Smoothing wind farm output power through co-ordinated control and short term wind speed prediction

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The work presented in this thesis has been conducted by the author,
all other work has been appropriately referenced.
Abstract

In recent years the energy sector has looked to renewables as a means to reduce emissions. Wind power is able to provide large amounts of energy at a reasonable cost from presently available products. Thus the amount of wind generation has risen steeply in recent years, notably in the countries of northern Europe. However, this rise in wind power has lead to issues regarding the variability of the wind power output. Wind power is related to the wind speed, which varies greatly. This variability can cause issues with wind operators’ ability to participate in electricity markets and can also lead to a rise in balancing costs.

The system proposed in this thesis aims to reduce the variation of wind farm output seen in the minute to minute time-scale and provide controllability in longer time-scales. To do this the system uses short-term wind speed predictions and the inertial energy storage of the wind turbines themselves and does so in a co-ordinated fashion across the whole farm. Using short term wind speed predictions, the amount of energy in the wind is calculated for the next short period. This energy can be exported in a controlled manner using the inertial energy to cover short-term wind energy shortfall or excess. The rotor speed must vary for the storage effect to be achieved and this requires extra control systems to prevent over-speed or turbine stalling.

The system was tested and found to be effective at smoothing the output power in a range of different wind scenarios. Tests were performed to assess the effects of using co-ordinated control on the frequency of an example grid and on the use patterns of portfolio generators. Both tests show that the use of a co-ordination controller at wind farm level reduces the balancing burden on the remainder of the system in comparison with the common maximum power form of control.
Acknowledgements

I would like to thank my supervisor, Professor Tim Green, for his advice, support, and inspiration through the course my Ph.D. I would also like to thank my supervisor for the first year of my Ph.D, Dr Carlos Hernandez-Aramburo, who got me started on the correct course for my research.

I would like to thank the EPSRC for providing financial support.

I would like to acknowledge the work of Mike Hughes and Mark Collins for providing some of the models. Additionally I would like to acknowledge David Hails at NAREC for providing me with a large amount of wind data. I am also grateful to Richard Silversides for his help formulating some of the maths. Without this help I would not have been able to complete my research.

I am grateful to my friends in Control and Power, especially Cees, Dan, Jeff and Nathaniel for their support, suggestions and for providing an excellent sounding board.

Last, but not least I would like to thank my family and friends for their support and patience through my studies and for putting up with me throughout.
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# Table of Symbols

## General Power Symbols

- $\Delta V_{\text{node}}$: Change in voltage at a node caused by power flow
- $P_{\text{line}}$: Real power flow in the line to the node
- $R_{\text{line}}$: Resistance of the line
- $Q_{\text{line}}$: Reactive power flow in the line
- $X_{\text{line}}$: Reactance of the line
- $V_{\text{node}}$: Standard voltage of the node

## General Wind Power Symbols

- $m_{\text{air}}$: Mass of moving air
- $\rho$: Density of air
- $A$: Effective area of wind turbine (blade disc area for standard turbines)
- $V$: Incoming wind speed
- $E_k$: Kinetic energy of moving air
- $P_{\text{air}}$: Power of moving air
- $P_w$: Power from the wind, captured by the turbine
- $\lambda$: Tip Speed Ratio (TSR)
- $\omega$: Rotor speed
- $\omega_{\text{rated}}$: Rated rotor speed
- $R$: Rotor radius
- $C_p$: Performance co-efficient of a wind turbine
- $C_p(\lambda)$: Performance co-efficient of a wind turbine (subject to TSR)
- $\beta$: Blade pitch
- $C_p(\lambda, \beta)$: Performance co-efficient of a wind turbine (subject to TSR and blade pitch)
- $\lambda_i$: Intermediate value for $C_p$ curve approximation
- $c_1 - c_9$: Constants for $C_p$ curve approximation
- $C_{p_{\text{max}}}$: Peak of the $C_p$-curves
- $\lambda_{\text{opt}}$: TSR at which $C_{p_{\text{max}}}$ is achieved

## AAD Calculation Symbols

- $n$: Number of samples
- $P_i$: Current power sample
- $P_{i+1}$: Following power sample
Statistical Up-Sampling Symbols

\( \bar{V} \) Average recorded wind speed for the last minute
\( V_{max} \) Maximum recorded wind speed in the last minute
\( V_{min} \) Minimum recorded wind speed in the last minute
\( V_{SD} \) Standard Deviation of the wind speeds in the last minute
\( P_d \) Desired probability that a gust will meet or exceed \( V_{max} \)
\( N_{gusts} \) Number of gusts required such that the probability that one meets or exceeds \( V_{max} \) is approximately equal to \( P_d \)
\( P(1) \) Probability that one gust meets or exceeds \( V_{max} \)
\( P(2) \) Probability that, in a series of two gusts, one gust meets or exceeds \( V_{max} \)
\( P(3) \) Probability that, in a series of three gusts, one gust meets or exceeds \( V_{max} \)
\( P(\text{N}_{gusts}) \) Probability that, in a series of \( N_{gusts} \) gusts, one gust meets or exceeds \( V_{max} \)

Wind Farm Model Symbols

\((x_i,y_i)\) Co-ordinates of turbine i before rotation
\((x_i^*,y_i^*)\) Co-ordinates of turbine i after rotation
\((x_c, x_c)\) Co-ordinates of the centre of rotation
\(x_{min}\) \(x\) co-ordinate of the front turbine
\(\delta_x(i)\) Distance in the \(x\) direction between turbine i and the front turbine
\(\delta_t(i)\) Delay between the wind time-series’ of turbine i and the front turbine
\(V_{avg}\) Average wind speed for calculating the time delays
\(V_{source}(t)\) Un-delayed wind time-series
\(V_i(t)\) Wind time-series for turbine i
\(N\) Number of turbines

Wind Turbine Control Symbols

\(T_w\) Aerodynamic torque from the blades
\(T_e\) Electrical torque from the generator
\(T_e^*\) Commanded electrical torque
\(T'_e\) Commanded electrical torque before modification by the under-speed controller
\(\omega_{max}\) Maximum allowable rotor speed
\(\omega_{min}\) Minimum allowable rotor speed
\(\beta_{max}\) Maximum blade pitch
\(K_p\) Pitch control proportional gain
\(K\) Torque control non-linear gain
\(V_a\) Wind speed for operating point A
\(A\) Operating point A
\(V_b\) Wind speed for operating point B
\(B\) Operating point B
\(B'\) Interim operating point on trajectory from A to B
\(V_c\) Wind speed for operating point C
\(C\) Operating point C
\(C'\) Interim operating point on trajectory from A to C
Portfolio Model Symbols

\( P_F \)  \hspace{0.5cm} \text{Power output of the fast generator}  \\
\( P_M \)  \hspace{0.5cm} \text{Power output of the medium generator}  \\
\( P_S \)  \hspace{0.5cm} \text{Power output of the slow generator}  \\
\( P_{\text{port}} \) \hspace{0.5cm} \text{Power time-series for the portfolio}  \\
\( P_{\text{gens}} \) \hspace{0.5cm} \text{Power time-series for the generators}  \\
\( P_{\text{wind}} \) \hspace{0.5cm} \text{Power time-series for the wind farm}  \\
\( C_L \) \hspace{0.5cm} \text{Wind prediction confidence level}

Co-ordinated Controller Calculation Symbols

\( \dot{V}_i(t) \) \hspace{0.5cm} \text{Predicted wind time-series for turbine i}  \\
\( E_{\text{wind}} \) \hspace{0.5cm} \text{Energy coming from the wind in the next 120s}  \\
\( E_{\text{rotor}} \) \hspace{0.5cm} \text{Inertial energy in the rotor}  \\
\( E_{\text{total}} \) \hspace{0.5cm} \text{Total energy available in the next 120s}  \\
\( E_{\text{high}} \) \hspace{0.5cm} \text{Energy to calculate high schedule}  \\
\( E_{\text{low}} \) \hspace{0.5cm} \text{Energy to calculate the low schedule}  \\
\( E_{\text{in}} \) \hspace{0.5cm} \text{Energy for the schedule calculation}  \\
\( E_{\text{ramp}} \) \hspace{0.5cm} \text{Energy not produced in the ramping}  \\
\( g \) \hspace{0.5cm} \text{Ramp-rate limit}  \\
\( t_r \) \hspace{0.5cm} \text{Time spent ramping}  \\
\( T \) \hspace{0.5cm} \text{Time for a single prediction period}  \\
\( P_1 \) \hspace{0.5cm} \text{Previous power output}  \\
\( P_2 \) \hspace{0.5cm} \text{Power output at end of schedule}
# Table of Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>AAD</td>
<td>Average Absolute Differential</td>
</tr>
<tr>
<td>BWEA</td>
<td>British Wind Energy Association</td>
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<tr>
<td>CCGT</td>
<td>Combined-Cycle Gas Turbine</td>
</tr>
<tr>
<td>DECC</td>
<td>Department of Energy and Climate Change</td>
</tr>
<tr>
<td>DFIG</td>
<td>Doubly-Fed Induction Generator</td>
</tr>
<tr>
<td>DTI</td>
<td>Department of Trade and Industry</td>
</tr>
<tr>
<td>EPE</td>
<td>European Power Electronics And Drives Association</td>
</tr>
<tr>
<td>EPSRC</td>
<td>Engineering and Physical Sciences Research Council</td>
</tr>
<tr>
<td>EWEA</td>
<td>European Wind Energy Association</td>
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<tr>
<td>GPC</td>
<td>Generalised Predictive Controller</td>
</tr>
<tr>
<td>HAWT</td>
<td>Horizontal-Axis Wind Turbine</td>
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<tr>
<td>LIDAR</td>
<td>Light Detection And Ranging</td>
</tr>
<tr>
<td>NAREC</td>
<td>National Renewable Energy Centre</td>
</tr>
<tr>
<td>OC</td>
<td>Over-speed Controller</td>
</tr>
<tr>
<td>OCGT</td>
<td>Open-Cycle Gas Turbine</td>
</tr>
<tr>
<td>PI</td>
<td>Proportional plus Integral</td>
</tr>
<tr>
<td>PSF</td>
<td>Prediction Safety Factor</td>
</tr>
<tr>
<td>STATCOM</td>
<td>Static Synchronous Compensator</td>
</tr>
<tr>
<td>TSR</td>
<td>Tip-Speed Ratio</td>
</tr>
<tr>
<td>UC</td>
<td>Under-speed Controller</td>
</tr>
<tr>
<td>US EIA</td>
<td>United States Energy Information Administration</td>
</tr>
<tr>
<td>VAWT</td>
<td>Vertical-Axis Wind Turbine</td>
</tr>
<tr>
<td>WWEA</td>
<td>World Wind Energy Association</td>
</tr>
</tbody>
</table>
Chapter 1

Introduction

1.1 Wind Power Status

Over the past few decades global climate change has become a serious issue for all countries of the world. The Kyoto Protocol of 1997 marked a significant turning point in the world’s commitment to reducing the emissions of gases harmful to the environment. One of the main sources of greenhouse gases is energy generation, especially electricity generation with fossil fuel power plants. In response to Kyoto the EU has placed targets upon its member countries to achieve a total of 20% energy generation from renewable sources by 2020 along with a 20% reduction in greenhouse gases from their 1990 level[1].

In addition to the need to reduce the amount of greenhouse gases being emitted, many of the countries around the world have rapidly developing economies, especially India and China. These developing economies require greater and greater amounts of energy. In order for the global increase in demand to be met whilst still attempting to reduce greenhouse gas emissions, strong emphasis has been placed on the research and development of renewable sources of electricity generation like wind, hydro and solar[2]. Other potential emission-free electricity production methods, such as nuclear fusion, have also received a lot of interest but are still far from ready for full scale production.

The UK has additional drivers to those mentioned above. Historically, the country has been powered by a mixture of sources, including coal, gas, nuclear and hydro. However most of the nuclear plants and many of the coal plants are due to be decommissioned in the near future[2]. Direct replacements for these have been met with resistance, political in the case of nuclear and
environmental in the case of coal. Therefore there is a strong push towards renewables to fill the “Energy Gap” and ensure the electricity supply whilst meeting EU and Kyoto targets.[3, 4, 5]

Wind is the second most mature of the renewable technologies, behind large hydro power, and has the second largest world market share[6]. As such, wind generally plays a significant role in many country’s plans for meeting renewable targets and obligations from the Kyoto protocol and other such initiatives.

1.1.1 Global Wind Status

As with any renewable energy source, some places in the world have better access to wind power than others. Figure 1.1 shows the average wind speed at 80m\(^1\) for the whole world. As can be seen Northern Europe and North America have particularly good wind resources and this is reflected in the installed capacity figures.

![Figure 1.1: Map of global wind speeds][7]

As of mid 2010, 175GW of wind capacity was in place around the world, largely in Europe, United States and China. In the last decade, the wind industry has seen increasing growth each year, from 20GW installed in 2001 to 38GW added in 2009 and an estimated 44GW of additional wind capacity added in 2010[8]. This fast growth has meant that the installed wind capacity has been doubling approximately every 3 years since the turn of the century. China and the US are

---

1.80m is approximate hub height for most utility scale wind turbines
the two biggest installers of new wind generation, adding nearly 14GW and 10GW respectively in 2009. European countries installed much more modest numbers in this time. Table 1.1 shows the world’s top 20 wind producing countries by installed capacity.

<table>
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<tr>
<th>Country</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
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<td>USA</td>
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<td>16.8</td>
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Table 1.1: Wind power installed capacity (GW)[8]

After an initial period of activity in the United States in the 1970s and 80s (caused by high oil prices), Europe has become the home of wind energy. Denmark and Germany have lead the way through the busiest period of wind development, both in terms of developing and designing the technologies\(^2\), and installing the turbines themselves[9]. Despite losing top spot to the US and China in terms of total capacity, European countries still lead the way in terms of percentage of energy demand generated from wind with Denmark producing nearly 20% of its energy needs from wind energy alone (in 2007, 2008 and 2009, See table 1.2). Energy production is a particularly important figure for wind as it shows the actual production of the wind turbines, as opposed to the capacity figure which refers to capability to generate energy if the wind is blowing in the correct speed range. Few countries have reached double figures in terms of percentage energy produced from wind turbines (Table 1.2), all of them relatively small countries with low energy consumption. This shows there is a large amount of room for increased wind power before it causes trouble with

\(^2\)Some of the largest wind turbine companies come from these two countries, for example Vestas and Enercon
the grid system[10], a subject covered later in section 1.2.2. The top two in terms of total installed capacity, USA and China, produce as little as 2% and 1% of their energy from wind, respectively, and the world as a whole produces 2% of its energy from wind, a total of 340TWh in 2009.

<table>
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<td>0.8</td>
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</tbody>
</table>

Table 1.2: Wind power energy production as a percentage of total consumption[11][12]

1.1.2 UK Wind Status

The UK has had a wind presence since 1992[13] when the first wind farms were installed. The amount of wind power installed grew at a relatively modest pace in the early years, but the rate of installation has been rising in the last few years as shown in figures 1.2(a) and 1.2(b). The early slow growth is partly due to technological constraints and economic reasons, such as the small power output and high cost of small turbines. The small land area of the UK also causes issues with wind power. Wind projects are often met with local resistance during the planning stages as it is difficult to site them far from population and out of view. More recently the size of individual turbines has increased (figure 1.2(c)) meaning that the rate of wind growth in the UK has increased even though the average farm size, in terms of number of turbines, hasn’t increased at the same rate (figure 1.2(d)). In the near future the move towards a larger proportion of offshore wind farms, which often contain more turbines than their onshore counterparts, should mean that
rate of UK wind power installation should increase further.

![Graphs showing UK wind installation statistics from 1992 to 2010](image)

(a) UK Total Installed Wind Capacity  
(b) UK Total Number of Installed Turbines  
(c) UK Average Installed Turbine Size  
(d) UK Average Installed Farm Size

Figure 1.2: UK wind installation statistics 1992-2010[13]

In 2009 the UK ranked 8th in terms of capacity of wind turbines installed and 10th in terms of percentage of energy demand provided by wind. This is despite having one of the strongest wind resources in the world. In order to meet its renewable energy targets, the UK is currently adding to its 5.2GW of wind capacity currently installed with 2.5GW of wind farms under construction, 6.5GW with planning consented and a further 8.7GW in the planning process[14]. If all of these come to being, then the UK will have around 23GW of wind installed, which is 26% of the 2008 total electricity generation capacity. Much of this wind capacity is located in large near-shore and offshore wind farms.
<table>
<thead>
<tr>
<th>Status</th>
<th>Onshore (kW)</th>
<th>Offshore (kW)</th>
<th>Both (kW)</th>
<th>Percentage Offshore (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational</td>
<td>3863</td>
<td>1341</td>
<td>5204</td>
<td>34.7</td>
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<tr>
<td>Construction</td>
<td>1352</td>
<td>1154</td>
<td>2506</td>
<td>85.4</td>
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<tr>
<td>Consented</td>
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<td>2592</td>
<td>6201</td>
<td>71.8</td>
</tr>
<tr>
<td>Planning</td>
<td>6930</td>
<td>2260</td>
<td>9190</td>
<td>32.6</td>
</tr>
<tr>
<td>Totals</td>
<td>15754</td>
<td>7347</td>
<td>23101</td>
<td>46.6</td>
</tr>
</tbody>
</table>

Table 1.3: UK wind industry status[14]

1.2 Characteristics of Wind Power

Whilst wind power is one of most mature of the renewable technologies, it is not without its technical problems. The uncontrolled primary energy source (the wind) means that control of the electrical output power is only possible within limits and cannot be assured or dispatched. This can cause technical problems on the grid and increases the economic risk of market participation.

1.2.1 Wind Power in the GB Market

Electricity markets around the world work in various different ways but most have certain mechanisms in common. They typically function based on the pre-arranged sale of energy. The producers determine how much energy they have to sell in any given time slot and the energy is either purchased with bilateral contracts or with a pool system. This trading is performed before market closure, which is a number of hours before the actual production time. At market closure, the individual generators each provide the system operator with their production schedule for the next period. After market closure and before the production period, the system operator is able to adjust production schedules to avoid violation of grid constraints. After the production period, some form of accounting is usually applied to compensate/penalise for over/under production.

In Great Britain (GB), the market is based upon bilateral contracts with a market closure time of 1 hour for production periods of 30 minutes[15]. After the production period the energy produced by each generator is totalled and compared to the declared production schedule. If it is found short, extra Topup charges are applied and if it is found long, Spill prices are paid to the generator. There are no limits on the size or sign of the Topup and Spill rates, they are determined based on the cost of balancing supply and demand during that production period.

Wind power producers rely on the prediction of the wind to forecast their energy output. Current state of the art wind forecasting techniques still result in a fair amount of error[16] over the minimum 90 minute market period in GB. The errors are even larger if the wind farm owner wishes
Market contracts
arranged
System Operator
Corrections
Production
Period
Topup and Spill
Calculations
Market closure

Figure 1.3: Time-line of UK market bidding

to participate in the market further in advance. It is therefore common to see wind power producers not predicting their output energy and simply accepting the Spill rates for their energy[17]. These rates are most likely to be much lower than those that could be achieved by selling the energy in a contracted manner, but the risk of incurring Topup charges due to underproduction is too high given the errors in wind speed forecasts.

Some research places the revenue lost due to mis-prediction of the wind at around 10% of the total income of a wind farm[16]. This figure was for the Spanish market which uses a day ahead system, meaning the wind predictions will be less accurate. This is therefore likely to be a pessimistic view for the GB market as the predictions used will be more accurate over the shorter gate closure time frame.

Wind farms can participate in the market system as part of a portfolio of generators. The group of generators bid to the market as a whole, and whatever power is not produced by the wind farm is produced by other generators. In this way the zero production cost power from the wind is sold at its maximum value, whilst avoiding the some or all of the risks involved in market participation. However, the variable wind power now presents a problem similar to the balancing issue outlined below whereby other generators\(^3\) are required to act to counter the wind output changes.

1.2.2 Technical Issues

In addition to the purely economic issues of participation in the market, wind power has effects on the technical aspects of running a power grid. The balancing system, system reliability and voltage control all affected by the inclusion of wind power.

\(^3\)In this case other generators within the portfolio
1.2.2.1 Balancing Supply and Demand

There is a requirement for supply of electrical power to be matched to demand at all times as very little energy storage is available to cover any difference. This process is termed balancing and is handled in different ways in different grids. The nature of the organisation responsible for dealing with the arrangements for balancing and how it is funded differs from country to country but the basic common points are that balancing is needed when supply and demand are variable and it costs money to provide this service. Additionally, balancing must accommodate unplanned changes in generation, for example, due to generator failure.

Balancing supply and demand happens over two distinct time frames. Most of the demand is predicted beforehand and this is balanced by scheduling generators through the market. The remaining demand is unpredictable and can exhibit sudden changes. These changes are balanced as they happen by the balancing system.

Whilst the demand of a single house or business is very hard to predict as it is liable to rise and fall without warning, the demand of a large number of houses or businesses exhibits much less random variation. The demand from a commercial area will fall at around 5pm for example as businesses close for the day, while the demand from a residential area will rise at around the same time as people return home from work. This slow, predictable variation is balanced by scheduling the generators on the grid to produce predefined amounts based on the predicted demand. These generators are often the largest, cheapest ones which cannot change their output quickly, such as nuclear or coal generators. This is handled by the normal market system.

Even with a good prediction of demand, there will always be variations, large and small, that must be balanced on much shorter notice during the production period. This is well beyond the capabilities of slow base-load generators to react. This balancing is done with more expensive fast reacting ‘spinning reserve’, such as gas turbine generators. These are always running, producing some but not all of their power capability. This means they are ready to cover extra demand at very short notice or are able to quickly reduce their output in case of a demand reduction. The balancing mechanism is well founded and forms an extension to the UK electricity market whereby generators sell their balancing services to the transmission system operator for a larger fee than they might obtain through regular market contracts. These contracts are differentiated based on the speed of reaction for the generator and the amount of power and/or energy that there is available.
The GB balancing mechanism defines a number of different services that it is able to provide. The main services of interest with respect to wind are the faster services but the full range is outlined in[18].

As the vast majority of the power supplied to the GB grid comes from large rotating machines attached to thermal plant, the dominant dynamic effects come from these machines, and the regulations are designed towards their operation. When a load change is applied to a rotating thermal generator, its rotating speed will change as the control systems cannot act immediately. This in turn affects the frequency. In addition to this, each generator system\(^4\) has a predetermined power to speed profile for the generator, increased power is produced with the generator spinning at a lower speed. These two effects mean that the frequency of the system is an indication of the short term imbalance of generation and load at any given time[19]. A frequency of 49.95Hz could indicate that there has recently been an increase in load, that has not been corrected, or that the generation has been reduced in anticipation of a future load fall. If the system is balanced, the frequency is constant and will be set close to its nominal value (50Hz in the UK and Europe). Frequency response units respond directly and immediately to the frequency of the system to maintain it at its nominal value. Fast reserve units are called in when there is insufficient frequency response, they are able to rapidly change their power within two minutes of instruction. Fast start units are able to start from standstill within seven minutes. Due to the speed and magnitude of wind farm output variations, all three of these services can be called upon to accommodate the variations.

Initially, the presence of wind in the system, especially at distribution level, was most commonly treated as negative load[20]. This meant that variations in output power were absorbed into normal demand fluctuations. Research shows that small amounts of wind power penetration, below 20% of total energy requirement, can be tolerated with the current system without requiring extra balancing generators[21], but may lead to extra balancing cost[22]. This is because the variations of wind power are uncorrelated to that of the normal demand, meaning that the sum of the two does not necessarily lead to an overall increase in variation. However, there is the possibility of cases where extra reserve is needed as the demand and wind generation can act in the same direction beyond the capability of the present balancing system to compensate.

Larger wind penetrations can cause greater problems with the balancing system. The research in[23] indicates that once penetration rises above 20%, it could become worthwhile attempting to

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\(^4\)The Generator, prime mover, and associated control systems, such as the governor
minimise wind power variability for the sake of the balancing challenge. The cost of extra spinning reserve, in terms of having more plant ready to react and in terms of the high running cost of fast acting generators and the cost of starting a generator at short notice are large[23]. In addition to this basic economic factor, the requirement for extra ramping up and down of output power and start-ups, cause extra wear on the generators meaning that they perform less efficiently, further raising fuel costs. This is especially true if there is not enough fast acting generation and slower reacting plant is called-in to provide balancing services. At times the problem can go beyond economics and cause grid code violations which may cause the grid to collapse[24].

As most wind farms are operated so as to extract the maximum possible power from the wind, the ability of wind power to contribute to the balancing of the network is limited to reducing their output power, and spilling some incoming wind energy, when that service is needed. This is known as down-regulation and is useful when the load suddenly falls. In order for the wind farm to be able to respond to load changes in both directions, an amount of down regulation must be pre-set, allowing the farm to be able to increase or reduce its output on demand. A pre-set down-regulation will lead to reduced revenue, as some wind power that could have been produced (and sold) was not in order to allow up and down-regulation. This means that the benefits of being able to balance in both directions must outweigh the lost opportunities for it to be worth the operators providing this facility. These capabilities are found in modern wind farm controllers.

The most obvious solution to the problems of wind power variability would be to add some form of energy storage to capture the wind energy when it exceeds demand, and release this energy when the wind falls. However, there are few utility scale electrical energy storage options available to grid operators[25], and even fewer that find themselves in large scale commercial use like the pumped water storage system at Dinorwig[26]. Work is currently progressing in alternative options to utility scale energy storage in attempting to solve the variability problem and some key ideas are presented in section 1.5.1.

1.2.2.2 System Reliability

One aspect of system reliability that is relevant to wind power is the ability of a grid to cover the peak demand in any year. Typically grid operators try and maintain enough plant such that the peak load can still be met, even with the loss of the largest single source\(^5\). To this end,
each generator is counted towards the total with attention given to its reliability. A very reliable
generator would count towards the total by an amount approaching its rated capacity, whereas a
very unreliable generator does not count for as much.

The variation of wind power means that it cannot be guaranteed to produce power above
approximately 20-40%[27] of the rated power. This is known as the capacity credit of wind and
is averaged across a large number of turbines. This means that for every 1MW of wind installed,
only 0.2-0.4MW of other plant can be taken off-line if it is desired to maintain the same security
of supply guarantee that a certain peak demand can be met, even with some plant off-line. This
in turn means that the cost of running the grid increases as more wind power is applied to cover
the variation of wind output. This however, is not within the capabilities of wind turbine or wind
farm control to correct, and as such is not covered further.

1.2.2.3 Voltage Disturbances

The voltage at any node of the network is the standard network voltage, plus or minus changes
caused by the real and reactive power flow to the node. These changes are defined in equation 1.1
from Weedy and Cory[19]. The resistance, R_{line}, and reactance, X_{line}, of a line determine the volt-
age change for real power, P_{line}, and reactive power, Q_{line}, respectively. In transmission networks,
X_{line} is much greater than R_{line}, so the effect of real power variations caused by fluctuating wind
on the voltage is negligible. However, in weak networks and distribution networks the difference
between R_{line} and X_{line} is smaller, meaning that the fluctuations in P_{line} can be seen to cause
significant fluctuations in V_{node}.

\[ \Delta V_{node} \approx \frac{P_{line}R_{line} + Q_{line}X_{line}}{V_{node}} \]  

(1.1)

Voltage disturbances are categorised by size and duration of disturbance. The types that apply
most to wind are Sag, Swell and Flicker[28]. These problems are all within the capabilities of wind
farm controllers to deal with.

Sag (short term under-voltage) and Swell (short term over-voltage) are large disturbances in
the voltage (between 10% and 90%) for up to a minute. On weak grids, where the wind power is
dominant, these could be caused by a large drop (or rise) in wind power faster than other plant
can react to counter it. A power change rate limit can be applied by most modern farm controllers
which can limit these effects.
Flicker refers to intermittent small changes in voltage which cause lights to flicker in a way that is annoying to people. This can also cause difficulties with voltage sensitive equipment. Flicker is a common cause of complaints regarding electricity supply and is most problematic at frequencies of 0.1Hz to 10Hz[28] which overlaps the range of gusting frequencies commonly seen in wind. The tower shadowing effect can also exacerbate the problem. The total power output of a farm can be limited to reduce this effect in gusty conditions. This is, in effect, a basic form of wind power smoothing.

1.3 Wind Turbines

Wind turbines have been used for centuries to directly drive various processes, especially the grinding of grain and pumping of water. The use of wind power to provide utility scale electricity, however, is a relatively recent idea. The oil price shock of the 1970s was the significant trigger that started serious investment into the possibility of wind power providing large portions of a nations energy demand. Since then the development of wind power has proceeded at a strong pace, with installed capacity doubling every two years in recent years[8].

1.3.1 Power from the Wind

Generating power from the wind requires the conversion of the kinetic energy of the moving air into electrical energy suitable for exporting to the grid. The volume of air passing per second is simply the effective area of the turbine\(^6\), \(A\), multiplied by the wind speed, \(V\). This multiplied by the air density, \(\rho\), gives the mass of air passing per second (equation 1.2). The kinetic energy available per second, the wind power, is calculated using equation 1.4.

\[
\begin{align*}
    m_{air} &= \rho AV \\
    E_k &= \frac{1}{2} m_{air} V^2 \\
    P_{air} &= \frac{1}{2} \rho AV^3
\end{align*}
\]  

\(^6\)the rotor disk in the case of a typical horizontal-axis wind turbine

If all of this kinetic energy were to be removed that would mean that air would stop moving completely at the turbine, this clearly cannot be the case. It can be shown[9] that there is a
maximum amount of kinetic energy which can be extracted from a moving body of air which is
approximately equal to 0.59. This is known as Betz’s limit Wind turbine power conversion is
classified by the performance co-efficient, $C_p$, which is the total efficiency of the wind turbine
system from wind kinetic energy to electrical energy on the grid. The $C_p$ of a wind turbine varies
depending on turbine design, system dynamic state and turbine control system state but always
remains below the Betz limit. The power extracted from a wind is then the product of the kinetic
energy per second from equation 1.4 and the $C_p$. The $C_p$ of a turbine is significantly affected by
the speed it is rotating at, $\omega$, and the speed of the incoming wind. The ratio of these is known as
the Tip Speed Ratio (TSR, or $\lambda$).

$$\lambda = \frac{\omega R}{V} \quad (1.5)$$

$$P_w = \frac{1}{2} C_p(\lambda) \rho A V^3 \quad (1.6)$$

1.3.2 Wind Turbine Design

Over the time that wind turbines have been used for providing electricity many different turbine
designs have been used. Most aspects of the turbine have been investigated as possible ways of
extracting more energy, or generating energy a more effective way. These range from the main
provider of motive force (drag or lift) to the direction of the axis of rotation passing through all
manner of physical aspects such as the size of the turbine and the shape and number of the blades
or buckets.

1.3.2.1 Drag vs. Lift Turbines

There are two ways to get power from the wind, or any travelling fluid, they are drag and lift. Very
early turbine designs relied on the wind pushing the mechanism, or part of the mechanism such
as a bucket to provide the motive force. This is classed as a drag machine and works similar to a
basic waterwheel. Lift turbines instead utilise the same aerodynamic lift that is used in aeroplanes
to pull the machine around, these typically use wing shaped blades. Lift turbines are more efficient
than drag turbines[9] and as such are more commonly seen in commercial use.
1.3.2.2 Vertical Axis Wind Turbines

A number of wind turbines have been designed and built upon a vertical axis arrangement. The turbine is arranged with the blades on either side of the main axis of rotation which, as the name suggests, is aligned vertically. The vertical axis wind turbine (VAWT) (figure 1.5) has an advantage over horizontal axis wind turbines (HAWTs) in that they do not need to be orientated toward the wind but generate power equally well with any incoming wind direction and can thus handle winds that are directionally turbulent better than HAWTs[29]. Each VAWT, when used in a farm, also requires less space as they have a less significant effect on turbines downwind than HAWTs[30]. VAWTs can allow the the gearbox and generator systems can be placed lower to the ground allowing for easier access. The vertical axis however, means that in order to replace the bearings on the main shaft, the whole turbine is required to be disassembled, this is less of a problem with small versions but can be a serious issue with large turbines[29]. VAWTs come in both drag arrangements (a Savonious turbine for example) and lift arrangements (a Darreius arrangement is an example). VAWTs are also not capable of the higher efficiencies achieved with HAWTs as shown in figure 1.4.

Figure 1.4: Plot of the $C_p$ curves against tip speed ratio for various turbine types[31]

Early designs such as the Darreius turbines had the blades at either side of the axis, either straight or curved, which gave rise to pulsed torque. This pulsed torque was resolved by arranging the blades as a helix around the axis which produce a smooth torque through the full range of rotation. This helix design is used by small wind turbine designs to reduce vibration[32].
Despite these problems VAWTs have been put into use, both at utility scale and a smaller more household or business-focused scale. The Eole VAWT wind turbine\[33\] in Canada held the record for the largest wind turbine\[7\] at 3.8MW, for a long time before it was overtaken by modern HAWTs. It still stands as the world’s highest VAWT\[33\]. This turbine highlights the issue with the main bearings and was taken off-line for an extended period as it is not a trivial task to de-construct this 110m tall machine to replace them\[29\].

Larger scale VAWTs are uncommon but the ability of VAWTs to generate well with low wind speeds and their smaller size has lead to their being regularly used at smaller scale. These include the winged, lift machines\[32\] like the larger turbines but also some drag machines\[34\] and even combinations of the two\[35\].

1.3.2.3 Horizontal Axis Wind Turbines

The more common design of wind turbine is the horizontal axis turbine. These turbines have a number of blades arranged in a plane around a central hub. The hub is attached to a generator by an axle which is placed horizontally atop a tower. The number of blades found on these turbines typically range from one to twenty but for electrical applications there are rarely more than three blades. HAWTs are lift machines, relying on a wing-like profile of the blades to generate the forces required to rotate the machine. In order to do this, unlike VAWTs, the turbine must be yawed to face into the wind.

\[7\] In terms of designed power production
1.3.2.4 Upwind and Downwind HAWTs

Two types of HAWT arrangement are possible, those with the rotor disc downwind of the tower and those with the rotor disc upwind of the tower. The downwind turbine has the advantage that no yaw mechanism is required as the rotor can achieve this effect passively, and also the blades can be made more flexible and thus lighter[39]. However they do suffer very badly from the tower shadow effect, a pulsation of torque that occurs when a blade passes through the wake of the tower[39]. Upwind turbines require stronger blades (so they don’t bend backwards into the tower) and are thus slightly heavier, but the tower shadowing effect is much reduced. The requirement for a yaw mechanism is a minimal loss when the turbines are large as it is needed anyway to prevent the output cables twisting. In smaller downwind turbines, it is possible to use slip rings to transfer the power so the advantage of not requiring a yaw mechanism is more evident[39].

1.3.2.5 Number of Blades

The rotor disk, whether placed up or downwind of the tower, can be designed with different numbers of blades. There are a number of trade-offs related to number of blades. Whilst aerodynamic efficiency can be improved with increasing number of blades[31], this has a diminishing return.
Larger numbers of blades cost more in terms of materials and blade pitch mechanisms and they weigh more\cite{9}. Large numbers of blades are not used for electricity generating wind turbines as the efficiency gained is minimal, and the cost of each blade is large. Additionally large blade numbers mean lower rotational speeds, which means that for the generator to be efficient it would need to be very large, complex or have a higher ratio gearbox. For large scale electrical turbines the consideration is most often between one, two and three blades. Three bladed turbines provide a very small increase in efficiency from two bladed designs for the extra expense but they provide a smoother power output than two blades. This is because the tower shadowing effect is reduced as there are two unshaded blades to compensate for the shaded one. The reduced tower shadow effect also means that the off-axis forces on the drive-shaft are reduced. Two bladed turbines may run faster and are cheaper and lighter than three blades but the off-axis forces caused by tower shadowing require an extra mechanism to allow the rotor disk to teeter\cite{31}. Single bladed turbines have existed but were never popular as commercial products. In addition to cost and efficiency, environmental factors have lead to the dominance of the three blade turbine. As the blade number reduces, the rotational speed where the turbine is most efficient increases. This is useful as faster rotating electrical generators can be smaller, but these create more noise. Noise is a problem for
wind turbines as they often are placed near residential areas, so higher numbers of blades are more desirable to keep noise at a minimum. The final factor that leads to three bladed turbines being the most common is that of aesthetics, most people seem to favour the look of three blades to two or one\cite{9}.

### 1.3.2.6 Wind Turbine Size

The energy extracted by wind turbines comes from the kinetic energy of the incoming wind and this is directly proportional to the area of the rotor disc (assuming HAWT) as shown in equation 1.6. Therefore in order to increase the electrical output of turbines, their blade diameter has needed to be increased.

![Figure 1.8: Increase in wind turbine size over time\cite{40}](image)

From the 80s, diameters of three bladed HAWTs have increased from around 15m, in 1985, to over 120m in 2009. Tower heights have increased at a similar rate.

### 1.3.2.7 Blade Control

Horizontal-axis wind turbine blades can be categorised as one of three types: passive stall, active stall and pitch control. Passive stall systems rely on the blade aerodynamic design to slow the rotor when it is spinning to fast. Active stall uses a small motor or hydraulic system to twist the
blades a few degrees to achieve the same effect. Pitch control systems have a much larger range of blade motion and can fully control the power input from the wind by altering the efficiency $C_p$ of the turbine. Example curves of efficiency vs. tip speed ratio, $\lambda$, are shown in figure 1.10 for a range of blade pitch angles, $\beta$. In practice modern turbines have full blade pitch control and only older fixed speed generators are paired with active or passive stall blade design.

### 1.3.2.8 Mechanical Layout

In order to transmit the rotating mechanical energy harvested by the rotor disc to the electrical generators a series of mechanical subsystems are required. These range from a simple shaft through to complex multi-shafted gearbox arrangements[41]. The gearbox design is determined by the requirements of the electrical generators. Often the low rotational speed of the large turbine blades is unsuited to be directly coupled to the generator as many generate electricity at, or directly related to, the frequency of their rotation. Low generator rotational speed can also, lead to an excessively large or expensive generator design. A gearbox is obviously a large and heavy mechanical device that is susceptible to wear and can reduce system efficiency, so there is a trade-off in any design that incorporates one.

### 1.3.2.9 Generator Type

There are four main types of wind turbine generators, referred to in Ackermann[9] and this report as types A, B, C and D.

Type A turbines were the earliest on the market, these feature a simple ‘squirrel cage’ induction generator connected to the rotor hub by a gearbox to increase the speed so the generator can spin at synchronous speed. These are referred to as fixed speed turbine as the generator runs within 5% of synchronous speed all the time, using blade aerodynamics to ‘stall’ the blades when they over-speed, holding this speed steady.

Type B turbines are a modification to type As where the rotor of the induction machine is a wound rotor as opposed to a ‘squirrel cage’ with a power electronic device to modify the resistance in the rotor. The variable rotor resistance allows a much larger slip, around 10%, but these are still classed as essentially fixed speed machines.

Type C turbines use a doubly fed induction generator (DFIG) which allows an even greater slip by the addition of a power electronic converter connected to the rotor through slip rings which
processes up to 30% of the output power, allowing a 30\% - 40\% slip. As with the type A generator, type Cs require a gearbox.

Type D turbines have a full rated AC/DC/AC converter as their output. The use of this type of output can allow removal of the gearbox, as the rotational frequency is no longer related to the electrical frequency. This makes for a simpler, more robust mechanical design. The output of the generator is converted to DC using a rectifier and back to AC with an inverter. This means that the mechanical and electrical systems are independent, allowing the output power to be a low distortion 50Hz no matter what the generator supplies. However, this type of generator layout requires a much more expensive power converter than that used with type C.

Using the data on the Renewables UK (formerly BWEA) website[13] on the turbine models used in all of the currently operational UK wind farms it has been possible to generate market shares for the different turbine generator arrangements. The full data table is found in appendix A. For some turbines, data sheets were not available, or it is not clear which generator type the turbine has. These are classed as ‘Unknown’. This data is only for the UK but the trends are expected to be representative of the world.

![Figure 1.9: Installed capacity of wind turbine generator types over time[13]](image)

As can be seen in figure 1.9, type A turbines were initially by far the most popular due to
their simple robust design, but have lost favour in recent years. The popularity of type B turbines (by installed capacity) has never been great, with only a few manufacturers (most notably Vestas) producing models with this generator layout.

The ability of type C and D generators to work over a range of rotor speeds allows them to harvest energy more efficiently over a range of wind speeds. This means that in many cases they are able to generate more energy than an equivalently sized turbine with a type A generator. The added control capabilities of the type C and D generator designs have also lead to their increased popularity. The more complex mechanical design of turbines with a type C generator, with gearbox and rotor slip rings, is balanced by the more expensive power electronics components of the turbines with a type D generator and no gearbox. It is expected that as the cost of power electronics falls, the advantages of the type D turbine will become more clear and it will see even greater use. This is starting to show in the market as most, if not all of the major turbine manufacturers produce a type D design and only a few still produce types A and C generators.

1.3.3 Wind Turbine Control

For this thesis, only the most common turbines are considered. These are the turbines in which a type C or D generator is paired with pitch control blades. Variable speed turbines have two main points of control: the blade pitch angle and the electrical power output. In addition to these two control actions, there is the nacelle rotation, or yaw, which for most studies, including this one, is assumed to be already aligned to the wind. The blade pitch control alters the aerodynamic torque applied to the system which provides the input power. The electrical power output alters the electrical torque applied to the system. The blade pitch and electrical power are controlled separately so as to achieve different aims. From now on the two controllers are referred to as the pitch controller and torque controller respectively.

The aim of the control system in a wind turbine is to manipulate the rotor speed, normally to a value at which optimal power is obtained from the turbine. This single control aim requires only the power output as a controlling action, meaning the blade pitch is either unneeded or used for a different task. Wind turbines are built with the blades able to produce much more power than the generator can export, this is to ensure that most of the time they produce high powers. This means that the electrical systems of the turbines saturate before the aerodynamic systems. When the electrical system is at its limit the pitch controller is often used to reduce the turbine
efficiency so that the power input from the wind is limited to the rated maximum of the electrical subsystem.

1.3.3.1 Pitch Controller

In most control systems the blade pitch is used to limit the incoming wind power to the rated electrical power so as not to overload the generators and power converters. This is commonly achieved using a simple P[9] or PI[42] controller to limit the turbine speed to a maximum. This means the turbine speed control is passed from the electrical system to the blade pitch system when the electrical system is at its limit.

Other control aims are suggested in the literature for the blade pitch when it is not being used to limit input power such as reducing the variations in output power and as a form of co-ordinated control (covered in later sections 1.5.2 and 1.4.2) and as a means of limiting the effects of turbine to turbine shadowing[43].

![Figure 1.10: Plot of the turbine efficiency (Cp) against tip speed ratio for different values of blade pitch (\(\beta\)) using the equations in[9]](image)

Figure 1.10: Plot of the turbine efficiency (Cp) against tip speed ratio for different values of blade pitch (\(\beta\)) using the equations in[9]
1.3.3.2 Torque Controller

A common torque controller[44] uses a lookup table to provide the appropriate electrical torque for any given rotor speed. This lookup applies an output torque such that the system remains at the optimal rotor speed and exports maximum power. Another torque controller found in the literature uses a non-linear feedback control loop. The error signal is the square of the measured rotor speed. The controller is detailed in[42]. Another similar torque controller is used in[45]. Both of these non-linear control systems maintain the rotor speed at its optimal by the careful selection of the non-linear loop gain, such that the maximum power is extracted from the wind.

Different torque controllers are required for the maximum power extraction and power limited regions of turbine operation and a common control difficulty is managing the transition between these smoothly[42]. Unfortunately methods to avoid this are often proprietary to the individual turbine manufacturers and unavailable in the public domain.

Both of these controllers are covered in greater detail in section 3.4.2.1.

1.3.3.3 Reactive Power Control

In addition to the two main control points on the turbines, there is the need to control the voltage at the point of connection of the turbine, or farm, to the grid. Due to the short distances of the cables involved, the resistance is low. Therefore the voltage is controlled by manipulating the reactive power generated or consumed by the wind turbines. Type A and B generators rely on capacitor banks to compensate the inductive reactive power generated by the machine and as such have no practical capability of controlling the voltage at the grid connection point. The power converters in types C and D allow a range of reactive power generation, meaning that they can effectively control the terminal voltage of the turbine or the farm. This voltage control is commonly a part of modern grid codes as it allows the wind farm to stay connected during a fault on the grid.

In addition to the two main control points on the turbines, modern generator systems are able to control their consumption or production of reactive power. The older generators (types A and B) were not able to provide this capability and as such required external devices, such as capacitor banks, to compensate for any reactive power consumed in the generators.

There is provision in the GB grid code (and others) for wind farms to be required to provide varying reactive power to control the voltage at the grid connection point[46].
As wind farms become larger, disconnecting them during a fault on the grid, as was the standard procedure in the past\cite{47}, is more of a problem. This is because the loss of a large amount of generation may cause further issues within the rest of the grid once the fault is cleared. As well as being able to compensate for the reactive power consumed within the generator systems, reactive power capabilities can allow wind turbines to stay connected to the grid during a fault\cite{48}.

\subsection*{1.3.4 Wind Turbine Inertia}

As the size of wind turbines has increased greatly over the years (figure 1.8), so has their weight and the amount of inertial energy stored within the rotating blade disc. The Enercon E70, for example, is a typically sized turbine at 70m diameter and 2.3MW rated power, its hub weight is approximately 40 tonnes\cite{38}. If this is rotating at its maximum speed of 21.5rpm it has nearly 14MJ of rotational kinetic energy. This means that without any wind at all, it could produce full rated power, for 6 seconds before the blades stop.

The possible use of the kinetic energy stored in the inertia of wind turbines rotors has received a large amount of interest recently. Methods to use the inertia mainly fall into two categories: aiding in primary frequency response\cite{49,50,51} and power output smoothing\cite{52}.

The authors of\cite{53} attempt to quantify the amount of inertial energy available for use and identify the operating conditions under which it can be used freely. It was found that there is energy that is freely usable, but only under a small set of operating conditions near the middle of the wind speed range. This energy supply was found to be about equivalent in scale to that available in a synchronous generator of similar rated power. However, due to the limited operating conditions this much energy is only available about 15\% of the time as opposed to 100\% of the time with a synchronous generator.

Due to the relatively small amount of energy available from the rotor inertia, most work around it has centred on helping to mitigate the effects of large demand changes on the frequency of the network. This is where the controllability of inverter based wind turbines\textsuperscript{8}, and their reduced dependence of power output on wind speed, are most suited. The inertial energy is accessed by exporting more power than is coming in from the wind causing the rotor to slow. It is therefore available near instantly. This near instant burst of extra energy is used to supply the demand change, preventing the frequency from falling far enough to violate limits set by the grid operator.

\textsuperscript{8}Types C and D
This energy has to be recovered later by reversing the process and exporting less energy than is coming from the wind, but this can be done over an extended period of time. The energy recovery is possible because other generators will have by this time been able to react and can produce additional energy to cover this reduced wind turbine output. The results of[49] show that the frequency low point and recovery time can be improved by using the stored inertial energy. This technique is also found in modern farm controllers from the likes of GE[51] and Vestas[50].

It has also been shown in[52] that the inertial energy storage inherent in wind turbines is useful to smooth the power output under gusty wind conditions. The authors show that by allowing greater freedom of rotor speed, a wind turbine can produce a much better regulated power output.

The extent to which any of these techniques can be applied is limited by the maximum and minimum rotor speeds allowed. The rotor speed of the turbine at the start of an ‘event’ can also alter the effectiveness of any inertial storage techniques.

1.4 Wind Farms

Wind developers have always sought to make the most of any land or sea area they have available for wind power. This, and the fact that wind turbines produce small amounts of power compared to conventional generators means that, if possible, turbines are placed in groups at a site. This group of turbines is known as a wind farm or wind array. This thesis will use the term wind farm. Since the early years of wind power in the UK, wind turbines have been placed in small groups, most commonly under ten and only a few installations a year are larger than this. This is because, on land, there are often obstacles such as roads, buildings and forests which must be avoided. There have always been large farms however, one farm of 103 turbines was installed in 1992, the first year of large scale wind power in development the UK. This is shown in the average size of UK wind farms 9, figure 1.2(d), which has stayed fairly static over this time. In recent years as the popularity and feasibility of offshore wind farms has risen, so has the average size of a wind farm. Offshore farms have fewer restriction on space (within reason), so large farms are possible. This trend towards offshore farms has also lead to a change in farm shape. Onshore farms are placed on or around land features 10 and as such are irregular, but offshore farms are normally arranged in regular rows and columns with the turbines evenly spaced.

9In terms of number of turbines.
10Whilst forests, buildings and hills upwind of the farm all negatively effect the incoming wind to a farm, placing a farm on top of a hill actually has a positive effect as the wind speed increasing as it climbs the hill.
1.4.1 Wind Farm Co-ordination and Control

Co-ordinating controllers within a wind farm toward a common goal is a relatively new concept. Previously, each turbine was controlled independently to achieve maximum power output at all times regardless of the outputs of the other turbines or requirements of the grid\textsuperscript{[54]}. With the increasing penetration of wind power and hence the increasing effect it has on the grid, stricter grid codes have become a requirement for connection to the grid.

The requirements of these new grid codes include reactive power availability for voltage regulation and fault ride through capabilities which have lead to the rise of the more advanced turbine generator concepts (such as type C and D turbines). Some grid codes, such as the Danish grid code, have gone further than this and require extra control capabilities from the whole farm\textsuperscript{[54]}.

In reaction to these extra requirements, the Horns Rev wind farm\textsuperscript{11} was one of the first to have a wind farm co-ordination controller in addition to each turbine having a local controller. This farm controller has the ability to override the set points for the power output of each turbine to a value lower than the maximum available power. As a farm, this means that a number of control modes are available:

- Delta control maintains each turbine power (and hence the farm power) a fixed amount below the maximum available. This means that the farm can command an increase, as well as a decrease, in power in response to an external command. This ability can be sold as an ancillary service as part of a system balancing mechanism.

- Balance control limits the turbine power at a maximum. This is as close to despatchable power as is available with current systems.

- Maximum power generation remains as before.

- With all of these types of control, a limit on the maximum rate of change of power output is also able to be set. This can help with the balancing system.

Most turbine manufacturers offer a similar set of control operations for their new wind farms.

1.4.2 Wind Farm Co-ordination Research

In addition to the aforementioned real implementations of wind farm controllers, there are a number of research projects suggesting ideas that could be implemented within a co-ordinated wind farm.

\textsuperscript{11}At the time of its construction, the largest offshore wind farm.
The research of[55] initially targets the use of storage to aid wind farm total output power smoothness, finding that the addition of an extra storage controller and some discrete storage can indeed significantly reduce variation in the power output. The second part of the paper concerns coordination control. The authors investigate the possibility of replacing some, if not all, of the discrete storage needs with wind turbine ‘potential to generate’ storage like that of Delta control. This too results in a significant reduction of output power variation, but at the expense of total energy produced albeit with a reduced cost of external storage. A small subset of the farm’s turbines are instructed to produce less than the available power, allowing them to be used by a storage controller to smooth the farm’s output power variations. The authors postulate some possible arrangements for this storage including, varying the number of turbines defined as storage devices, how to select them and whether to reallocate turbines as storage on the fly.

The authors of[56] use short term persistence predictions of the wind to command outputs that correctly supply a demand. For the simulation, a small system was set up with a demand, wind generator and a diesel balancing generator. The demand is predicted by an observer in the system and the wind is predicted using persistence predictions. The two predictions are used to command the wind farm to power the load, any difference between the power from the wind and that consumed by the load is supplied by the diesel generator. This controller uses fuzzy logic to determine the output commands for the turbines given the aforementioned predictions. This is done with the aim of reducing the frequency variation at the wind farm output connection. The frequency deviation in the modelled system is directly related to the power output variation so this controller is, in effect, aiming to smooth the power output. The use of persistence predictions means that this controller will struggle to deal with very turbulent wind conditions but the use of predictions at all is interesting. The outcome of this research was that the frequency deviations were smoothed and the diesel generator was required to work less to balance the supply from the wind and demand from the loads. These outcomes show promise for this kind of control as a balancing network support system. The load, and prediction thereof, are analogous to the demand on a grid, and contracted production profiles, so this system could be adapted to work in a more ‘real-life’ situation.

The work in[45] takes an alternative approach. Co-ordinated control here is achieved through the pitch controllers rather than torque controllers as used in the previous two papers. The turbine torque controllers are initially commanded to keep the rotor speed at its optimum. This ensures
that all the aerodynamic power input to the system is converted to electrical power. Pitch control for each turbine is commanded by a central farm system to limit and smooth the aerodynamic power input. The pitch is adjusted so as to minimise output power variation. This is done by reducing the efficiency of the turbines, which reduces the output power variation for a given wind variation. In order to prevent the number of pitch change commands overwhelming the pitch actuators, the commands are split by frequency. The low frequency changes are passed to the pitch control, and the high frequency changes are overlaid on the torque control signal to each turbine. The use of the turbine torque controller means that a certain amount of inertial storage is utilized by this high frequency power-variation suppression control. This is an interesting use of the pitch controller as the point of coordination leaving the torque controller largely to its default task of maximising the output power.

The final paper to review for turbine coordination\[57\] is one that does not concentrate on smoothing the wind power output but introducing a new type of controller to the mix. The authors here utilise an optimising controller to coordinate the turbines. The cost function centres on minimising the difference between the power output of the farm and the requested power output (here it is assumed this is a command from the grid operator) with a secondary objective of minimising the losses within the farm collector network. The paper shows that this system works effectively, automatically setting the power outputs of turbines nearer the point of grid connection to a higher value than those further away meaning that, when there is excess wind energy, the power losses in the farm are reduced. The use of an optimising controller is very interesting within the field of wind farm control, as, if one can be realised that effectively suppresses variation, this would be, by definition, the ideal controller. However the secondary objective of minimising power losses within the farm is not especially important. No attempt was made to investigate the effects of wind variation on the controller as only fixed value winds and steps were used.

### 1.5 Wind Power Smoothing

In addition to the smoothing techniques already covered, there are a number of research papers of note that focus on the task of reducing power variation in wind farms. These generally come in two categories, systems that require discrete storage and those that do not.
1.5.1 Smoothing With Discrete Storage

With the lack of utility scale storage available to smooth out the variations in wind power output the next logical step would be to put a storage system in every wind farm, or every turbine. Both routes have been suggested in the literature. Wind farm storage is generally applied to another piece of ancillary equipment often used with wind farms, like a STATCOM\textsuperscript{12}[58, 59]. Wind turbine storage often puts the storage device into the DC-bus\textsuperscript{[60, 61]} of the wind turbine generator. This technique obviously presupposes type C or D generators are used.

STATCOMs are often placed in wind farms, especially those with DFIG or fixed-speed turbines, to provide voltage support in case of a fault. This can mean that a wind farm is able to stay connected and provide reactive power during faults which is often a requirement of grid connection under modern grid codes\textsuperscript{[54]}. As this equipment is already in place in many cases, and only utilised for part of the time, it has been suggested that connecting a storage device to the DC-bus of the STATCOM allows it to be used to help smooth the wind farm output power variations by producing and consuming real power as and when needed. The work in\textsuperscript{[58, 59]} both suggest such a system. The authors provide simulations showing that with sufficient storage the STATCOM can provide a good smoothing effect. This approach, however, requires extra equipment to be added to the farm, namely the batteries and perhaps also the STATCOM itself. The power deviation that can be corrected is limited by the rating of the STATCOM. A large farm can produce very large deviations, above the rating of a STATCOM suited to reactive power support. This is especially true if the farm consists of type C or D turbines where the STATCOM would be lower rated as they can produce reactive power at the turbine as well. Another limitation is the energy storage. This limits how long it can provide support during these power deviations.

The work of\textsuperscript{[60]} (\textsuperscript{[61]} works in a very similar manner) achieves its smoothing effect by placing small storage devices such as super-capacitors or batteries within the turbines themselves and connecting them to the DC bus of the turbine. When aggregated across the whole farm, these produce results like those of larger storage systems but obviously don’t require such a large single device to achieve the effect. The storage can, however, be limited in its effectiveness in type C turbines as the smoothing power has to be passed through the power converter, which is rated at approximately a third of the total turbine rating.

\textsuperscript{12}STATCOMs are power electronic devices comprising of a single inverter connected to a DC bus capacitor. They are able to provide positive and negative reactive power. They are used for many purposes in distribution networks including voltage control.
1.5.2 Smoothing Without Discrete Storage

Keeping closely to the established control architecture, the research in [62] replaces the standard lookup tables mapping rotor speed to output torque in order to achieve a smoothing effect. Typically, the look-up between rotor speed and power output is designed to follow the peaks of the $C_p$ curves of a wind turbine meaning that maximum power is extracted at all times. This research suggests that by changing the target torque, a smoothing effect may be achievable at the expense of maximum energy production. A number of different look-up tables were simulated. The simulations show that it is possible to have near perfect smoothing by having a flat curve $^{13}$ but this leads to instability and/or large amounts of underproduction. A compromise between the single power curve and a maximum power curve can be found that produces an appreciable amount of smoothing for a reasonable amount of energy loss.

The work in [63] keeps the wind farm equipment as standard and instead uses the already available blade pitch actuators to smooth the power output. Each turbine is fitted with a generalised predictive controller (GPC) for the pitch to allow them to deal with the rapidly changing wind inputs without this showing on the power outputs. In order to deal with larger average wind speed changes which may cause the GPC to go unstable, a fuzzy logic compensator is added to track these.

Another complete redesign of the control structure is found in [64] with the aim to treat the wind turbine as a power filtering device. The rotor electrical torque is logically split into two time frames. The slow changing torque is defined by the commanded reference power and the fast changing torque commanded of the generator is used to filter out disturbances from various sources. The net result is a smoothed power output.

1.6 Work to be Presented

Wind farm power output varies as the cube of wind speed. Wind speed changes significantly in two distinct time periods as show in the Van der Hoven [65] spectrum (figure 1.11). The slow change from hour to hour, day to day and week to week is beyond the capabilities of wind farm controllers to smooth out without additional large scale storage. The shorter time period of seconds to minutes, however, is well within the capabilities of wind turbine and wind farm controllers to smooth. A number of problems arise with this variation in the seconds to minutes time frame:

$^{13}$This means same power produced for all rotor speeds
issues that affect the operation of the grid such as frequency and voltage changes, wind farm owners have difficulty bidding directly to the market due to risks, and the balance of supply and demand is affected.

![Horizontal wind Speed Spectrum showing two distinct peaks, one in the hundreds of hours time-scale and one in the minutes time-scale - Van der Hoven][65]

This thesis aims to combine the areas of wind turbine co-ordination, turbine inertial energy storage and short term wind speed prediction to aid in the smoothing of wind farm power output. Chapter 2 identifies the questions to be covered in the thesis and the methods to be used to answer them. Chapter 3 describes the models used. Chapter 4 explains the control system developed within this research. Chapter 5 shows the results, comparing them against the success metrics introduced in Chapter 2. Chapter 6 provides the authors conclusions and suggestions for further work.
Chapter 2

Research Problem Formulation

This thesis aims to identify how to combine the methods of inertial energy storage, wind farm co-
ordination and short term wind speed prediction to smooth wind farm output power in the seconds
to minutes time frame. The research challenge is to design a co-ordinated controller and test it
against performance metrics which highlight its ability, or lack thereof, to mitigate some of the
problems that wind variability causes. In doing this, an assessment of the controller’s contribution
to overall power system performance can be made.

This chapter summarises the information regarding system problems presented in Chapter 1
with respect to how a controller might alleviate these. It covers the metrics by which performance
can be assessed and the core techniques to be utilised by the controllers.

2.1 Problem Statement

In order to design a control system for wind turbines, one must first set out the problems the
controller aims to solve. The way in which each problem can be aided by the proposed controller
is then addressed.

2.1.1 Affects on Grid Operation

With wind penetration at around 10% of total energy production in the UK grid, the variations
of wind power lie in the ‘noise’ of the grid caused by changes in load and can easily be dealt with
using standard mechanisms such as frequency control plant. As that penetration figure increases
up to 20% and beyond, large unpredictable variations in wind power output can have a significant
effect on operation of the grid. The effect can be exacerbated by times of high wind power and
low load, such as a stormy night. This would mean that for these periods wind contributes a very large portion of the total supply and can have extra effect on grid operation.

2.1.1.1 Primary Frequency Response

Large scale, short term disturbances in the load/supply balance cause the extra power to be drawn from, or supplied to, the inertia of the rotating generators on the grid. This in turn causes them to speed up or slow down, affecting the frequency of the electricity produced. As already covered in section 1.2.2.1, the changes present in today’s system are small enough to be dealt with by the balancing system as is, but at large wind penetrations the power drop of a wind farm experiencing a wind lull, or power rise given an increase in wind speed, could cause frequency drifts that are significant enough to reach the limits imposed by the grid operators. In order to counter this, more generators would be required to sit idle, or at part load, to compensate for the effects of these variations. As wind penetrations rise this becomes more difficult to achieve due to the cost of providing these extra generators, and the practical problems inherent in having large amounts of plant sitting unused most of the time.

Being able to remove short term power drops, and limit the ramp rate of larger power drops will mean that it is still possible to use the current frequency response system to deal with wind power, even at much higher penetrations.

2.1.2 Bidding to the Market

Wind farm operators and owners may have difficulty participating in the electricity market on their own (that is, not part of a portfolio of generators) due to uncontrollable output variation. It is possible to predict average farm power over the next few hours with some confidence using simple prediction techniques such as persistence prediction. However, within this period the power output can vary greatly from minute to minute. This window of a few hours is enough to participate in some electricity markets as they are currently operated. The GB market, for example, requires proposed energy schedules for half hour periods an hour ahead. During the market production period, the output power of a wind farm (or any other producer) is measured, and the total energy is calculated. If this is not equal to that which was scheduled an hour earlier, then the producer will need to pay over or under-production penalties known as out of balance charges. The high chance of penalties is a major factor in whether wind farms participate individually in the market.
These out of balance charges are used to fund the balancing mechanism. It is reasonable to say that as wind (and other variable generation) penetration rises, causing more short term problems for the balancing mechanism, the system of charges will need be revised to continue to cover the actual costs of balancing. A number of different methods could be used to ensure that the extra costs imposed by variable generation on the balancing market, are met by those generators themselves. It would be advantageous to be able to smooth output power to avoid these extra costs.

As it stands wind farm owners are able to get around this risk of penalties by bidding to the network as part of a portfolio of generators whose characteristics complement those of the wind farm. These portfolio generators are effectively tasked to generate the power that the wind farm cannot in order to make up a smooth power for the whole group. This is akin to a small scale version of the balancing network.

Standard wind turbine control methods allow wind farms to be commanded to produce a fixed power output below their available maximum which could mitigate the risk associated with wind farm market bidding at the expense of energy production. It would be an advantage to develop a system that reduces the chance of market penalties whilst producing a high percentage of the available energy.

2.1.3 Balancing the Grid

Should wind continue to increase its contribution to the total power production on the grid, the problems with uncontrolled variation of output power will become more significant to the balancing of the grid. In normal grid operation, supply and demand must always be balanced because there is no cost-effective means to store significant amounts of energy to cover over/underproduction. A separate balancing system is used to instruct generators that are paid extra to run part loaded so they can increase or decrease their generated power to maintain this balance.

It has been shown on the Irish grid[23] that increased wind penetration can lead to increased stress on the generators used in the balancing services in that a greater number of stop/starts and ramp up and down events occur. These extra operations caused by the variable wind mean that the balancing generators are used in a less efficient state and cause a greater amount of wear. This in turn means they cost more to operate in terms of maintenance and fuel costs. This can mean that there is a limit to wind penetration in grid systems as there is a limit to the maximum
amount of balancing that is affordable. There will be a cost point at which it is more efficient to try and smooth the wind output than attempt to increase the balancing mechanism’s capabilities.

This problem is also present when the wind producers bid to the market as part of a portfolio of generators except that the balancing task is performed by other generators in the portfolio before the variation is passed onto the grid. This incurs the same, or similar, costs within the portfolio so it is still desirable to reduce or remove the variability.

In both the portfolio of generators and individual wind farm cases, a reduced amount of wind power variation allows a greater amount of wind to be integrated into electricity networks without incurring the extra costs of increased volume of balancing service or increased duty on that service.

2.2 Methods to Smooth Wind Power

In order to smooth out the wind farm output power, a new arrangement of controllers, in both the turbines themselves and the farm as a whole, are proposed. A number of new concepts are proposed in this research to achieve the smoothing effect. The system in this thesis has three aspects which are combined to enable smoothing of wind farm output power.

The first aspect of the controllers is not a new idea but one present in a large amount of the literature either explicitly or implicitly. As modern wind turbines are variable speed, each wind turbine has available to it a small, but not insignificant, amount of energy storage in the form of rotor kinetic energy. This thesis aims to use this to smooth the power output. The way in which the turbine controllers utilise the kinetic energy is novel and explained fully in sections 4.1.3 and 4.1.4.

The next core principle of the control system is a novel method of wind prediction utilising recent data from upstream turbines to predict local wind speed. This is covered more fully in section 4.1.1.

Finally, as the main aim of the research is to smooth the power at the farm level, the control should also act at the farm level. Individually the turbines acting to smooth their own outputs using kinetic energy storage is useful, but is not a complete solution. A farm co-ordinator is able to have knowledge of the state of all of the turbines, meaning it can act to smooth the output at the farm terminals, but can also use this overall knowledge to command turbines to compensate for each other’s variations. For example if a turbine in one part of the farm has a large amount of energy stored, and high winds, it can produce extra to allow other turbines to increase their local
storage. This means the farm as a whole has a greater level of energy stored. The full workings of the farm co-ordinator are detailed in section 4.2.

2.2.1 Inertial Energy Storage

Any power smoothing effect is achieved by either spilling excess energy or placing it in some form of energy storage. It was desired for this research to add no extra equipment to a farm to achieve smoother output. To reduce the amount of energy that is spilled, it is required to find a place to store energy, even if it is only for a short period of time. The inertia of the rotor is a good place to store excess energy as it is directly connected to the mechanical systems of the turbine and the large rotating mass of the blades and hub allows for a reasonable amount of energy to be stored.

Equation 2.1, taken from[66], allows a calculation of the moment of inertia for a 3 blade turbine. Using the values for a typical modern 2.3MW turbine with hub mass of 40 tonnes and a 70 metre blade diameter\(^1\) provides an estimate of typical moment of inertia. Equation 2.2 allows us to calculate the rotating kinetic energy at 3 rad/s as 24.5MJ.

\[
I = \frac{1}{9}mr^2 \tag{2.1}
\]

\[
E = \frac{1}{2}I\omega^2 \tag{2.2}
\]

This means that up to 10 seconds of full output (2.3MW) can be produced with no input with presently available turbines. This rotational speed is higher than the quoted rated rotational speed for the E70 turbine. It is believed that the \(C_p\) curve used in this thesis results in higher rotational speeds as the appropriate curve for the E70 turbine is proprietary and unavailable. However, a wind turbine with 10s of full output inertial energy is not an impractical system. Of course, limits must be placed on the amount of energy drained from, or stored in, the rotor kinetic energy to prevent turbine stalling, or over-speeding, but there should still be enough energy available to perform the short term smoothing operations required.

\(^1\)Data is taken for the Enercon E70 turbine[38]
2.2.2 Wind Speed Prediction using a Transport Delay Model

The first new idea in this research is to use the wind speed data from turbines upstream to predict future wind at turbines downstream. Any changes in wind take time to travel across the farm. A gust experienced by a turbine at the front of the farm will be detected by a turbine downstream as much the same wind speed profile, but at a later time. This is a significant simplification of the real world as it does not take into account turbulence or other effects that could cause changes in a wind speed profile (land features for example). However, as a starting point for predictions its should provide a useful, reasonably accurate indication of expected wind speed for downwind turbines.

As wind turbines are placed hundreds of metres apart to avoid the worst of the turbulence of one turbine affecting another downstream, it can take sixty seconds or more for a gust to travel from one row to the next (assuming 600m separation and 10m/s wind for example). This is a significant prediction period which can be used to alter the control of the downstream turbine to make the most of the change in wind. This 60 seconds of data could easily be augmented using simple persistence predictions or extra devices, such as LIDAR systems[67], which are able to detect the wind speed at a distance.

![Diagram of wind speed prediction](image)

Figure 2.1: Example of delay based wind prediction across a wind farm for use in wind power smoothing

Figure 2.1 shows an example of this wind speed prediction in action. The aim is to smooth
the power output of turbines on the right-hand side (red turbine) using wind information from those which are upstream (blue turbine on the left-hand side of the diagram). The blue turbine is controlled using a maximum power tracking controller, its power output follows the rise and fall of wind speed. It is clear that with mid range (between cut-in and rated) wind speeds, a small change in wind speed leads to a large change in power output. However, if the upstream turbines communicate their measured wind speeds to those downstream, this additional information allows for anticipatory action to be taken.

The wind speed variation shown in figure 2.2 is used as an example. The downwind (red) turbine controller, tasked with producing smoothed wind power, knows that after the rise in wind speed it will drop below its former value. This means that, to produce smooth power, it should not track the rise in power, but continue to produce a steady power throughout. This scenario is shown in figure 2.2. The rotor speed plots show that the power smoothing turbine allows a greater variation in rotor speed to enable energy storage. The difference between the smoothed and unsmoothed rotor speed plots show that when the red turbine is producing less output power than the blue, its rotor speed is increasing with respect to the unsmoothed rotor speed, and vice-versa. The stored and released energy is shown in the shaded area.

2.2.3 Farm Level Co-ordination

The objective of this research is to enable the output power of a whole farm to be smoothed, therefore it is most effective to manage the power at the farm level rather than the individual turbine level. Inherently some communications between turbines are going to be required in order to achieve the prediction across the farm. It is therefore not much of an extra hardware issue to add in a farm level co-ordinator. The availability of farm-level wind speed and power output information is becoming more widespread as most modern wind farms include this facility.

The farm co-ordinator is tasked with arranging the outputs of the turbines such that the overall target for the whole farm is achieved. With each turbine attempting to produce a smooth flat output the farm output can be smooth and flat also. Even if the turbines have excess energy available to them the farm as a whole should not over generate as this could cause penalties in a market situation, or it could mean that in a short time the farm will have to drop its power back down if the wind falls, this is unwanted variation. The overall target can be set either as a market bid, or as a very low frequency filtering of the available power so that it tracks long term wind
Figure 2.2: Example of using transport-delay prediction across a wind farm to smooth wind power output. In plots (b) and (c), the blue and red traces refer to the blue and red turbines in figure 2.1 changes but not gusts.

A farm level co-ordinator would enable management of spatial effects like gusts passing across the farm. Initially each turbine is able to perform smoothing on the gusts but there will be cases when the turbine inertia is too small to achieve a completely smooth output. In this case the farm co-ordinator could instruct another turbine in a different part of the farm to compensate. This means that in practice a combination of inertial storage and ‘potential to generate’ storage is used.
to create a smoothing effect.

2.3 Methods to Assess Success

In order to assess the proposed smoothing controllers, a series of measures and methods must be devised that will allow comparison of results. The measures need to have a real meaning in terms of the problems to be addressed, introduced in section 2.1.

2.3.1 Direct Measurement of Power Variation

The most obvious system to measure the effectiveness of a system designed to reduce power output variation, is to directly calculate the variation using a standard method.

2.3.1.1 Standard statistical measures

The standard statistical measures of spread such as range, interquartile range and standard deviation would seem to be the natural starting point for a measure of output power variation. Unfortunately, these calculations, whilst easy to perform, do not provide results that are particularly relevant to the electricity grid. Statistical measures do not attach importance to the order in which the samples occur in time, this means that sharp variations between successive samples which can cause the frequency and voltage effects described in Section 2.1 are ignored as shown in figure 2.3. The standard deviation can give an overall measure of how much variation is present in the power signal that might be of use in assessing likelihood of penalties for the market case but otherwise the standard statistical measures will not be used.

2.3.1.2 Average Absolute Differential

The average absolute differential (or AAD) calculation expressed in equation 2.3 was devised in this research as a way to assess variation whilst taking into account the sample to sample changes which are important for frequency and voltage variation. The measure is the sum of the absolute change in power from sample to sample. This is then divided by the sum of the powers to provide a power independent measure.
$$AAD = \frac{\sum_{i=1}^{n} |(P_i - P_{i+1})|}{\sum_{i=1}^{n} P_i}$$  \hspace{1cm} (2.3)$$

AAD shows a significant improvement over standard deviation as shown in figure 2.3 in that it can differentiate between a simple step and a series of transitions.

The AAD measurement provides a single value method of assessing the variation of a power signal that remains relevant to frequency drift and flicker, however it is too simplistic to be used as the only measure.

### 2.3.2 Measurement of Effects on the Grid

For some of the effects addressed in this research, the best way to measure the effectiveness of smoothing is to model the effects of non smooth power on the electricity network and directly measure the problems that arise. This should also work well for frequency changes and flicker.

#### 2.3.2.1 Measurement of Effects on a Portfolio

The effect of a wind farm on the balance of a network can most effectively be measured using a similar methodology to flicker and frequency drift above. A simple system which is representative
of the main grid (or a smaller portfolio) is simulated and the action of the balancing generators is observed. For this research a small portfolio of 3 generators with a range of response speeds and a single wind farm are combined as one portfolio bidding to the market. This portfolio must generate a predetermined amount of power. The wind farm generation is the input, and the reaction of the other generators is the output. The amount of ramping required of the other generators is the measure used to assess effectiveness of a smoothing method. Additionally the amount of uncompensated variation passed onto the grid for outside balancing is a useful measure.

2.3.2.2 Frequency Variation

The grid-model method of assessing frequency changes models an example grid of generators and loads, complete with regulators and governors. The wind power is applied as a disturbance and the frequency changes are measured directly.
Chapter 3

Modelling

In this chapter, the models to be used in this thesis will be described in detail. This includes the models of the wind, wind turbines, wind farm and those controllers that are established features of wind turbines.

3.1 Wind Modelling

The main input to any wind farm model is that of the wind itself. Wind in any region is caused by complex interactions between different layers of the atmosphere and energy from the sun. Wind speeds are severely affected by any objects that may be in the path of flow, including changes in land height. This all means that it is very difficult to completely and accurately model the wind through any wind farm. Two different methods have been used in this thesis in an effort to reduce the complexity of this problem. The most obvious solution is to acquire measured wind data, however, the interest here is in wind gusts occurring at a rate well above the sampling rate used in most publicly available wind data. Hence, a method of infilling data with reasonable, statistically generated wind speeds has been developed to make use of realistic data. Measured wind data is very useful to test whether a wind farm system can deal with real world conditions. However, during development and early testing it is more informative to use a synthetic wind source. For this purpose, a controllable wind source is also described here.

Most commonly when modelling wind farms, an aggregated turbine model is used to represent all of the turbines in the farm and so only the single wind input is needed. This technique is not suitable for investigations into co-ordination and smoothing so an array of wind turbine models was used. Each individual wind turbine needs a unique wind input which is representative of that
experienced in a real situation. As with the generation of the wind speed data itself, the modelling of the traversal of wind across the farm and any correlations between winds experienced at different turbines requires an extremely complicated fluid dynamic analysis. Therefore, an alternative is required to provide the inputs for each turbine from the original source data. A wind delay model is proposed that is a great simplification of the real world but is approximately representative.

3.1.1 Wind Source Modelling

There are two separate wind source models used within this thesis. One source uses measured data and because of its low sample rate is up-sampled using some recorded statistical properties of the wind. The second wind source is a fully configurable synthetic wind model which is very useful for testing specific wind speed cases in a controlled manner.

3.1.1.1 Up-sampling Measured Wind

The real wind data comes from a full year of minute-sample rate data kindly supplied by the National Renewable Energy Centre (NAREC). It was measured at hub height in a real wind farm. The available data are the average, $\bar{V}$, maximum, $V_{\text{max}}$, minimum, $V_{\text{min}}$, and standard deviation, $V_{\text{sd}}$, of the wind speed for each minute. The low sampling rate (although higher than most data of its type) renders the data unsuitable for the time horizons of interest here. However, the extra information in the max, min and S.D. allows some statistical methods to be used to synthesise representative data between the real data points.

Between the data points that were recorded, the wind would not have been a constant speed and there would most likely have been a series of variations, or gusts, throughout this period. With just this data available, it is impossible to know for sure what actually happened, but, using statistical methods, it is possible to synthesise a representative set of wind data between the measured points. It is proposed to form the missing data from series of gusts. The wind speed of the gusts is assumed to be normally distributed around the mean wind speed, and with the standard deviation recorded. The gusts are to be uniformly distributed in time. The aim of the wind up-sampling technique is to generate a series of normally distributed random wind speeds to represent the gusts. The number of gusts is calculated such that the probability of a gust having a wind speed at or above the maximum wind speed is $P_d$. This $P_d$ is a control variable that allows the system to be tuned to give realistic results, for example, if $P_d$ is set to 1, then an infinite
number of gusts would be required to guarantee that one is at or above the maximum. In the studies that follow a $P_d$ of 0.3 was chosen for best results.

We begin by noting that the probability, $P(1)$, of a single gust exceeding the recorded $V_{max}$ is fully determined by the recorded average wind speed, $\overline{V}$, and standard deviation, $V_{sd}$, as expressed by equation (3.1). The task is to find the number of gusts, $N_{gusts}$, such that the probability, $P(N_{gusts})$, of any one of them exceeding $V_{max}$ is equal to the specified parameter, $P_d$. If the probability, $P(1)$, of a single gust having wind speed above or equal to the maximum recorded speed is low, 0.1 for example, and the desired probability, $P_d$, is 0.3, then a large number of gusts, $N$, would be required before the probability of any given gust in a sample period having this maximum speed is achieved.

The first step is to calculate $P(1)$ using equation (3.1). This assumes that the wind gusts are distributed with a normal distribution which is a fair assumption given the standard deviation data is provided.

$$P(1) = \frac{1}{\sqrt{2\pi V_{sd}^2}} e^{-\frac{(V_{max}-\overline{V})^2}{2V_{sd}^2}}$$  \hspace{1cm} (3.1)

Given $P(1)$ it is a simple extension to calculate the probability that $N_{gusts}$ gusts include one greater than or equal to the maximum. The probability that a series of $N_{gusts}$ gusts includes one with wind speed equal to or greater than the maximum is $P(N_{gusts})$. For example, a series of two gusts containing exactly one at a speed above or equal to the maximum must be one of the following cases: the first gust had this maximum speed (probability $P(1)$), or the first gust did not have this speed ($1 - P(1)$) and the second gust did ($P(1)$). This leads to a probability of $(1 - P(1))P(1) + P(1)$. Similar logic follows for larger values of $N_{gusts}$ to give the final calculation in equation (3.2).

$$P(2) = (1 - P(1))P(1) + P(1)$$

$$P(3) = (1 - P(1))^2P(1) + P(2)$$

$$\cdots$$

$$P(N_{gusts}) = \sum_{k=0}^{N_{gusts}} (1 - P(1))^k P(1) = (1 - (1 - P(1))^{N_{gusts}+1})$$  \hspace{1cm} (3.2)
Setting \( P(N_{\text{gusts}}) = P_d \) and rearranging the equation to give \( N_{\text{gusts}} \) as the subject, allows the calculation of the number of gusts required to achieve the target likelihood of any gust being at or above the maximum wind speed. Clearly the calculated value will not always be a whole number, so it is rounded for use in later calculations.

\[
P_d = (1 - (1 - P(1))^{N_{\text{gusts}}+1})
\]

\[
N_{\text{gusts}} = \frac{\ln(1 - P_d)}{\ln(1 - P(1))} - 1 \quad (3.3)
\]

A wind speed for each of the \( N_{\text{gusts}} \) gusts is generated using a random number generator with a Normal distribution. The sample time for each gust is generated using a random number generator with a Uniform distribution. The other data-points are linear interpolations between these randomly generated gusts to produce a full minute of high sample rate data.

Figure 3.1 shows example of this process. The real data are shown in red, with lines for max, min and average. The synthesised data are shown in blue. The synthesised dataset has a higher data rate than the real data and remains within the max and min bounds and tracks the average. Figure 3.2 shows the same real wind data, but the synthesised data are based upon a higher \( P_d \). This shows the ability to ‘tune’ the gustiness of the synthesised wind data set.

An example step-by-step run of the statistical data synthesis algorithm is shown in appendix B.

### 3.1.1.2 Synthetic Wind Model

To complement the measured wind data model with its single point of control (\( P_d \)), it is required to have a configurable synthetic wind input for some tests. This enables the testing of the system’s performance under certain controlled conditions and allows easier interpretation of the results. The simulated wind model is based upon Simulink wind turbine blocks provided by Risø National Lab[68]. For this research, only the wind source block is used. This block consists of a random number generator, some filters to make this stream of random numbers representative of wind experienced by a wind turbine and another set of filters to simulate the tower shadowing effect. As the wind is generated separately to the turbine simulations (this is requirement of the wind delay model, explained later in section 3.1.2), the tower shadowing block, which requires the turbine
rotational speed to calculate the shadowing, must be simulated with the turbines and not with the rest of the wind source. The tower shadowing block is separated from the rest of the block. The remaining parts are left as provided by Risø.

The control inputs provided by Risø for specifying the wind are the average speed and turbulence intensity percentage. The desired wind output profile is produced by simulating the wind source block and varying the control inputs. Figures 3.3 and 3.4 show example outputs of the source model with a range of wind speeds and turbulence intensities.

3.1.2 Wind Transport Modelling

Having produced the wind speed profile using one of the aforementioned methods, the next process is to generate separate profiles for each turbine based on their location within the farm and the direction and speed of the wind. For this study, the wind direction is chosen before the simulation start and is held constant for the duration of the simulation. For a given wind direction, the turbine that is first to experience a wind front must be identified. This turbine is treated as experiencing the wind source with zero delay. The distance from this turbine to each of the other turbines along the direction of the wind is used to calculate the time it will take a wind front to reach them. A
Figure 3.2: Statistical wind filling example using $P_d = 0.7$, showing the effect of modifying the $P_d$ value

simple transport delay is assumed. To simulate the wind from different directions, the whole farm is rotated around its centre before the delay distances are calculated. This assumes that the wind ‘front’ is straight and at least as wide as the farm.

Figure 3.5 shows the wind source and farm arrangement with the wind coming in at an angle $\alpha$ to the farm. The first process is to rotate the whole wind farm about its centre $(x_c, y_c)$ to simplify the delay calculations. This operation is performed once per simulation, as the wind is assumed not to change direction during a simulation period.

$$
\begin{pmatrix}
    x_i^* \\
    y_i^*
\end{pmatrix}
\begin{pmatrix}
    \cos \alpha & -\sin \alpha \\
    \sin \alpha & \cos \alpha
\end{pmatrix}
\begin{pmatrix}
    x_i - x_c \\
    y_i - y_c
\end{pmatrix}
+ 
\begin{pmatrix}
    x_c \\
    y_c
\end{pmatrix}
= (3.4)
$$

Equation 3.4 allows calculation of the new co-ordinates for the turbines, $(x_i^*, y_i^*)$, rotated an angle $\alpha$ around the centre point, $(x_c, y_c)$, from their original position $(x_i, y_i)$. This leads to the wind source and farm arrangement shown in figure 3.6.

After rotation the first turbine to experience a wind front is that with the smallest $x^*$ co-ordinate. The distance in the direction of the wind from the first turbine to each other turbine is simply the difference in $x^*$ co-ordinate between the turbines, $\delta_x$. This distance is used to calculate
the time delay between each turbine’s wind input and the wind source, $\delta_t(i)$, shown in equation 3.5. This produces a time shifted wind profile for each turbine, as show in figure 3.7. $V_{avg}$ in equation (3.5) is a fixed value for the entire test. This simple transport delay model, based on the average wind speed, may not be realistic. However this simplification allows a reasonable model of the wind without having to model complex interactions between gusts as they travel across the farm or resorting to computational fluid dynamics. These issues are acknowledged as significant but beyond the scope of this thesis.

$$x_{min} = \text{minimum}(x_i)$$

$$\delta_x(i) = x_i - x_{min}$$

$$\delta_t(i) = \delta_x(i)/V_{avg}$$

$$V_i(t) = V_{source}(t + \delta_t) \quad (3.5)$$

Figure 3.7 shows the output of the spatial model which is a delayed wind profile for each turbine. The dashed vertical lines identify one point in the wind profile in order to illustrate the
delay from one turbine wind input to the next.

3.1.3 Turbine Wake

For the purposes of this research it is assumed that the wake created by each turbine is completely dispersed before the wind reaches the next turbine. Therefore, no shadowing or wake effect is applied for turbines downstream. It is normal to choose the spacing of the turbines in a wind farm to ensure this is true under most situations.

3.2 Wind Turbine Modelling

The wind turbine model is made up of a set of subsystems. These include the aerodynamic interactions between the turbine blades and the incoming wind, the mechanical power transfer equipment and gearbox (if present), the electrical generator system and any electrical equipment required to connect to the grid. The following sections describe how each subsystem is modelled in this thesis. Figure 3.8 shows the basic layout of the wind turbine subsystems.
Figure 3.5: The initial arrangement of farm and wind source for the wind transport model showing the wind coming in at an angle, $\alpha$, from the farm

3.2.1 Aerodynamic Subsystem

The aerodynamic subsystem includes all of the wind turbine parts that interact with the wind. This most obviously includes the blades themselves with their blade pitch mechanisms but also the rotation of the turbine nacelle to face the wind and the tower shadowing effects.

3.2.1.1 Blade Disk Model

The model representing the blades of the turbine produces a power output, $P_w$, based on the wind speed input, $V$, the blade angle of attack, $\beta$, and the rotor speed, $\omega$. The power is calculated using the equation introduced in section 1.3.1 and repeated below.

$$P_w = \frac{1}{2} \rho A V^3 C_p(\lambda, \beta)$$  \hspace{1cm} (3.6)

$$\lambda = \frac{\omega R}{V}$$  \hspace{1cm} (3.7)

The $C_p$ curve (figure 3.9) is non-linear and dependent on many things including blade shape,
temperature and air pressure but an approximation was published by Heier[69] which was later improved upon by Ackermann[9] using curve fitting algorithms to make it better match to modern turbine data sheets. The approximation equation is as follows:

\[ C_p = c_1 \left( \frac{c_2}{\lambda_i} - c_3\beta - c_4\beta^{c_5} - c_6 \right) e^{-c_7/\lambda_i} \]  
(3.8)

\[ \lambda_i = \left[ \left( \frac{1}{\lambda + c_8\beta} \right) - \left( \frac{c_9}{\beta^3 + 1} \right) \right]^{-1} \]  
(3.9)

The constants are defined in table 3.2.1.1. A family of \( C_p \) curves can be obtained for different values of \( \beta \). These curves are shown in figure 3.9

<table>
<thead>
<tr>
<th>( c_1 )</th>
<th>( c_2 )</th>
<th>( c_3 )</th>
<th>( c_4 )</th>
<th>( c_5 )</th>
<th>( c_6 )</th>
<th>( c_7 )</th>
<th>( c_8 )</th>
<th>( c_9 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.73</td>
<td>116</td>
<td>0.4</td>
<td>0.002</td>
<td>5</td>
<td>21</td>
<td>1.5</td>
<td>0.08</td>
<td>0.035</td>
</tr>
</tbody>
</table>

Table 3.1: \( C_p \) Curve Constants
3.2.1.2 Tower Shadowing

The turbine tower creates a disturbance in the upstream wind flow reducing the effectiveness of the blades as they pass through it. As the blades pass in front of the tower the total power output of the turbine is reduced. This power ripple shows at three times the rotor speed for a three bladed turbine. The wind model from the Risø Wind Turbine Blockset for Simulink has the ability to model the tower shadowing effect but only if the wind source and turbine are simulated together. This is not possible with a single wind source and a transport delay for each turbine. So, some modifications were made to separate the shadowing block from the main wind source. This shadowing block is modelled with the turbine model and provides the same performance as the original.
3.2.1.3 Nacelle Rotation

For this study it is always assumed that the nacelle is always rotated to face the wind.
3.2.2 Mechanical Subsystem

3.2.2.1 Shaft Model

The mechanical subsystem of the wind turbine is responsible for transferring power from the aerodynamic subsystem to the electrical subsystem. This typically consists of an arrangement of shafts and gearboxes. For the Enercon turbine example used in this study no gearbox is necessary as the generators are designed for low speed operation. Modelling the shafts of the system as being flexible would allow the effects of shaft dynamics on the electrical systems to be observed. However, these are short term transients and are not relevant on the time-scales of this study.

Instead the shaft model consists of only a single inertia to represent the blades, hub and generator. The equation relating rotational speed, $\omega$, to electrical torque, $T_e$, and aerodynamic torque, $T_w$, is therefore expressed by the rotational moment of inertia equation 3.10.

\[
\dot{\omega} = \frac{1}{I_{rotor}} (T_w - T_e)
\]  

(3.10)

$I_{rotor}$ is calculated using the equations from[66] (reproduced here, equation 3.11) and data from the Enercon E70 data-sheets[38] as representative of a 2.3MW wind turbine.

\[
I_{rotor} = \frac{1}{9} mr^2 = 5.4 \times 10^6 kgm^2
\]

(3.11)

3.2.3 Electrical Subsystem

The dynamics of electrical subsystems, such as the generator and inverter, are typically much faster than those of the wind gusts considered in this study. As such the electrical systems can be modelled as a unity gain; the desired electrical torque determined by the controllers is supplied immediately.

3.3 Comparison to the Enercon E70

For the turbine model to be a realistic representation of modern turbines used in wind farms some of the constants, such as a rotor diameter and electrical maximum power, were taken from the data-sheet of an existing wind turbine. The Enercon E70[38] is a 2.3MW turbine with a type D generator and a gearbox-less drive-train. Table 3.3 shows the data used.
### Table 3.2: E70 data used for model

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated Output Power</td>
<td>2.3MW</td>
</tr>
<tr>
<td>Rated Wind Speed</td>
<td>13 m/s</td>
</tr>
<tr>
<td>Rotor Diameter</td>
<td>71m</td>
</tr>
<tr>
<td>Hub Mass</td>
<td>38.8 Tonnes</td>
</tr>
<tr>
<td>Blade Pitch Control</td>
<td>0 - 35 Degrees</td>
</tr>
</tbody>
</table>

Despite the availability of several characteristics of the E70, a full $C_p$ curve is not available and one had to be approximated using the equations in Ackermann[9]. This approximate $C_p$ curve allows the turbine model to be scaled to match the E70 but it is highly unlikely to match it in dynamic performance. This is most noticeable in the rotor speed which does not match the E70 data well. The turbine model used in this research can be considered generic and typical of real life but not an exact model of an E70.

### 3.4 Wind Turbine Control

The turbine model used in this research has two points of control. These are the blade pitch and the generator reaction torque, $T_e$. The basic layout of the control scheme presented here is shown in figure 3.8. The benchmark control system used for comparison to the co-ordinated controller is described below.

#### 3.4.1 Pitch Control

A pitch controller is required to regulate the shaft speed. At low wind speeds the shaft speed will be held low by the generator reaction torque and the pitch controller will saturate at minimum pitch. It only becomes active under high wind speeds. A simple proportional controller was found to be sufficient. The control signal is multiplied by $-1$ as increasing the blade pitch acts to reduce the rotor speed. The pitch controller for the benchmark control scheme is shown in figure 3.10. Its task is to control the rotor speed at its rated value by varying the torque applied to the shaft by the blades when the electrical torque is saturated at its maximum. This is done by a proportional controller to reduce the error between current rotor speed and $\omega_{\text{rated}}$. This controller incorporates saturation such that the blade pitch does not reduce below zero, as this is the limit in real turbines. When the rotor speed is below $\omega_{\text{rated}}$ the pitch control will saturate at its lower limit of zero. This is
the case when the wind speed is below $V_{\text{rated}}$ and the wind power is below the electrical maximum power and the torque controller dominates the shaft speed control. On the other hand, higher wind speeds will provide more power than the electrical systems can export, and the rotor speed will rise above $\omega_{\text{rated}}$. The pitch control will rise above its lower saturation limit and dominate the shaft speed control.

![Figure 3.10: Standard blade pitch controller](image)

3.4.2 Torque Control

3.4.2.1 Maximum Power Point Tracking

Many modern variable speed wind turbines track the maximum power point by means of a rotor speed to torque relationship. Equation (3.12), found in the literature[42] relates turbine rotor speed to optimum electrical torque. Such a controller is to be used in the power maximisation region where the aerodynamic power available is less than the rated electrical power. The torque control is not saturated in this region and the pitch control is at its lower limit, so the torque control dominates.

$$T_e = K \omega^2$$

$$K = \frac{1}{2} \rho \pi R^3 \frac{C_{p\text{max}} \lambda_{\text{opt}}}{\lambda_{\text{opt}}^3} \quad (3.12)$$

The torque curves for a set of winds speeds and zero blade pitch are shown in figure 3.11 below as dashed lines. The dashed pink line on the diagram is the maximum power line, which is set by the limits of the inverter output. The solid red line shows equation (3.12) limited at the maximum power.

The system can work despite not having knowledge of the current wind speed. To explain its function one must consider an example. If the wind speed is $V_a$ and has been for some time, the system will rotating at $\omega_a$ (marked with a dotted vertical line), at which point $T_e$ (marked with a red line) is equal to $T_w$ (the dashed line marked $V_a$) and the rotor speed will not be changing. This
Figure 3.11: The equation of optimum torque up to the maximum electrical power (shown in red). Also shown is an example trajectory from an initial operating point, A, to a higher torque operating point, B, via mid-point B’ (and trajectory to C via C’).

is system operating point A on figure 3.11. If the wind speed increases to $V_b$ then the aerodynamic torque from the blades rises above the electrical torque from the generator. This is point $B'$. As $T_e < T_w$ this is not a stable point and the rotor speed will increase until the system is at an operating point at the intersection of the red line and the dashed line marked $V_b$. This is point $B$. A similar series of events occurs if the wind speed drops to $V_c$. The system will initially move to operating point $C'$ then decelerate to operating point $C$. 
3.5 Wind Farm Modelling

With the wind input model and turbine models complete, the next step is to develop a wind farm model. To test the effect of the arrangement of the wind farm upon the smoothness of the power output, a number of different turbine layouts were compared. The farm model takes into account the spatial arrangement of the turbines. This means that wind delays can be generated for the wind inputs for each turbine ($\delta_t(i)$). The output of the farm is then considered as simply the sum of the individual turbine outputs. Power losses in the collector network are not considered significant to this study and are not modelled.

3.5.1 Turbine Arrangements

Two sizes of farm were considered, one of 9 turbines in a 3x3 arrangement and one of 81 turbines in a 9x9 arrangement. In each case the turbines are spaced at approximately seven rotor diameters (560m) in all directions. As an alternative to the 9x9 farm model, an 81-turbine model can be formed by summing 9 different simulation runs of the small farm. This is an arrangement of 9x3x3 turbines. The wind in each simulation run is uncorrelated but has the same average speed and turbulence level. This means that the 9x3x3 farm simulates the smoothing effect of having a number of distantly placed small farms rather than a single larger one.

To demonstrate the smoothing effects of these farm arrangements (before considering the effects of any coordination), each farm is simulated with the benchmark torque controller from section 3.4.2.1 under the same wind regime. The wind direction for these benchmarks is 0 degrees, head on into the rows of turbines.

Wind was set at an average of 10m/s with a turbulence intensity of 3% rising to 15% (as shown previously in figure 3.3). The output of the 3x3 was multiplied by 9 for ease of comparison to the larger farms.

The power outputs for the three farm arrangements are shown in figure 3.12. The 9x9 farm shows a reduced level of power output variation when compared with the smaller 3x3 farm. The pattern continues onto the 9x3x3 farm which shows an even greater improvement in smoothness. Here, as the wind is uncorrelated between each small farm. Any gust which affects a single group of 3x3 turbines within the farm as it crosses the turbines is clearly not present in the other 8 farms. This means that any variation one of the wind inputs has a less significant effect on the total output. The main point of interest to show here is that larger, more distributed farms show
a reduction in power output variability without any extra control systems. It is important that any smoothing control system shows improvements for a range of farm layouts, even where some inherent smoothing is present.

![Comparison of power outputs for 3 farm arrangements with the same wind input](image)

Figure 3.12: Comparison of the power outputs for the 3 farm arrangements with the same wind input

### 3.5.2 Wind Front Directions

In addition to the smoothing effect of farm size, there is an effect on output power smoothness related to the angle of the wind front with respect to the farm. This is because as the angle of the wind changes, the number of turbines affected at the same time changes, as does the delay between turbines. As described in the wind delay model section, the model has provision for allowing the farm to be rotated to simulate the effects of the wind coming from different directions. Using the delay model it is clear that different rotations of the farm will cause different delays between the wind inputs to the turbines. These delays can at times correspond to delays between gusts in the wind input which means that wind turbines will receive peaks or troughs in wind speeds at the same time, causing their power outputs to be correlated, and much less smooth. The opposite effect is also possible. The following work is all performed with the 3x3 farm arrangement.

The plot of power AAD (see section 2.3.1.2 for description) for the farm under the wind regime
in figure 3.3, across a range of angles is shown in figure 3.13. It shows that there is a significant reduction in total variation for certain wind angles. This is because the distances between the turbines at these angles correlate with the gusting frequency of the wind in such a way that turbines experiencing high winds are balanced by others receiving low winds.

![Figure 3.13: Plot of AAD of the farm power output for angles Between 0 and 45 Degrees](image)

Figure 3.13: Plot of AAD of the farm power output for angles Between 0 and 45 Degrees

Figure 3.14 shows the power outputs for three rotations of the farm: 0, 35 and 45 degrees. One of the most smooth outputs for this wind input is found when the wind is at 16 degrees to the farm rows. The 45 degree plot, however, shows a less significant improvement. Both of the angled simulations show reduction in variation over the benchmark 0 degree simulation as there are less turbines experiencing the wind at once. If the wind is at 0 degrees to the farm rows the turbines experience the wind in groups of three, whereas, if the wind is at an angle the turbines can each experience the wind singly or in pairs. The optimum angle is in this case at 35 degrees but this not only relies on the turbine arrangement but the frequency components of the wind speed itself. If the wind gusts happen to occur at the same intervals as the delays across the farm then the power variation will be significant.

It can be seen from figure 3.13 that most rotations can provide an appreciable smoothing effect. This effect is obviously only available as a ‘bonus’ smoothing effect and cannot be relied upon in
Figure 3.14: Comparison of the power outputs for the 3 farm rotations with the same wind input real life. For the rest of this study, no rotation will be applied as this ensures that at least the rows of turbines receive correlated wind, which is likely to be the worst case in most situations.

3.6 Grid Modelling

The model for testing the effects of the wind farm output smoothness on the other generators on an example grid was developed by Mike Hughes and adapted for use within Imperial College by Mark Collins. The model comprises 3 main generators, each 2000MVA, to represent large areas of generation. The generators are connected by 500kV transmission lines. Connected to these transmission lines are two load centres, each 2000MW. This represents a medium loaded grid case. At one of the nodes on the grid, a wind farm is modelled, rated at 81 turbines of 2.3MVA. This will serve as the input for the wind power and represents approximately 5% wind penetration by load. The layout of the generators, line models, loads and wind farm is shown in figure 3.15.

The 3 incumbent generators are modelled as synchronous machines with steam turbines. The governors are simplified models and no boiler dynamics or steam pressure delays are modelled.

The wind farm is modelled as an inverter. The full control system including current and power control loops is modelled.
Figure 3.15: Layout of the example grid model

The output of interest to this thesis is the frequency at which the system runs. This is because disturbances in the frequency are one of the main indicators of imbalance.

### 3.7 Portfolio Sources

For tests relating to farms as part of a portfolio of sources, it is important to model the reactions of other generators to the output of the wind farm. For this study the dynamics of the other sources are modelled simply with ramp-up/-down rates and a maximum power output. The portfolio is a scale model of a realistic scenario. The envisaged scenario is that of 500MW of wind combined with 1000MW of coal, a 500MW CCGT and a 200MW OCGT, these are scaled down to match the 9 turbine case, this makes them 20MW, 50MW, 20MW and 10MW respectively. In order to represent a higher wind penetration in the portfolio the conventional generators can be scaled down with respect to the wind power.

Typical ramp rates for various generator types have been found in the literature and three generators have been selected to form the portfolio with the wind farm. The slow generator for
the portfolio is designed to represent an older thermal generator which has a large power output (compared to the wind farm at 9 turbines of 2.3MW), 50MW, and a very slow ramp rate of 1%/minute (0.5MW/min)[70]. The next generator is the medium speed unit, it is modelled as a combined cycle gas turbine generator and provides 20MW of power and a ramp rate of 10%/minute (2MW/min)[70]. The final generator is another 10MW gas turbine, but this time arranged as an open cycle turbine which is capable of much higher ramp rates of 20%/minute (2MW/min)[70], this is designated the fast generator.

The wind farms in this thesis are assumed to be targeted to do the best they can at all times, whether that is in terms of maximum power or maximum smoothness. This means they do not react to the power outputs of the other sources in the portfolio. This absence of feedback between the portfolio and wind farm means that the portfolio’s reaction can be calculated as a post-processing task.

The portfolio model requires a number of inputs: a target power output for the whole portfolio, a predicted power output for the wind to initialise the generators and the power output from the farm simulation. The target is larger than the maximum power output of the farm which means that the target is never exceeded by the wind farm alone. The expected wind output is predicted using a persistence model as used in real wind farms. In this case it is based upon the initial wind input which is in the middle of the wind speed range for all simulations. The predicted wind power output comes with a confidence level which is set high for simulations with little change and low for simulations with high change. This confidence level is used to set the initial output for each of the generator groups. For example, if the prediction is thought to be very accurate then most of the difference between the target power and predicted wind power can be output by the slow generators without much risk of these being unable to react to the changes in wind output power. However, if the confidence level is low, it is best to produce as much of the difference between the target and prediction with the faster generators as they will be able to react to changes in the wind farm output power should they occur.

With these inputs, the portfolio model first assigns a initial power output to the portfolio generators to make up the majority of the difference between the predicted wind output and the target output, the proportion of the difference assigned to the slow generators is determined by the wind prediction confidence level. The initial powers for the medium and slow generators are set to half of the remaining difference each. Equation 3.13 shows how the three initial outputs
\[ P_{gens}(0) = P_{port} - P_{wind} \]
\[ P_S(0) = P_{gens}(0)C_L \]
\[ P_M(0) = P_F(0) = \frac{P_{gens}(0)(1 - C_L)}{2} \] (3.13)

With the initial inputs set, the portfolio model executes the pseudo-code in Appendix C for each farm power output sample. This sets the power outputs for each generator within its max/min and ramp rate limits. If the limits (either on ramp rate or maximum/minimum power) cause the portfolio to be unable to generate the exact amount of power difference between the farm output power and the portfolio target in any given step then the remaining difference (or excess generator) is passed onto the grid. This remainder would in a real system be required to be balanced by outside plant.

The results of a run of the portfolio model are shown in figure 3.16 with ramp rates and power limits used shown in table 3.7.

<table>
<thead>
<tr>
<th>Name</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Farm Model</td>
<td>3x3</td>
<td>N/A</td>
</tr>
<tr>
<td>Wind Regime</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Speed 10 Throughout</td>
<td></td>
<td>m/s</td>
</tr>
<tr>
<td>Max Farm Power</td>
<td>20.7</td>
<td>MW</td>
</tr>
<tr>
<td>Target Power</td>
<td>21</td>
<td>MW</td>
</tr>
<tr>
<td>Predicted Wind Power</td>
<td>10</td>
<td>MW</td>
</tr>
<tr>
<td>Wind Prediction Confidence</td>
<td>0.8</td>
<td>N/A</td>
</tr>
<tr>
<td>Slow Generator - Ramp Rate</td>
<td>1</td>
<td>%/min</td>
</tr>
<tr>
<td>Medium Generator - Ramp Rate</td>
<td>10</td>
<td>%/min</td>
</tr>
<tr>
<td>Fast Generator - Ramp Rate</td>
<td>20</td>
<td>%/min</td>
</tr>
<tr>
<td>Slow Generator - Power Limit</td>
<td>50</td>
<td>MW</td>
</tr>
<tr>
<td>Medium Generator - Power Limit</td>
<td>20</td>
<td>MW</td>
</tr>
<tr>
<td>Fast Generator - Power Limit</td>
<td>10</td>
<td>MW</td>
</tr>
</tbody>
</table>

Table 3.3: Table of values used for the portfolio model

As can be seen in figure 3.16 the slow generator (in brown) takes up the base load and does not change as much as the other generators during the simulation. Very little of the varying output of the wind farm is within the capabilities of the medium generator to compensate, so the orange segment changes only a small amount during the simulation. The red segment, for the
fast generator, changes a lot during the latter part of the simulation, especially around the 5000s mark, showing that these generators do the majority of the balancing. The blue segment shows the power provided by the wind farm. The sum of all of the parts should ideally be a flat line that matches the power bid to the market for the whole portfolio.

The portfolio here is not able to completely smooth out the variations of the wind farm, and some outside balancing is required from the grid through the standard balancing network. This is shown in the lower plot. Of importance here is not only the magnitude of the outside balancing required (in terms of power) but also the frequency of the spikes, and total balancing energy required. Less effective portfolios do not only output larger spikes on average, but more of them.
Chapter 4

Co-ordinated Controller

The control system presented in this thesis comprises of two distinct parts. One part of the controller lies in the turbines themselves, the other is a farm level co-ordinator. Figure 4.1 shows the basic layout of the co-ordinated control system for the farm. In order to smooth the wind power output as much as possible the system works by setting fixed power outputs for each turbine for a period of time. Clearly a single fixed power output cannot be held for extended periods of time. Experience with the simulation model showed that a period of 120s was reasonable and was adopted for the work to be described here. A 120s period can facilitate smoothing in the gustiest conditions used here. All of the systems within the control scheme function periodically at 120s, referred to as the prediction period.

Co-ordination across the farm is achieved via the torque controllers with the pitch controllers acting independently on each turbine. The torque controllers act upon commands received from the farm co-ordinator. The turbine pitch controller retains its normal duty of speed limiting.

Figure 4.1: Layout of the proposed farm control scheme for N turbines
Figure 4.2: Layout of the proposed turbine co-ordination, control and modelling blocks

At the farm level, the co-ordinator is tasked with meeting a predetermined target power output for the whole farm. The turbines propose power schedules based upon predicted wind inputs for the next 120s. The farm co-ordinator then returns power commands for each turbine for the next prediction period based upon matching those schedules to the farm target. The whole process of turbine prediction and farm co-ordination repeats every 120s.

4.1 Turbine Level Systems

The layout of the turbine systems is shown in Figure 4.2. The turbine level systems have two tasks. The first is to propose power schedules for the next production period using the energy input calculated from the wind speed data provided by turbines upstream. The second task is to ensure the turbine does not stall or overspeed at any time when producing the commanded profiles.

To prepare the power schedules, the turbine system first calculates the total energy input for the next prediction period using predicted wind speed data from upwind turbines. Then a power schedule is constructed to utilise this total energy. This is passed to the farm co-ordinator.

When producing the commanded power schedule, the turbine must maintain its rotor speed between fixed limits at all times. An under-speed controller is provided that limits the output (generator) torque and an over-speed controller is provided that limits the input (turbine) torque.
4.1.1 Wind Prediction Method

Each turbine is provided with knowledge of the farm layout and its position within it. Given that the wind direction is known, it is a simple matter to calculate which turbines are upwind, and by how far as described in section 3.1.2. This task could be completed by the farm co-ordinator which can then pass wind speed information from turbines upwind to those downwind, along with the amount of delay to apply. This way turbines downwind can have wind predictions that are reasonably accurate for short periods of time, in the order of a few minutes.

This study examines a simplified case in which the wind direction does not change during a simulation. There is therefore no need to recalculate the delays during a simulation run. The wind predictions that each turbine requires can be approximated by delaying the wind input to the turbine by 120s. This predicted wind can be have noise added to represent prediction inaccuracies and turbulence effects. The full wind prediction, transport delay, and wind input distribution system layout is shown in figure 4.3.

![Wind Source Model](Wind Source Model)

Legend
- Source Model
- Transport Delay Model
- Prediction Model

![Figure 4.3: Distribution of wind inputs and wind predictions to each turbine.](Figure 4.3: Distribution of wind inputs and wind predictions to each turbine.)

In a real situation, 120s of prediction might not be achievable via the wind transport delay method at all times due to short delay times caused by high wind speeds for example. This level of prediction would also be unavailable to the turbines furthest upwind. These problems could be overcome by using a LIDAR system [67] which is capable of detecting wind speeds as far as 100m away with present technology. Alternatively, if it was not possible to predict a full 120s of data using LIDAR or transport delay methods, persistence prediction methods could be used to complement the wind delay method to fill in any missing prediction data with minimal loss of accuracy.
Figure 4.4 shows two wind speed plots: predicted wind speed in blue (shifted down by 1m/s for clarity) and real wind input in red. As can be seen, the predicted wind input leads the real wind by 120s and shows no distortion.

![Figure 4.4: Function of the wind speed prediction block, predicted wind in red and source wind in blue](image)

It is unrealistic to expect wind predictions to be completely accurate. Therefore to show the systems resilience to prediction inaccuracy and in-farm turbulence, noise must added to the either the wind signal or the prediction signal so that they are different. In this study the noise was added to the prediction signal. The noise is generated by a normally distributed random number generator. Noise signals with a range of standard deviations and zero mean were generated to add to the wind predictions. Figure 4.5 shows the predicted wind (in white in the middle) with ever increasing amounts of noise added (shown in progressively darker colours). The noise signals used in this study are as large as ±30%. The effects this noise has on the other blocks within the turbine will be highlighted.
4.1.2 Energy Prediction

The next step for the turbine predictor is to calculate how the predicted wind profile for the next 120s translates to energy input over that period. To calculate the energy input from a wind speed time-series a corresponding power time-series is created, then integrated across the prediction period to give the total energy input.

The power time-series can be created either through simulations of the turbine or from the static power versus wind speed characteristic. The simulation technique will lead to a more accurate power prediction as it would take into account the rotor speed through the time period (which has a significant effect on the power output from a given wind speed). However, it is very computationally demanding to perform a simulation within the turbines without sacrificing a significant amount of accuracy through use of large time-steps or approximations. So for this study the static analysis was used. The power for any given wind speed was calculated using equation (1.6) and a fixed $C_p$ of 0.5 (the peak $C_p$ value for the E70 turbine) subject to the maximum electrical output power (in this case 2.3MW). The power time series was then integrated across the prediction period to give the total energy input.
Figure 4.6 shows a run through for a 120s prediction period. The first plot shows the wind speed input, the second plot shows the power production for optimum $C_p$. The third plot is the cumulative energy production (integration of the power production). At $t = 120$s, the end of the prediction period, the accumulated energy value (marked with a dashed red line) is passed onto the next part of the calculation as $E_{wind}$.

The energy input from the wind in a prediction period is only part of the energy available to the turbine. There is also the energy stored within the turbine inertia. The total inertial energy is calculated using equation (2.2) with a deduction made for the amount of inertial energy that should be retained to allow proper operation in the next period. Two values for inertial energy are calculated, one for the maximum rotor speed allowable (maximum storage, minimum power out) and one for the minimum rotor speed (maximum power out, minimum storage). The maximum storage case will often lead to a negative energy, showing that energy needs to be fed into the storage to reach this state. This inertial energy is then summed with the wind input energy to calculate the two energies available for the next 120s period, $E_{high}$ and $E_{low}$ as shown in equation (4.2).
\[ E_{\text{min}} = \frac{1}{2} I \omega_{\text{min}}^2 \]  \hspace{1cm} (4.1)

\[ E_{\text{max}} = \frac{1}{2} I \omega_{\text{max}}^2 \]

\[ E_{\text{now}} = \frac{1}{2} I \omega^2 \]

\[ E_{\text{high}} = E_{\text{wind}} + E_{\text{now}} - E_{\text{min}} \]

\[ E_{\text{low}} = E_{\text{wind}} + E_{\text{now}} - E_{\text{max}} \]  \hspace{1cm} (4.2)

Figure 4.7 shows 3 prediction periods worth of energy data using the predicted wind speeds from 4.4. The higher energy values passed to the power profile construction block are highlighted with dashed lines.

![Figure 4.7: High and low energy predictions calculated from predicted wind](image)

As the energy is calculated by integrating the power output over a whole 120 second prediction period it should be resilient to the zero mean prediction noise. Even though the wind speed noise is zero mean, the non-linear relationship between power and wind causes this to have a net positive
effect on the energy and power calculations. However, this effect is small. Figure 4.8 shows the higher energy profile for the predicted winds shown in figure 4.5. Even at the very high noise levels the energy shows only a small amount of variation, much less than 5% for the 30% wind speed prediction variation.

![Figure 4.8: Variation of energy predictions with wind speed prediction noise](image)

These tests show that the energy calculation systems work well with respect to rejecting high levels of noise in the predicted wind and thus with high levels of prediction inaccuracy.

### 4.1.3 Power Schedule Construction

With knowledge of the energy available for the next prediction period, the proposed power schedules can be constructed.

If the inertial energy storage is assumed to be ideal and sufficiently large, then during a prediction period, the calculated energy can be exported at any rate desired. The turbine power schedule construction is performed based upon this assumption. The obvious solution is to export the energy at a fixed rate for each prediction period. However, this causes problems at the transitions. Therefore in this study the turbine predictor creates a simple schedule consisting of a ramped
section, with fixed ramp-rate, and a constant power section. This is shown in figure 4.9. This schedule shape also allows a maximum farm ramp limit to be set as is common practice in other modern wind farm controllers (described in section 1.4.1). Of course, the inertial energy storage is not ideal and large changes in wind speed can lead to energy excess or insufficient storage, these cases are dealt with by separate controllers outlined in sections 4.1.5.1 and 4.1.5.2.

![Figure 4.9: An example power schedule, showing ramped and static sections. Also highlighted are important features: the fixed ramp-rate, g, the start and finish powers, P1 and P2, and the rise time, tr](image)

Constructing a power schedule that exports all of the available input energy given the fixed ramp-rate, g, and the final power from the previous period, P1, requires finding the roots of equation (4.7) for the final power of the proposed profile, P2. There are two possible values of the gradient: the positive or negative fixed ramp rate limit. The gradient to be used is determined before the roots are found as this simplifies the process of choosing the correct root. If \( P_1 > P_2 \) then the negative rate limit is used and vice versa.
\[ t_r = \frac{P_2 - P_1}{g} \]  
\[ E_{ramp} = \frac{(P_2 - P_1)^2}{2g} \]  
\[ E_{in} = P_2 T - E_{ramp} \]  
\[ E_{in} = P_2 T - \frac{(P_2 - P_1)^2}{2g} \]  
\[ 0 = \left( \frac{-1}{2g} \right) P_2^2 + \left( T + \frac{P_1}{g} \right) P_2 + \left( \frac{-P_1^2}{2g} - E \right) \]  

Of the two roots that solve the equation, one will lead to a negative value of \( t_r \), which is clearly false, so the other root is used. In the case of no real roots, it is not possible for the power to plateau during the prediction period. The power will have to continue ramping up or down for the entire period. The resultant power schedule is a prediction of the most the turbine can produce for each period, given the predicted input wind energy and desired retained storage.

The full calculation of power schedule is performed for both the high and low predicted energy inputs. These two schedules are used by the farm co-ordinator to produce commands for each turbine as explained later in section 4.2.

As the energy values are noise resilient, it is to be expected that the power profiles are equally noise resilient. This is shown clearly in figure 4.10. The power profiles show less than 5% variation for the highest noise level.

Figure 4.11 shows the change in energy calculation (blue) and power profile (red) between the high (30%) noise and no noise wind predictions for a whole 3000 second test. As you can see, even with the 30% variation in prediction, the energy calculation and power profile do not stray further than 5% from the no noise values.

The full turbine predictor system has been tested and is verified. It is accurate to the design and works well in the presence of noise. For the remainder of the tests presented in this study, no prediction noise is added, as it is clear that it has minimal effect.

### 4.1.4 Inertial Storage

Treating the energy input as a single value which can be output gradually across a 120 second period means that, during that time, the instantaneous power input and output are likely to be
Figure 4.10: Variation of power profiles over 3 prediction periods when wind speed prediction noise is added mismatched.

In order to maintain the steady output power in case of varying input power any excess energy, or energy shortfall, must be dealt with. It is assumed that no external storage is to be added to the turbines or the farm. This means the only available energy storage medium is the inertial energy of the turbine rotor disc. This is accessed by accelerating the rotor to store energy and decelerating the rotor to retrieve it as explained in section 2.2.1.

The amount of energy stored within the rotor disc inertia is constrained by the upper and lower rotor speed limits. The upper limit is a design limit, to prevent excessive wear and the possibility of the turbine rotor suffering mechanical damage. The lower limit is set to prevent the turbine from stalling as low rotor speeds lead to low tip speed ratios, which produce less power and in turn a lower speed and ultimately increasing the likelihood of a stall. The upper and lower speed limits are implemented through the over-speed pitch controller (OC) and the under-speed torque controller (UC).
4.1.5 Turbine Speed Controllers

The torque command from the farm co-ordinator is feed-forward term, shown as $T_e'$ on figure 4.2. In order for the turbine to remain within the rotor speed limits, a pair of controllers are required. The two controllers limit the rotor speed at the upper and lower speed limits, but take no action if the rotor speed is between them. The upper rotor speed limit is controlled using the blade pitch as with most turbine control schemes. If the turbine spins too fast, the blades are pitched so as to reduce the incoming power, thus limiting the rotor speed. This has no direct effect on the output power. The torque controller, under normal conditions, simply passes on the instructions from the farm coordinator to the generator system. However, when the rotor speed is low the torque controller acts to prevent the turbine stalling by reducing the commanded electrical torque.
4.1.5.1 Over-speed Controller

The Over-speed Controller (OC) is realised as a proportional controller as in other turbine control schemes. This arrangement is shown in figure 4.12. It is similar to that used in standard wind turbine systems (shown in figure 3.10) but here the maximum speed $\omega_{max}$ is set not at $\omega_{rated}$ but 10% higher as the extra speed is useful for storing inertial energy without putting much extra stress on the system.

![Figure 4.12: Over-speed pitch controller](image)

4.1.5.2 Under-speed Controller

The Under-speed Controller (UC) is the main cause of reduced smoothness when operating the farm. This means its design is critical to the success of the whole farm controller.

The controller reduces the electrical torque applied by the generator systems so that the system does not stall. The risk of stalling is found when the turbine starts to move to the left of the $C_p$ curve (figure 3.9), and the efficiency of the turbine is reduced. This is based upon $\lambda$ rather than just the rotor speed, however if the control is based upon $\lambda$ then the changing wind speed has direct effect on the power output, which is not desired.

The UC is a PI controller acting to correct the error in rotor speed, by applying a correction term to the electrical torque signal, as shown in figure 4.13. If the reference rotor speed ($\omega_{min}$) is fixed, then it cannot be correct for all wind speeds as the resultant $\lambda$ is the critical term when considering stalling. So a modification is applied to it. At or above 10m/s wind speed the reference rotor speed is a fixed at 2.1rad/s. As the wind speed falls the reference rotor speed is reduced in proportion, until it limits at 1.3rad/s. The reference rotor speed is not directly related to the wind speed for the aforementioned reason, but if its not reduced the system performance is poor at low wind speed.
4.2 Farm Co-ordinator

The farm co-ordinator is tasked with keeping the farm power output as close as possible to an overall target. To do this, it commands the turbines to produce at or below their proposed maximum power schedules. This farm level co-ordination allows the farm to function as a whole, smoothing the total power output and meeting the requests of the farm operator.

4.2.1 Target Setting

There are two schemes for setting the target value for the whole farm: an arbitrary value, or a value that tracks the low frequency changes in wind speed.

The arbitrary value can be fixed or time varying and is set by the farm operators. This can, if set below the available power, lead to the smoothest power output. It can also allow the farm to work as a frequency response unit or simply reduce the requirements for balancing plant at the expense of lost production.

Tracking the low frequency changes in wind speed allows the co-ordinated farm system to provide a smooth power output that approaches the maximum available. There is a balance to be found between the amount of energy produced and the smoothness with which it can be output. The target tracking filter is realised as a low pass filter with the cut-off set with a period greater than the prediction period, for these simulations it is set to 2 prediction periods. The output of this filter is sampled and held every prediction period.

The output of the tracking filter is shown in figure 4.14. This is compared to the output of the wind farm with maximum power controllers. It shows that the target tracks the available power, albeit with significant lag, whilst removing the high frequency components.
4.2.2 Prediction Safety Factor

If the target is not met consistently the output of the farm will not be smooth. It is beneficial to smoothing that the choice of target is conservative when using a fixed target. However, when tracking the wind, the farm control system must ensure the target is achievable, especially when the wind is very changeable. To this end, the target is reduced from the filtered predicted wind power by a scaling factor called the Prediction Safety Factor (PSF).

The PSF allows the system to deal with very variable wind conditions which might cause prediction errors or rapid power variations that cannot be managed with the inertial storage. It also helps to counter the inaccuracies arising from the use of the static wind speed to power relationship to predict energy. The controller can modify the PSF for each prediction period based on previous outcomes. When the wind speed is constant the PSF should approach 1. This is because when the wind is smooth, the rotor speed will have settled to give optimal $C_p$ (or the system will be in constant power mode) which means that the power predictions should be accurate. However during variable wind conditions the PSF should be lowered to ensure as much of the variation as possible can be dealt with with in the inertial energy storage and the power output can remain smooth.

The main indicator that the system is commanding a power that cannot be produced without
draining the inertial storage is the action of the UCs. If the UCs are required to act then clearly the available energy has been over-estimated and could not be delivered. This indicates that the system should be more conservative in the future. The PSF is therefore adjusted based on the actions of the UCs. The total energy not delivered because of the intervention of the UCs of the turbines over the last 120s is calculated. If this energy is above a certain value then, at the next prediction period, the PSF is stepped down by 0.1, this ensures the overproduction should be cleared within the next 120s. If in the next 120s the UC still removes too much energy then the PSF will step down again, this continues until the UC either stops drawing energy or the PSF reaches 0.01. The PSF rises when there has two entire prediction periods without the UCs acting. The PSF only steps up by 0.05 to avoid constant changing between two values.

Figure 4.15 shows the actions of the PSF algorithm over a 3000s simulation. It shows that once the UC energy (second plot) crosses the dashed red line, the PSF is reduced before the next prediction period which effectively settles the variations. At the beginning it can also be seen that the PSF rises from its initial value of 0.9 as the UC doesn’t need act at all in this time.

Figure 4.15: Action of the PSF algorithm for a number of prediction periods
4.2.3 Power Schedule Allocation

The farm co-ordinator has the task of allocating individual power production targets to each turbine in order to realise the overall target for the farm. Individual targets can be any power level that is lower than the maximum power proposed by the turbine. During this step, the ramped section is not taken into account as it simplifies the decision making process and is not something the farm co-ordinator can change.

The co-ordinator receives the predicted maximum and minimum power schedules from each turbine, calculates the sum and compares it to the overall farm target.

If the maximum proposed power for all of the turbines is still not sufficient to meet the farm target, there is nothing further to be done. The co-ordinator instructs the turbines to produce their maximum schedules and waits for the next prediction period.

If the target lies between the maximum and minimum the sum of the turbines can produce, then the co-ordinator commands some of the turbines to produce their minimum power to bring down the total, one turbine will also be commanded to produce a power between its maximum and minimum to complete the overall target. The turbines are ordered to produce their minimum in ascending order of proposed power. This allows the turbines with the least available power to deliver less and store as much energy as possible. All of the excess energy is stored within the farm in this case.

If the target is below the sum of the minimum proposed powers then all the turbines are commanded to produce their minimum less the amount required to bring the farm down to its target production. This means that some of the excess energy is spilled as all of the turbines have stored as much as they can.

4.2.4 Farm Co-ordinator Example

The best way to explain the function of the farm co-ordinator is with an example. An example farm of two turbines is considered. The two proposed schedules for each turbine (red and blue) are shown in figure 4.16. It can be seen that the blue turbine is predicting lower power outputs than the red turbine, largely because the power output in the previous prediction period \((P_1)\) was lower.

Given these two predictions the farm can now compare them to its predefined target. The sum of the high profiles is shown in brown, and the sum of the low profiles is shown in teal in the left
side of figure 4.17. The farm co-ordinator does not take into account the ramping sections. Three hypothetical targets are shown, with dashed lines, to highlight the three possible cases the farm co-ordinator can experience.

Figure 4.17: Function of the farm co-ordinator allocating targets for the 2 turbines based on 3 possible farm targets
The dark blue target is higher than the brown farm prediction, meaning that it is unobtainable. The farm co-ordinator commands the two turbines to produce their maximum schedules. At the end of the prediction period, both turbines will be at minimum stored inertial energy.

The black target is between the two farm predictions. This means that the turbines are taken in ascending power order (blue then red) and commanded to reduce their output. The net result is that the blue turbine produces its lower profile, and the red turbine produces between its two profiles. All of the excess energy should be stored, the blue turbine’s inertial storage should be full, and the red turbine’s storage around half full by the end of the period.

Finally the green target is below the two farm predictions. This means that both turbines are commanded to produce their minimum power less the difference between the lower farm prediction and target shared between the turbines. Both turbines then produce a profile an equal amount below their lower prediction. As much energy is stored as possible within the farm, but both turbines will need to spill some excess using their OC.

### 4.2.5 Farm Co-ordinator Modes

With each block having been tested in isolation, it is now possible to test the function of the wind farm co-ordination system as a whole. The system can work in 3 modes. In addition to the main smoothing mode using the tracking target, the two other modes in which the co-ordinated system can run are using a fixed target and maximum power mode. The following sections detail some initial tests of the controller in these modes.

#### 4.2.5.1 Smoothing Mode

The system works as intended in smoothing mode and it is able to reduce the wind output power variation. Figure 4.18 shows the output for a full run of 3000 seconds. It is clear that the wind power output can be smoothed with a co-ordinated controller (red plot) with respect to the maximum power controller (blue plot). The energy effectiveness is the percentage of the maximum power controller output by the co-ordinated controller, it shows the amount of energy that had to be sacrificed to achieve a smoother output, in this case 10%. The AAD effectiveness is the AAD of the co-ordinated controller divided by that of the maximum power controller. Low numbers show a much reduced AAD, in this case the AAD has been reduced to 8% of the value for the maximum power controller.
The plot of rotor speed for this simulation is shown in figure 4.19. The rotor speed for one turbine with the co-ordinated controller (red plot) is higher than that of the maximum power controller (blue plot) throughout and varies more. This extra variation shows the storage and retrieval of energy in the rotor speed. The higher rotor speed shows that the co-ordinated controller is acting at a rotor speed that is above optimum for the majority of the time, this means that power output will be lower, but there is extra stored energy to smooth the power.

4.2.5.2 Fixed Target Mode

The fixed target mode allows the system to produce any power below the maximum available. This mode can allow the farm to contribute to the balancing system as an ancillary service. Figure 4.20 shows that the co-ordinated controller is able to output a fixed target power if required. This target can be altered at any prediction interval. If the target is too high the system falls back to a normal smoothing method, this is shown around the 2000s mark, If the target is higher than the available power for an extended period of time the system will fall back onto under-speed control.
Figure 4.19: Rotor speed plots for the smoothing mode performance test. The rotor speed for 1 turbine in each farm (maximum power in blue and co-ordinated controlled in red) is plotted

4.2.5.3 Maximum Power Mode

Maximum power mode is an extension of the fixed target mode. If the target is set to a level higher than the maximum power capability of the farm then the turbines will be forced to fall back on the under-speed controllers as any excess energy stored in the rotor inertial will soon be drained. In this situation the co-ordinated control method exports the majority of the power available. This is shown in figure 4.21. The controller is still active, with ramp limits and profile construction. This means that at times the power output does not track exactly the maximum power, but the vast majority of the available energy is exported, 94% in the example simulation. As this significantly increases the AAD, it is not likely to be a useful mode in real systems.

The design of the co-ordinated controller has been presented in this section and its performance tested, from block level up to system level. Chapter 5 continues the testing of the controller under different wind scenarios and assess its impact on the grid and other generators.
Figure 4.20: System performance - Fixed target mode
Figure 4.21: System performance - Maximum power mode

<table>
<thead>
<tr>
<th>Energy Effectiveness</th>
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Chapter 5

System Performance Testing

This chapter presents the performance test results for the wind farm co-ordinated control system introduced in Chapter 4. A series of tests were carried out to assess the performance of the system as a whole and compare it to the reference control technique, the non-linear torque controller of section 3.4.2.1, in terms of power production and smoothness. The system was then tested to ascertain its performance with respect to the metrics laid out in Chapter 2. All of the tests were performed in smoothing mode.

5.1 Tests Under Simulated Wind Conditions

For the initial system tests, it was required to be able to control the wind speed and turbulence so that the performance of the system could be tested under specified conditions. All of the tests simulated 2 hours. The initial wind speed for all of the tests was 10m/s and low turbulence intensity (3%). The turbine rotational speed was initialised as stable and at the optimal for 10m/s wind speed. All system states (targets, etc.) were initialised based upon the assumption that this wind would continue throughout the 2 hour test. This meant that the initial target was approximately 11MW for a 9 turbine farm.

5.1.1 Medium Wind

The first system tests keep the wind speed at the 10m/s initial speed and just vary the turbulence. The medium wind speed, low turbulence system test is to act as the benchmark for the rest of the system tests as they are the conditions the system was designed to perform best in. Figure 5.1 shows the output of the co-ordinated controller in red and the maximum power controller in
blue. The co-ordinated controller clearly produces a smoother wind power output whilst remaining within 15% of the maximum power controller (marked with a dotted red line in the third plot) for the majority of the time. The co-ordinated controller only requires to the sacrifice of 10% of the total energy to reduce the AAD by almost 90% under this wind regime.

![Graph showing system performance with co-ordinated control](image)

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Figure 5.1: System performance - Medium wind, low turbulence

Increasing the turbulence of the wind speed input will increase the power output variation of the turbines with maximum power controllers. The results of the simulation run with the same medium wind but with higher turbulence intensity (rising to 15%) at the end of the run are shown in figure 5.2. This shows that even though the variation of the co-ordinated control turbines increases, largely due to the actions of the under-speed controllers, they are still significantly less variable than the maximum power controllers. It is clear that at times, around 5500 seconds for example, the system has had to sacrifice total power output in order to achieve lower variation. This is through the action of the PSF control system. The PSF is designed to react slowly so as to avoid sacrificing too much energy. This slow reaction is what leads to the high levels of under-speed action around the 6500 second mark.
5.1.2 High Wind

To test the system response during changes in the wind speed the next two system test’s wind profiles increase the speed of the wind from 10m/s to 17m/s during the latter part of the test. This will move the turbines into the electrical saturation region and thus their output should not vary at all at this time.

The results of the high-speed, low-turbulence test are shown in figure 5.3. The efficiency of the co-ordinated control system drops soon after the wind rises as the wind target tracking system lags behind the maximum power. Other than the target lag, the co-ordinated system performs in a very similar manner to the maximum power controller.

Increasing the turbulence of the wind in the latter part of the test should have little to no effect as the systems are already saturated. Figure 5.4 shows that this is indeed the case, with the maximum power controllers only leaving their saturated state for a brief period. The co-ordinated control system does not exhibit this, which means that this system will be less stressful for any
5.1.3 Low Wind

As it is a state in which the turbines will spend a lot of their time, the low wind case is of more interest than the high wind. It is also an area where smoothness can be improved, unlike the saturated high wind state. Both low turbulence (figure 5.5) and high turbulence (figure 5.6) simulation plots show that the co-ordinated control system can still improve the smoothness of the farm output power in low wind conditions. At the lower wind speeds the co-ordinated system is less energy effective than at mid and high wind speeds. This is because it need to leave a certain amount of stored energy to reduce the risk of stalling. This effect is especially apparent during the high turbulence period of the second simulation (figure 5.6) as the two effects combine to reduce the power effectiveness to as low as 50%.

Figure 5.7 shows the reference rotor speed for one of the under-speed controllers during the test shown in 5.6. It shows that the rotor reference falls during the low wind speed period. This
ensures that the system remains as near as possible to the optimum $\lambda$ and keeps outputting a power near the maximum available.

### 5.1.4 Measured wind

The tests with controlled wind conditions are very useful to characterise the system under fixed, predictable conditions but do not completely represent real situations. The wind data statistical up-sampling method described in section 3.1.1.1 allows the co-ordinated controller to be simulated with a more realistic wind profile. Two sections of wind data were used to verify the function of the co-ordinated controller, one from a very windy day, and the other from a calm day.

The results of the calm day (figure 5.8) show that the system can output a smooth power in realistic wind conditions. The target filter lag again has an effect here, reducing the power efficiency of the system, especially at around 3700 seconds. However, for the most part the system remains high efficiency and smooth. This test is a low wind speed test, with the output power rarely reaching the medium wind speed expected power of 11MW. The low wind speed explains
the relatively low energy effectiveness of 77%.

The results of the windy day test are shown in figure 5.9. For the 2 hour period simulated, it is clear that the co-ordinated system works effectively to smooth the power for the majority of the time. The initialisation period caused some underproduction during the first prediction period or two. The under-speed controller has caused a few ‘events’ which would require smoothing by other equipment but they are short in duration and not common (events no closer together than approximately 15 minutes) so this should be achievable with a storage system if needed, or within the balancing system without excessive strain. The system is able to export 73% of the available energy with the variation much reduced.

5.2 Effect of Farm Configuration

The effect of farm configuration on the maximum power controllers has been shown, in section 3.5, to be significant. To see whether these effects carry through to the co-ordinated controller,
or have a zero or negative impact, a series of system tests were performed on the different farm configurations. The wind input for these tests is a medium-speed, high-turbulence wind.

Figure 5.10 shows the power output of the 3 maximum power controlled wind farms in sub-figure (a), and that of the co-ordinated controlled farms in sub-figure (b).

A very similar result to that in Figure 5.2 is obtained for the small farm tests. The only changes are caused by the use of a new randomly generated wind input. The results therefore give another example of how the co-ordinated controller performs under turbulent winds.

Increasing the size of the farm increases the amount of storage available to the farm co-ordinator along with reducing the amount of natural variation of the farm output. These two effects combine to enable the co-ordinated controller to produce a significantly smoother power output (as shown in Figure 5.10(b)), especially during the later part of the test where the turbulence is increased. This is still achieved at the expense of total power output which stays at approximately 90% of the maximum available for the low turbulence and only falls to 80% during the high turbulence periods.
Figure 5.7: Under-speed controller reference rotor speed for the low wind speed, high turbulence test

When simulating the 9x3x3 farm, each group of nine turbines is treated entirely separately. Nine co-ordinators are provided and each only works with 9 turbines. Thus the storage available to smooth the wind is reduced for each co-ordinator compared to the 9x9 farm case. Though each controller only has a small amount of storage, there is a smaller amount of natural variation with the 9x3x3 farm than the 9x9 farm, so the coordinated output variation is also reduced. The stepped output caused by the periodic operation of the system is also much reduced as the farm winds are not correlated. The net result of significantly less natural variation but also smaller amounts of co-ordinated storage compared to the 9x9 farm results in similar levels of improvement compared to the 3x3 case.

5.3 Effects of the Co-ordinated Controller on Other Systems

It is important to assess the performance of wind farm control systems in terms of the effects they have on other devices within a network, these include other portfolio generators and the generators involved in the balancing mechanism. This is especially true when the aim of the controller is to
smooth the power output of the wind farm as the smoothing is attempted in order to prevent the worst of the wind variations from affecting the network.

### 5.3.1 Effect on Portfolio Sources

Wind farms are often considered as part of a generation portfolio for purposes of entering the electricity markets. The energy provided by the market participant is the sum of the energy produced by the wind farm and that produced by the other generators in the portfolio. To avoid top-up and spill charges, the energy delivered must match the predetermined bid. Therefore, any variations in the wind power output should be countered by other generators in the portfolio so that the total portfolio energy does not vary.

The model for a portfolio of sources was described in section 3.7. This model is scaled such that the wind is 20% penetration by rated power. The outputs of the maximum power controlled wind farm and the co-ordinated controlled wind farm were used as the inputs to two simulation runs of the portfolio model. The wind input for these runs was the medium speed high turbulence
The power output of the maximum power controller varies by a small amount throughout the simulation run. This output of the portfolio with this wind farm is shown in figure 5.11(a). The wind power variation at the start of the test is within the capabilities of the conventional generators to compensate. In the latter part of the simulation, when the wind turbulence increases, the amount of power variation also increases. The variation is now too fast and too large in magnitude for the fast and medium generators to counter so outside balancing is required.

When the co-ordinated controller is used (figure 5.11(b)) then the farm output is significantly less variable in the early part of the simulation. This means that the generators are required to ramp up and down much less in order to compensate. In the latter part of the simulation the co-ordinated controller still causes power variations which are beyond the portfolio’s capability to compensate due to the changes in wind power output having too high a rate of change. The co-ordinated controller, however, requires much less outside balancing both in terms of magnitude and duration.
Scaling each of the other generators to 25% of their original size means that the wind farm is now 50% of the portfolio. Figure 5.12 shows the portfolio output for the 50% wind case, it is clear that the variation of total portfolio output has increased greatly as the other generators are unable to compensate. The outside balancing requirement has increased with both farm controllers. The co-ordinated controller still however requires less outside balancing than the maximum power controller in terms of frequency of requirement, total energy required and magnitude of power required. The balancing requirement for the 50% penetration co-ordinated controller is similar to that required by the 20% maximum power controller.
Figure 5.12: Comparison of the effects on the generation portfolio of the maximum power controller and the co-ordinated controller when the wind farm is 50% of the portfolio. Wind is shown in blue, fast generator in red, medium generator in orange, and slow generator in brown.

(a) Portfolio output with the 25% scaled portfolio - Maximum power controller
(b) Portfolio output with the 25% scaled portfolio - Co-ordinated controller

The reduction in required outside balancing when using the co-ordinated controller is sufficient such that the medium and fast generators are not required. Figure 5.13 shows the results for a portfolio consisting of just the slow generator at 50MW and the wind farm at 20MW. It is clear that the outside balancing required by the wind farm with the co-ordinated controller is not significantly increased over that required by the full portfolio of 3 generators. However, the increase required when using the maximum power controller in the same reduced portfolio is significant. This is because the variations in wind power output when using the co-ordinated controller are very fast in nature and beyond the capabilities of the generators to compensate. The variations, however,
are smaller in magnitude, frequency and duration than those output when the maximum power controller is used.

5.3.2 Effect on Other Grid Generators

The grid model described in section 3.6 was used to simulate the effects of both the maximum power controller and co-ordinated controller on other grid generators. Another medium-speed high-turbulence wind input was created to simulate another power output for the two controllers to test grid generator response. These simulation results are shown in figure 5.14. The per unit base was maximum farm power.

![Wind power inputs to the grid model simulation, maximum power controlled wind farm in blue, co-ordinated controlled windfarm in red](image)

Figure 5.14: Wind power inputs to the grid model simulation, maximum power controlled wind farm in blue, co-ordinated controlled windfarm in red

There are two main types of output that the co-ordinated controller can produce: the fully smoothed, stepped output that signifies it is working correctly, or the variable output that is caused by the action of under-speed controller. These two cases are both shown in this simulation run, for a few prediction periods around 1500 and 6300 seconds respectively. These will be treated separately when considering the effects on grid frequency.
Figure 5.15 compares the grid frequency resulting from the maximum power controller and co-ordinated controller when the co-ordination is working well to smooth the power output. The effect of the smoothed but stepped power output is to create short-lived disturbances in the frequency of the modelled grid. These deviations, however, are much smaller in magnitude and regularity than those caused by the constant variation of the maximum power controller in this time. The model was provided with initialisations for a larger wind farm and thus all of the frequency results are below regulations, however the actual level of the frequency is less important than the variations for this comparison.

![Graph of Grid Frequency](image)

**Figure 5.15: Grid simulation - Frequency plot for the effectively smoothed time periods**

The example from later in the simulation, shows the effects of the under-speed controllers on the frequency of the grid generators (figure 5.16). During this part of the simulation the under-speed controllers are required to act to prevent turbine stalls. This clearly has a larger effect on the frequency of the modelled grid than when the smoothing is working effectively. However, the grid frequency variations are not significantly greater than those caused by the maximum power controllers. The variations also last for much less time than those of the maximum power controller.
Figure 5.16: Grid simulation - Frequency plot for the under-speed controller dominated time periods

The results presented in this section have shown the performance of the co-ordinated controller under a range of different wind conditions, the effect of farm configuration on the co-ordinated controller, the effect of the co-ordinated controller on a portfolio and finally the effect the co-ordinated controller has on the variation of system frequency. The next section presents the conclusions of this study along with further work.
Chapter 6

Conclusions and Further Work

6.1 Concluding Remarks

In order to meet the challenges inherent in increasing the penetration of wind power into the GB grid it is important to be able to produce wind power in as controlled and predictable a manner as possible. Large unpredictable variations in wind power output can cause issues with the grid frequency and voltage and they can also make the task of balancing supply and demand more difficult and expensive. In addition to this, the inability to accurately predict the power output of a wind farm makes it a high economic risk for wind farm owners to participate in the wholesale energy market without working as part of a portfolio of generators. These portfolio generators are required to counter as much of the wind power variation as possible so as to avoid being charged for mis-production and this is, again, made more of a challenge by the highly varying wind output.

This study has presented a new control architecture for large groups of turbines that utilises the inertia of the wind turbine rotor to smooth out short term variations in power. Each turbine is able to predict the wind energy input for the next 120 seconds using the assumption that the wind input will be a delayed version of that experienced by turbines upwind. The turbine level systems then use the predicted wind input to calculate the amount of energy they have available for the next 120 seconds. The use of energy predictions allows the system to be noise resilient. A scheme has been proposed in which turbine controllers propose power schedules based upon these energy predictions. These proposals are communicated to a farm level co-ordinating controller that decides on the best arrangement of the proposed schedules in order to meet a target power output for the whole farm.
The presented co-ordinating control system was tested across a range of different input wind conditions. Under the majority of conditions likely to be experienced, the co-ordinated controller is able to smooth the wind power output. The proposed system reduced the Average Absolute Differential (AAD described in section 2.3.1.2) measurement by up to 94%, sacrificing as little as 10% of the energy under ideal conditions (wind in the middle range and low turbulence). Under less ideal conditions (wind in the low range and high turbulence) the co-ordinated system is still able to reduce output variation by at least 21% with, in this case, 27% of the energy lost.

Under high wind conditions the smoothing system acts in a similar manner to maximum power tracking controllers. The electrical system reaches rated power and the blade pitch controllers spill any excess wind power. In this case it is not possible to achieve a significant smoothing effect. It is in the middle wind speed range, when the turbine electrical systems are capable of exporting all of and more than the available wind power, that the smoothing is most effective. Instead of tracking the changes in the wind like the maximum power controller, which leads to a continuously changing wind power, the co-ordinated controller is able to export the wind energy in a controlled manner. The output of the co-ordinated wind farm under these conditions is for the most part smooth across 120 second periods, with ramped sections between. When the wind speed is low, the co-ordinated system is still able to smooth the output power, but at a slightly reduced total output energy. This is because at low wind speed periods the rotor speeds of the turbines are also low and less stored energy is available for smoothing.

It was found that the prevention of stalling by the under-speed controller leads to significant variation in the output of the co-ordination controlled wind farm. This is because the under-speed controller acts when production falls short of prediction. Because this is a prediction failure, the co-ordinated controller had not taken this event into account. The under-speed controller is also the cause of the reduced power yield during low wind speed periods. The under-speed controller, however, is necessary in order to be able to treat the energy input as a single value that can be exported at an even rate across a whole 120 second period without calculating the rotor speeds for the entire period beforehand.

In addition to the synthetic wind cases, the system has been tested and has proved functional with realistic wind input. The minute to minute data provided by the National Renewable Energy Centre was used to test the system with real wind data from two different periods, one on a calm day and one on a windier day. The real wind data was up-sampled, using the statistical data
provided, to give a plausible wind speed profile at the higher data rate required by the controllers. The system was found to be able to smooth the output power effectively with this more realistic wind data.

Three methods were proposed to quantify the effectiveness of the proposed controller. The first is a simple measure of variation, the Absolute Average Differential. The other two methods directly assess the affects of the wind farm controllers on other generators in a portfolio and the frequency control of the grid.

The affects of wind power smoothing on other generators in a portfolio were assessed by adding a wind farm with the proposed controller to a portfolio of slow and fast conventional generators. The co-ordinated controller reduced the amount of ramping and start/stop action that was required of the other generators, and significantly reduced the amount of unmanaged variation that was passed to the rest of the grid. This reduces the stress and efficiency penalty on other generators created by wind power and may even allow different configurations of portfolio to be used.

To directly assess the influence of the wind farm output on the grid, both the smoothed and un-smoothed wind power outputs were input to a model of an example grid. It was shown that the co-ordinated controller causes less disturbances on the grid frequency than the maximum power controller. The smoothing was able to reduce the frequency changes from constantly variable to smaller disturbances. Even when the smoothing effect is not possible (because the under-speed controller was required to act to prevent a stall) the frequency variations are no greater than those caused by the maximum power controller with the same wind input.

### 6.2 Authors Contribution

In order to realise the co-ordinated controller, a pair of pre-existing ideas have been combined with some new techniques. The use of a transport delay model for producing wind speed inputs for a group of wind turbines and the use of wind turbine inertia are not new ideas. However combining the two techniques to calculate the amount of energy available in a period of time and export that energy in a controlled manner is novel. The power schedule construction and under-speed torque controller are also unique to this thesis.

In addition to the turbine-level blocks, the farm-level co-ordination technique was proposed. The use of co-ordination to facilitate farm function is not novel but the method used in this thesis was designed specifically to work with the power schedule style predictions.
As well as the functional blocks that were designed for the purposes of this controller, the wind up-sampling method for increasing the sample rate of the wind data using statistical information was devised for this work. This is a very useful technique as very little wind data is to be found at high sample rates.

In order to assess the effectiveness of the proposed wind power smoothing method, a means of qualitatively calculating the power variations was required. The proposed AAD calculation was designed to take into account the sample to sample variation in the power output. In addition to the direct variation calculation, a model of a portfolio was developed to assess the effects of the different wind farm controllers on other generators in a generation portfolio.

6.3 Further Work

The proposed control scheme and turbine model are suitable as a platform for investigating the effects of wind farm power output smoothing. However, there were many elements of the newly designed control method and model that are not yet complete. Following the model through from the inputs to the outputs the main areas that require further work are detailed here.

The wind generation and up-sampling systems are useful but there has not been any way of verifying that their output corresponds to that seen by a real wind turbine. Some real measured data is required, at a high enough sample rate in order to verify these models.

Having acquired a single wind input, the propagation of the wind to each turbine in the farm is also a key area where improvements need to be made. The delay model is an over-simplification of real life. Either real measured data for all of the turbines is needed, or a more thorough fluid dynamics model of the transport of the wind through the farm is required to ensure that any control systems are designed with realistic inputs. This is also the case for turbine to turbine shadowing effects. These shadowing effects have been left out of this thesis as it was assumed that the farm was designed such that the shadowing effects will be negligible. It is necessary to investigate whether this assumption is true. A full set of measurements of power and wind speed for all of the turbines in a farm would be useful for this.

The model of the turbine itself is much simplified over a full model. This was because the high frequency effects of the synchronous machine and inverter are unlikely to have an impact on the low frequency wind power smoothing and vice-versa. However, to ensure the system is viable then a full model simulation should be performed.
The design of the under-speed controller is crucial to the smoothing effort as it is the only part that can cause unpredicted variation. The proposed design is functional but a system could be envisaged that better detects the likelihood of stalling, possibly via measurement of the system $\lambda$. Alternatively a small amount of energy storage, either batteries or capacitors, could be employed to cover under-speed events to prevent them from causing power output variation. The size of this storage would be much reduced over that of a full smoothing storage system.

It is worthwhile to test whether other schedule designs beyond the basic ramp then static power have any impact on the performance of the system. An exponential rise of power might lead to an improvement. An amount of delay before ramping might be useful to allow the turbines to ramp at different times, reducing the stepped effect on the farm output.

The fact that the farm controller ignores the ramped sections means that a large ramped section will leave the system far from its target a large amount of time. Taking into account these ramped sections may also allow the removal of the stepped effect from the total farm output power. For example, if one turbine has power available, and another needs to ramp to its final power, the turbine with excess energy could compensate for the ramped output of the other. This would mean that the sum of the two turbines is smoother.

The portfolio and grid model provide useful results in the areas they were designed for. However a single grid model should be developed with a range of generators to model the balancing system. This new model could provide more complete results for both the frequency variation and balancing need with different wind farm controllers.

In addition to the further technical work required, there needs to be a full economic study to assess the viability of the proposed control system. This system requires a certain amount of energy to be sacrificed in order to achieve its smoothing effect. It is assumed that the variation of wind power incurs a cost within the grid system in order to balance the changes. This cost currently is not paid by the wind farm owners as the balancing network is not set up with wind in mind. An economic study could assess the various ways in which the balance network changes could be redistributed or recalculated and in each case could determine how much energy could be sacrificed in order to avoid these charges.
Appendix A

Full Data Table for UK Wind Farms

The full list of wind farms in the UK by the year they were installed. The data taken from the
Renewable UK website, is partially incomplete, where data is missing, a ? is placed in the table.

From the available data, the wind turbines are classified based upon their generator type: A,
B, C or D. Where data was missing or the data-sheets were not available and clear, the turbines
are classified as U. The U classification does not form a significant proportion of the total numbers
and as such the data is reliable.
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Appendix B

Run Through of the Statistical Up-sampling Method

The method of increasing the sample rate of the wind in a meaningful realistic way is described in section 3.1.1.1. However, it is helpful to perform a full run-through of the method for clarity.

The first step is to calculate the number of gusts required using equation (3.3), repeated here for ease of reference.

\[
P_d = (1 - (1 - P(1))^{N_{gusts} + 1})
\]

\[
N_{gusts} = \frac{\ln(1 - P_d)}{\ln(1 - P(1))} - 1
\]  

(B.1)

Having calculated the number of gusts, in this case 19, each must be allocated a time sample between 0 and 599, a whole minute sampled at 10Hz. This is a uniformly distributed random number. The first plot of figure B.1 shows the 19 gust sample times. Each gust is then allocated a wind speed. This is a normally distributed random number using the initial statistical data provided. The second plot of figure B.1 shows the wind gusts in their correct positions.

Every other sample of the 600 must be given a value, these are interpolations of the already calculated gust samples. The wind profile is shown in the third plot of figure B.1

The interpolated wind profile can exhibit a very high rate of change, which is obviously not realistic, so finally a low pass filter is applied to the wind data to give the profile shown in figure B.2. This whole process is repeated for every minute of required data.
Figure B.1: Statistical Run-through Intermediate Steps

Figure B.2: Statistical Wind Run-through Final Results
Appendix C

Portfolio Model Pseudo-code

desired_power = bid_power - wind_power
power_out(1) = desired_power(1)
forward_index = 2

while index < length(desired_power) {

    ## Set up the max and min achievable outputs given the rate limits and power limits

    max_power_achievable = power_out(index - 1) + ramp_rate*step_size
    min_power_achievable = power_out(index - 1) - ramp_rate*step_size

    if max_power_achievable > max_power_limit
        max_power_achievable = max_power_limit
    endif

    if min_power_achievable < min_power_limit
        min_power_achievable = min_power_limit
    endif

    ## Figure out if we are between the limits or have hit them
if desired_power(index) > max_power_achievable
    power_out(index) = max_power_achievable
elseif desired_power(index) > min_power_achievable
    power_out(index) = desired_power
else
    power_out(index) = min_power_achievable
endif

## Move on

index = index + 1

}
Bibliography


[65] V. der Hoven I., “Power spectrum of horizontal wind speed in the frequency range from 0.0007 to 900 cycles per hour,” Journal of the Atmospheric Sciences, vol. 14, no. 2, pp. 160–164, —1957—.


