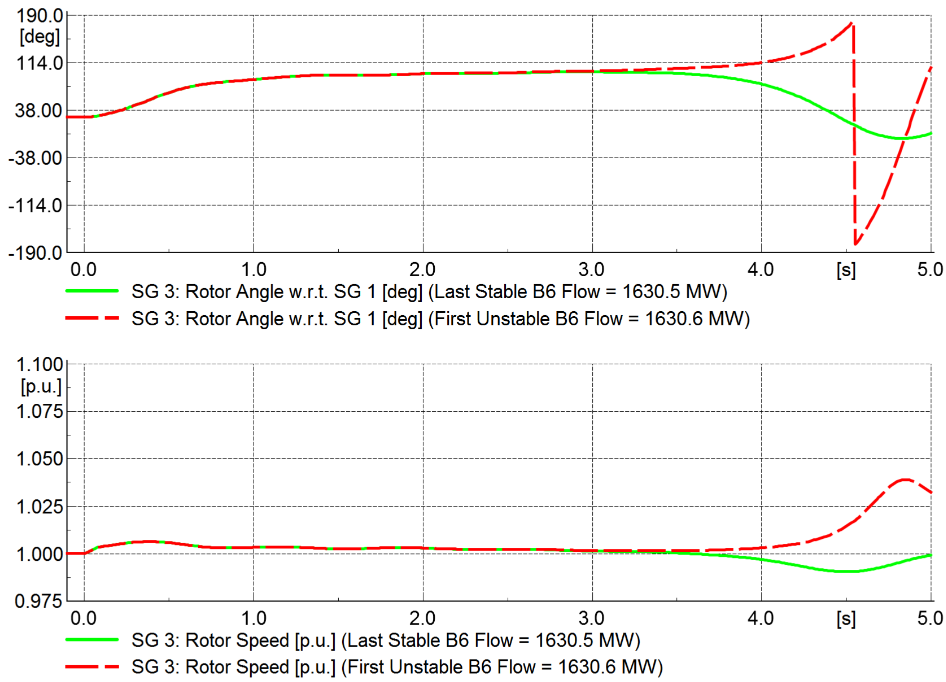
The results obtained from the studies carried out in this section are intended to illustrate key trends. Working with a heavily simplified test system, such as that used in these studies, means that although the absolute magnitudes of the CCT and B6 boundary power transfer limits may not reflect the real world values exactly, the qualitative impact of the removal of inertia and/or the penetration of wind power on the test system provides useful insights into the transient behaviours exhibited by the real world transmission system.

As a baseline for comparison in the analysis discussed in further sections, the critical fault clearing time and B6 power flow limit for the fully synchronous base case was found. Fig. 4.2 shows, for the synchronous generator connected in Area 3, the rotor angle and speed response for the last stable and first unstable clearing time and pre-fault B6 boundary power transfers respectively.

It can be seen that for a 1400 MW B6 boundary transfer, the last stable fault clearing time is 191.3 ms and the first transiently unstable clearing time is 191.5 ms. In the B6 flow case, when the pre-fault flow is 1630.5 MW the transient response to an 80 ms fault is stable, but when the boundary power transfer is 1630.6 MW transient stability limits are breeched and the response is therefore unstable.



(a) CCT.



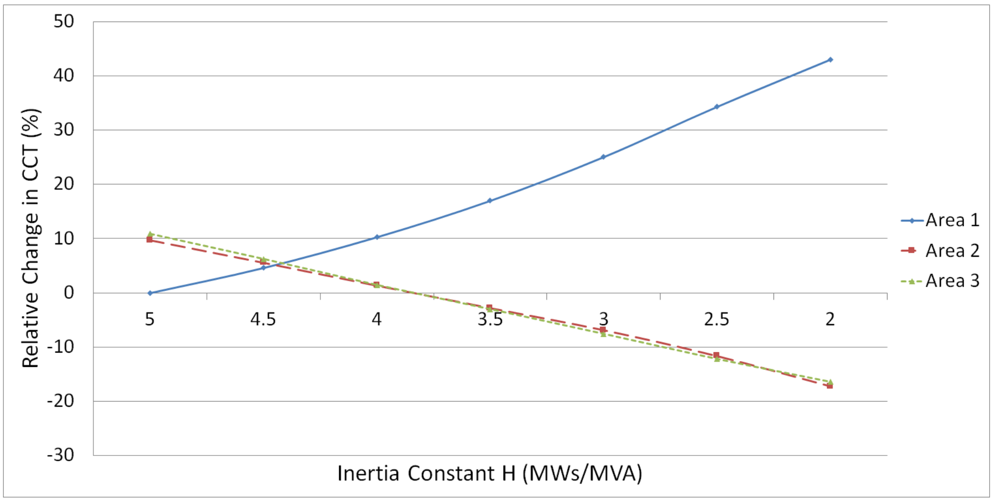
(b) B6 Limit.

Figure 4.2: SG 3 rotor angle and speed response (stable and unstable).

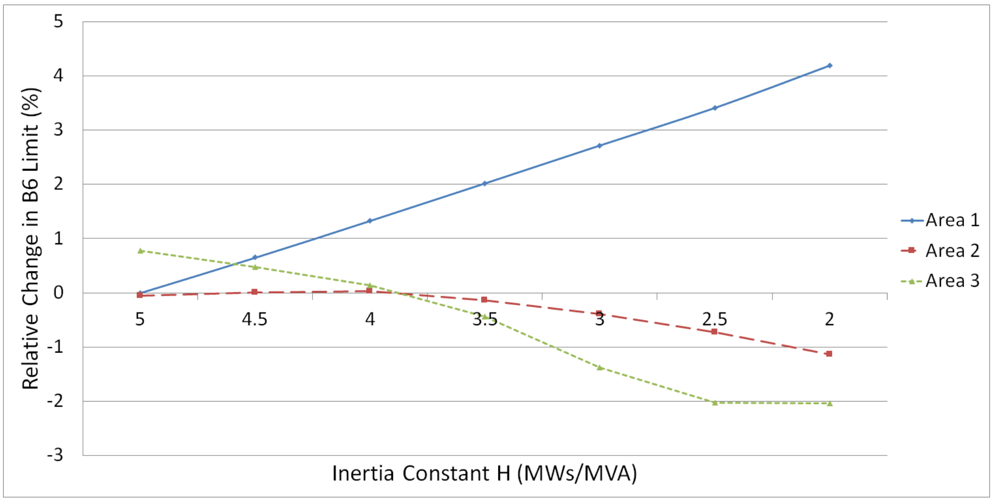
This therefore means that the baseline CCT = 191.3 ms and the baseline B6 limit = 1630.5 MW. The impacts on both the CCT and the B6 boundary power transfer limit as a result of the changes examined in the analysis will subsequently be given in terms of a percentage increase or decrease relative to these baseline figures.

4.3 Impact of Synchronous Generator Inertia

A useful conceptual reference point in the examination of the impacts of wind power displacing synchronous generation is to consider a case where the inertia values of the synchronous machines themselves are changed, simulating the loss of inertial response which is experienced as wind generation displaces synchronous machines. This insight into how the distribution of system inertia impacts transient stability can then provide a baseline for comparison when wind power instead partially replaces the synchronous machines. A comparison of the transient system behaviour (first rotor angle swings) can then be used to establish how the wind penetration influences the transient response of the system and whether the displacement of inertia is an influential aspect which will dictate the changes in stability characteristics experienced in the event of increased wind penetration levels.



(a) CCT.



(b) B6 Limit.

Figure 4.3: Impact of reducing synchronous generator inertias on CCT and B6 Limit.

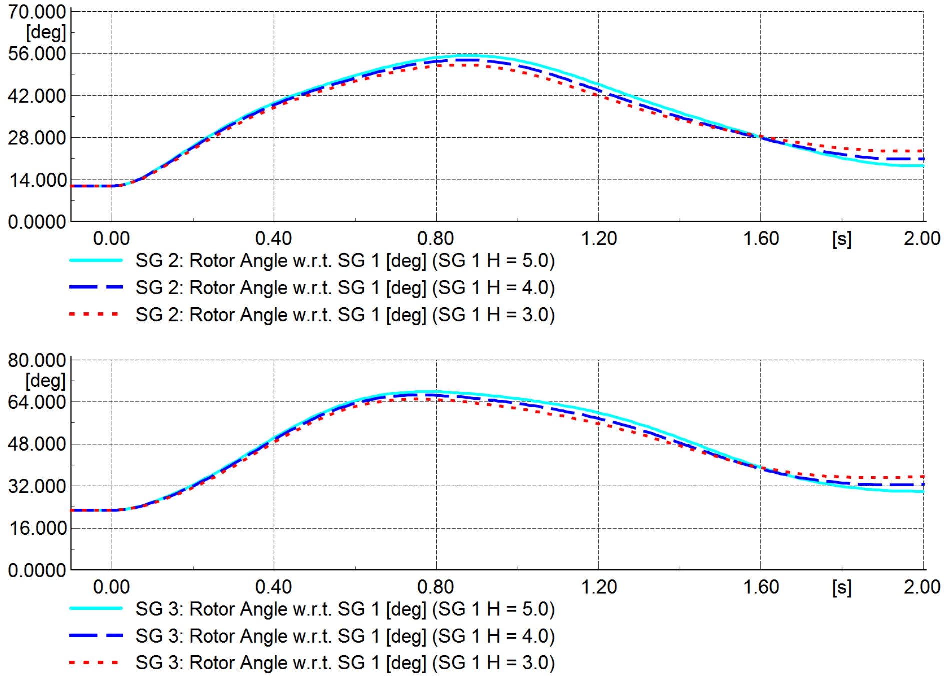
Fig. 4.3 shows the change in CCT and B6 Limit for a B6 boundary short-circuit fault which is experienced when the inertia constant of each of the three synchronous generators is varied between H = 5 and H = 2 MW.s/MVA, with the other two machine inertias held constant at their original values. These sensitivities are in relation to the fully-synchronous base case (CCT = 191.3 ms; B6 Limit = 1630.5 MW.) It can be seen that when the inertia of Area 1 (England and Wales) is reduced from its original value of 5 MW.s/MVA, there is a corresponding rise in the CCT and B6 Limit, whereas the opposite result is found when Areas 2 or 3 have their inertia constant reduced from their original value of 3.84 MW.s/MVA.

Table 4.1: Impact of reducing synchronous generator inertias on CCT.

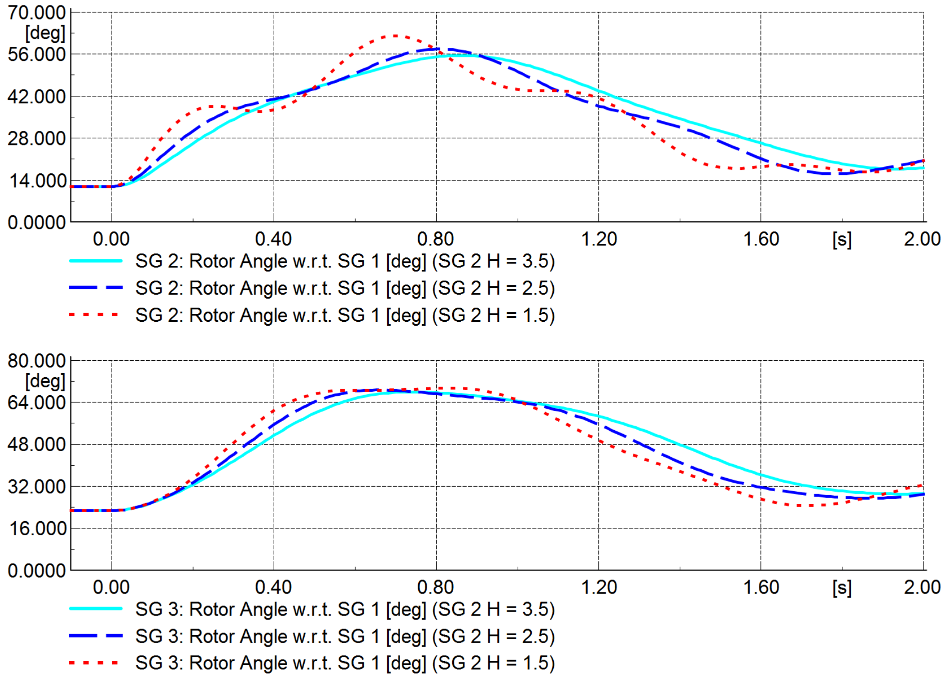
	CCT Deviation between H = 5 and H = 2 (%)
Area 1	+42.983
Area 2	-26.954
Area 3	-27.273

The results in Table 4.1 show that a reduction of the inertia constant in each of the areas of 60% (5 to 2 MW.s/MVA) results in a range of CCT variations between approximately -27% and 43%. Therefore the transient stability margins are highly sensitive not only to the total amount of inertia, but the geographical distribution of that total inertia around the system.

By examining the transient rotor angle response in each case, a picture can be developed of how the distribution of inertia around the system manifests itself in changes in the initial transient behaviour, i.e. the first rotor swing. Fig. 4.4 shows the changes in the first transient rotor angle swing responses of SG 2 and SG 3 (with respect to the rotor angle of SG 1) that occur when the inertia constant is reduced in each of the three areas. It can be seen that as the

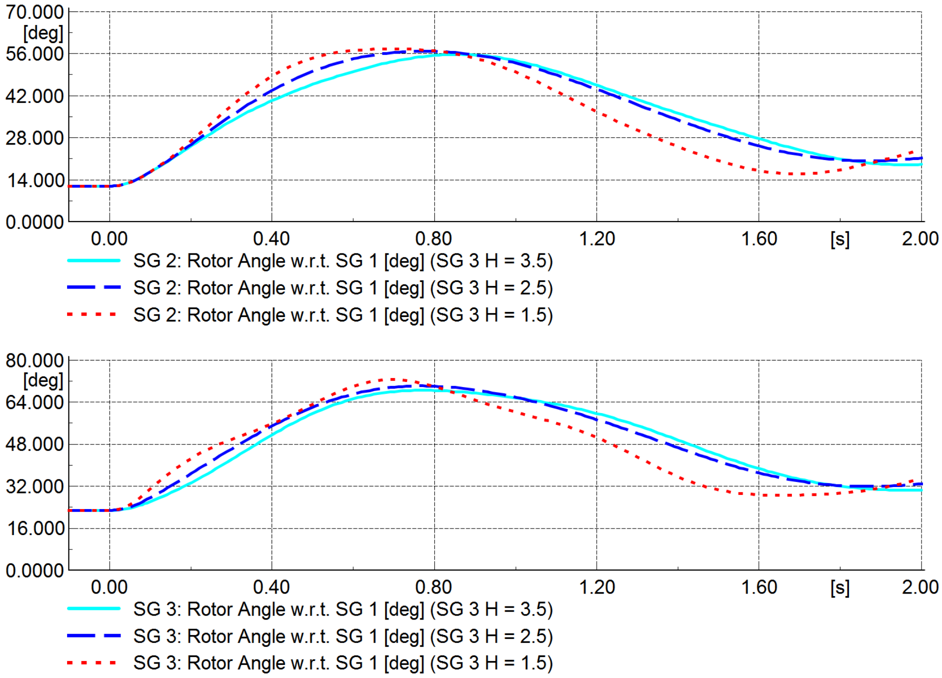


(a) Area 1.



(b) Area 2.

Figure 4.4: Impact of area inertias on SG 2 and SG 3 transient rotor angles.

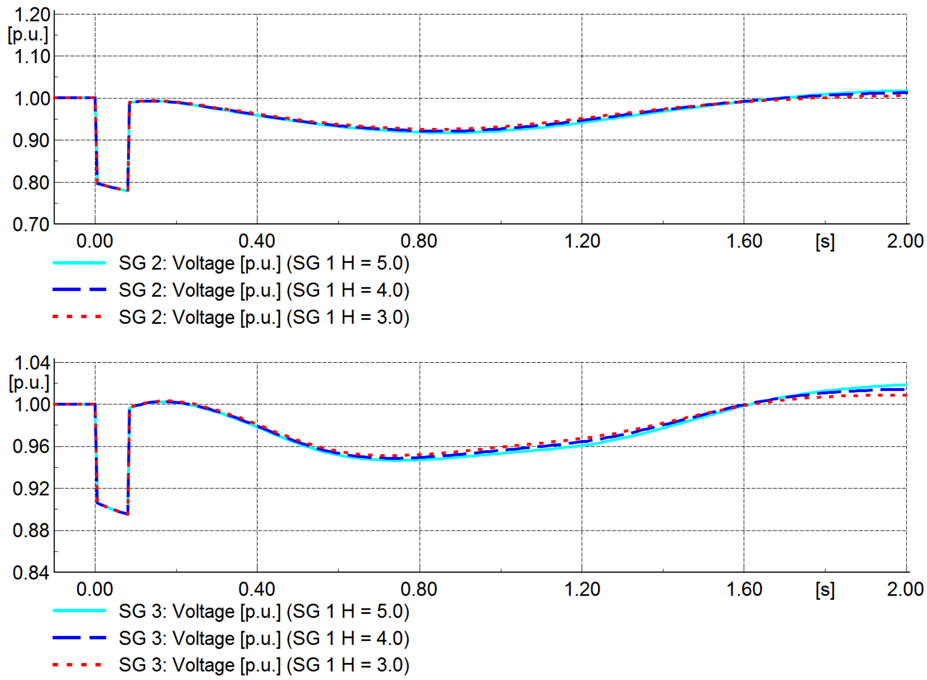


(c) Area 3.

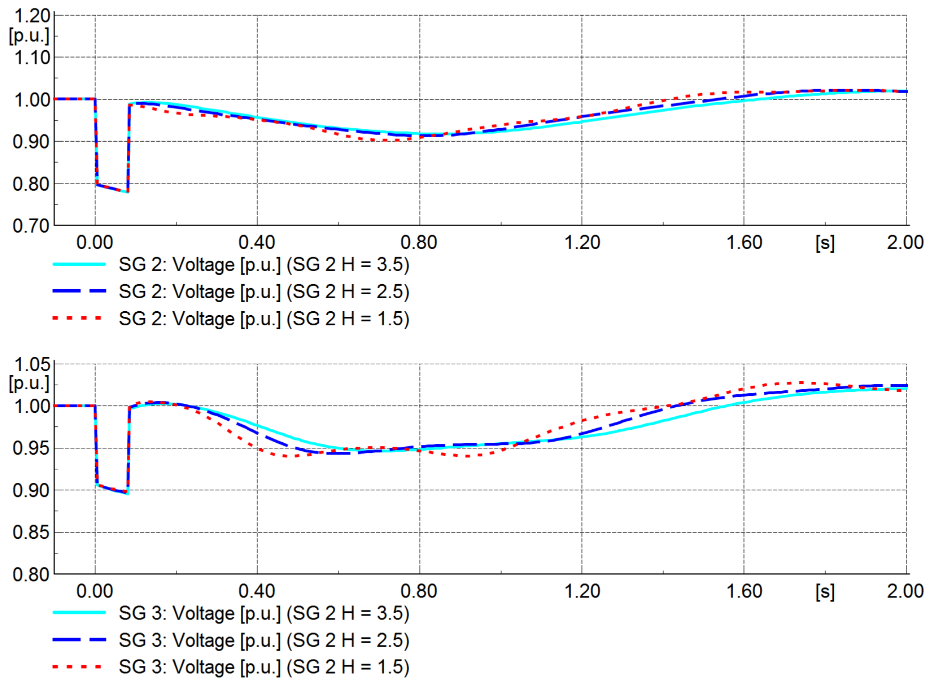
Figure 4.4: *(continued)* Impact of area inertias on SG 2 and SG 3 transient rotor angles.

inertia constants of SG 2 and SG 3 are reduced (Figs. 4.4(b) and 4.4(c)), there is an increase in the initial rate of rotor angle swing of both generators, as well as a corresponding increase in the maximum rotor angle deviation experienced during the first swing period. Conversely, when the inertia constant of SG 1 is reduced (Fig. 4.4(a)) there is a reduction in the rate of change of rotor angle and the maximum angle reached for both SG 2 and SG 3. The important point here is that as the *relative difference in inertia* between E&W and the Scottish generators is reduced (this happens when E&W becomes smaller), then the result is that the E&W system swings more coherently with Scottish system for the given fault. The more coherent the rotor swings of the two regions, the smaller the magnitude of the relative angle swing and the more transiently stable the system response is to a cleared short-circuit fault. These results help to explain the characteristics exhibited in Fig. 4.3 where the transient stability limits are increased (i.e. the system is more transiently stable) when the inertia constant of SG 1 (E&W) is reduced and the transient stability limits are reduced (i.e. the system is less transiently stable) when the inertia constants of SG 2 (SS) and SG 3 (NS) are reduced.

It is also important to note that the change of inertia constant has an impact on the transient response of the terminal voltages of each of the synchronous machines. Fig. 4.5 shows the sensitivities of the generator terminal voltages during the transient period to the changing inertia constants for the three area cases. It can be seen in each case that the inertia constants of the synchronous generators have no impact on the terminal voltages experienced by the machines during the fault-on period (voltage dip), but that there is a marked difference in the voltage profiles experienced post-fault (voltage recovery).

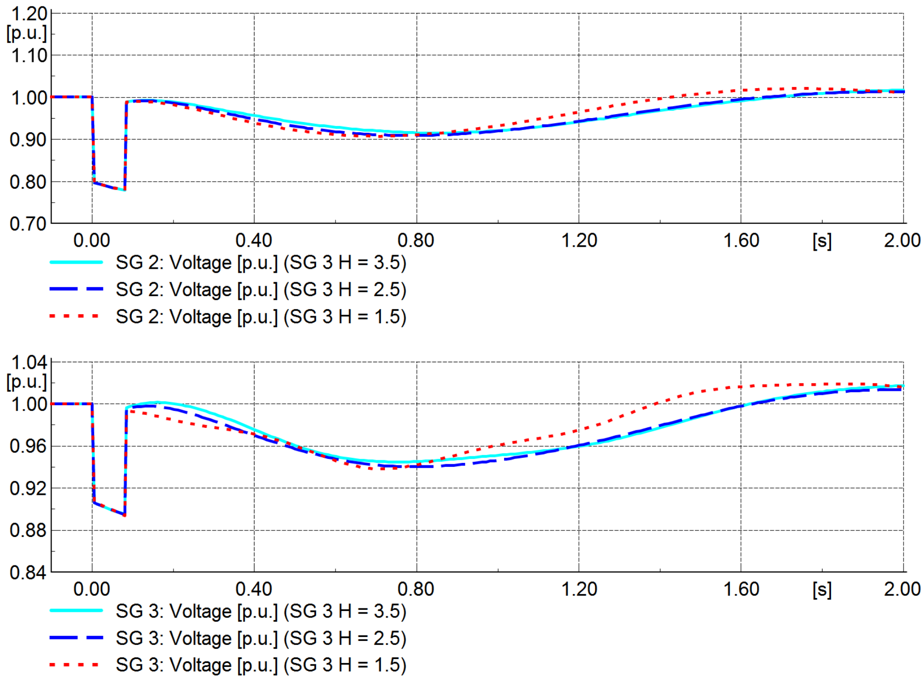


(a) Area 1.



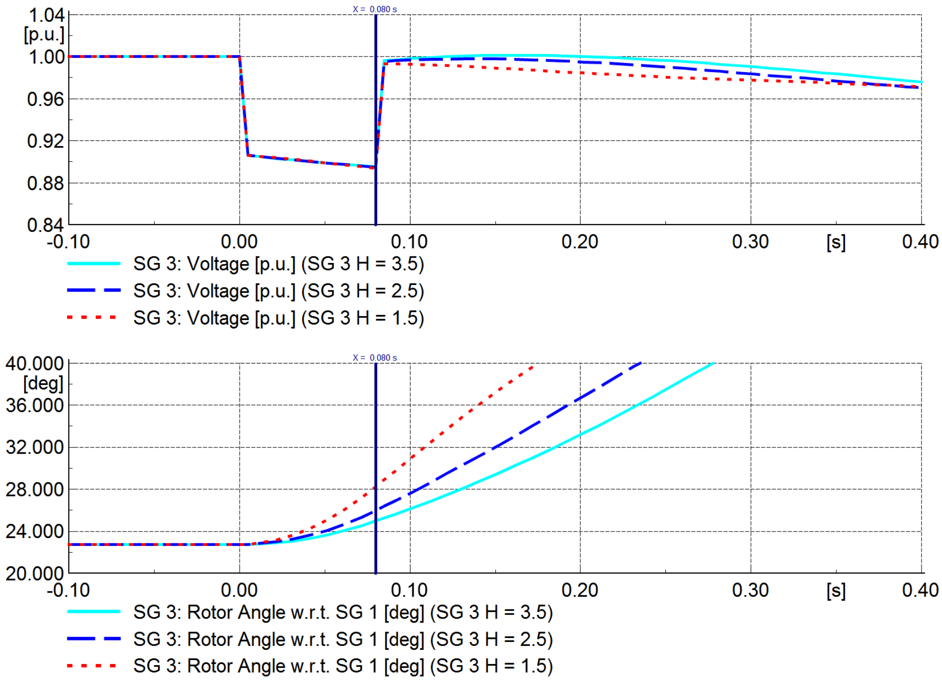
(b) Area 2.

Figure 4.5: Impact of area inertias on SG 2 and SG 3 transient voltage response.

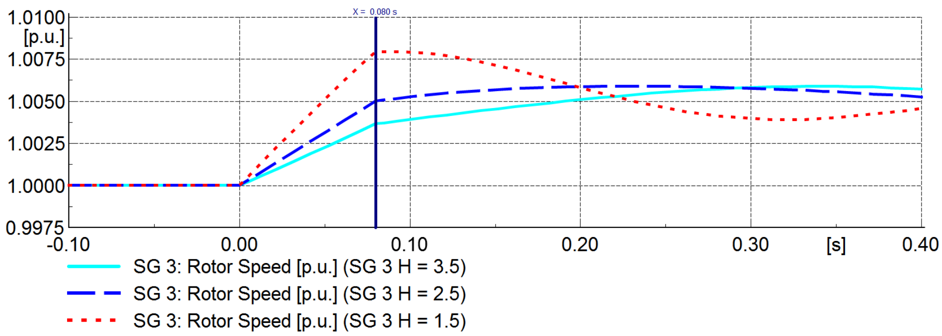


(c) Area 3.

Figure 4.5: *(continued)* Impact of area inertias on SG 2 and SG 3 transient voltage response.



(a) Voltage and Rotor Angle.



(b) Rotor Speed.

Figure 4.6: Detail of SG 3 short-circuit voltage, rotor angle and speed response.

Key to understanding the impact of inertia on the rotor angle swings is to investigate the degree to which the difference in transient period rotor angle swing behaviour is dependent directly on the physical inertia of the rotor and not related to the post-fault terminal voltage of the machine.

Fig. 4.6 shows, for the SG 3 case, a detailed view of the terminal voltage and

Table 4.2: Rotor acceleration experienced by SG 3 during fault-on period for different inertia values.

SG3 Inertia	Rotor Speed Reached (p.u.)	Acceleration (p.u./s)
H = 3.5	1.00375	0.0469
H = 2.5	1.005	0.0625
H = 1.5	1.008	0.0100

rotor angle responses during the short-circuit and for a short time thereafter (the beginning of the transient period), including the sensitivity to the inertia of the machine. A vertical line has been added to show the moment at 80 ms where the short-circuit fault was cleared by switching out the faulted line on the B6 boundary. It can be seen that there is a significant rotor angle change between the inertia cases while the fault is still active (before 80 ms) and the machine experiences identical terminal voltage magnitudes (Fig. 4.6(a)). During the fault-on period, the starting trajectory of the rotor drift is therefore fully dependent on the value of the machine inertia, not the value of the terminal voltage, which is constant across the inertia cases. The lower the synchronous inertia of the machine, for the same terminal voltage dip, the higher the acceleration experienced by the rotor (Fig. 4.6(b) and (c) and Table 4.2)) and therefore the greater the rotor angle drift in the early post-fault period and the beginning of the first rotor swing. Once the fault has been cleared at 80 ms, there is a notable change in the terminal voltage between the inertia cases, which comes as a result of the differing rotor speed values and hence differing EMF values induced in the stator coils. This baseline study of a simple reduction in inertia values provides a basis for comparison with the case of synchronous generation being steadily replaced by wind power plants, reflecting the real-world growth of renewable power generation, in the following section.

4.4 Impact of Wind Power Plants on Transient Stability

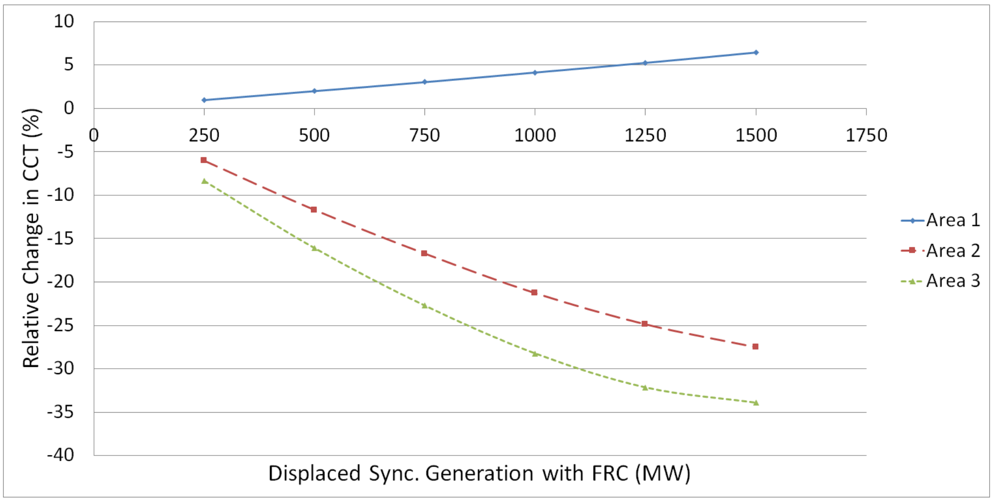
To examine the impact of the geographical location and penetration level of installed wind power on the transient stability of the system, Fully-Rated Converter (FRC) equipped wind power plants were connected within each of the three generation areas in turn, displacing a corresponding amount of synchronous generation in that area. The results give an impression of the marginal impact on transient stability if a single new wind power plant were to be installed in each of the three system areas. The wind plants were set to a power factor of 0.9 lagging at the beginning of the simulation.

The IEC standard wind turbine models can be set in a range of voltage control modes for time-domain simulations, including controlling for constant voltage, or constant power factor. In real world power systems, it may be advantageous to the operation of the system to tailor the type of reactive power control logic employed by a particular wind turbine or farm depending on the physical location of the generating unit, i.e. whether it is directly connected to the transmission system or embedded within a distribution system, or for other operational reasons. In transmission system applications it may be desirable to operate in a mode where the point of common coupling (PCC) voltage is maintained, allowing for the continual fluctuation in the supply of reactive power, ensuring that the transmission system voltage is kept between strict boundaries. Alternatively it may be better to operate a distribution system connected wind farm in a constant power factor mode, allowing the distribution system operator to have a more predictable reactive power supply from the wind farm, and thus less concern over the large losses associated with high reactive power flows at lower distribution voltage levels. The impact on the transient stability margins of increased FRC wind power penetration will be studied for both power factor control (the IEC model default setting), and voltage control, to discover any differing impacts between the two modes. The models allow the user to configure the reactive power control mode employed in the steady-state and also the control mode employed by the wind farm during the LVRT activation. It is the LVRT reactive power control mode that is being studied in this section, therefore the pre-fault steady-state is identical in all cases.

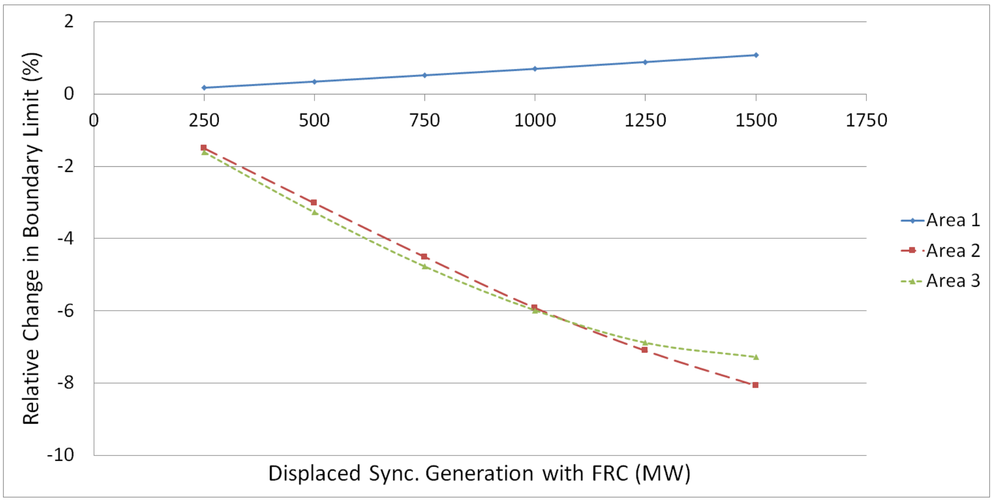
4.4.1 FRC Wind Farm in Power Factor Control Mode

Firstly the wind power plants were set to operate in a constant power factor mode, the default setting for the IEC FRC wind turbine type found as a template in the DIgSILENT PowerFactory built-in library.

Fig. 4.7 shows the sensitivity of the CCT and the last secure B6 boundary power flow as a function of the replaced synchronous generation in increments of 250 MW (1.13% to 5.65% of the total system demand) in each of the three areas in turn. It can be seen from the results that there is a much smaller relative impact when wind is added to Area 1 (England and Wales) when compared to the other areas. This is due to the relative size of the synchronous generation in England and Wales when compared to those in the Scottish areas, and therefore the replacement of a much smaller proportion of the area synchronous generation with the same size of wind farm. These results show a similar characteristic to those shown in Fig. 4.3, but instead of a reduction in



(a) CCT.



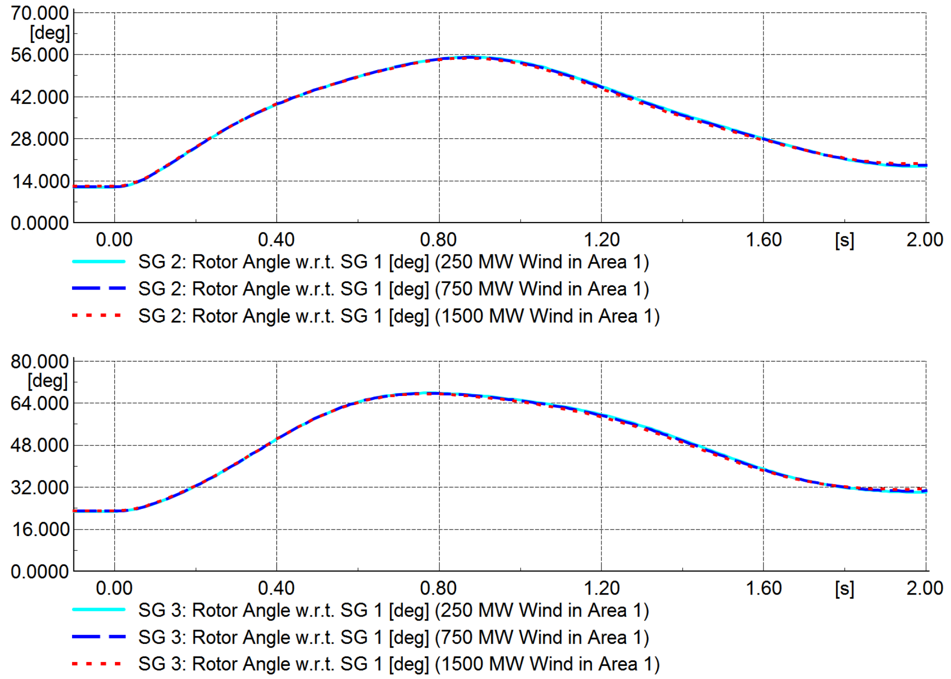
(b) B6 Limit.

Figure 4.7: Impact of pf-controlled FRC wind farms in each area on CCT and B6 limit.

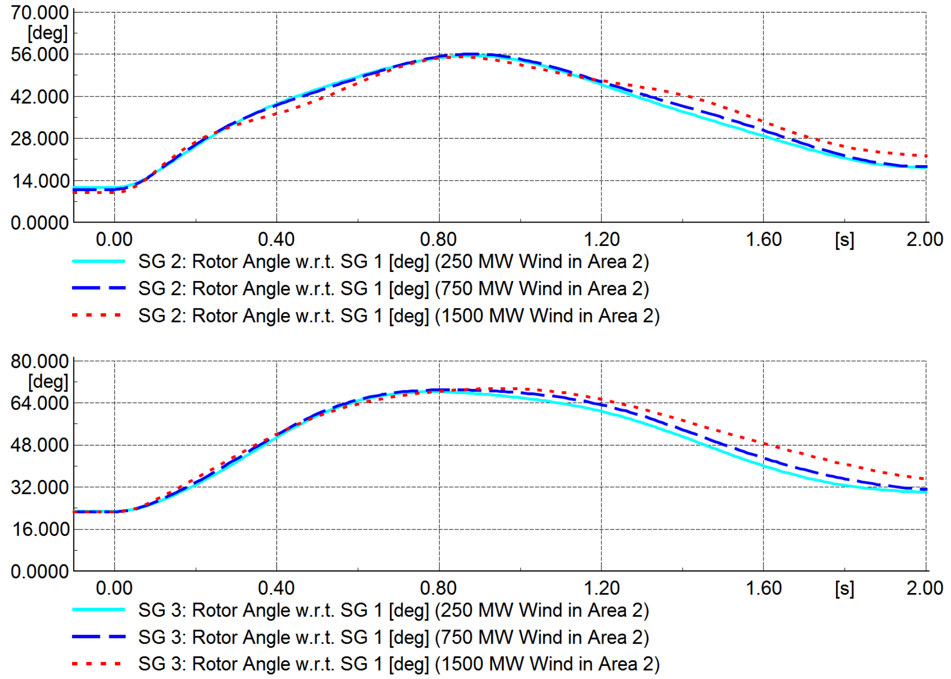
generator inertia constants for the three areas, the total synchronous generation is progressively reduced through replacement by wind generation. Similar illustrative rotor angle response tests to the previous inertia-reduction-only analysis were then carried out, where a B6 pre-fault active power flow of 1400 MW and a fault clearing time of 80 ms were used and the trajectory of the first synchronous generator rotor angle swings were monitored. Three wind penetration cases are shown in the figures for clarity.

Fig. 4.8 shows the change in the rotor angle responses of SG 2 and SG 3 when wind penetration is increased in steps of 250 MW in each of the three areas in turn (meeting 1.3% to 7.8% of the Area 1 demand, 14.3% to 85.8% of the Area 2 demand, and 33.3% to 199.8% of the Area 3 demand). It can be seen that a similar rotor angle characteristic emerges when compared to the simple fully-synchronous inertia reduction carried out in the previous section (Fig. 4.4). The effect is particularly acute in the case of wind penetration in Area 3, where an increase in the wind power penetration (and therefore a decrease in the total inertia) causes a higher initial rotor acceleration and a corresponding increase in the maximum rotor angle drift in the first swing. As well as the simple loss of inertia, there will be a significant difference in the control response and transient behaviour between synchronous generators and wind turbines.

Fig. 4.9 shows the voltage, rotor angle and rotor speed response of SG 3 when the Area 3 wind penetration is increased. A slight difference in the pre-fault steady-state rotor angle of the machine is found between the cases as the size and dispatch of the synchronous generation has been reduced, which will have some impact on the post-fault behaviour, however, in these tests, it is the relative magnitudes of the accelerations that is the dominant factor (Table 4.3.)

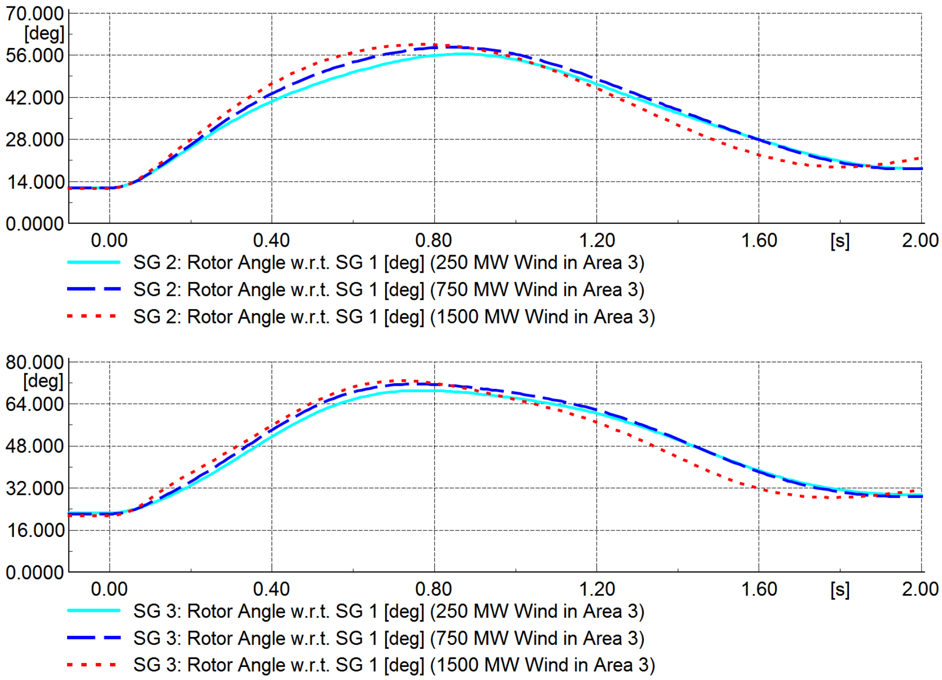


(a) Area 1.



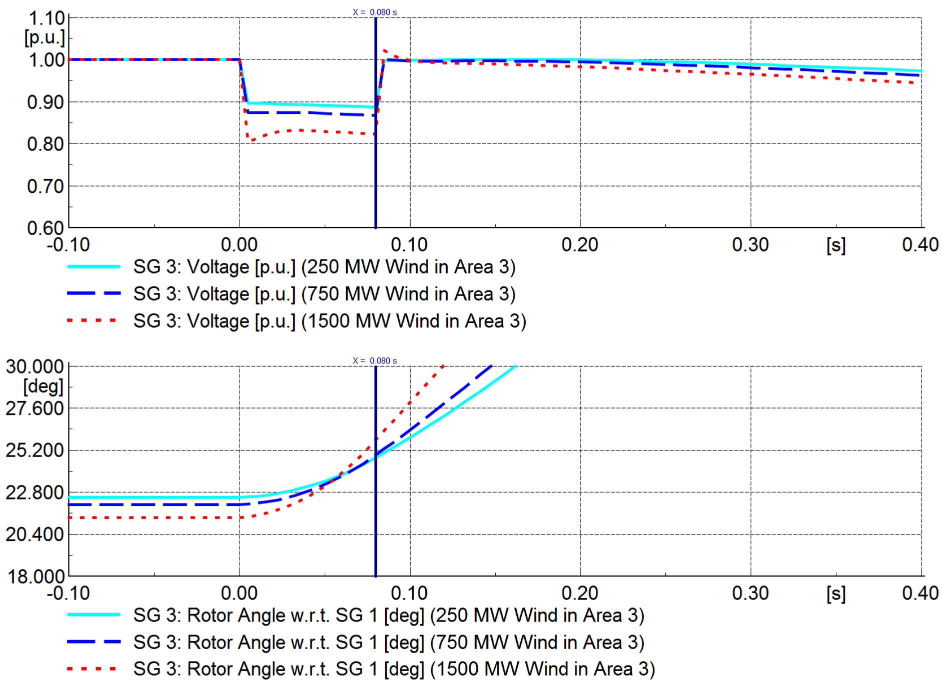
(b) Area 2.

Figure 4.8: Impact of pf-controlled FRC wind farm in each area on SG 2 and SG 3 transient rotor angles.

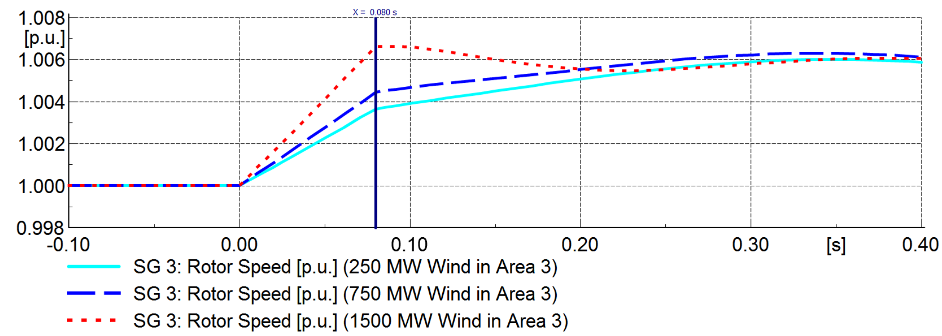


(c) Area 3.

Figure 4.8: *(continued)* Impact of pf-controlled FRC wind farm in each area on SG 2 and SG 3 transient rotor angles.



(a) Voltage and Rotor Angle.



(b) Rotor Speed.

Figure 4.9: Detail of SG 3 short-circuit voltage, rotor angle and speed response with wind power.

Table 4.3: Rotor acceleration experienced by SG 3 during fault-on period for different wind penetrations.

	Rotor Speed Reached (p.u.)	Acceleration (p.u./s)
250 MW Wind	1.0036	0.0450
750 MW Wind	1.0043	0.0537
1500 MW Wind	1.0067	0.0837

In contrast to the fully-synchronous case, there is a noticeable deterioration in the generator terminal voltage magnitude as the wind penetration is increased at the expense of synchronous penetration. As discussed previously, this depression in the terminal voltage of the machine acts to constrain the amount of active power exported from the machine, and conservation of energy dictates that the rotor will be less able to convert its kinetic energy into electrical energy and will therefore experience a higher acceleration. This study, and the previous inertia-only study, show that when pf-controlled FRC wind turbines replace synchronous generation, the corresponding loss of inertia and also the difference in the short-circuit terminal voltage behaviour both drive the change in transient stability margins by contributing to the change in the trajectory of the rotor angle swing during the transient period and therefore throughout the first swing.

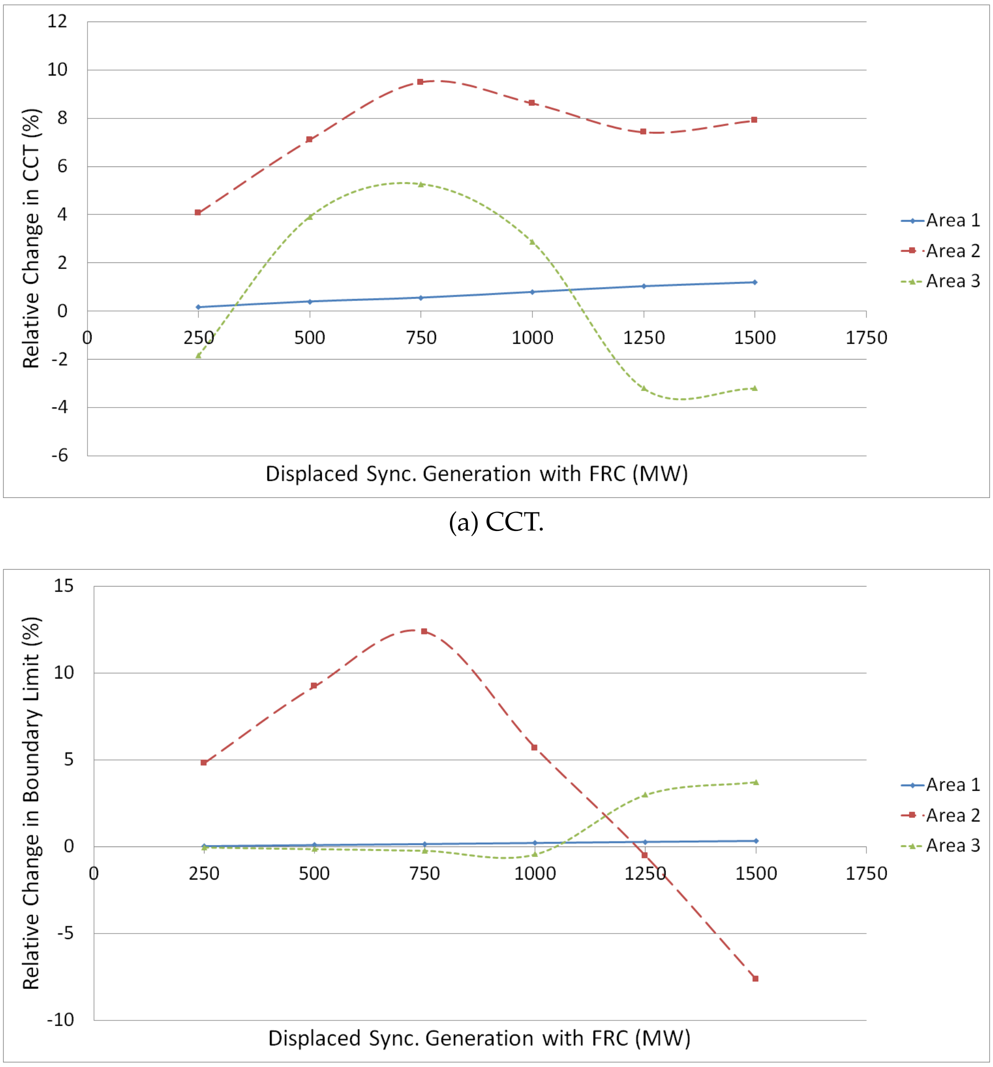
When FRC-equipped wind power in power factor control mode replaces synchronous generation, there is an erosion of the transient stability margins which is analogous to a simple loss of inertia, plus an extra component resulting from the larger terminal voltage drop experienced by the local synchronous generator. As will be investigated in a later chapter, there may be benefits in terms of transient rotor angle responses which can be gained through the full or partial mitigation of the transient voltage erosion from increased wind penetration. By utilising the wind farm to maintain a higher terminal voltage experienced by the synchronous generators, the magnitude of the rotor accelerations may be reduced and transient stability margins improved.

4.4.2 FRC Wind Farm in Voltage Control Mode

The wind turbines' reactive power controller was then set to the voltage control mode and the same tests were carried out, namely the impact of wind penetration in the three areas on the transient stability margins.

Fig. 4.10 again shows the sensitivity of the CCT and the last secure boundary power transfer limit as a function of the replaced synchronous generation, this time with the wind farms' reactive power controller set to voltage control mode. A much more complicated picture emerges than in the pf-controlled case described previously. In the Area 2 and Area 3 cases there is now a highly non-linear characteristic both for CCT and B6 limit. Also, in contrast with power factor control mode (Fig. 4.7), there is now a large difference in particular between the CCT and B6 Limit behaviours when focusing on the Area 3 case. In pf-control mode, both CCT and B6 Limit decrease fairly linearly with wind penetration, while in v-control mode the CCT initially increases while the B6 Limit decreases with wind penetration. Both then experience a reversal at higher penetrations.

The changes in CCT/B6 limit characteristic as a function of wind penetration warrant a further investigation of the system behaviour in the voltage controlled case. From Fig. 4.10 it can be seen that there are drastic changes in the CCT vs. penetration characteristic in Area 2 and Area 3 above a wind penetration of 750 MW and a similar change in the B6 flow vs. penetration



(a) CCT.

(b) B6 Limit.

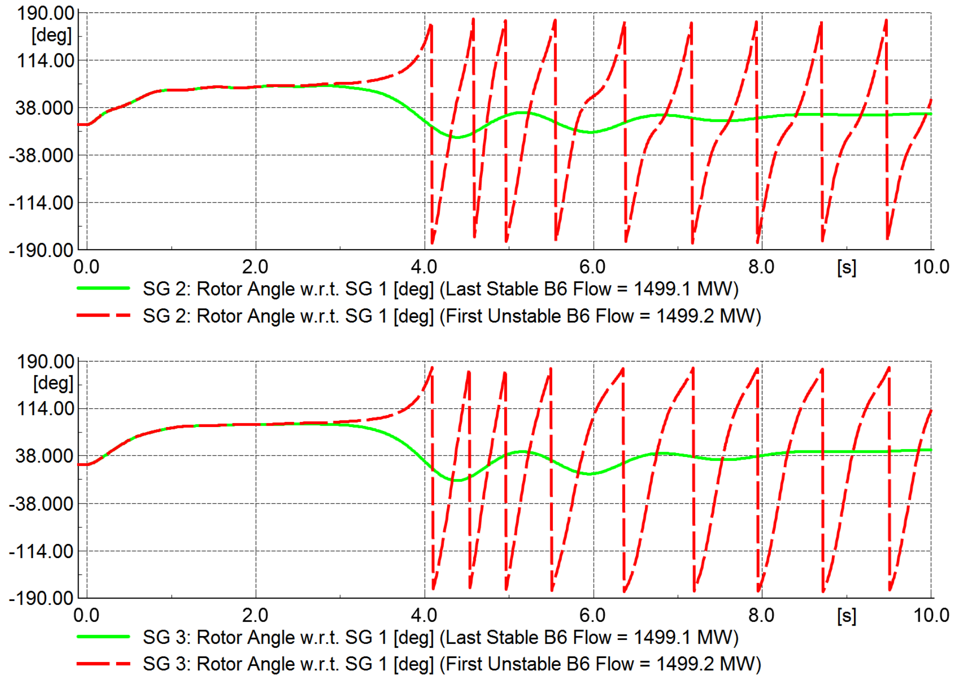
Figure 4.10: Impact of v-controlled FRC wind farms in each area on CCT and B6 limit.

characteristic for Area 2, where the previously rising CCT/B6 limit peaks and starts to reverse. In the voltage-controlled wind farm case there appears to be a limit above which additional wind penetration leads to the manifestation of a fundamentally different physical behaviour in response to the same pre-fault condition and the same transient short-circuit fault (type and duration).

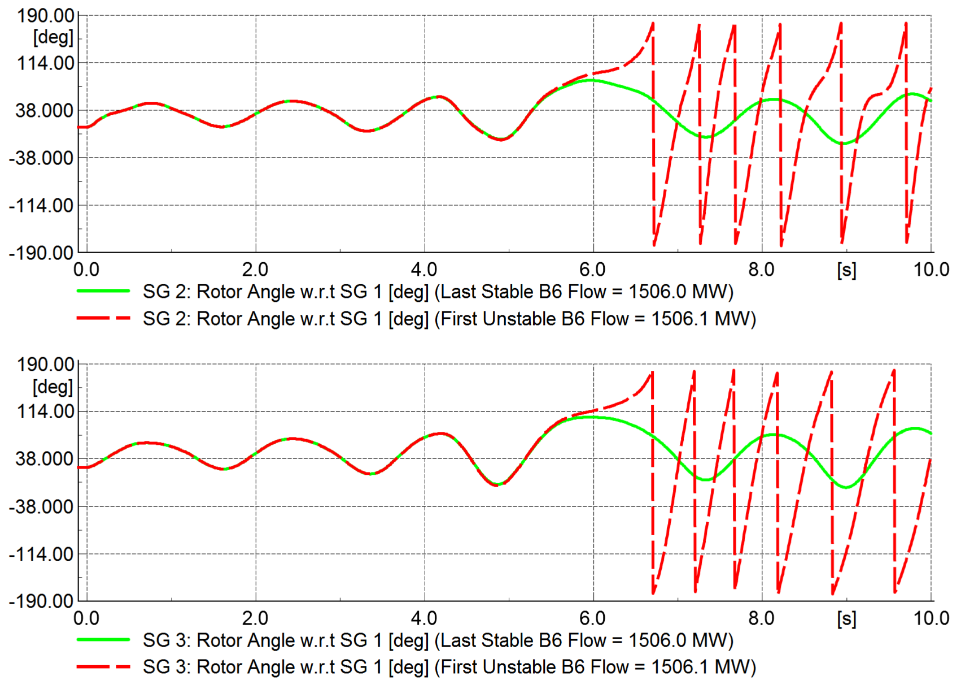
Fig. 4.11 shows a comparison between the instability modes when a 1500 MW pf-controlled or v-controlled wind farm is installed in Area 2. At this high wind penetration, the instability behaviour is very different between the two modes. In pf-control mode the instability manifests in pole slipping on the first rotor angle swing, which is long in duration. In v-control mode the first several rotor angle swings are smaller and shorter but the rotor angle reaches an unstable separation on the fourth swing and pole slipping occurs. In the pf-control mode, the rotor angles in the last stable case come to a new steady-state angle within around 10 seconds, while in the v-controlled case the rotor angles continue to oscillate well beyond 10 seconds (Fig. 4.12).

Fig. 4.12 shows a 30 second view of the voltage controlled test from Fig. 4.11. It shows that even when the rotor angle stability is maintained (i.e. no pole slip) within 30 seconds, there is still a severe and long-lasting oscillation in the rotor angle. This shows that high wind penetrations in Area 2 may not be desirable when the FRC wind farms are set to voltage control mode when compared with power factor mode.

Fig. 4.13(a) shows the active power responses of the wind farms for each of the wind penetration cases (wind farms integrated in areas 1, 2 and 3). As can be seen, the test case (1400 MW B6 flow and 80 ms fault clearing time) is unstable in the long term when a 1500 MW wind farm is integrated in Area 2.



(a) Power Factor Control.



(b) Voltage Control.

Figure 4.11: Instability comparison between pf- and v-control with 1500 MW FRC in Area 2.

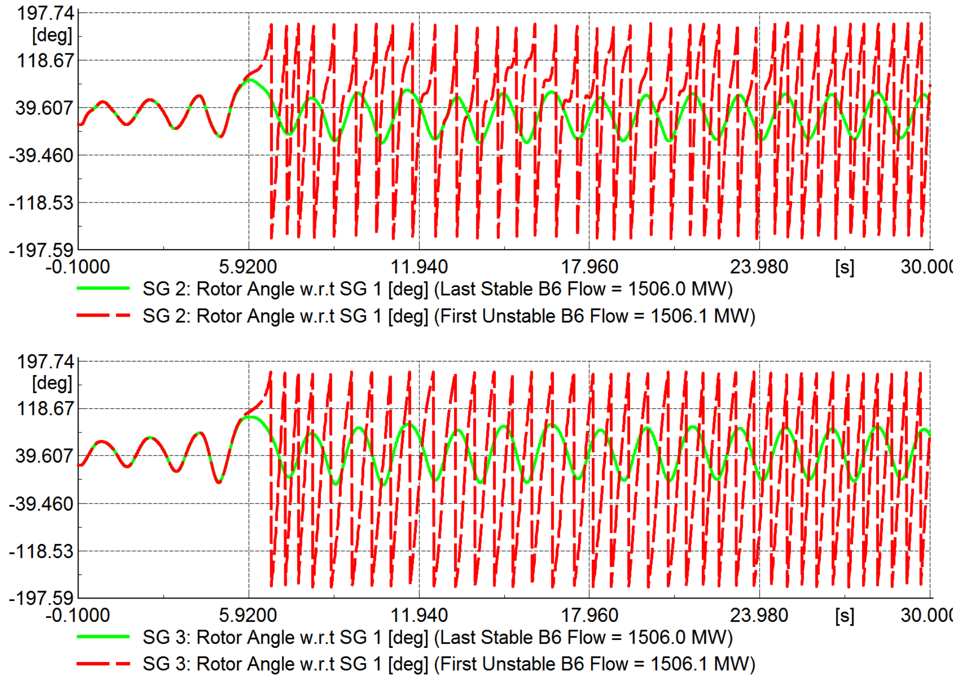
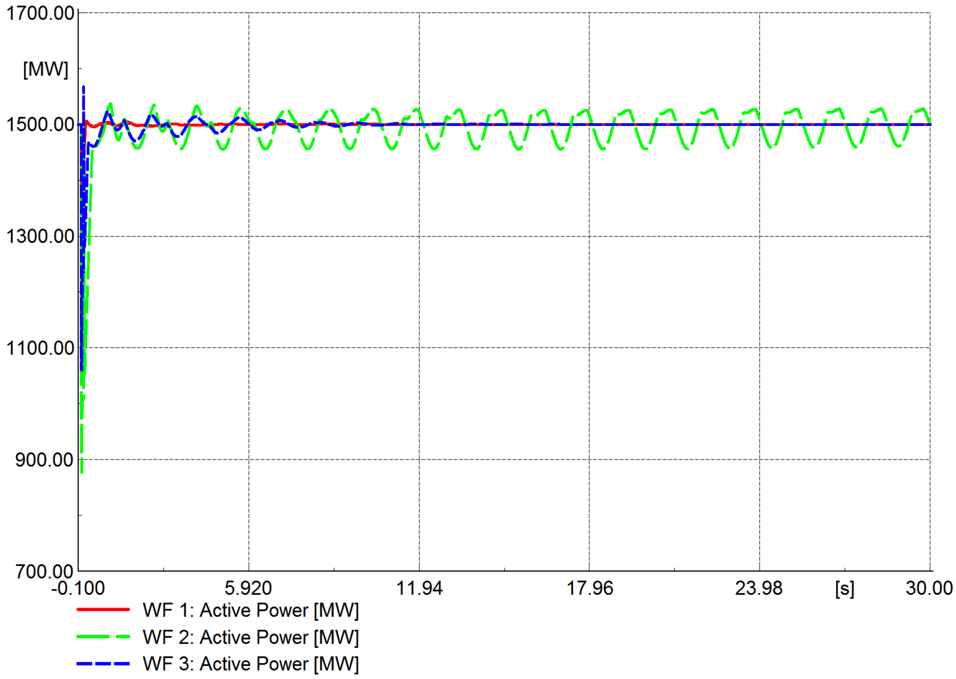


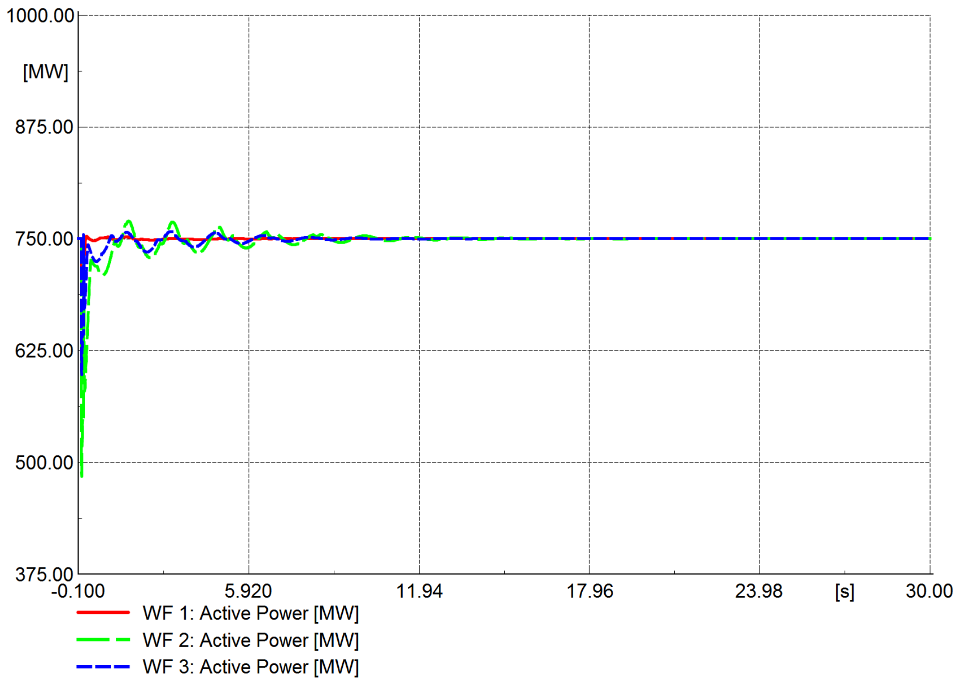
Figure 4.12: Longer view of v-control FRC instability with 1500 MW FRC in Area 2.

This is not the case for the pf-controlled case. Due to the proximity to the fault (and therefore the severity of the transient voltage dip) and the high wind penetration, the voltage controlled mode results in long-term unstable behaviour. For this demonstration, the wind farms were then reduced in size to 750 MW (Fig. 4.13(b)), in order that long-term stability is maintained and the qualitative impact of the wind farms on the synchronous generator first swing responses can be investigated.

Fig. 4.14 shows the nature of the rotor angle instability leading to pole slipping in SG 3 when a 750 MW wind farm is integrated in Area 2. It can be seen in Fig. 4.14(c) that it is not the first rotor angle swing which leads to the instability, rather in the unstable case transient instability is manifested in the third rotor swing of SG 3. By examining the active power output of SG 3 in

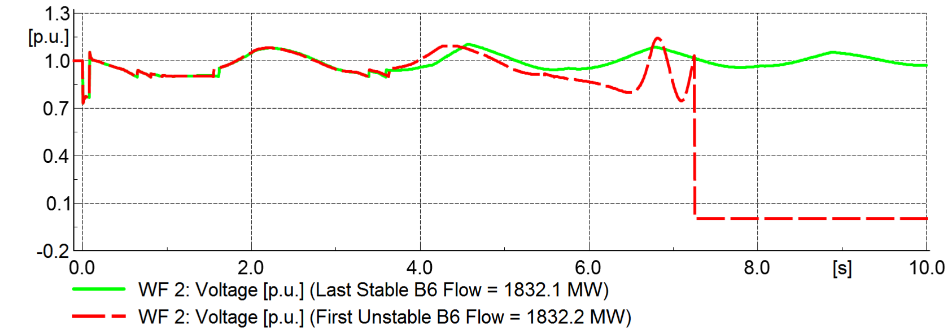


(a) Long-term unstable with 1500 MW wind.

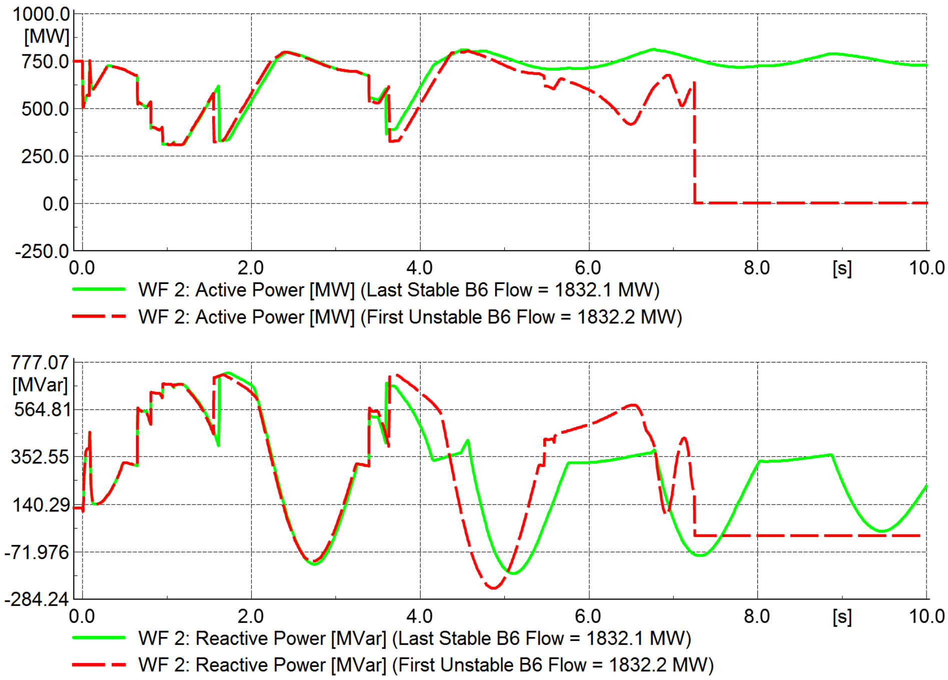


(b) Stable with 750 MW wind.

Figure 4.13: Unstable v-control wind farm behaviour, alleviated by studying at a lower penetration level.

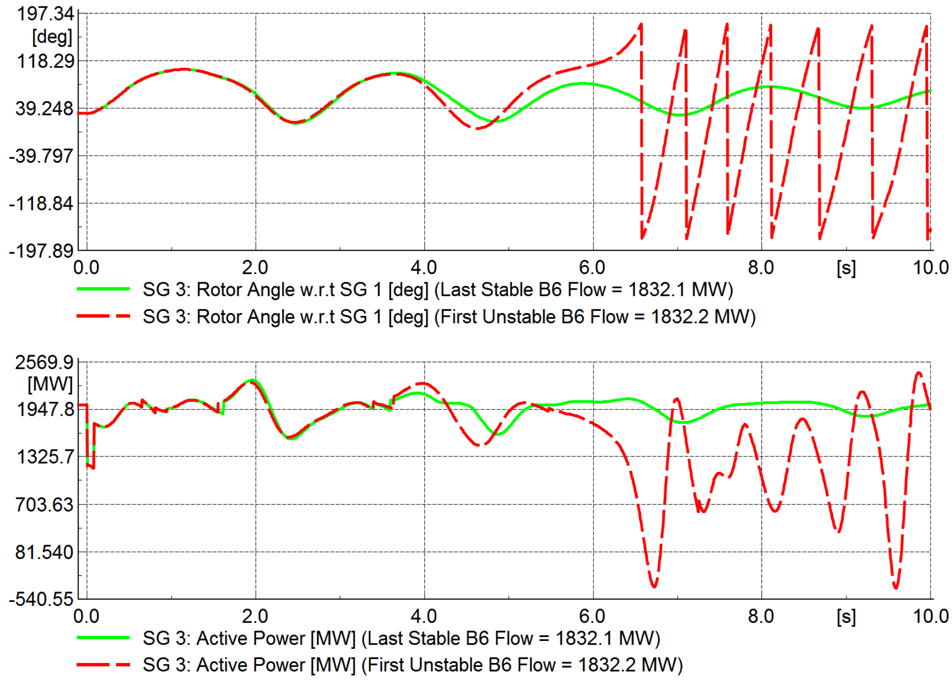


(a) WF 2 Terminal Voltage.



(b) WF 2 Active Power and Reactive Power.

Figure 4.14: Stable/Unstable transition at B6 limit with v-controlled FRC in Area 2.



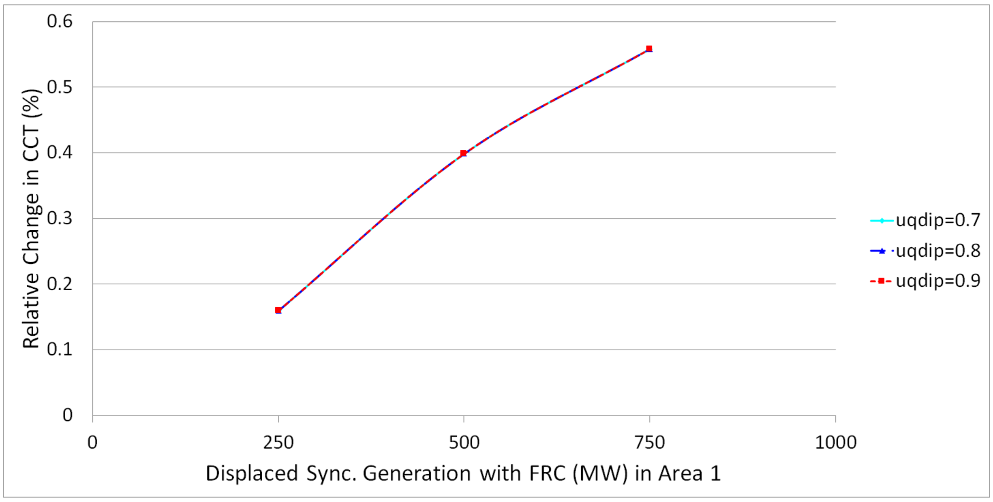
(c) SG 3 Rotor Angle and Active Power.

Figure 4.14: *(continued)* Stable/Unstable transition at B6 limit with v-controlled FRC in Area 2.

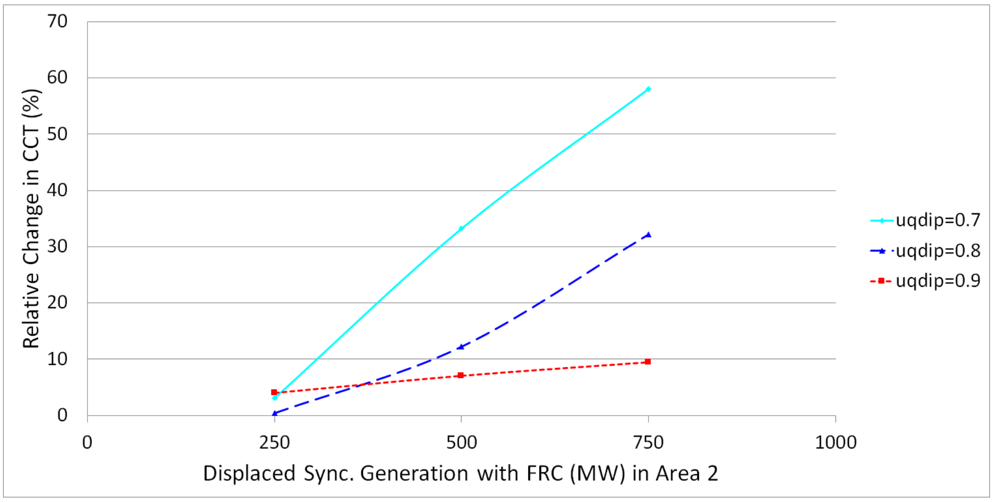
this case, at approximately t = 3.5 s there is a significant increase in the SG 3 active power output along with a rapid drop in the rotor angle when compared with the stable case. On examination of the behaviour of the local wind farm, it can be seen that a corresponding drop in the wind farm active power and increase in reactive power (and therefore terminal voltage) occurs in parallel with the synchronous rotor angle drop just after t = 3.5 seconds. Whenever the wind farm experiences a terminal voltage of 0.9 p.u. the LVRT logic takes over to produce this behaviour. Such discontinuities in the behaviour of the wind farm active and reactive power outputs may prove undesirable to overall system transient stability if they lead to destabilising forces on the synchronous generator rotors. These results show that there may be cases where the system is actually recovering to a new steady-state operating condition (transient stability is being maintained), but the terminal voltage of a wind farm is oscillating in a slow manner, and the LVRT voltage threshold is barely breached. This breach can then cause an otherwise stable system to become unstable with the next synchronous rotor angle swing because of the wind farms' spurious LVRT behaviour.

Sensitivity to LVRT Activation Threshold Value

As shown previously, beyond the transient period (first swing) there may be rotor angle instability brought on by correct, though in context undesirable, control actions. If an otherwise stable response to a transient short-circuit fault results in longer-term voltage oscillations, which then trigger an LVRT activation in the connected wind farms, the discontinuities in the wind farm active and reactive power outputs can cause sudden imbalances between generation



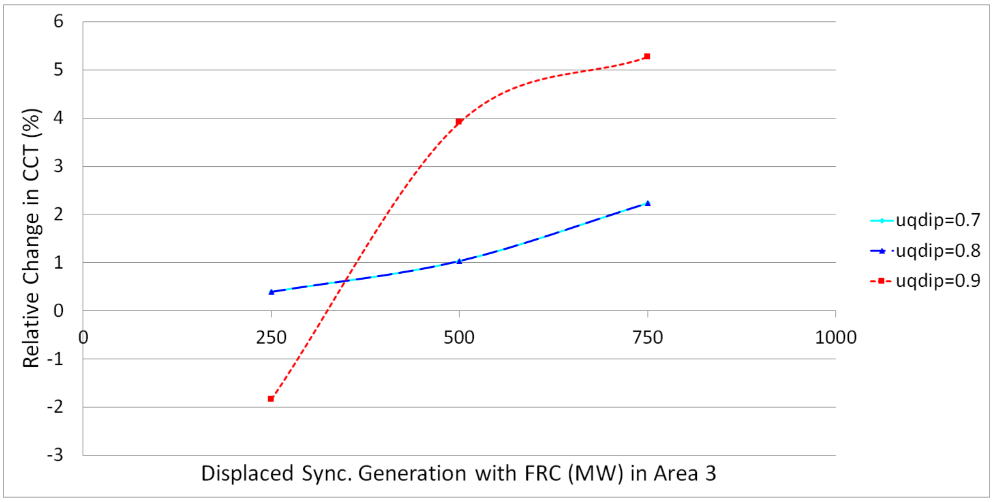
(a) Area 1.



(b) Area 2.

Figure 4.15: Sensitivity of CCT to LVRT activation threshold.

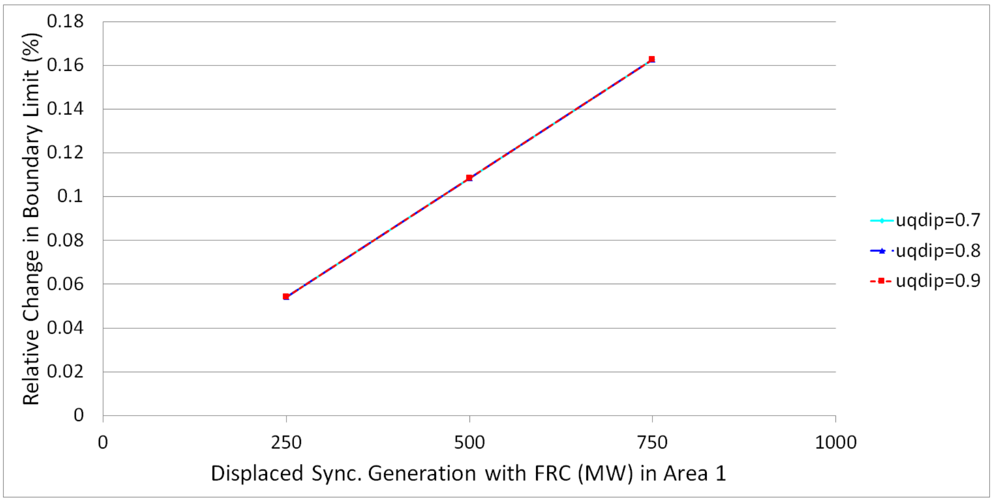
and demand, and also voltage fluctuations, which lead to unstable rotor angle responses in the synchronous generators long after the first swing period. Though the major focus of this thesis is to study the first swing transient behaviour, it is important to note that the wind farms' LVRT settings and behaviour can have a significant impact on the longer term stability of the system.



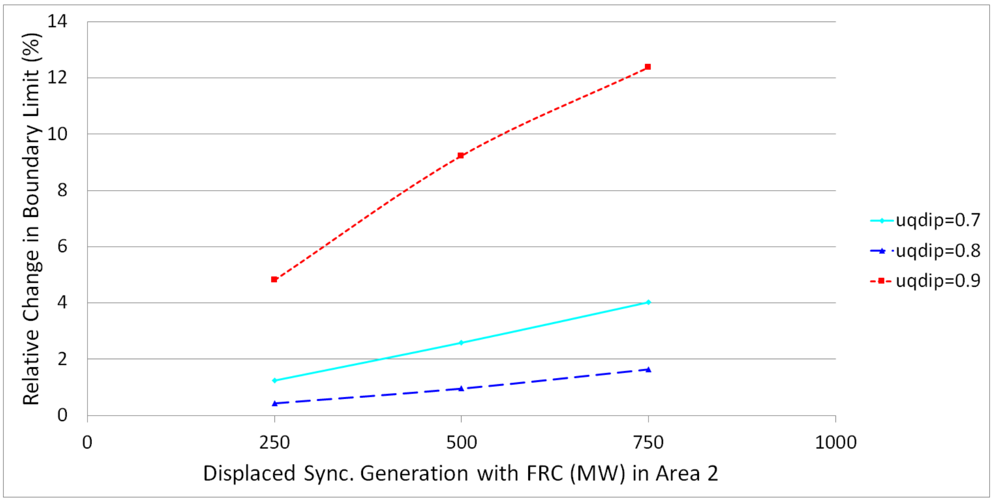
(c) Area 3.

Figure 4.15: *(continued)* Sensitivity of CCT to LVRT activation threshold.

Figs. 4.15 and 4.16 show the CCT and B6 Flow sensitivities to changing the LVRT threshold value of the v-controlled wind farms (denoted as "uqdip" in the controller settings). The default value of the parameter uqdip is 0.9 p.u. There is no change in transient stability margins when the wind farm is in Area 1, because in those cases the terminal voltage of the wind farms does not breach 0.9 p.u. in the transient period. The Area 2 and Area 3 results show that the transient stability margins are highly sensitive to the LVRT threshold value setting, and also show notably different sensitivities between the two stability metrics. For example, in the Area 2 case there is a marked increase in the CCT value when uqdip is decreased, while the B6 limit results show a higher value of uqdip being most beneficial to the transient stability margin. In the case of wind power in Area 3, there is a distinct increase in the transient stability margin when utilising the higher LVRT threshold of 0.9 (the results for 0.8 and 0.7 are identical as neither are tripped by the voltage dip experienced by the distant wind farm). In contrast, for the B6 power flow limit case, the use of the

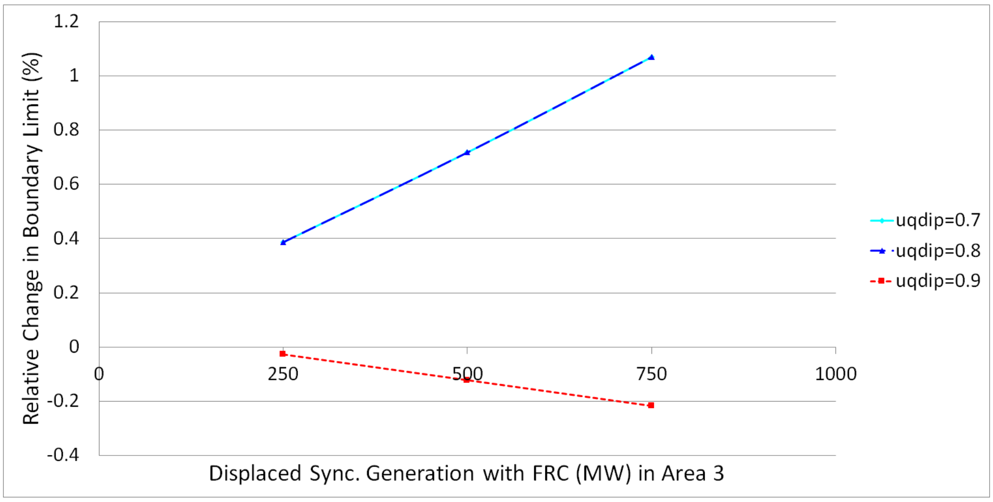


(a) Area 1.



(b) Area 2.

Figure 4.16: Sensitivity of B6 Limit to LVRT activation threshold.

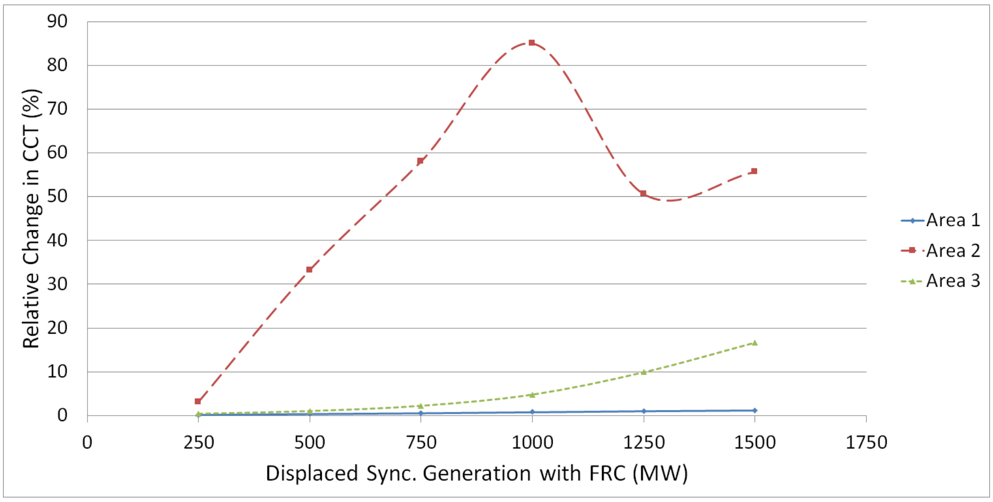


(c) Area 3.

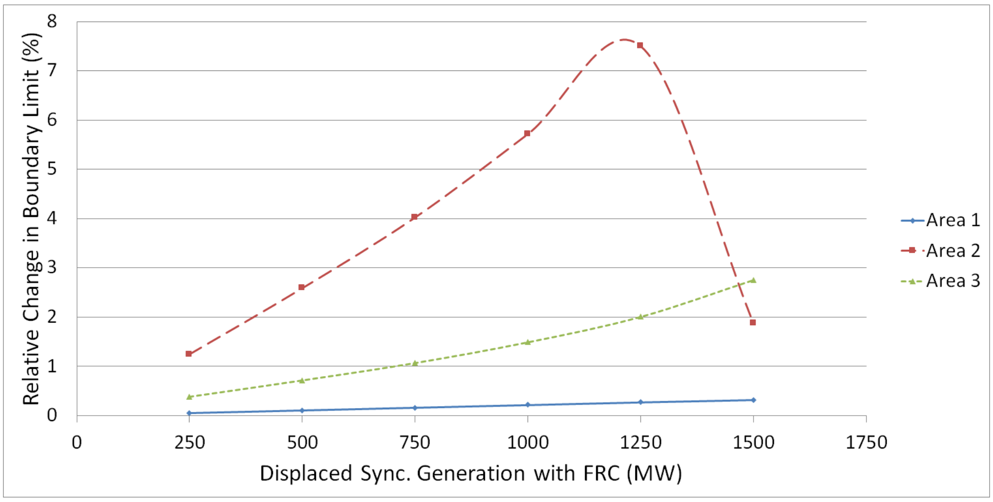
Figure 4.16: *(continued)* Sensitivity of B6 Limit to LVRT activation threshold.

lower values provides an increase in the transient stability margin.

Fig. 4.17 again shows the sensitivity of the CCT and the last secure boundary power transfer limit as a function of the replaced synchronous generation with the wind farms set to voltage control mode. Now the reactive power controller LVRT threshold voltage has been reduced from 0.9 p.u. (seen in Fig. 4.10) to 0.7 p.u. This change means that at higher wind penetrations, the wind farms no longer cause post-first-swing instability in the synchronous rotors which were originally caused by the terminal voltage of the wind farms breaching 0.9 p.u. voltage. This discontinuous behaviour manifested itself in rapid swings in the rotors due to the wind farms temporarily reducing their active power to provide reactive power. The immediate response was to quickly reduce the magnitude of the current rotor swing, but at the expense of causing subsequent swings to be larger, thus delaying the moment of instability. When the LVRT threshold is lowered to 0.7 p.u., scenarios where long-term stability would be maintained (i.e. high wind penetration in Area 2) are now able to



(a) CCT.



(b) B6 Limit.

Figure 4.17: Impact of v-controlled FRC wind farms in each area on CCT and B6 limit (LVRT voltage threshold = 0.7 p.u.)

run their course and become stable without the unwanted triggering of LVRT.

The alteration of the LVRT activation threshold may not be practicable in real power systems, however these illustrative results show that a high threshold value can easily lead to transient stability problems by creating unstable rotor swings in the synchronous generators beyond the first swing period. There is a need to recognise that not all low-voltage scenarios are the same. When the terminal voltage experienced by a wind turbine is slowly oscillating and approaches a hard-and-fast limit such as 0.9 p.u., it can be highly detrimental to the system stability for that wind turbine to suddenly enter LVRT mode. Such large discontinuities in how the wind farms produce active and reactive power should be reserved for times when there is a genuine fault, and not when a limit is barely breached during otherwise stable behaviour. It may be useful to the system stability that wind turbine control systems are equipped to react not only to the absolute value of terminal voltage as a trigger to LVRT behaviour, but to the rate of change of voltage, which will be much higher when caused by a genuine short-circuit event and would reduce the chance of a spurious trip into LVRT mode when doing so may cause further instability.

There exists a trade-off between the stability limits and the LVRT threshold value. These studies show that LVRT threshold crossing can bring on post-first-swing instability in the synchronous generator rotor swings. It is desirable for the threshold to be high (e.g. 0.9 p.u.) in order to correctly respond to the initial voltage dip, but be able to not trip into LVRT mode in the subsequent seconds after fault while voltage is oscillating but recovering towards a new steady-state value as the system stability is being maintained. By maintaining a high LVRT threshold voltage, this allows more electrically distant wind farms to contribute to potentially grid-stabilising injections of reactive power, however this high LVRT threshold may be responsible for those wind farms that are electrically closer (and therefore have a deeper voltage dip and shallower, more oscillatory voltage recovery) spuriously tripping into LVRT mode in an otherwise stable post-fault period, inadvertently causing instability in the longer term.

4.5 Discussion

In this chapter the transient stability impacts of replacing synchronous generation with fully-rated converter equipped wind farms has been shown. In particular it is observed that when the wind farms' reactive power controller is set to power factor control, replacement of synchronous generation in the exporting regions (Area 2 and Area 3) results in a steady decline in transient stability margins as a function of wind penetration, while increased wind penetration in the importing region (Area 1) results in improvement in the transient stability margins. These trends are in broad agreement with the base case where wind farms do not replace the synchronous generation but the inertia constants of the three areas are varied, showing that the power factor controlled wind farms have a similar characteristic impact to simply removing inertia from the respective areas.

This picture is complicated by changing the wind farms' reactive power controllers to operate in voltage control mode. In this case there is a much more complex relationship between the transient stability margins and the penetration of wind farms on the transmission system. It has been shown that the power system stability is more sensitive to the control system of the wind farms in this mode, as the rapid switching between active and inactive LVRT control logic based on the wind farms' terminal voltage can act to bring on longer-term rotor swing instability in the synchronous generators. Also, long-term voltage and power oscillations in the system are found at the higher wind penetrations, particularly in the Area 2 case. It is outside the scope of this thesis to deeply analyse the complex physics and control conditions of the voltage-controlled wind cases, but it has been shown that such considerations must be taken into account when choosing the control settings for wind farms in power systems.

The remainder of the thesis will be devoted to a study of control techniques which may be employed in the wind farms in order to help mitigate the erosions of transient stability margins, bringing the power system closer toward the historical, less prohibitive limits and therefore allowing continued growth of non-synchronous resources. The techniques are intended to be focused on reducing the magnitude of the first synchronous generator rotor accelerations and swings, therefore the discussion in this section around longer-term stability has been identified as an avenue for future work.

CHAPTER 5

Reactive Power Gains for Transient Stability Improvement

As described in the discussion on transient stability in Chapter 2, a wind farm control strategy which could potentially provide mitigation of the transient stability impacts is the targeted use of reactive power control in the transient period (during the fault and the first swing of the synchronous generator rotors). As discussed previously, the typical immediate control response to a terminal voltage dip (brought on by a short-circuit fault) is for the wind turbines to temporarily prioritise reactive power over active power, while respecting the apparent power limits of the turbine's power electronic converter system. The transient reactive power injection is intended to support the terminal voltage [108], and therefore the voltage profile of the local portion of the power system. From the point of view of transient stability, holding the system voltage profile as closely to nominal as possible should therefore allow the neighbouring synchronous generators to export electrical power in a less constrained fashion and mitigate the rotor accelerations which lead to transient instability in the transient period. The impact of altering the magnitude of the wind farms' reactive power response under a short circuit condition will be examined here, and discussed in the context of improving the transient stability margins as detailed in Chapter 4.

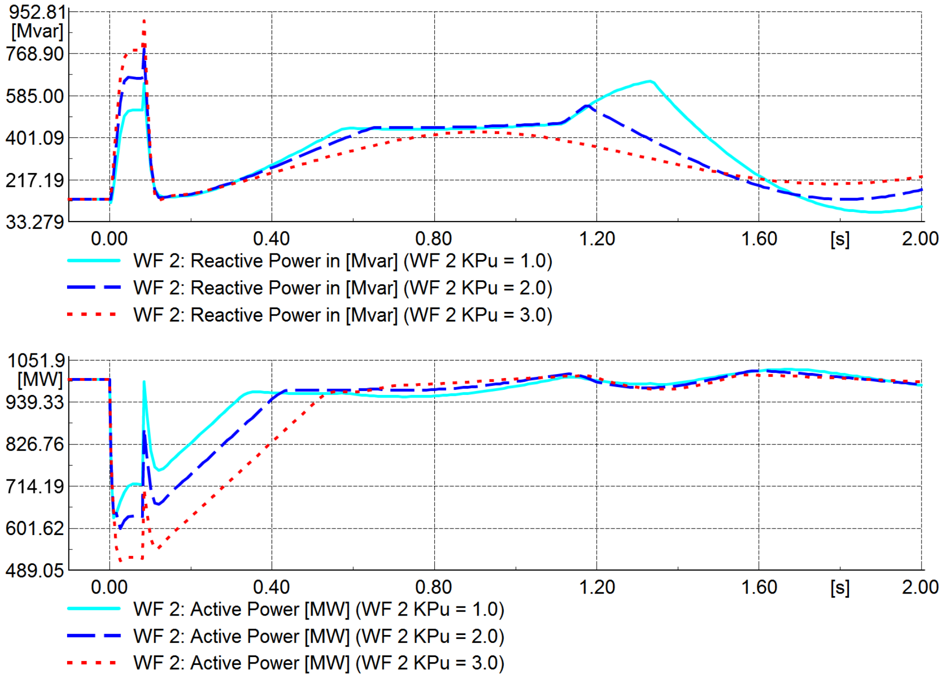
5.1 Proportional Gain of Reactive Power Controller

As discussed in Chapter 2, the transient stability of the power system for a given fault scenario is sensitive to the voltage profile of the system in the transient phase (i.e. the first swing). By maintaining relatively high voltages at the synchronous generators terminals during the transient period, the generators have a higher power export capability during the first swing. This effect should translate into a relative increase in the transient stability margin of the system due to decreased rotor accelerations and therefore a smaller swing during the fault period.

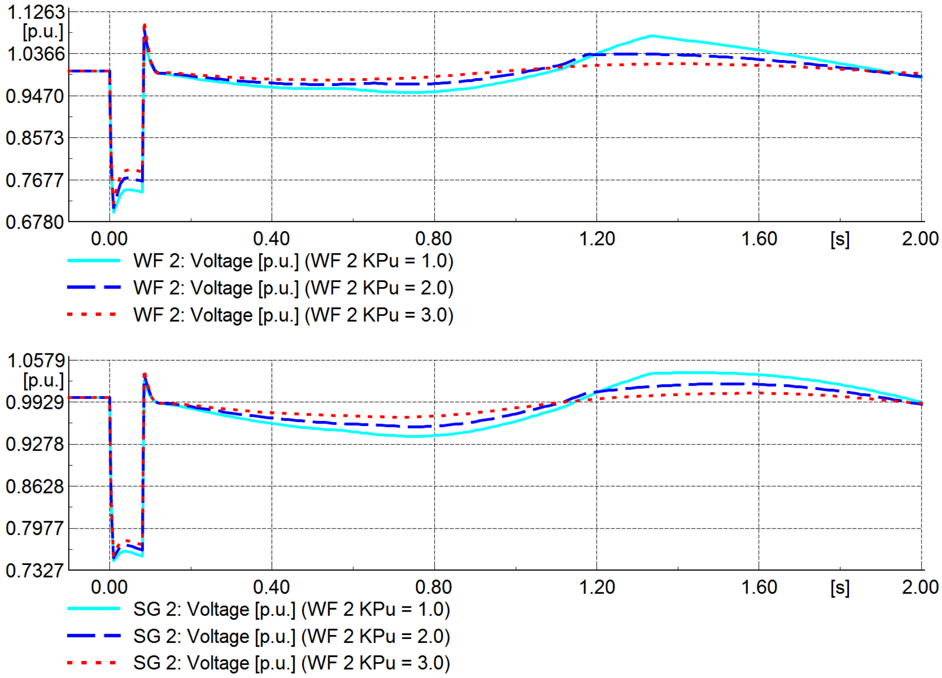
By this token, tests were carried out where the proportional gain of the wind turbine reactive power controller was adjusted and its impact on the transient stability metrics was monitored. The IEC wind turbine models give the option of operating in several reactive power modes for transient analysis by setting parameter MqG in the reactive power controller. The default setting of the turbine models is power factor control, in which there is no reactive power gain parameter that can be modified. Therefore, for this test, the wind turbine reactive power control models were set to operate in mode 0 (voltage control) so that the transient stability sensitivity to the proportional gain of the voltage controller (parameter KPu) could be studied. As shown in the previous chapter, the long-term instabilities at higher wind penetrations caused by the wind farms in voltage control mode mean that only wind penetrations up to 750 MW are shown here. The goal in this section is therefore to show the sensitivity to the reactive power gain for wind penetrations up to 750 MW, where the system transient behaviour allows more visibility of the sensitivity than would be the case at the higher penetration levels.

5.1.1 FRC Wind Turbines

Figs. 5.1 and 5.2 show the impact of the reactive power proportional gain (KPu) on the transient response of the key system variables while in voltage control mode. These impacts are seen more clearly in the case of the wind farms being located in Area 2 than Area 3 due to the relative proximity to the fault location and therefore the larger voltage dip experienced. It is observed that an increase in the reactive power gain gives the expected increase in the immediate reactive power injection from the wind farm. There is also a corresponding drop in the wind farm active power output in the fault period (which continues in the recovery period) (a). This drop in the active power from the wind farm, along with the increase in the terminal voltage of the synchronous generators in both Area 2 and Area 3 (b), allows the synchronous generators in the exporting region to release more active power during the transient period and therefore acts to reduce the magnitude of the first swing in the rotor angle (c)

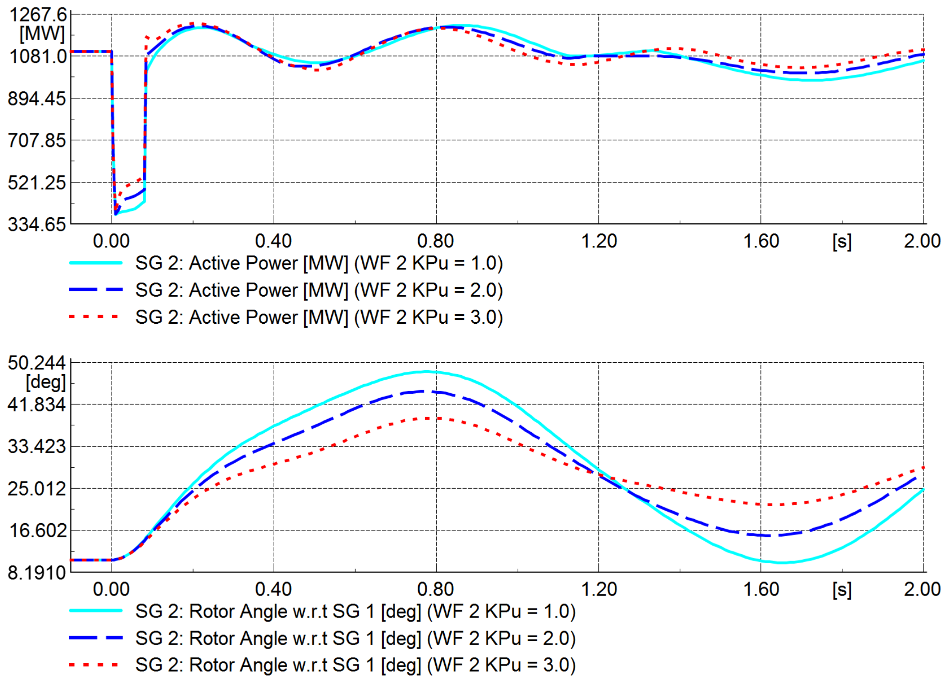


(a) Reactive and Active Power responses.

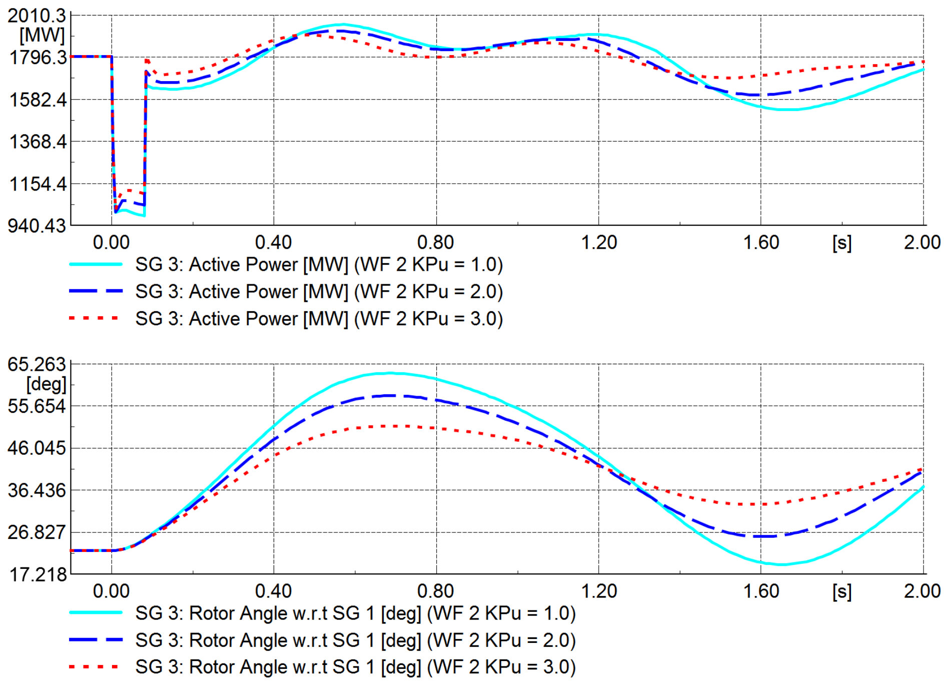


(b) Terminal voltages in Area 2.

Figure 5.1: Impact of KPu on transient response (FRC in Area 2).

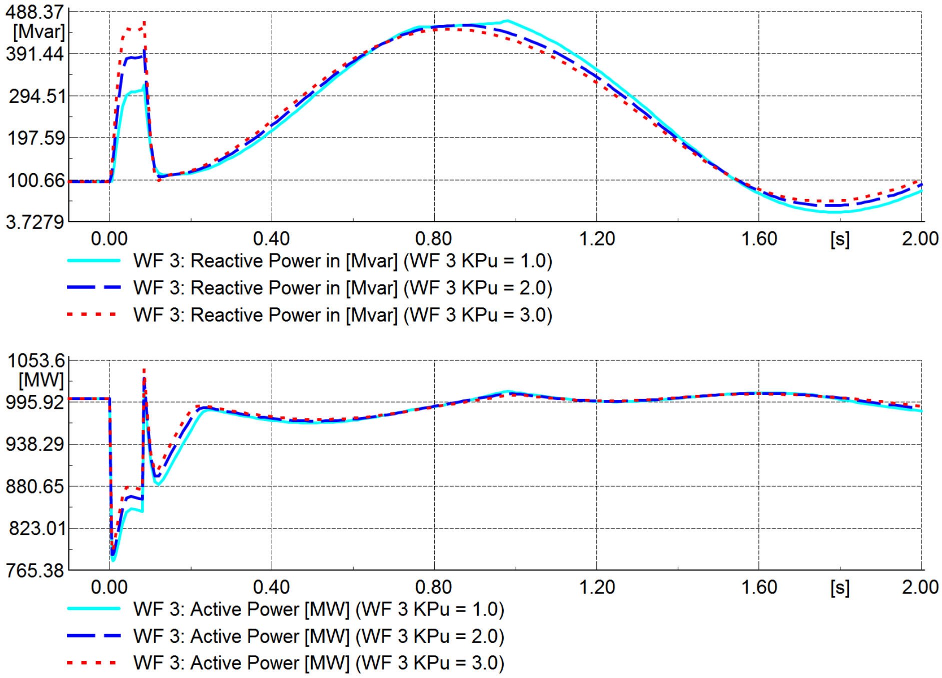


(c) SG 2 Active Power and Rotor Angle response.

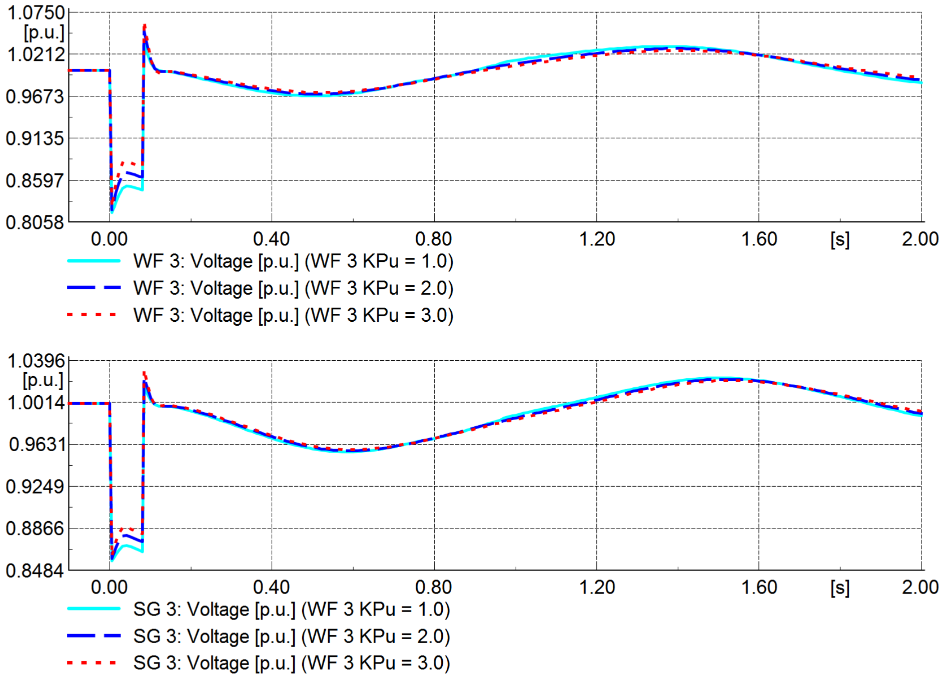


(d) SG 3 Active Power and Rotor Angle response.

Figure 5.1: *(continued)* Impact of KPu on transient response (FRC in Area 2).

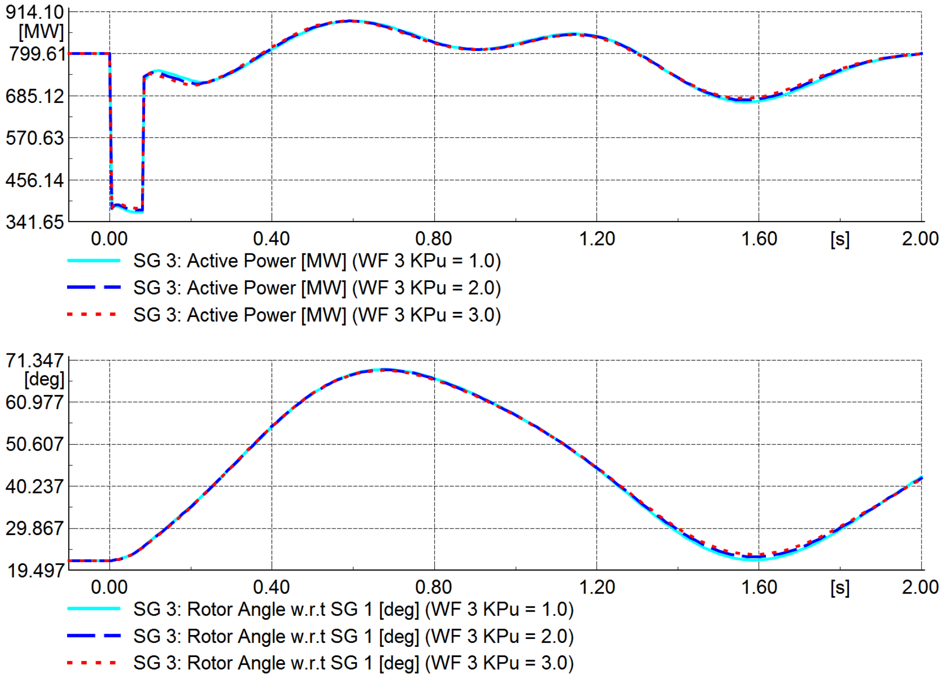


(a) Reactive and Active Power responses.

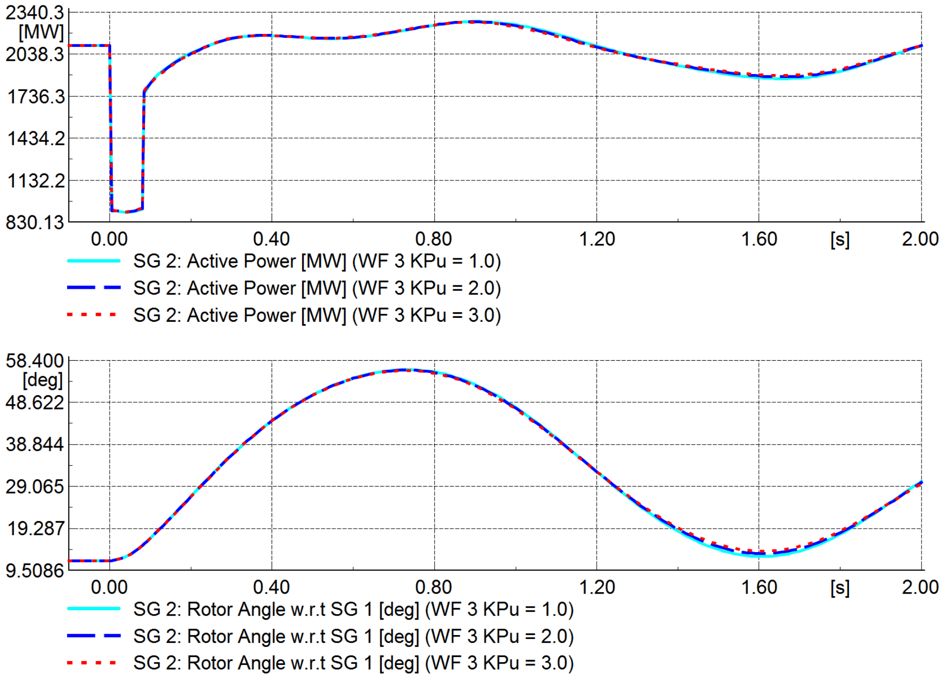


(b) Terminal voltages in Area 3.

Figure 5.2: Impact of KPu on transient response (FRC in Area 3).

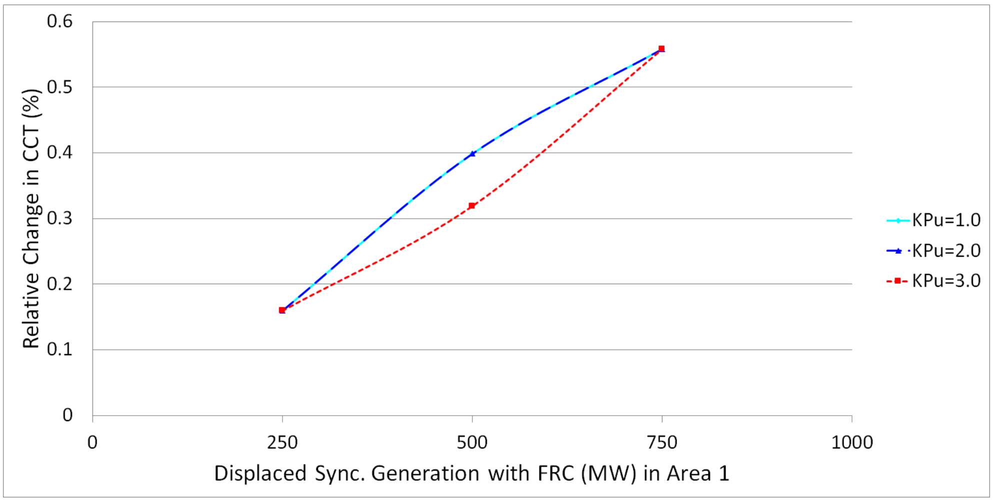


(c) SG 2 Active Power and Rotor Angle response.

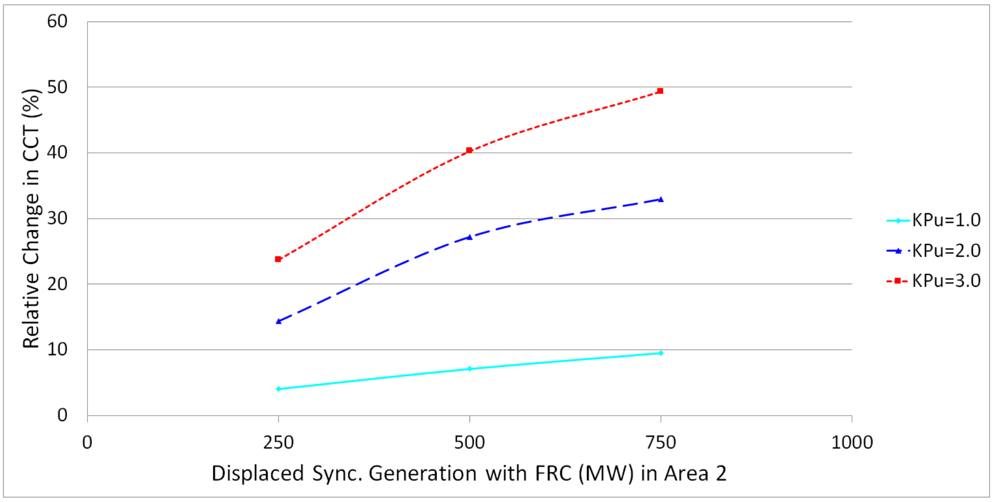


(d) SG 2 Active Power and Rotor Angle response.

Figure 5.2: *(continued)* Impact of KPu on transient response (FRC in Area 3).



(a) Wind Farm 1.



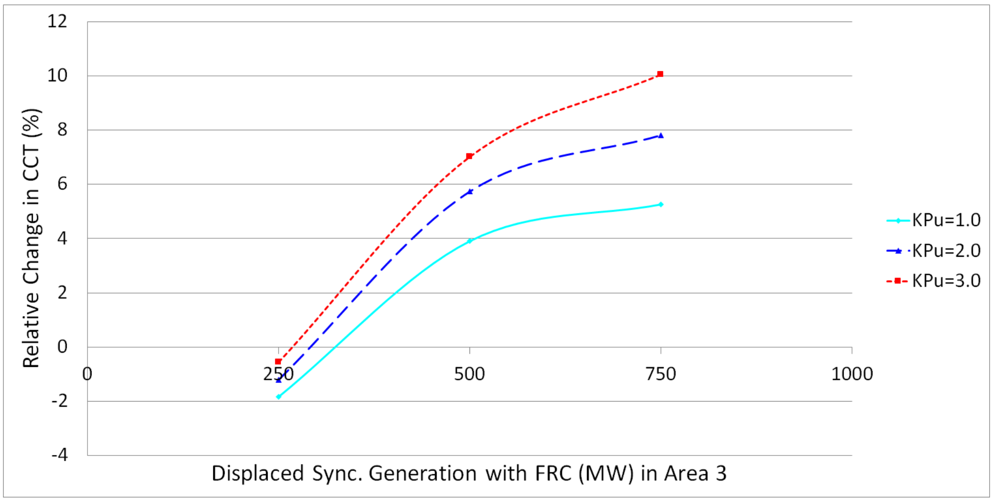
(b) Wind Farm 2.

Figure 5.3: Impact of KPu on CCT (FRC).

and (d). These reduced rotor angle swings should translate into an increase in the transient stability of the system to the short-circuit fault under test.

The transient behaviour shown here suggests that the use of a higher voltage-mode gain (KPu) in the reactive power controller should result in increased transient stability performance, as measured by the CCT of the fault.

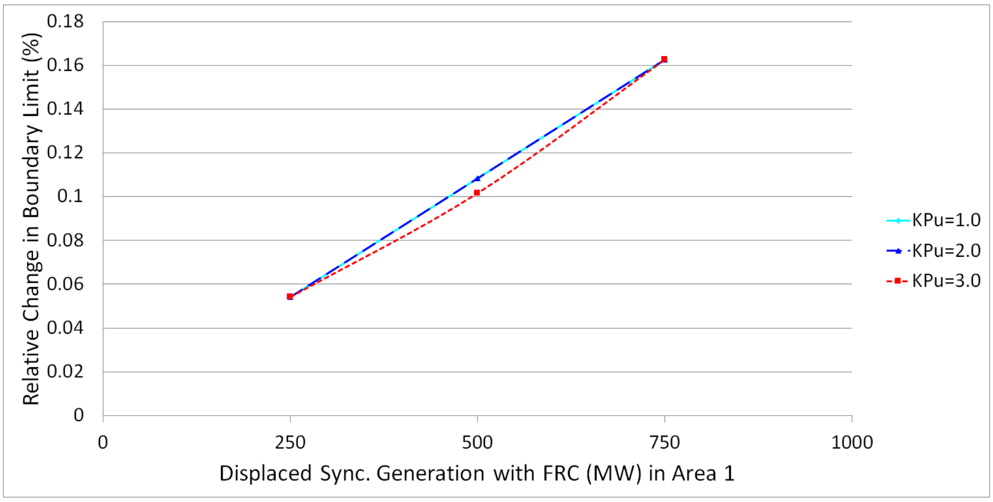
As can be seen in Figs. 5.3 and 5.4, the proportional gain of the reactive



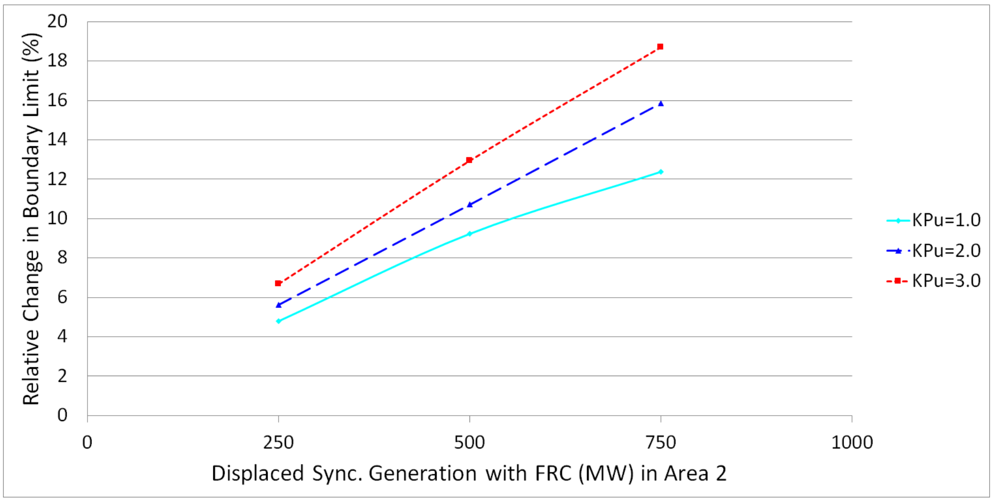
(c) Wind Farm 3.

Figure 5.3: *(continued)* Impact of KPu on CCT (FRC).

power controller in the wind turbines has a significant impact on the critical clearing time and B6 limit of the transient fault under investigation. When the reactive proportional gain is altered in Area 1 there is negligible impact. However, an appreciable increase in the stability margins occurs with increased reactive proportional gain (KPu) in both Area 2 and Area 3 and across the spectrum of wind penetration levels. As shown above, the proposed explanation for this behaviour holds that as the wind turbines in the exporting region (Areas 2 and 3) provide elevated reactive power during the transient period, thus improving their terminal voltage profile, they decrease their active power output. This active power reduction from the wind farms, coupled with an improved local voltage profile, allows the local synchronous generators to feed the loads located in the exporting region with the portion of active power that is no longer supplied by the wind farms. This acts to reduce the magnitude of the synchronous generator rotor swings in the transient period. Therefore it is beneficial to the overall system transient stability when there is an increased

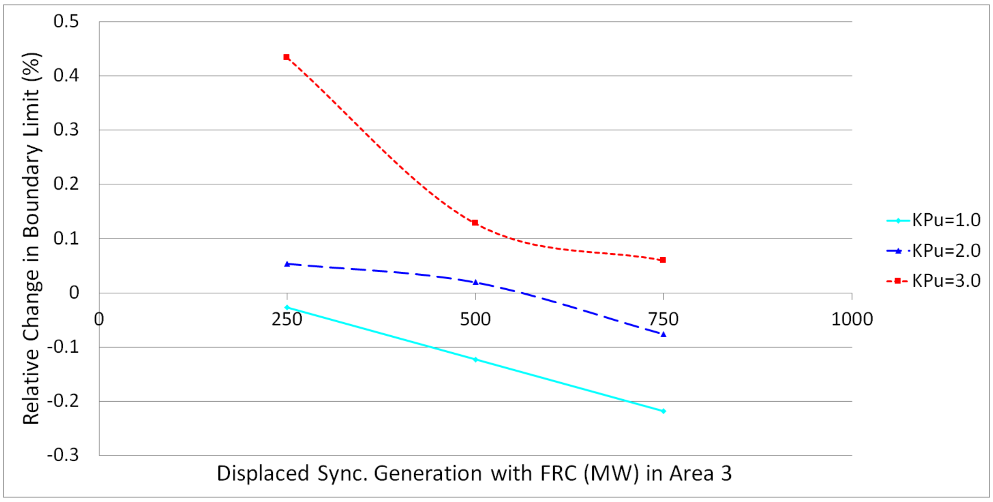


(a) Wind Farm 1.



(b) Wind Farm 2.

Figure 5.4: Impact of KPu on B6 Limit (FRC).



(c) Wind Farm 3.

Figure 5.4: *(continued)* Impact of KPu on B6 Limit (FRC).

transient reactive power contribution from the wind farms, particularly when the wind farms are located closer to the fault location.

The increased transient reactive power contribution must viewed in the context of other system security considerations, such as voltage limits and losses from reactive power, especially if the wind farm is embedded inside a distribution system.

5.1.2 DFIG Wind Turbines

A similar set of tests were carried out for the a case where the wind farms are represented by DFIG wind turbine models. Again, the wind farm reactive power controllers were set to voltage control (the default for the IEC DFIG model) and the parameter KPu was modified and its impact on the transient responses, as well as CCT and B6 limit were plotted. The default value for KPu in the DFIG models is 2.0 (rather than 1.0 in the FRC models), therefore the study took this value as the baseline and compared it to higher values for

KPu.

The DFIG results tell a similar story to those of the FRC wind farms, and can be found in the Appendix. The replication of the test with DFIG models lends support to the hypothesis that the use of higher reactive power proportional gain acts to increase the transient stability margins as explained previously. It is therefore recommended that network operators focus on maximising the reactive power injection from wind farms during LVRT operation, while of course ensuring that wind farms provide this injection in a manner which does not jeopardise the integrity of their equipment (mechanical and power-electronic).

5.2 Discussion

This chapter has shown the transient stability benefits which can be found by tailoring the magnitude of the transient reactive power injection from wind farms during short-circuit faults. For both FRC and DFIG wind farms integrated in the exporting region of the power system, the use of higher proportional gain in the reactive power controller leads to improvements in the CCT and B6 boundary flow limit. The mechanism that leads to this improvement has been shown. As the wind farms' transient reactive power injection is increased, there is a corresponding improvement in the voltage profile experienced by the local synchronous generators, both during and after the fault-on period. The improved voltage level experienced by the local synchronous generators allows them to export more of their rotor kinetic energy in the form of electrical active power, causing retardation of the rotor accelerations and therefore higher transient stability margins. In tandem with the voltage effect, it is observed that the wind farm controllers reduce the active power outputs of the turbines in the fault-on and transient periods (though the active power recovers at the same rate). This reduction in the wind farms' active power output throughout the transient period also allows the local synchronous generators to export more of their active power, as this power is serving a larger proportion of the local load, which formerly would have been served by the local wind farms. This control action from the wind farms effectively acts as a local load increase on the synchronous generators, causing further retardation of the rotor accelerations and improved transient stability behaviour.

The following chapter will take the concept further by examining the use of a different strategy for transient stability improvement, namely tailoring the active power recovery in the transient period to enhance the benefits discussed in this chapter.

CHAPTER 6

Active Power Ramp Rates for Transient Stability Improvement

6.1 Impact of Active Power Ramp Rates

As discussed in Chapter 3, the post-fault active power recovery ramp rate of wind power plants is expected to impact transient stability margins by impacting the relative rotor angle drift of the synchronous machines across the transmission corridor between the exporting and importing areas in the first-swing transient period. The following chapter aims to show the impact of altering the ramp rate on CCT and B6 power flow limits across the range of penetration levels, and explain that impact in terms of the changes in the first-swing rotor angle behaviour of the synchronous generators in the system.

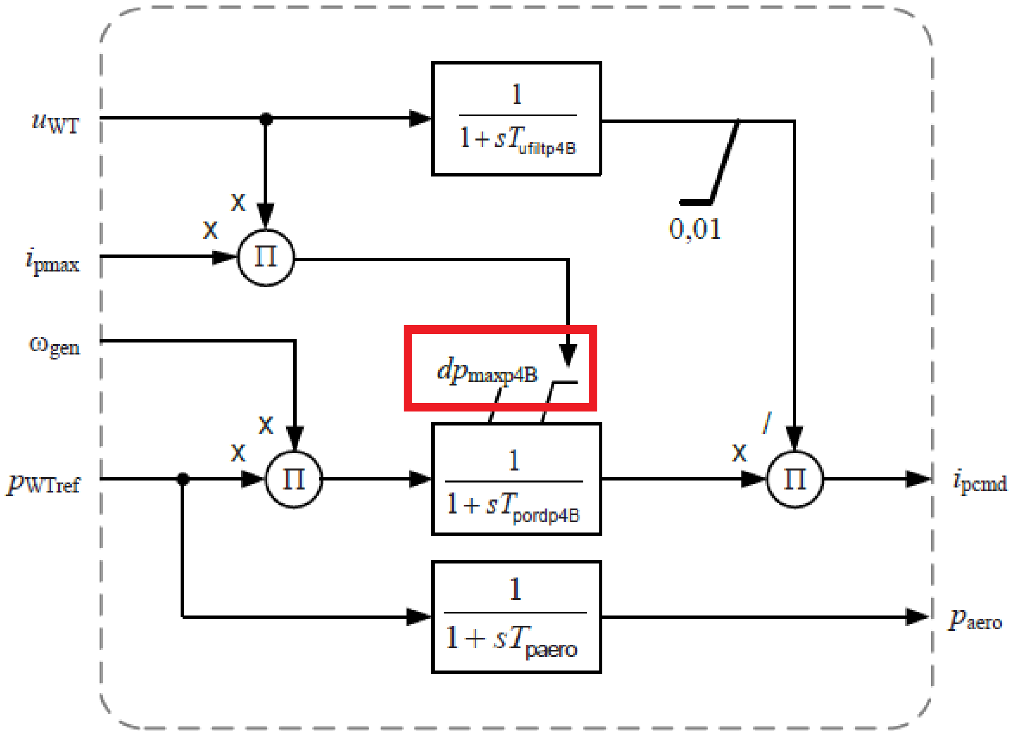


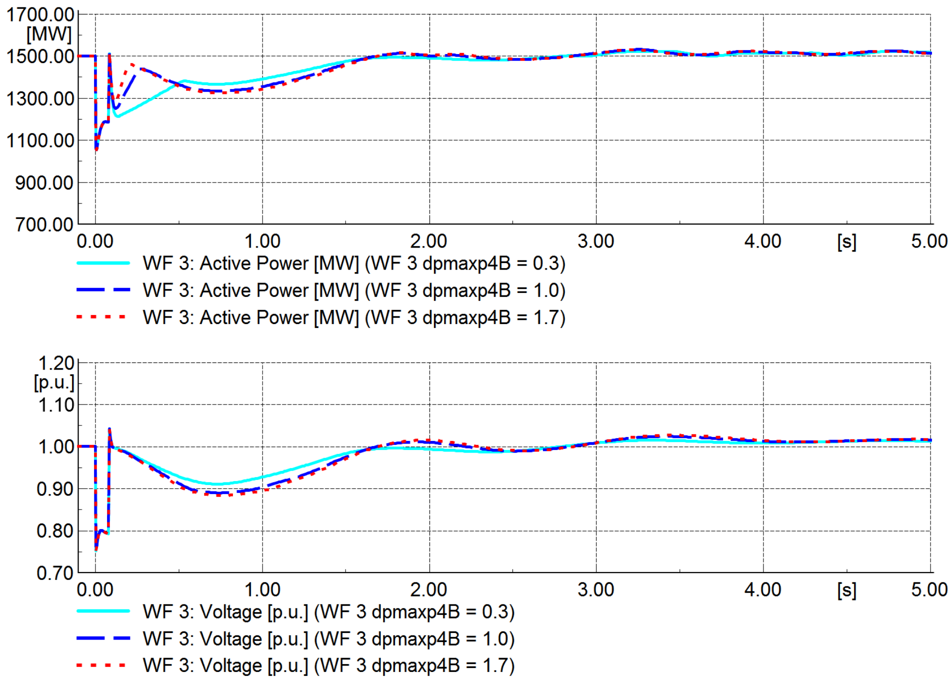
Figure 6.1: Block diagram of type 4B P control model.

Fig. 6.1 shows a block diagram of the P (active power) control section of the type 4B wind turbine control system model. The parameter “dpmaxp4b” is altered to provide the tailored active power ramp rates discussed in this section.

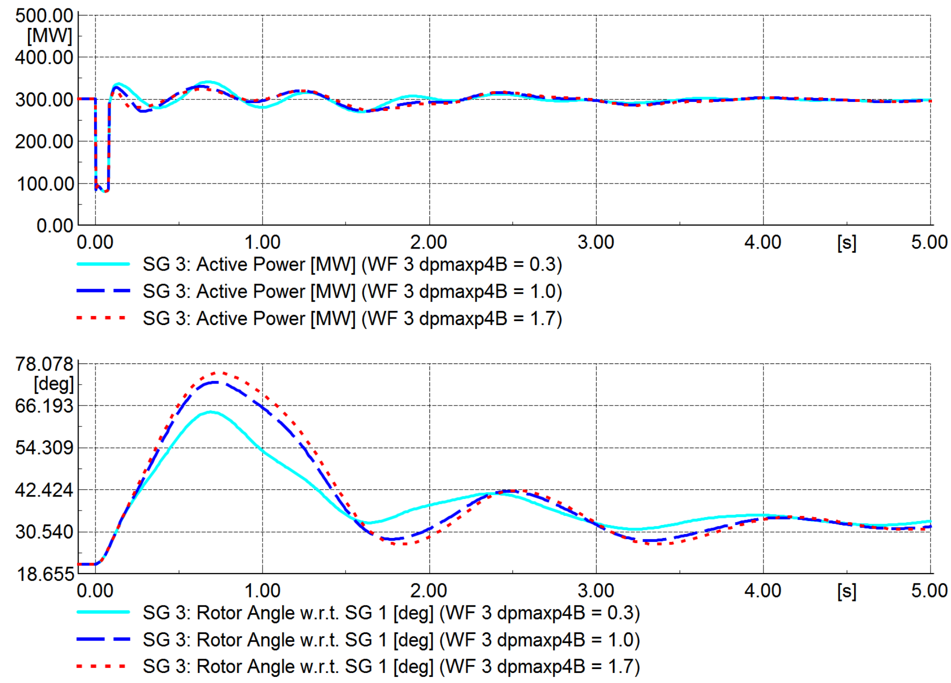
6.1.1 Fully-Rated Converter (FRC) Wind Turbines

First, the concept of active power ramp rates are illustrated in the case of an FRC-equipped wind farm being integrated in the exporting region. Assuming the same demand in the three areas, when wind power plants within the exporting region recover their active power at a slower rate (Fig. 6.2(a)), this has a similar effect to a local load increase during the critical first swing of the synchronous machine rotors, comparable in concept to the insertion of a local braking resistor [109]. This manifests in the synchronous machines as a reduction in their accelerations as they are able to supply more of their kinetic energy to local loads during the crucial beginning of the first rotor angle swing (Fig. 6.2(b)), rather than across the stability-constrained corridor to the rest of the system at a large electrical distance, due to the energy not served by the wind farms in the exporting region while ramping. This leads to reduced rotor angle swings in the immediate post-fault period and therefore improved transient behaviour. As can be seen from Figs. 6.2(c) and 6.2(d), the slower active power ramping from the wind farm also results in a decreased reactive power response from the wind farm and synchronous generator in the immediate post-fault period, due to the grid voltage profile being improved.

It can be seen from Figs. 6.3(b) and 6.3(c) that the reduction of the active power recovery rate can provide a significant positive impact on the CCT when the wind power plant is located in either Area 2 or Area 3 (i.e. the exporting region). The boundary power transfer limit results exhibit a similar uplift in the transient stability margin when the wind is integrated into Area 2 or Area 3 (Figs. 6.4(b) and 6.4(c)). The effect is amplified at higher wind penetrations, for example providing an uplift of around 14% (28 ms) in the CCT and 5% (75 MW) in the boundary power transfer limit at the highest penetration level when the ramp rate in Area 2 is decreased from the nominal value of 1.0 to 0.3 p.u./s. The impact in Area 3 is a 10% (19 ms) increase in the CCT and a 4% (67 MW) increase in the B6 limit. An impact on transient stability margins can also be seen when altering the ramp-rate in Area 1 (Fig. 6.3(a)). For this test system, with a large disparity between the relative size of the exporting and importing

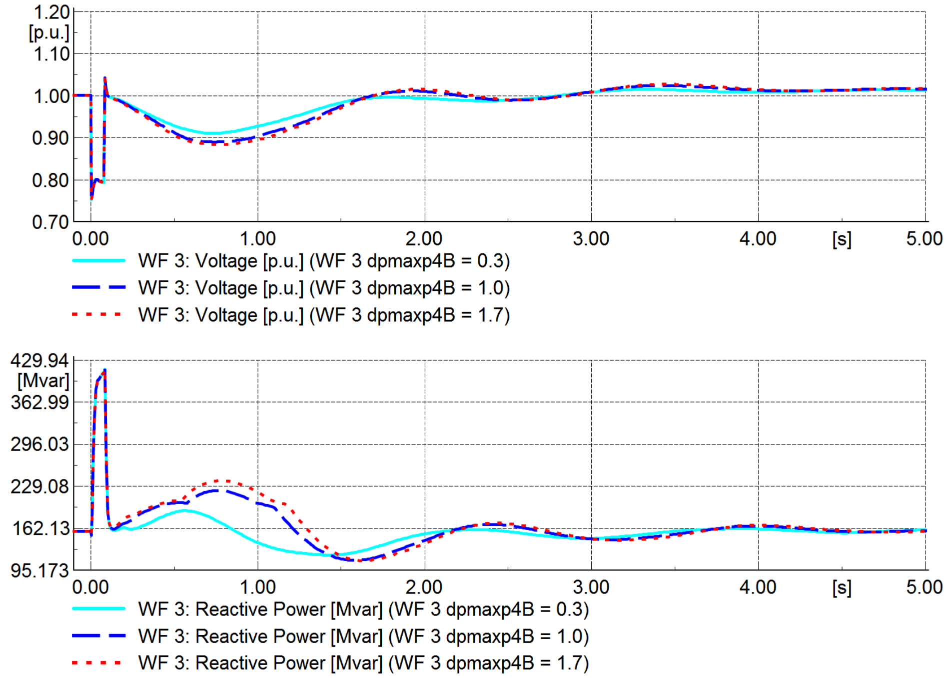


(a) Three different wind farm active power recovery rates (p.u./s).

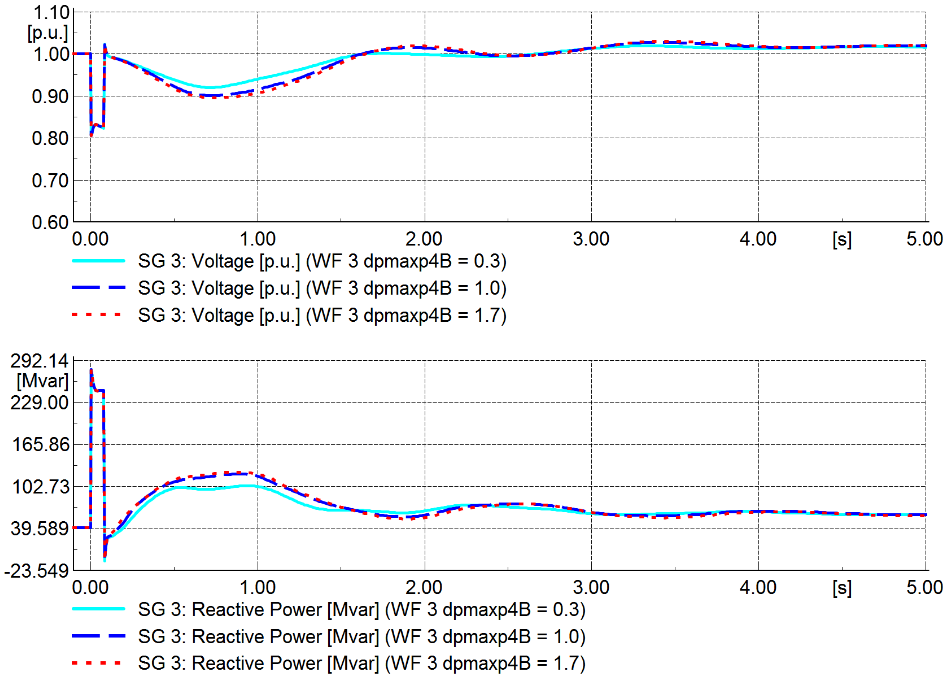


(b) Beneficial impact on SG 3 active power output and rotor angle response.

Figure 6.2: Impacts of FRC ramp rates.

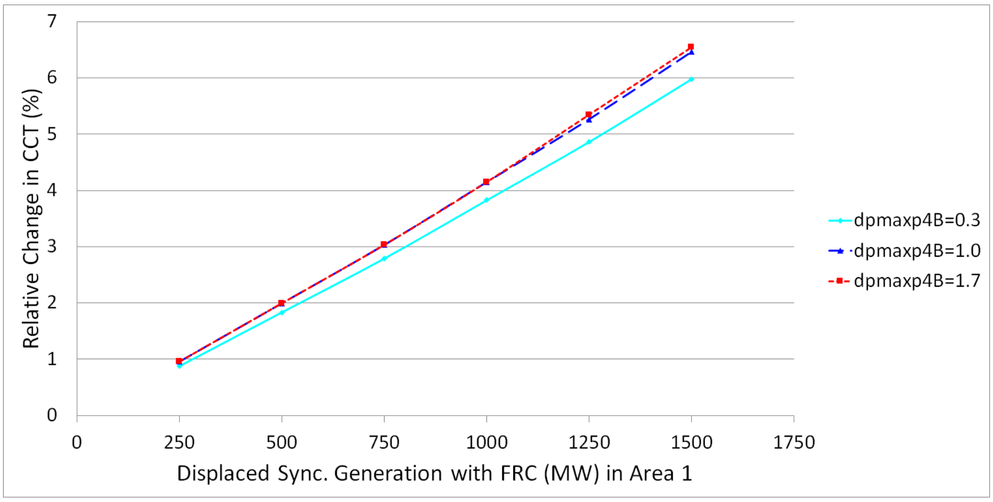


(c) Impact on wind farm 3 voltage and reactive power.

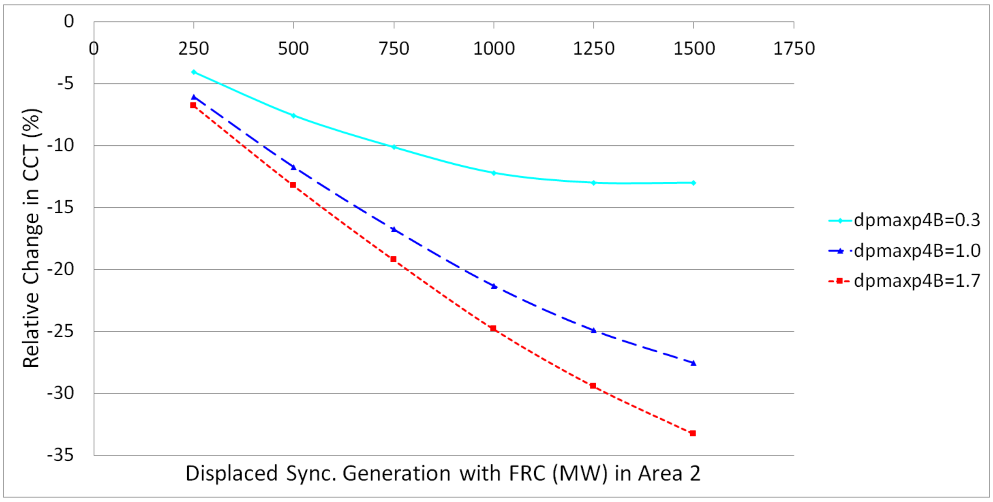


(d) Impact on synchronous generator voltage and reactive power.

Figure 6.2: *(continued)* Impacts of FRC ramp rates.

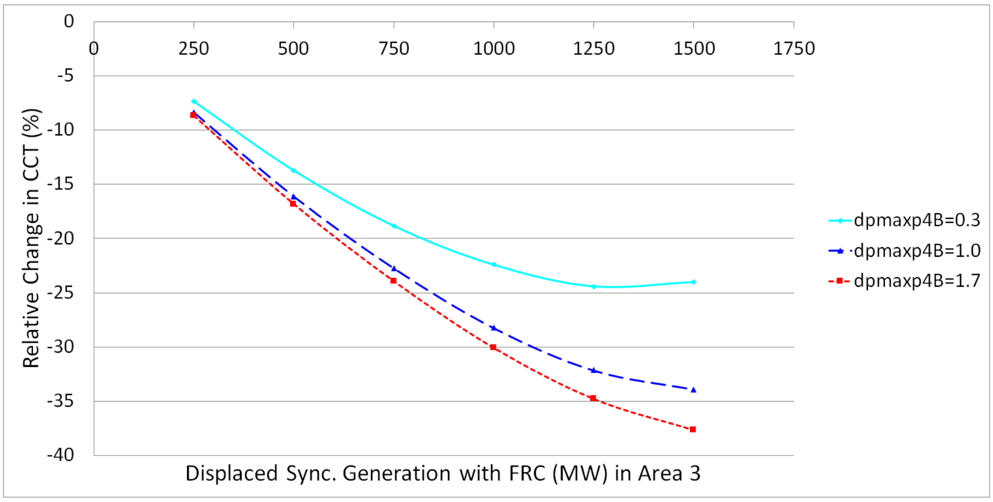


(a) Area 1.



(b) Area 2.

Figure 6.3: Impact of FRC ramp rate (p.u./s) on CCT.



(c) Area 3.

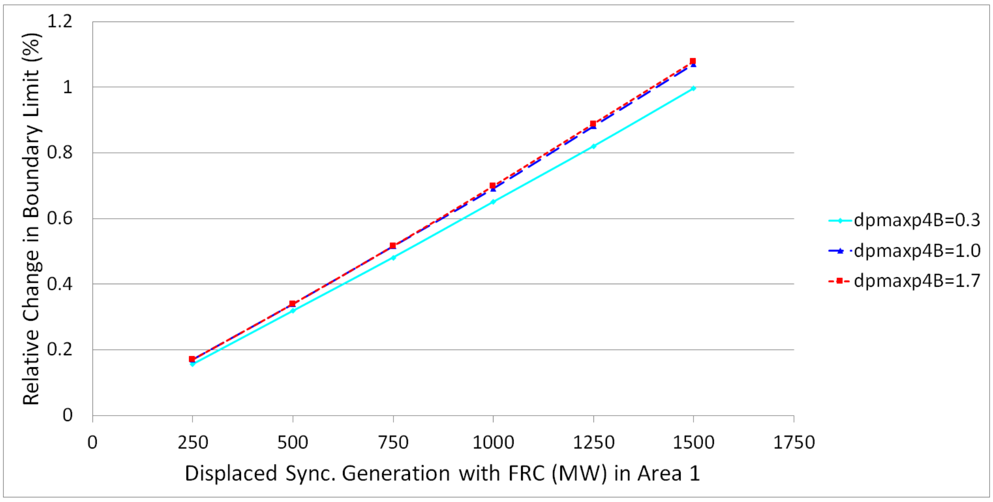
Figure 6.3: *(continued)* Impact of FRC ramp rate (p.u./s) on CCT.

regions, this effect is rather small. Significant transient stability benefits could be gained in other systems by utilising faster ramp rates in importing regions along with slower ramp rates in exporting regions. These results ultimately show that, given knowledge of the location of a transient fault and the pre-fault operating condition of the system, it may be possible to increase transient stability margins by actively tailoring the active power recovery rates from the wind power plants connected to the network.

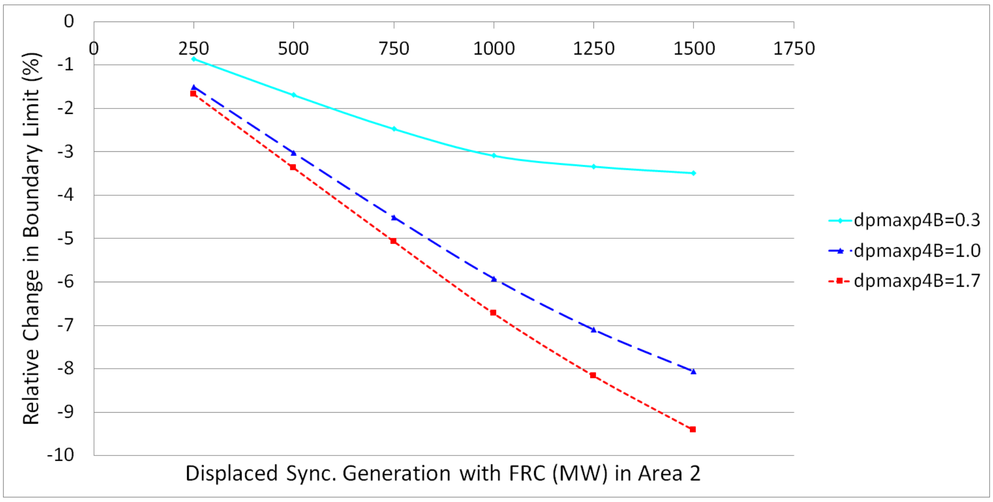
6.1.2 Doubly-Fed Induction Generator (DFIG) Wind Turbines

The same experiment was run for a case where the wind turbines modelled in the scenario are Doubly-Fed Induction Generator (DFIG) equipped.

Fig. 6.5 shows a block diagram of the P (active power) control section of the type 3a wind turbine control system model. The parameter "dpmaxp" is altered to provide the tailored active power ramp rates discussed in this section.

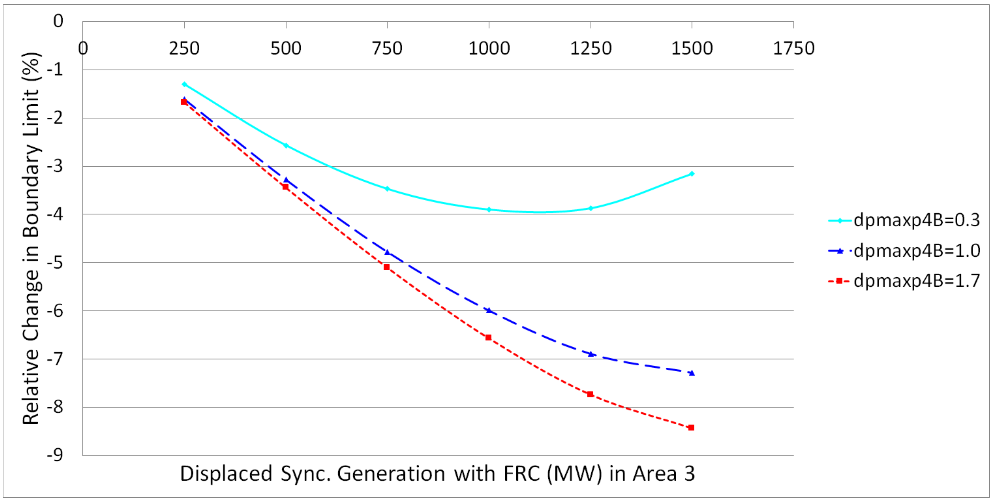


(a) Area 1.



(b) Area 2.

Figure 6.4: Impact of FRC ramp rate (p.u./s) on boundary power transfer limit.



(c) Area 3.

Figure 6.4: *(continued)* Impact of FRC ramp rate (p.u./s) on boundary power transfer limit.

It can be seen in Figs. 6.6 and 6.7 that there is a more complicated relationship between the wind penetration, active power recovery ramp rate and the CCT/B6 flow values than those found in the case of FRC wind turbines. A similar effect is found in Area 1, with a linear increase in CCT and B6 flow limit with increased wind penetration, and relatively little impact on these values with the change in active power recovery rate. DFIG Penetration in Area 2 takes a completely different character to the FRC case, with a linear growth in CCT and B6 limit with penetration level, and a noticeable improvement in the stability limits with the slower active power recovery. This is in contrast to the negative impact on the CCT and B6 flow with increasing penetration of FRC wind turbines in Area 2. Finally, there is a much more complicated impact when DFIG wind turbines are utilised in Area 3. At lower penetrations there is a negative impact on the CCT and B6 limit, which is reversed and becomes a positive contribution to the stability limits as the penetration increases

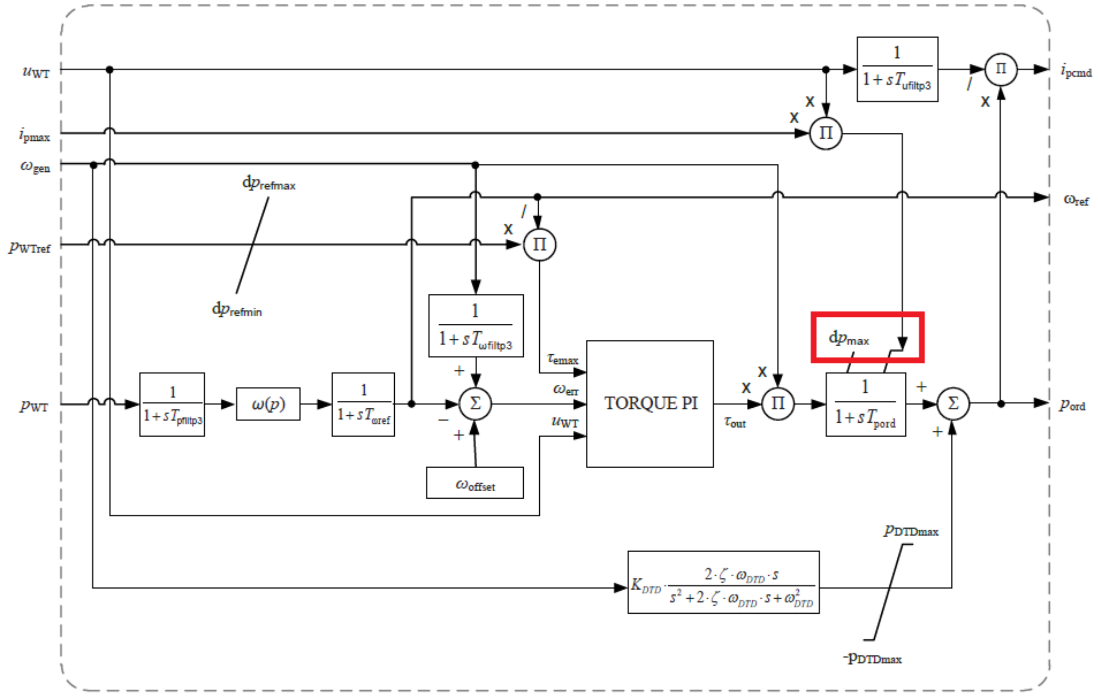
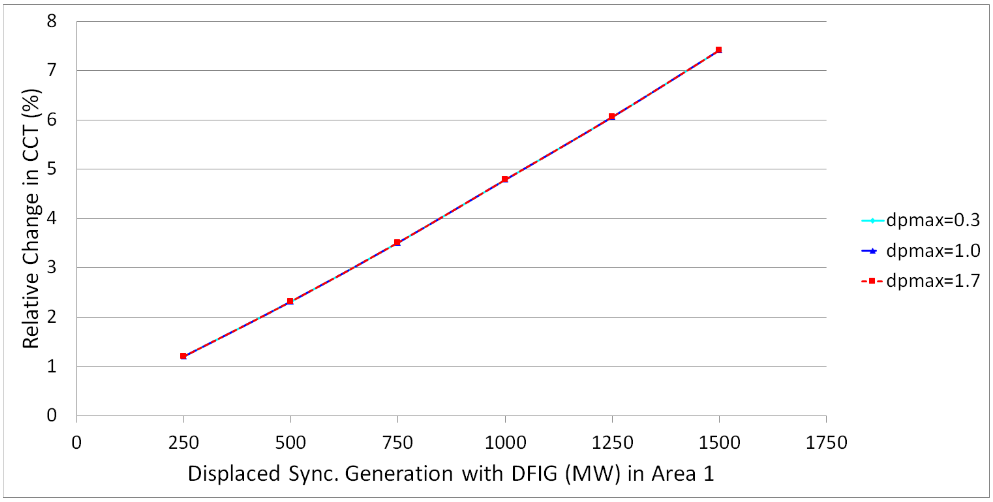
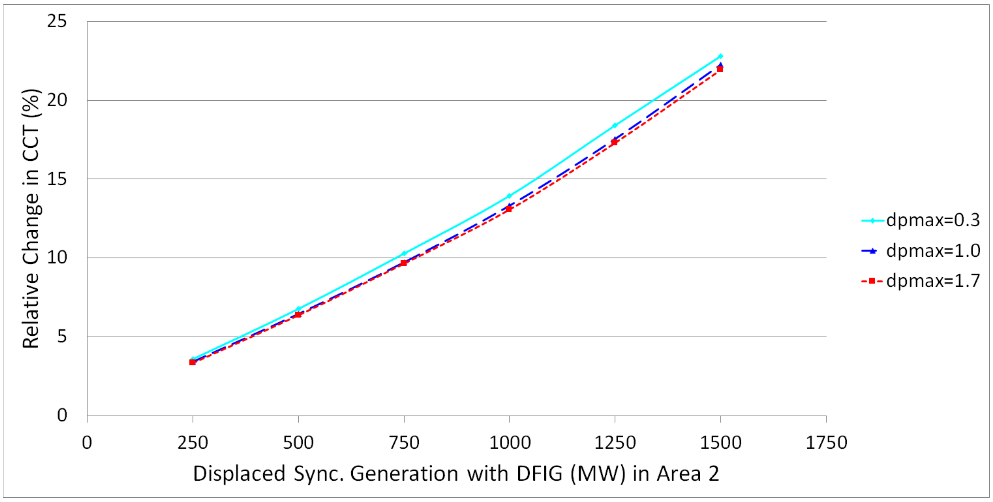


Figure 6.5: Block diagram of type 3A P control model.

to the higher values. In the DFIG case it can also be observed that a significant improvement at each datapoint is found with the use of slower active power recovery rates, which is in agreement with the results obtained in the FRC case and lends weight to the initial hypothesis that the use of slower post-fault active power recovery rates in the exporting regions are beneficial to transient stability margins.

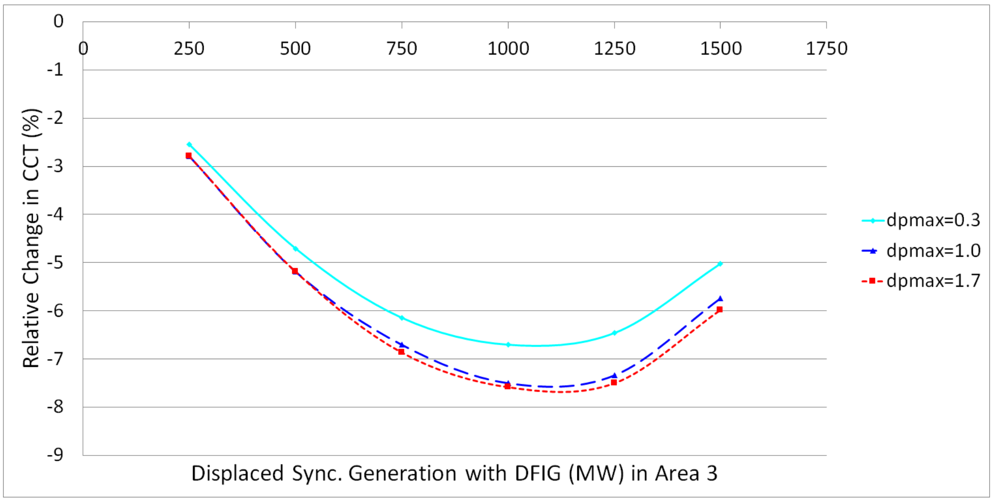


(a) Area 1.



(b) Area 2.

Figure 6.6: Impact of DFIG ramp rate (p.u./s) on CCT.



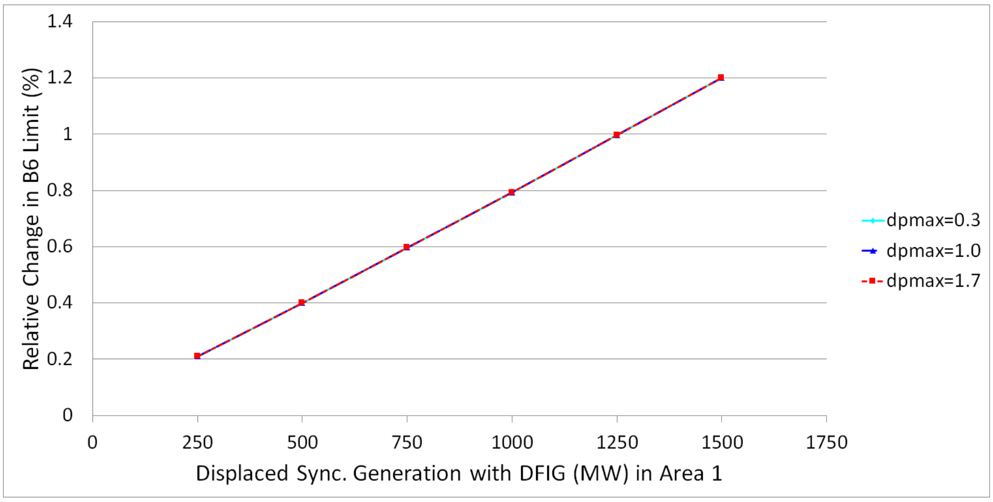
(c) Area 3.

Figure 6.6: *(continued)* Impact of DFIG ramp rate (p.u./s) on CCT.

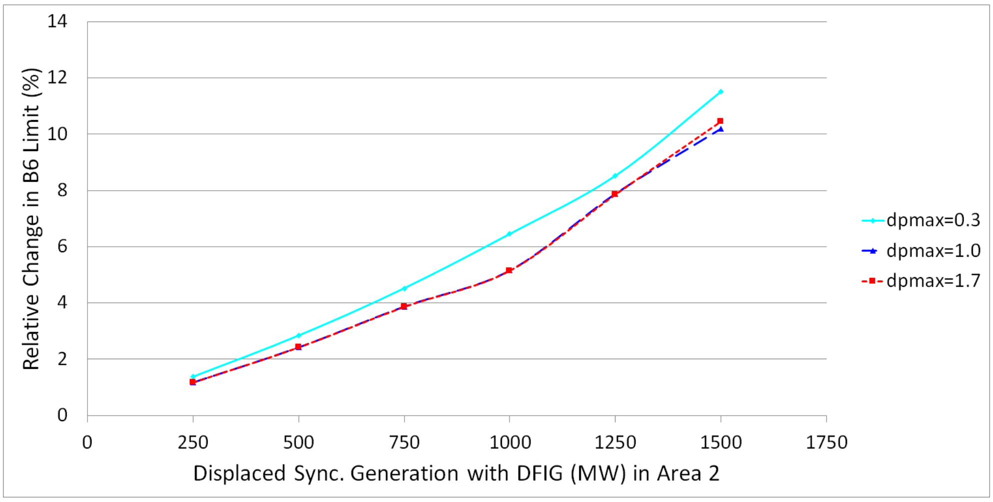
6.2 Active Power Ramp Rates and Frequency

Studies were carried out to investigate how the wind power recovery rate would impact the system frequency response in the event of a permanent short circuit fault leading to a loss of synchronous generation. For this study a short-circuit fault was applied at the receiving end of a line connecting a 500 MW synchronous generator which was cleared through line disconnection after 80 ms, resulting in the loss of the generator.

Scenarios were simulated with the loss of generation and pf-controlled FRC wind farms connected in Areas 1 and 2 (importing and exporting regions, respectively), and for each scenario the post-fault active power ramp rate was simulated as 0.3, 1.0 and 1.7 p.u./s. The frequency was monitored on the transmission network and the impact of the wind farm active power recovery rate on the frequency response was recorded. Only scenarios where the connected wind farm is in the same area as the fault are included. When the wind farm

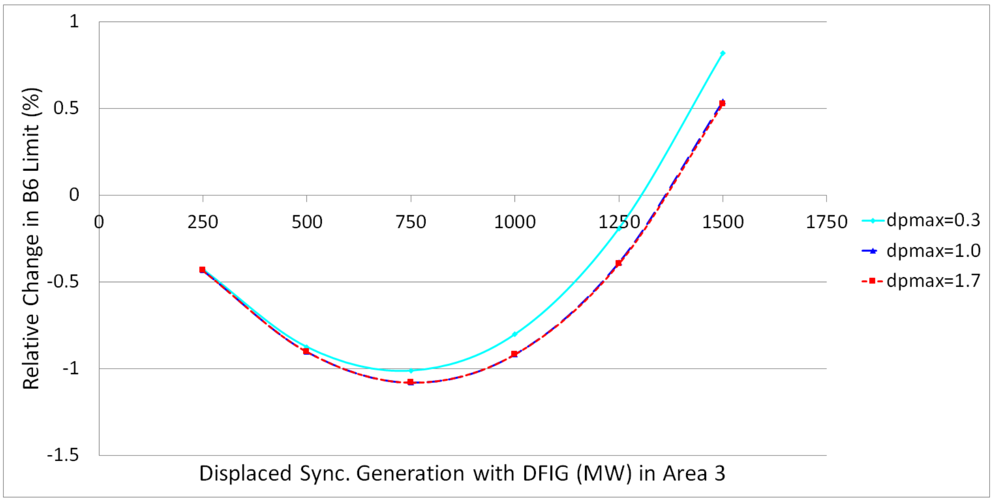


(a) Area 1.



(b) Area 2.

Figure 6.7: Impact of DFIG ramp rate (p.u./s) on boundary power transfer limit.

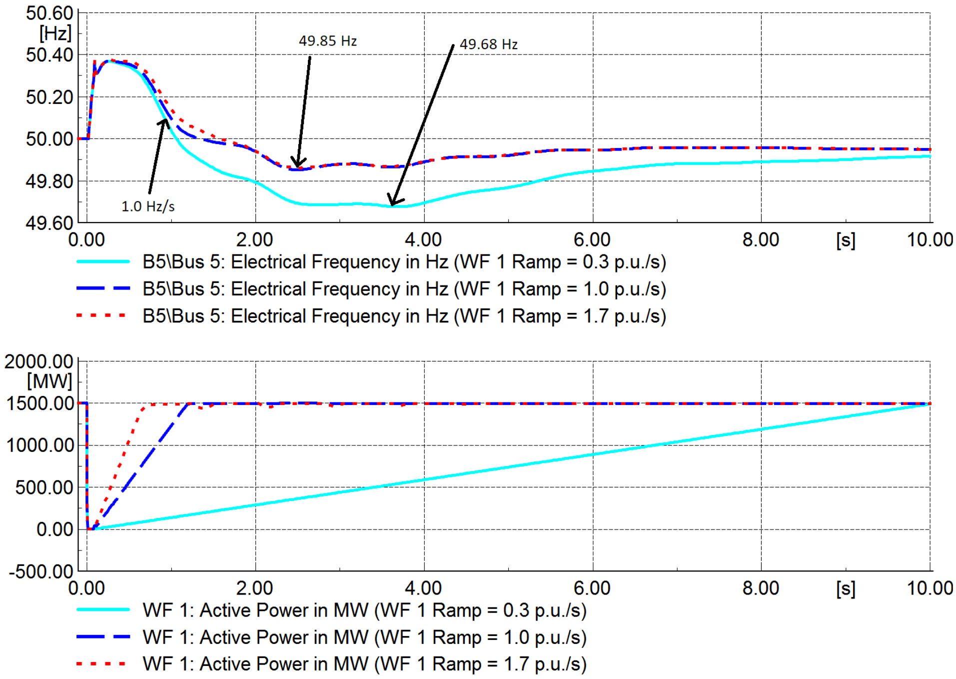


(c) Area 3.

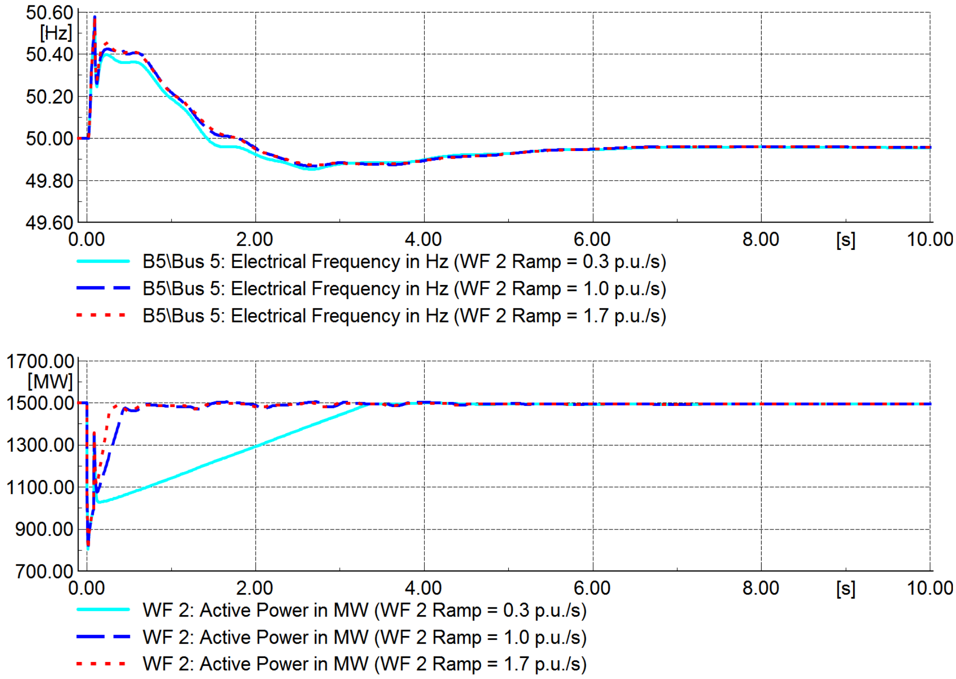
Figure 6.7: *(continued)* Impact of DFIG ramp rate (p.u./s) on boundary power transfer limit.

is located in a different area from the fault there is negligible difference in the frequency response for altered recovery rates. This is due to the electrical distance between the fault and the wind turbines being too great, and the low voltage ride-through response is therefore much smaller.

Figs. 6.8 and 6.9 show the system frequency response to the permanent short-circuit fault and subsequent line clearance, leading to the loss of 500 MW of synchronous generation from the two areas in turn. It can be seen that there are significant impacts on the frequency experienced when the wind farm is integrated in each area. The data show that the use of slower active power recovery rates from the wind farms have a detrimental impact on the frequency, with a notable increase in the magnitude of the deviation from nominal frequency when the wind farm and loss-of-generation fault are located in Area 2. Depending on the operating condition and the settings of RoCoF and under-frequency load shedding relays in a given network, this could be sig-

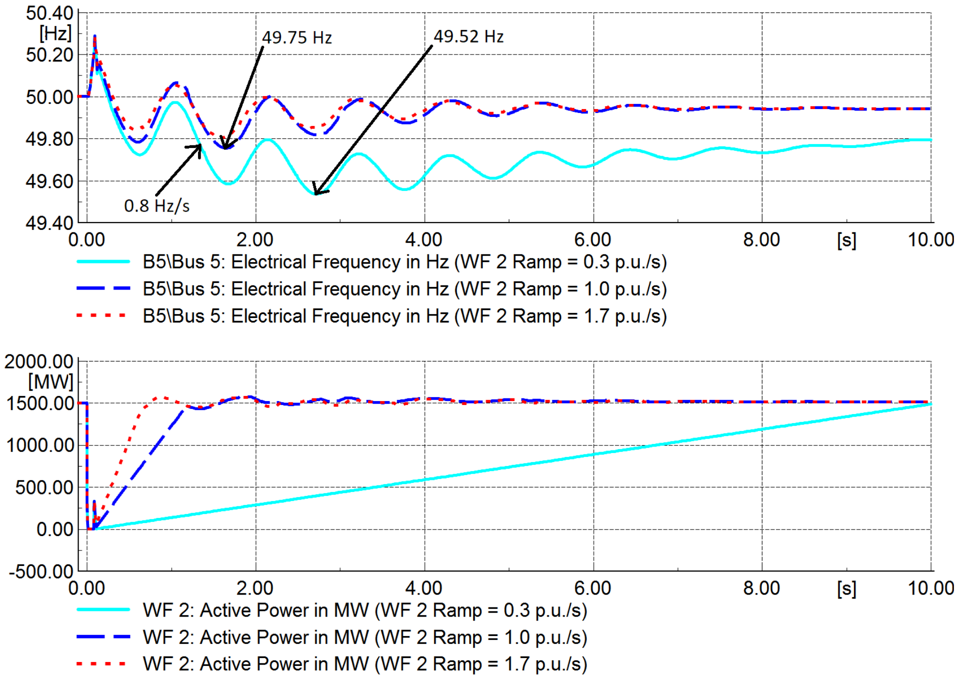


(a) SG fault in Area 1, FRC in Area 1.

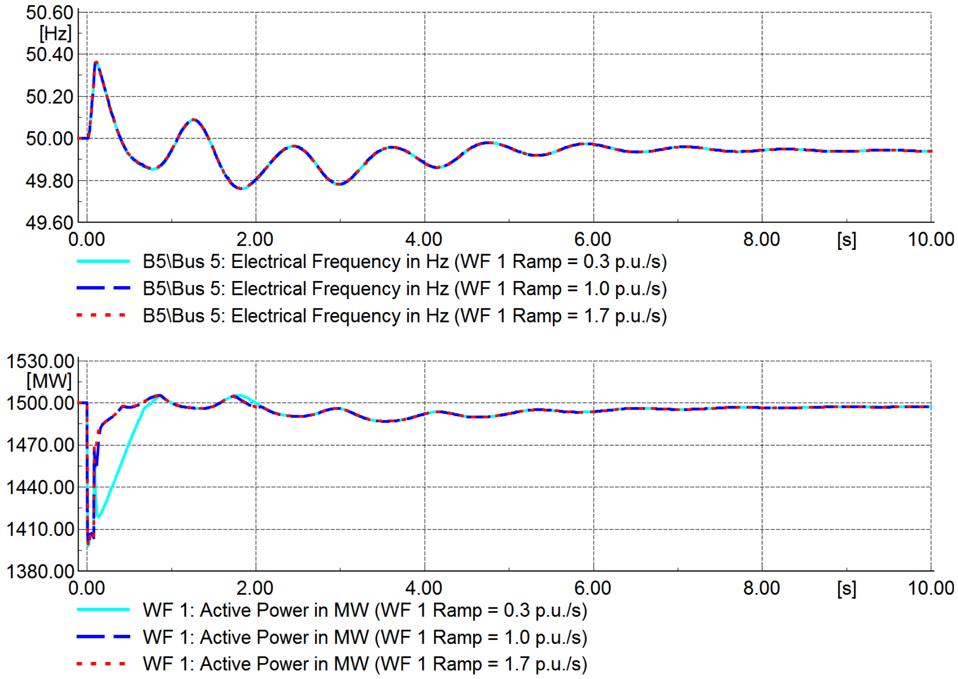


(b) SG fault in Area 1, FRC in Area 2.

Figure 6.8: Impact of FRC ramp rate (p.u./s) on frequency response after Area 1 loss-of-generation fault.



(a) SG fault in Area 2, FRC in Area 2.



(b) SG fault in Area 2, FRC in Area 1.

Figure 6.9: Impact of FRC ramp rate (p.u./s) on frequency response after Area 2 loss-of-generation fault.

nificant and result in unwanted tripping of generation protection relays and hence compounding the initial loss-of-generation. As discussed previously, RoCoF relays may be set at or around 1 Hz/s, in this case the deterioration of frequency stability induced by the altered recovery rates would result in an unwanted RoCoF trip event. The results suggest that the use of slower active power recovery for transient stability enhancement must also include careful consideration of the resulting erosion of frequency stability margins. A useful continuation of this research may include a study of the feasibility of pairing slow ramp rates in exporting regions with fast ramp rates in importing regions, giving transient stability benefits while also maintaining the overall energy production from the wind farms and therefore mitigating erosion of frequency stability.

6.3 Discussion

The use of reduced active power ramp rates from wind farms in exporting regions shows promise as a means of improving the transient stability margins in power systems, however there are other factors which must be considered in order to maintain overall grid operability and ensure that other stability aspects are not compromised. There have been concerns from the Irish TSO [85] that the reduction in active power from wind farms during depressed voltage fault conditions is already problematic in terms of longer term frequency stability, particularly when considering extremely high wind penetrations on the order of over 50% of the instantaneous demand.

In order to mitigate this problem, it may be necessary for the wind farms to adhere to different control logics depending on the type and relative location of the fault, and the pre-fault operating point of the system. Coordinated control could be required that ensures that only when the wind farm is in an exporting region and the fault has occurred on a transmission line feeding the importing region then the slower active power ramp rate was utilised. Conversely, wind farms on the importing side of the fault could improve the transient stability margins by employing a fast active power recovery in these situations.

In circumstances where a loss of generation fault has occurred, it may be more beneficial for the overall system security for all wind farms to employ as fast an active power ramp rate as possible. A promising area of development for such control may be found in the relatively new field of Wide Area Monitoring Systems (WAMS) and the use of Phasor Measurement Units. By actively monitoring the voltage angle differences across key transmission corridors, automatic grid control systems in the future could be able to identify the correct control logic to be adopted by the wind farms distributed around the system to which will best manage transient or frequency stability in the event of a set of credible contingencies. Another key prerequisite to the successful implementation of such control methods will be wide-spread and high speed communication systems at the transmission level [110].

The technique might be completely impractical during periods of extremely high instantaneous wind power penetration as a proportion of demand. Frequency stability issues may be caused by the overall loss of active power from wind exceeding the greatest loss of infeed (synchronous) and therefore the breech of frequency limits. A global controller would have to recognise that during such high wind scenarios, the entire wind fleet should recover as quickly as possible to post-fault active power levels [80].

CHAPTER 7

Conclusions and Future Work

The recent rapid growth in renewable power generation shows no signs of slowing down and there is potential for significant deployment of energy storage technologies to complement this growth. Such developments will precipitate a measurable reduction in traditional sources of electrical power, such as those which utilise fossil fuels. This reduction in older synchronous generation, and the inertia and various control capabilities that go along with it, is at the root of the key changes in power system operation which are already being experienced and will continue to be experienced by system operators around the world.

It is accepted by these power system operators that unprecedented changes are necessary in the way that power systems are designed and operated in the coming decades and a drastic move away from traditional methods is needed.

With the current and future high growth rates of wind and solar generation in power systems, comes the need to understand and even harness the differing dynamic characteristics of the generation fleet. By utilising the inherent control capabilities of the generators themselves to mitigate stability issues, rather than by expanding the power transfer capability of the network, inconvenience and cost to the public can be minimised.

Utilising a simplified power system model of the GB transmission system, several aspects affecting transient stability margins and limits have been identified and illustrated. It has been shown that the replacement of conventional generation with wind power plants can act to erode *or* improve transient stability margins for faults on a critical corridor within the GB transmission system, depending on the location of the wind power plant relative to the fault, whether the plant is in an importing area or exporting area, and the control settings and parameters of the wind farms embedded in the system. Further, it has been shown through two different stability metrics (critical clearing times and pre-fault boundary transfers) that the utilisation of reduced post-fault active power ramp rates from the wind turbines in the exporting area, or (to a lesser extent in this test system) increased post-fault active power ramp rates from the wind turbines in the importing area, can provide improvements in the transient stability margins on the order of up to 14% in the scenarios studied.

In order to utilise the ramp rate technique for transient stability enhancement, careful consideration must be given by grid operators regarding where and when it is appropriate for wind power plants to provide such a service to the grid operation. If the system operator can be confident that transient stability issues exist only in particular areas and for particular faults, fixed modifications of the wind turbine ramp rate settings might be specified. In comparison with insertion of braking resistors, with which the effect is analogous, no new equipment is required and the effects are distributed across the system according to where wind farms are connected. However, if requirements vary widely with system conditions, ideally there would be coordinated control amongst the fleet of wind power plants which would assess which regions are importing or exporting and, for a given fault, when their controllers should react to help mitigate transient instability. Such coordinated control systems would be a fruitful avenue of research which would facilitate the use of this ramping technique for stability enhancement and, depending on the power system, could be implemented in a centralised or decentralised manner.

It was also shown in Chapter 5 that some measure of the transient stability problem can be mitigated through the tailoring of reactive power controller gain in the wind farms. By utilising a smaller proportional gain in the reactive power controller, this can have a similar impact on the transient response of the neighbouring synchronous generators to that of the active power ramp rates discussed in Chapter 6. By reducing the immediate reactive power injection from the wind farms, their active power export to the system is marginally reduced (by lengthening the voltage depression at the machine terminals), hence allowing the neighbouring synchronous generators in the exporting region to export more active power in the transient period and improve their transient rotor angle behaviour. For example, the scenarios tested here achieved an uplift in the transient stability margins on the order of 40% at the highest tested wind penetration scenario. Some combination of the tailored use of higher reactive power gains and slower active power recovery could potentially provide vast gains in the transient stability margins of the power system, should an appropriately designed control system become available.

7.1 Scope for Future Work

The work carried out in this PhD constitutes a pilot study of the transient stability impacts of wind power plants and, in particular, the impact of the LVRT reactive and active power behaviour on transient stability margins within the GB power system. Due to the simplistic nature of the test system used for the analysis in this thesis, there is of course a limited level of confidence that can be taken in the efficacy of the techniques. A first step has been taken in the investigation of these techniques and it is expected that, after more detailed analysis, they could be applied not only to the power system of Great Britain, but to other power systems anticipating high growth in renewable power sources.

Due to the simplified network, the techniques have been shown to provide benefits in terms of transient stability with respect to a single fault case. Further work on the topics discussed in this thesis should be carried out on more high-fidelity power system models based on real-world networks and further consideration should be given to the control and communication architectures necessary to facilitate robust usage of the techniques, such that the wind turbines always respond correctly to a wide range of faults and pre-fault operating conditions.

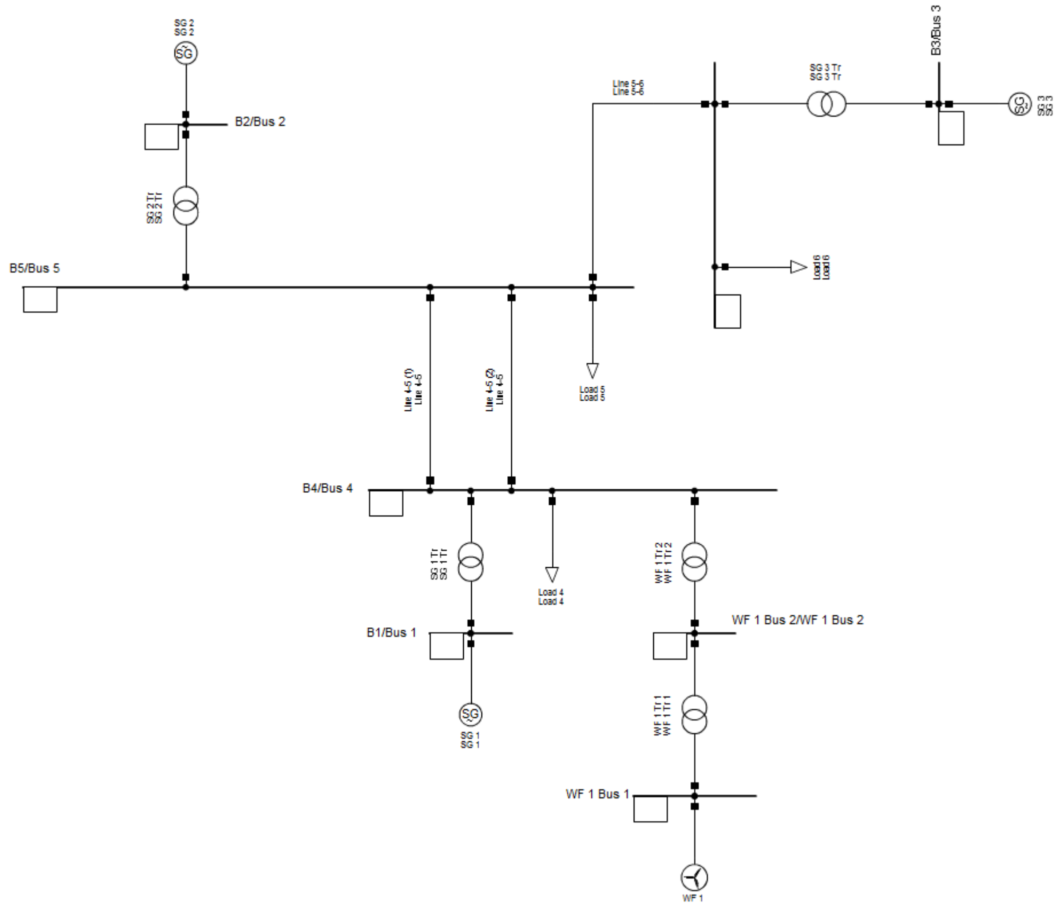
In order for these techniques to be fully exploited in real time in an arbitrary power system, the control logic, either within the wind farms or within a centralised controller, should be able to: (1) differentiate between a tie-line fault and a loss-of-generation fault, (2) correctly identify whether the wind farm is operating within an exporting or important region and (3) have an indication of the location of the fault within the power system and therefore be able to ramp active power in the manner which most benefits the overall transient response of the system to the given fault (i.e., fast or slow ramping). Advances in measurement, protection, communications and control systems will contribute to the achievement of these tasks and advance power system operators towards the goal of a fully flexible and controllable power system which is resilient to a multitude of fault conditions. If these techniques can be deployed in a more decentralised control architecture, it should be possible to mitigate any problems which may arise as a result of long distance communications and the associated latency problems.

One could also imagine a system-wide optimisation being run which would include the reactive power control gains and active power ramp rates for each connected wind farm as control variables. Having a set of sensitivities, for instance, of boundary transfer limits as a function of ramp rates, the optimiser could work out, for a given generation/load dispatch and a set of likely faults, the optimal settings of the ramp rates in advance of any event occurring. The target for optimisation might be to minimise the overall cost of generation constraint (deviation from a fully economic dispatch). A communication and control infrastructure would be required to continually tailor the active power ramp rates, however since this optimisation would be carried out in advance and therefore offline, the computational and communications burden would likely be significantly less than the real-time, decentralised approach discussed above.

The preliminary investigation of the impact of the slow active power ramping on frequency response, when a loss-of-generation accompanies the short-circuit fault, gives an indication that it must be carefully considered. A potential avenue for further work in this area could be to study the use of fast ramping in the importing region in conjunction with slow ramping in the exporting region. It is expected that this could act to mitigate the frequency erosion shown in the preliminary study by maintaining the overall energy supply to the system during and following the short-circuit and loss-of-generation event. In the event where there can be no mitigation through fast ramping in parallel with slow ramping, the system operator would be required to quantify the amount of extra spinning reserve required to make up any shortfall in the power served while the exporting region wind farms are slowly ramping their active power back to pre-fault levels.

Major differences in the system transient stability impacts were observed between FRC- and DFIG-equipped wind farms. Generally it can be said that the techniques of reactive and active power control for transient stability enhancement were found to be more effective in the FRC case. It is recommended for future work that further investigation be carried out into the more complex relationship between the level of DFIG wind penetration and the transient stability margins. However, it is expected that the relative growth in FRC-based wind turbine technology over DFIG-based wind farms may make this analysis less and less important. Each of these conditions, along with the potential impacts of their malfunction, are avenues which will provide fruitful research opportunities for power systems researchers or operators.

Appendix A: DIgSILENT Power System Model

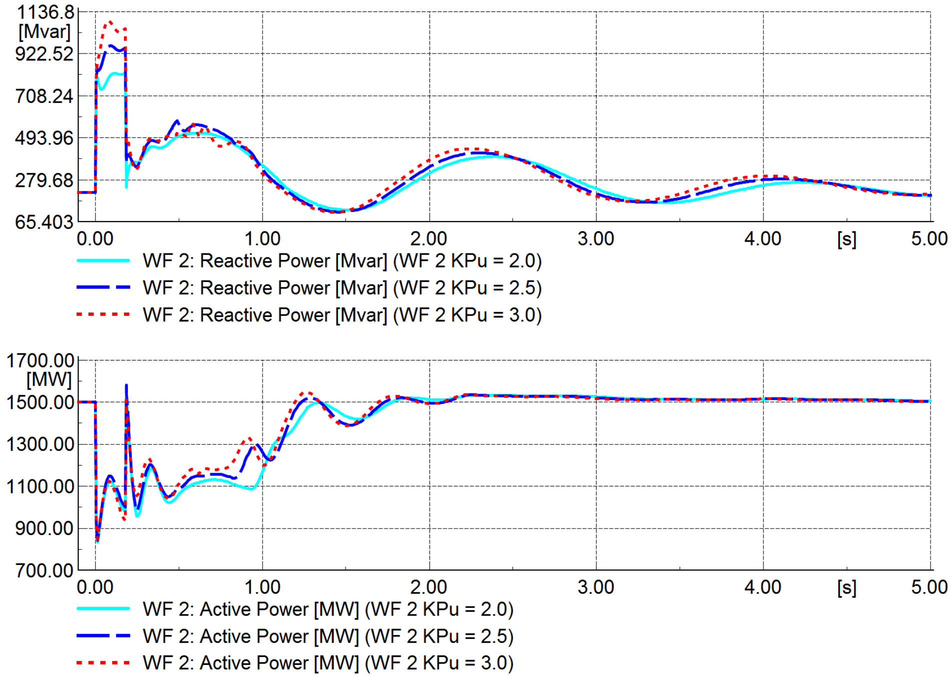


Appendix Figure 1: Test system as built in DIgSILENT PowerFactory including a wind farm connected in Area 1.

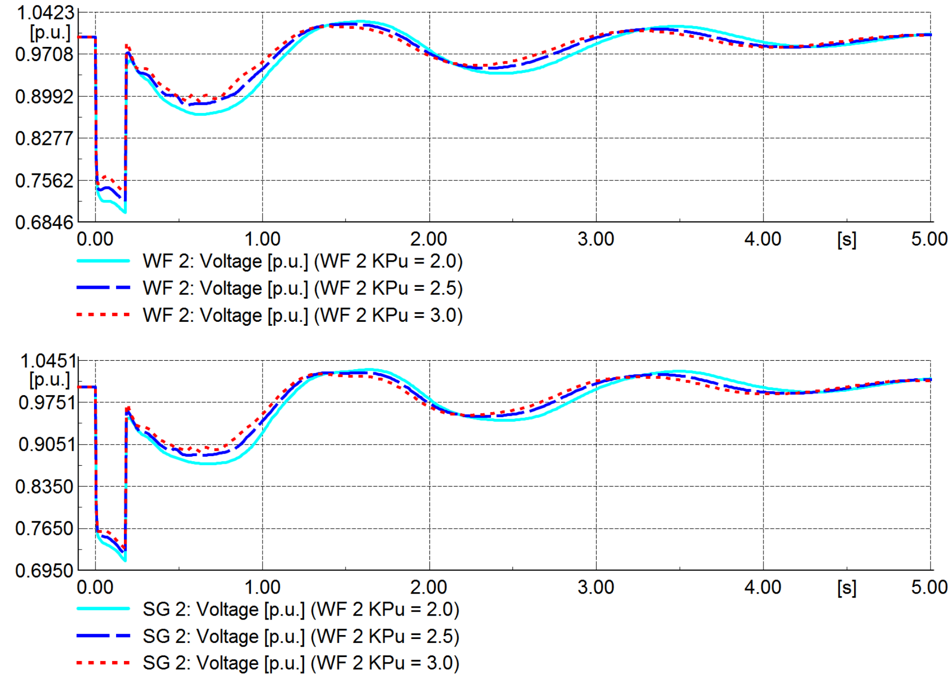
Appendix Table 1: Base case power flows.

Asset Name	Power Flow / Dispatch (MW)	Direction
Line 4-5(1)	700	N-S
Line 4-5(2)	700	N-S
Line 5-6	1050	N-S
SG 1	18240	Out
SG 2	2100	Out
SG 3	1800	Out
Load 4	19640	In
Load 5	1750	In
Load 4	750	In

Appendix B: Chapter 5 DFIG Results

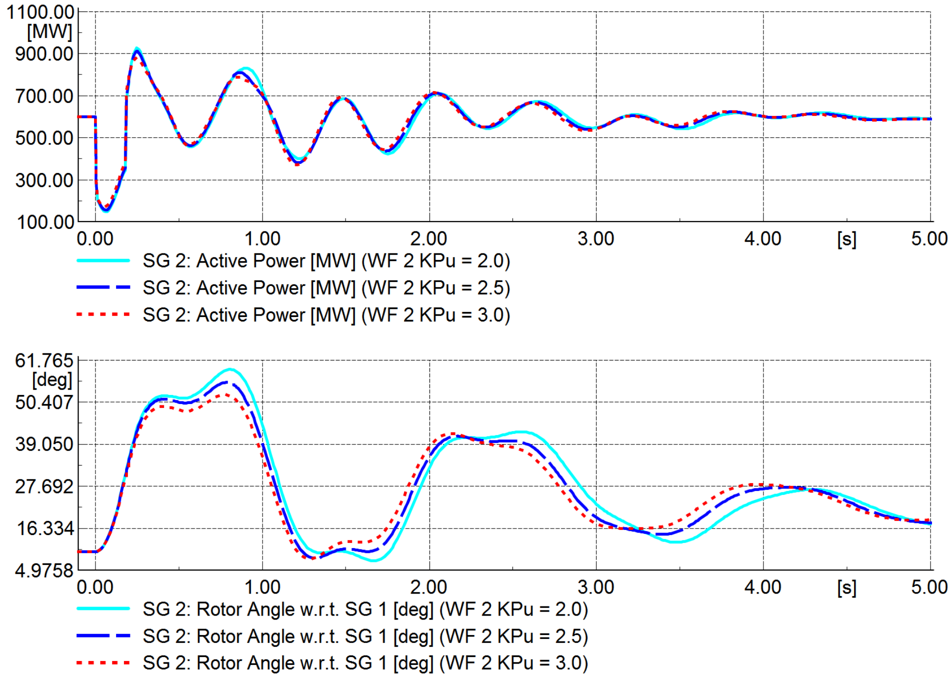


(a) Reactive and Active Power responses.

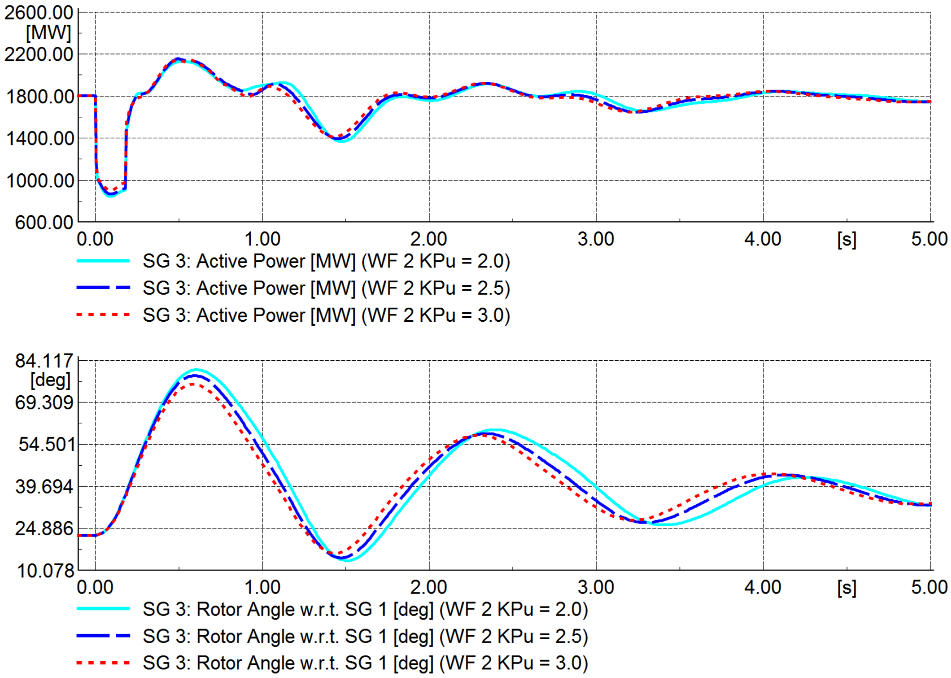


(b) Terminal voltages in Area 2.

Impact of KPu on transient response (DFIG in Area 2).

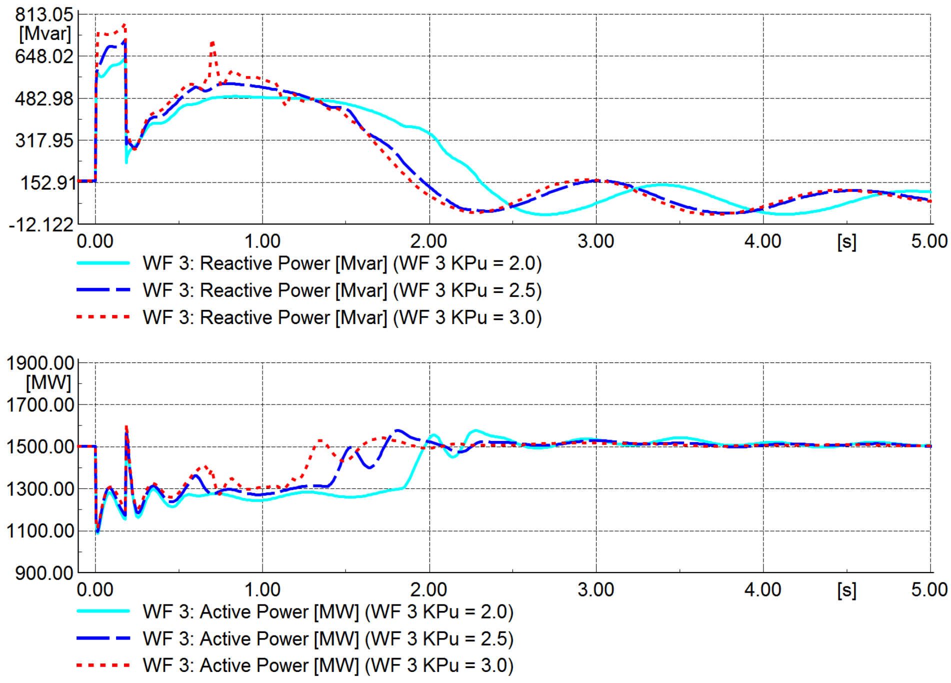


(c) .

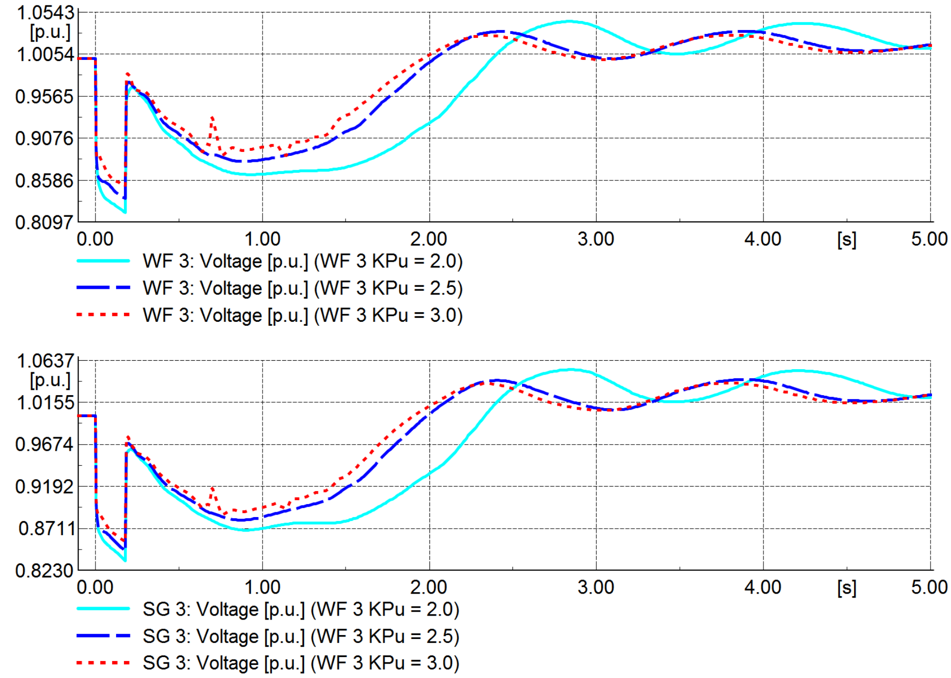


(d) .

(continued) Impact of KPu on transient response (DFIG in Area 2).

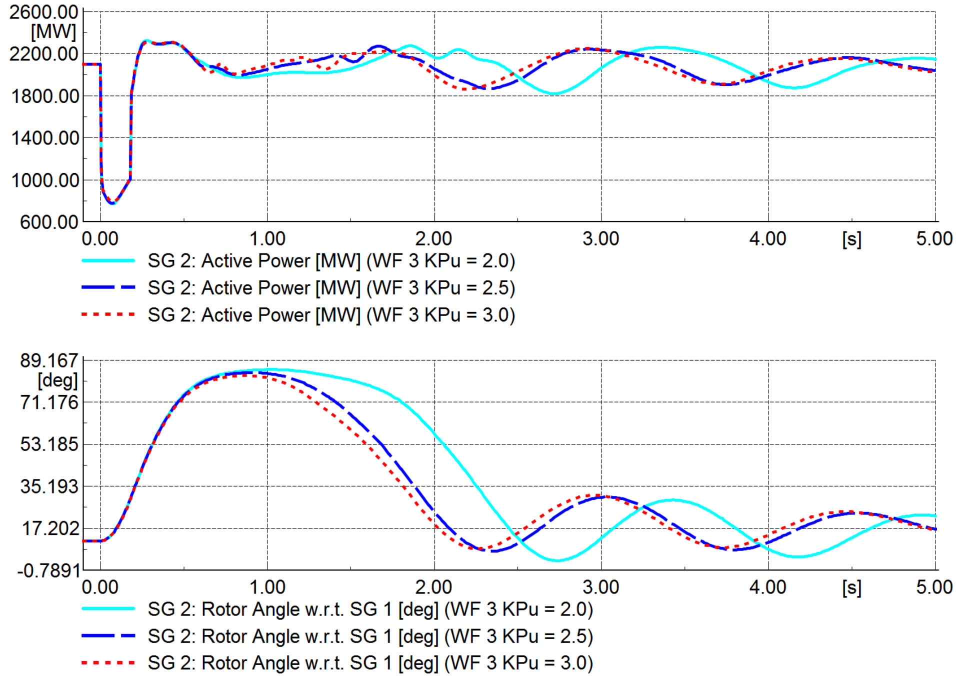


(a) .

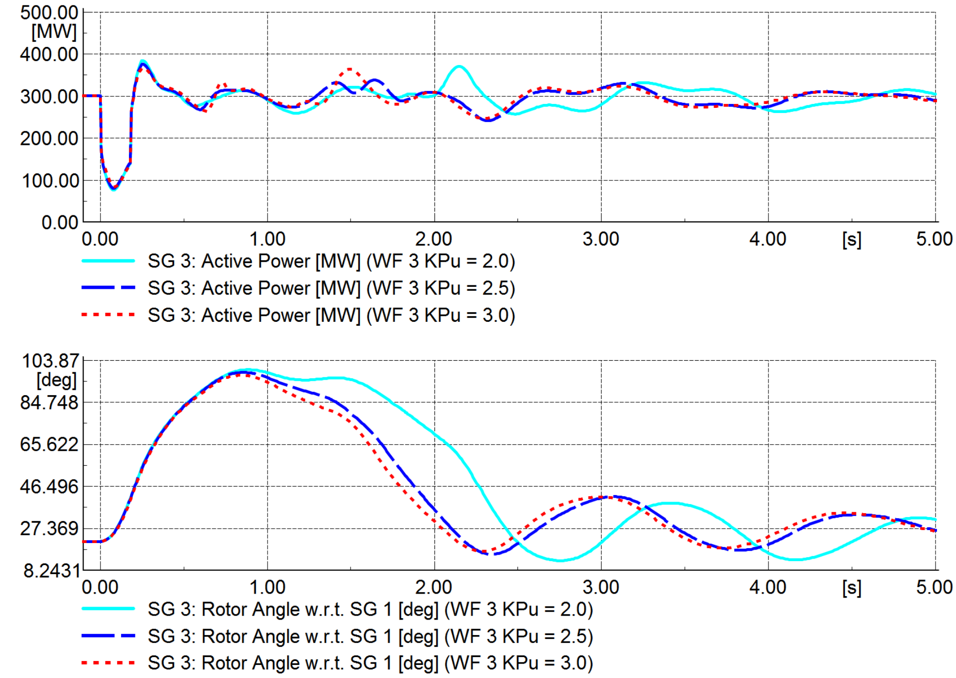


(b) .

Impact of KPu on transient response (DFIG in Area 3).

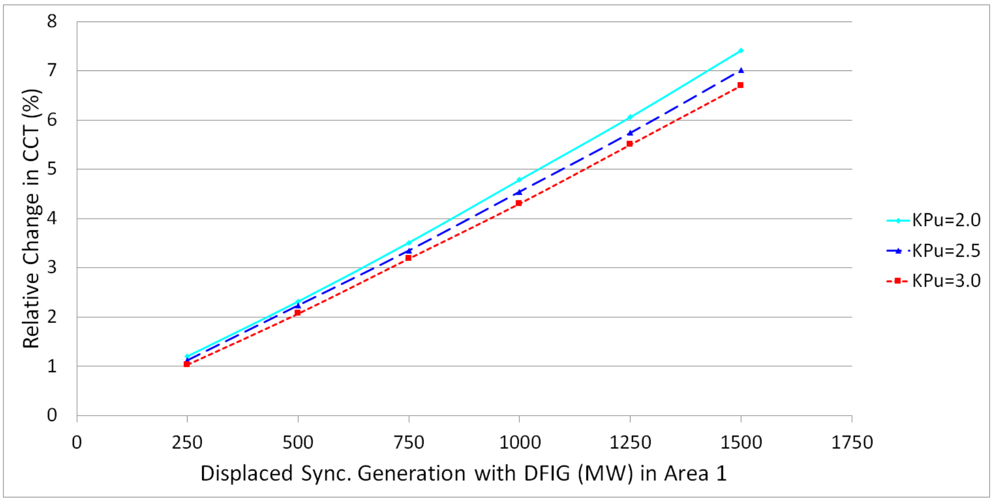


(c) .

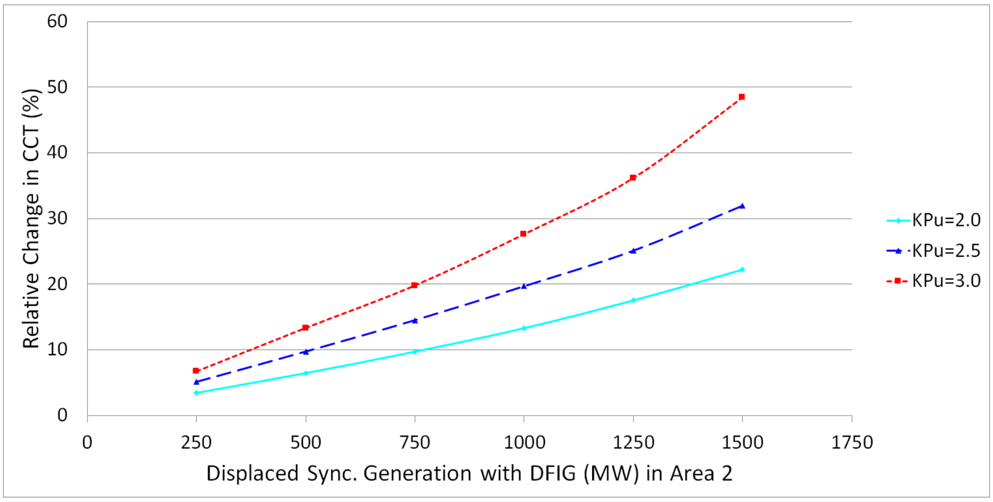


(d) .

(continued) Impact of KPu on transient response (DFIG in Area 3).

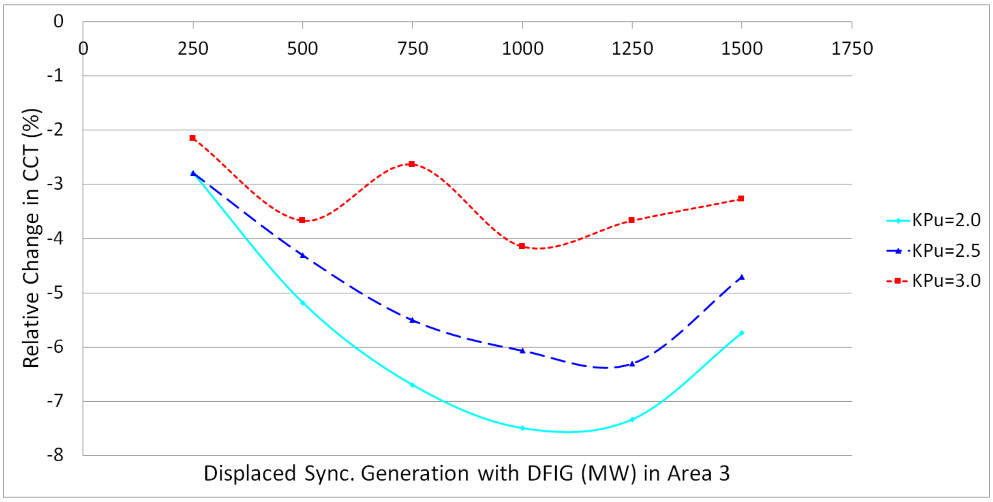


(a) Wind Farm 1.



(b) Wind Farm 2.

Impact of KPu on CCT (DFIG).



(c) Wind Farm 3.

(continued) Impact of KPu on CCT (DFIG).

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