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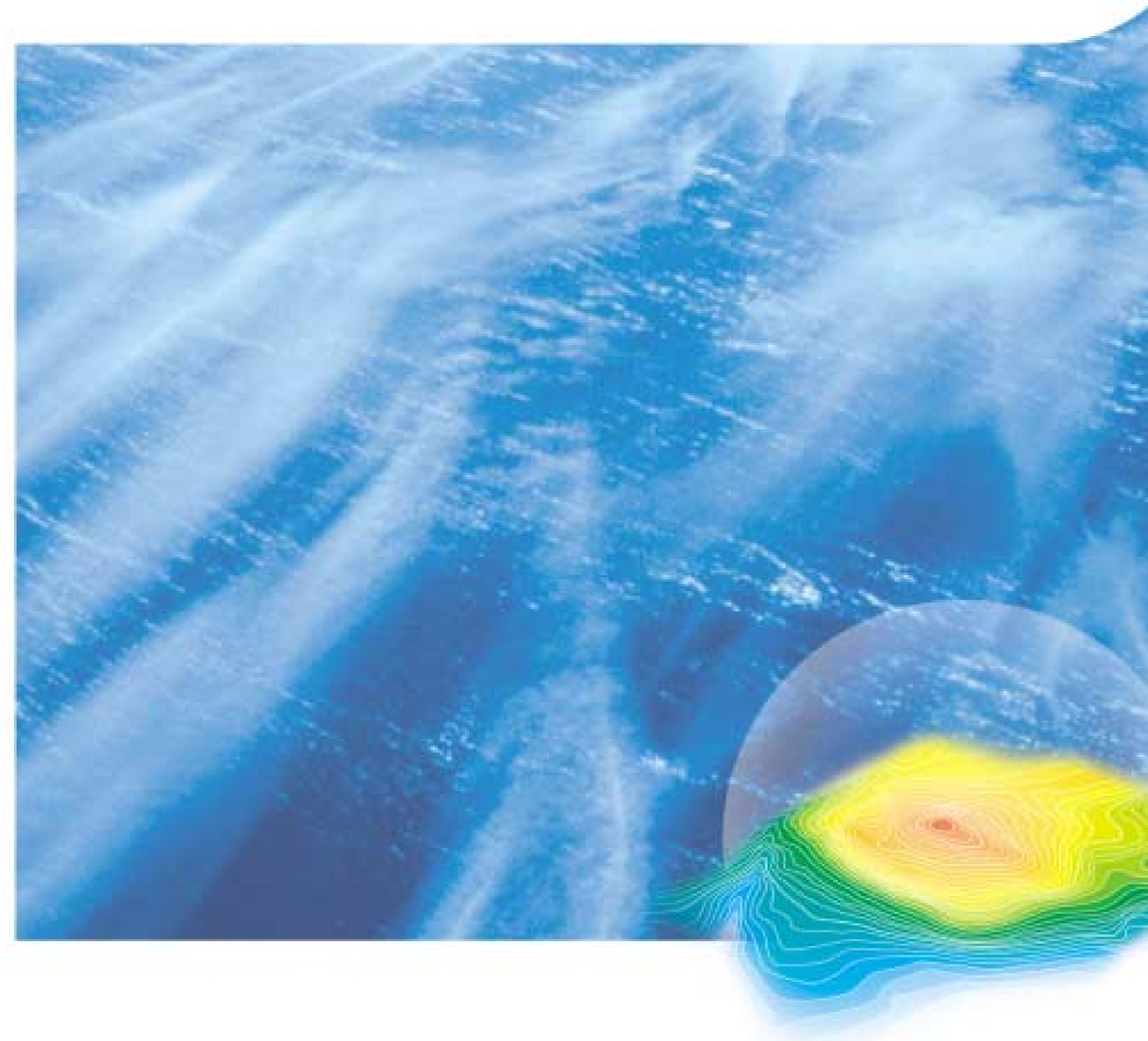

Operating Reserve Requirements as

Wind Power Penetration Increases in the Irish Electricity System

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Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System

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EXECUTIVE SUMMARY

Ireland is experiencing a rapid growth in the development of wind generation. In July 2004 there was 229 MW of wind generation connected in the Republic of Ireland (RoI) and 83 MW in Northern Ireland. A further 633 MW of wind generation had signed connection agreements in RoI and 35 MW in NI. In addition, 1,369 MW of connection applications have been made in RoI and 666 MW of connection enquires in NI.

In common with other renewable technologies wind generation produces environmental benefits by reducing emissions of carbon dioxide (CO_2), oxides of sulphur (SO_X) and nitrogen (NO_X) and particulates.

A feature of wind generation is its intermittency. The natural variability in wind speeds causes the level of wind generation to vary both at individual turbines, and, to a lesser extent, in aggregate across the island of Ireland. Unpredictable changes in the level of wind generation (due to inevitable forecasting errors), increase the required level of operating reserve which must be maintained by electricity system operators to ensure that demand for and the generation of electricity are continually met.

This report describes the results of a study commissioned by Sustainable Energy Ireland (SEI) to quantify any additional requirements for operating reserve arising from the growth in wind generation and to assess the impact any such additional operating reserve would have on costs and emissions, and the net environmental gain from wind generation.

Operating reserve

Operating reserve is the additional generating capacity carried on the electricity system over short periods of time to ensure that differences between forecast and actual volumes of generation and demand can be met. Differences between forecast and actual volumes can arise for a number of reasons, including:

- unplanned outages of generating plant or on the transmission or distribution networks;
- unpredicted changes in wind speeds, altering wind generation levels; or
- unpredicted changes in consumer demand levels due to:
  - weather patterns
  - TV pickups
  - other events, etc.

Operating reserve is called to act over short timescales, from seconds through to a few hours – the period before an unscheduled generating station can be brought onto the system to meet any enduring shortfall in generation. This study is narrowly focussed on the potential impact increased wind generation can have on operating reserve. Other potential impacts of wind on the wider system, for example on the optimal mix, capacity or operating regime of conventional generating plant or requirements for investment in distribution and transmission networks, are outside the scope of this report and have not been considered. Other studies[1] published recently have attempted to look at the wider effects that incorporating a greater capacity of wind generation could have on the wider electricity system in Ireland. Caution is advised in comparing directly the results of this study with others where a number of key assumptions may differ – including the assumed wind generation profiles, system operation scheduling methodologies and level of interconnection. In particular, the readers attention is drawn to the manner in which the results of this study are presented – for specific sample days. No attempt has been made to extrapolate the detailed results obtained here for a small number of sample days to a set of annual costs.

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1 ESB National Grid, "Impact of wind power generation in Ireland on the operation of conventional plant and the economic implications", February 2004.

Methodology

The objective of the study is to quantify technically and economically the impact that different levels of wind power will have on operating reserve requirements on the Irish electricity system.

To achieve this, the study has compared the operating reserve requirements on the system under a range of scenarios for variations in installed wind capacity and system operational modes. The study has been undertaken for two time horizons, 2006 and 2010 and three future capacities of installed wind generation:

- Wind Scenario 1: Year 2006 with 845 MW (650 MW in RoI and 195 MW in NI) of wind capacity;
- Wind Scenario 2: Year 2010 with 1,300 MW (1,000 MW RoI and 300 MW NI) of additional wind power;
- Wind Scenario 3: Year 2010 with 1,950 MW (1,500 MW RoI, 450 MW NI) of additional wind power.

In converting wind capacities into profiles of wind generation we have used actual metered generation data from the existing wind generators in Ireland to produce an annual profile of generation. This takes full account of increased diversity, the geographic spread of wind farms and technological development. In determining the required level of operating reserve we have used this aggregate profile of wind generation to assess the extent of changes in wind generation that can occur over various time horizons and the predictability of those changes. Only unpredicted changes in wind generation will lead to an increase in operating reserve.

System operators strive to operate the system at least cost, subject to constraints. Operating reserve is a major constraint on any electricity system but it is particularly stringent on the island of Ireland because of its small size and weak interconnection with other systems (currently limited to the 500 MW Moyle dc interconnector with Scotland, which although capable of providing operating reserve, is not currently configured to do so).

Increasing operating reserve improves the reliability of the system. For meaningful comparison of electricity systems, with and without wind power, it is important to maintain consistent reliability standards. In operating a system with wind generation, system operators will have to decide how to accommodate wind in their scheduling decisions.

The study has considered a number of alternative System Operator scheduling and dispatch strategies for managing an electricity system including a significant volume of wind generation, so as to be able to assess the sensitivity of operating reserve requirements both to wind levels and system operation modes. The modes considered are

- No wind (the base case);
- The fuel saver approach, whereby the system is scheduled without wind, but in real time conventional units are backed off to accommodate available wind generation;
- A forecast approach, where the expected level of wind generation are included in the scheduling of the system.

With the help of the system operators, three sample days have been chosen to study the wind scenarios and the scheduling methodologies.

- Winter peak day;
- Summer valley day;
- Shoulder business day;

These sample days have been chosen to reflect the two extremes in system operation – peak demand during winter and minimum summer demand – together with a more representative operating day. The small number of days considered is limited by the complexity of the modelling required, but is considered to be representative of extreme (winter peak day and summer valley day) and more typical (Shoulder business day) requirements for operating reserve.

In order to keep the study focussed, several key assumptions have been made. These assumptions are based on consultations and a review of the background material provided by the industry.

- System reliability and security is to be maintained at current levels.
- All operating reserve categories are assumed to be managed on an all-island basis.

- The Moyle dc interconnector will not provide frequency control in 2006 but will provide limited functionality in 2010.
- There will be a new 500 MW east/west dc interconnector by 2010 and it will provide limited frequency control.
- There will be an all-island electricity market in 2010 (but not before 2006).
- Most of the new additional thermal generation will be split between combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs).

Determining the operating reserve requirement

This study has made use of highly sophisticated modelling techniques that have been developed over a number of years at University College Dublin (UCD), Queen's University Belfast (QUB) and the University of Manchester Institute of Science and Technology (UMIST). The analysis combines results from a number of modelling techniques:

- Wind and load modelling are used to determine load and generator fluctuations from forecast levels, and the frequency control requirements that they create.
- A Dynamic Frequency Control Model, which models the response of the system up to 20 seconds following a major contingency.
- Static year round response / reserve allocation and costing simulation tool with a stochastic wind generation model.
- The Probabilistic Reserve Model, which assesses longer-term frequency control issues (20 seconds onward).

Results and conclusions

The physical requirement for additional operating reserve

This study indicates that the growth in wind generation will require additional operating reserve, but that this increase may not be substantial. Our findings are partly based on the assumption that system operators dispatch generation taking appropriate account of the expected wind generation (and the forecast error). This *forecast* approach represents a new paradigm in system operation, that to date has not been necessary, given the small capacity of wind generation presently connected to the system. Our findings in relation to the *forecast* approach may not be directly comparable with the results from other studies that have used more conventional dispatch techniques, such as the *fuel saver* approach also considered in this report.

Conventional generation units are required to track both scheduled (expected) variation in the system demand, and errors arising in either the demand or wind generation forecast. Load variability can at times be high, dominated by the morning rise and evening fall off in demand. Wind output variability is considerably less, even for the 2010B scenario. Consequently, net demand (defined as system demand less wind generation) variation should not greatly exceed system demand variation. With additional generation plant expected before 2010, the all-island system has the potential to be highly responsive with improved load tracking capability.

Fuel saver and *forecast* operating modes have been considered here. From a load following perspective, the major difference between these options is that more units will be committed in *fuel saver* mode (due to an expectation of total demand, rather than net demand), implying that the load following burden on individual units should be reduced. Since wind variability is relatively low, any increased load following requirement should be small. Being the larger system, it is probable that the ESB system will provide the majority of this requirement, over the NIE system.

In *fuel saver* mode, unit outputs will be reduced from that scheduled (due to availability of wind generation) causing a reduction in the required operating reserve levels. In *forecast* mode, any variation in the scheduled unit commitment will generally be less.

For short time horizons, errors in the wind forecast should be small, such that reserve targets can normally be maintained without undue effort – assuming that scheduling of committed plant and monitoring of windfarm output is actively managed.

For longer time horizons, wind forecast errors may cause operating reserve targets, on occasion, to be contravened. Available containment options will be dependent on circumstances and time of day.

Wind forecasting errors are correlated and this needs to be recognised by system operators. Assuming independent wind forecast errors for individual wind farms will underestimate the total wind forecast error which could be problematic for system operators, if they carry insufficient operating reserve as a result. This conclusion may also support the need for the centralised forecasting of Irish wind generation rather than wind farm-by-wind farm submissions of estimates to the system operator.

Additional benefits of diversity to the all-island system may be limited. It would appear that the existing wind farm distribution (2003) has captured a significant amount of the benefits of diversity. It is estimated that by 2006, with over 850 MW of wind capacity connected, most of the benefits of diversity will have been realised.

As a small island power system the total operating reserve targets are dominated by the largest infeed. Increasing wind penetration increases the need for operating reserve. However, with the scenarios investigated the largest infeed remains the dominant influence on operating reserve targets.

Only very small amounts of additional fast acting reserve (5-15 seconds) are required even for large wind penetration levels. However over longer time horizons, of 15 seconds to several hours) there is an increasing requirement for additional operating reserve as wind penetration increases.

Analysis of the future dispatches indicates that with a large wind penetration it may be beneficial to change the operation of the pumped storage station, Turlough Hill. Further detailed analysis is required in order to determine the optimal operational strategies for Turlough Hill.

In this study, it has been assumed that hydro generation units follow a scheduled profile for each day, and, therefore, do not contribute to the load following duty for the system. Hydro plant tend to be highly responsive with governor droops less than 4%. They therefore offer an untapped form of regulation.

Short-term dynamic results presented in this study indicate that there is a need for more detailed analysis of the response of wind turbine generators during large frequency events. This coupled with the recognised issues around fault ride through (i.e. voltage events) and the lack of data would indicate that wind turbine modelling and validation needs to be made a priority. This exercise would contribute to and enhance the development of a more robust wind turbine generator grid code.

Without more detailed data on the dynamic performance of wind turbine generators it would be difficult to make any conclusions about how they might impact the short term frequency dynamics in the future. However, a conservative view would be that in respect of contribution to system inertia, fixed speed wind turbine generators may be the technology of choice at this time.

The environmental and economic costs of additional operating reserve provision

The financial and environmental costs of any requirement for additional operating reserve have been calculated by comparing the operation of plant providing operating reserve in the *no wind* base case with those in the various wind scenarios. Environmental and operating costs may arise from the increased use of fuel in additional plant start-ups and in the part-loading of generators, where plant are operated at sub-optimal efficiency.

Traditionally, conventional generating plant is used for providing operating reserve. In order for synchronised plant to provide operating reserve (and response), it must run part-loaded. Thermal units operate less efficiently when part-loaded, with an efficiency loss of between 10% and 20%, although losses in efficiency could be even higher, particularly for new gas plant. Since the flexible generating units will be part-loaded to provide the operating reserve, other units will need to be brought on the system to supply energy that was originally allocated to these flexible plant. This usually means that plant with higher marginal cost will need to run, and this is another source of cost associated with the provision of operating reserve.

The impact that the identified requirement for additional operating reserve has on costs and emissions varies substantially between whether the system operator is including wind in the schedule of generation (the *forecast* approach) or not (the *fuel saver* approach).

In the *forecast* approach, our findings are that:

- the total capacity of conventional plant that is scheduled is less than in the *no wind* and *fuel saver* cases;
- the total system generation required (from conventional and renewable generators) is lower than in the *no wind* and *fuel saver* cases[2];
- the total fuel burn is substantially lower than in the *no wind* case and also less than in the *fuel saver* cases[3];
- carbon dioxide (CO_2) emissions are substantially lower than in the *no wind* case. In comparison with the *fuel saver* cases however, savings are less clear-cut, due to a different mix of plant under the two approaches. If the costs of carbon allowances under the EU emissions trading scheme were significantly higher than projected, this result might change.
- the cost of providing the required operating reserve is less than under the *fuel saver* cases. In some instances it is lower than even the *no wind* case[4]. The additional cost of operating reserve is relatively small and likely to be to less than €0.20/MWh in 2010 if there is 1,300 MW of wind or €0.50/MWh with 1,950 MW.

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2 This is due to the in-house demand of some generator auxiliaries being avoided.

3 Fuel savings are, at the least, directly proportional to the penetration of wind generation and can be greater.

4 This is particularly the case at times of high demand, where the additional wind generation displaces expensive peaking plant, while reserve can still be provided by baseload units at little cost.

Table of Contents

1. Introduction

1.1 This report describes the results of a study commissioned by Sustainable Energy Ireland (SEI) to determine the impact that increased wind generation will have on the requirement for operating reserve in the Irish electricity system.

1.2 The demand for, and generation of, electricity must be kept in constant balance in order to maintain the stability of the electricity system. Operating reserve is the additional generating capacity carried on the electricity system over short periods of time to ensure that differences between forecast and actual volumes of generation and demand can be met. Differences between forecast and actual volumes can arise for a number of reasons, including:

- unplanned outages of generating plant or on the transmission or distribution networks;
- unpredicted changes in wind speeds, altering wind generation levels; or
- unpredicted changes in consumer demand levels due to:
  - weather patterns
  - TV pickups
  - other events, etc.

1.3 Operating reserve is called to act over short timescales, from seconds through to a few hours – the period before an unscheduled generating station can be brought onto the system to meet any enduring shortfall in generation. This study is narrowly focussed on the potential impact increased wind generation can have on operating reserve. Other potential impacts of wind on the wider system, for example on the optimal mix, capacity or operating regime of conventional generating plant or requirements for investment in distribution and transmission networks, are outside the scope of this report and have not been considered.

1.4 This study has assessed the requirement for operating reserve from the perspective of an all-island system operator managing an electricity market comprising a mandatory gross pool. Under such a centralised market arrangement, the system operator is responsible for procuring and scheduling all the required operating reserve. This approach is consistent with the proposed new Market Arrangements for Electricity (MAE) in the Republic of Ireland (RoI) and the envisaged structure for the all-island market. In other, decentralised market structures (such as NETA in England and Wales), market participants may carry some operating reserve, with the system operator only responsible for residual (generally the shorter-term) operating reserve requirements. However, the distinction between market structures is largely one of allocating the costs of operating reserve, and not on the total requirement for operating reserve. We therefore believe that the results obtained in this study would be equally applicable were the all-island market to take a decentralised form.

The growth of wind generation in Ireland

1.5 The island of Ireland is experiencing a rapid growth in electricity generation from wind power. As of 8th July 2004 there were 229 MW of wind turbines connected in RoI, and a further 633 MW[5] with signed Connection Agreements[6]. In addition, 1,369 MW of wind generation is in the connection applications process and a further 271 MW have applications being checked[5]. In Northern Ireland (NI) there are 83 MW of wind generation connected as of 1 June 2004, with a further 35 MW of committed capacity and 666 MW of connection enquiries[7]. This suggests a potential wind capacity on the all-island system of over 3 GW, though in practice not all this capacity is likely to go ahead.

1.6 This growth in wind generation is largely in response to government support and incentives designed to promote renewable technologies to meet EU commitments under the Renewable Energy Directive[8] and the Kyoto Protocol. Wind generation is expected to have a positive environmental impact, offsetting emission of carbon dioxide (CO_2) and oxides of sulphur (SO_x) from conventional, fossil-fuelled generating stations.

1.7 However, in addition to creating environmental benefits, it has been suggested that the nature of wind generation may impact on the operation of electricity systems in such a way as to increase the requirement for operating reserve. This is because wind generation has a number of physical and technical characteristics that are very different to the conventional generation it displaces. Historically, these characteristics, which are discussed in Chapter 2, may include:

- a lack of inertial response;
- a limited ability to provide operating reserve;
- intermittent, and potentially unpredictable, electrical output that is correlated with that from other windfarms;
- distribution connection and self-dispatch (for smaller windfarms); and
- a varied ability to ride-through system faults.

1.8 The purpose of this independent study is to quantify any additional requirements for operating reserve arising from the growth in wind generation and to assess the impact any such additional operating reserve would have on costs and emissions, and the net environmental gain from wind generation.

1.9 The impact that wind generation will have on the electricity system as a whole will depend on a number of factors, which include:

- total capacity of wind installed and its proportionate size to the total system;
- size and geographic diversity of individual wind developments;
- type of wind generators installed – potentially determined by compliance with the requirements of the Grid Code and connection agreements;
- ability to accurately forecast wind generation;
- overall size of the electricity system;
- size, type and mix of conventional (and pumped storage) generating plant; and
- the level, and contractual nature, of interconnection with other electricity systems.

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5 CER, "Wind Generator Connection Policy: Direction by the Commission for Energy Regulation", CER/04/245, 9th July 2004.

6 A connection agreement entitles the generator to connect to the transmission or distribution system. Holding a connection agreement does not imply that the development is fully consented, or that it will definitely go ahead.

7 SONI (Personal communication).

8 Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market.

1.10 Accommodating the relatively small capacity of wind generation to date onto the Irish electricity system has not been onerous. However, as the proportion of wind capacity and generation on the system rises, not only may the requirement for operating reserve increase, but the availability of some types of reserve may also reduce (as conventional reserve providers are displaced).

1.11 The impact of wind generation on system operation has become an area of intense debate in Ireland since the Commission for Energy Regulation (CER) agreed[9] on 3 December 2003 to implement a request from ESB National Grid (ESBNG) for a moratorium on the signing of new wind connection agreements, pending a consultation exercise by CER. This process is ongoing and there is a direction from CER[10], which proposes lifting the moratorium subject to a number of new conditions on wind generator connections.

Wind and operating reserve study

1.12 The Irish government is currently considering its future policy and programmes on renewable energy. In order to assist the formulation and implementation of the policy, SEI has commissioned a series of studies to further the knowledge of renewables in Ireland.

1.13 Sustainable Energy Ireland is Ireland's national energy authority with a mission to promote and assist sustainable energy. Its remit relates mainly to improving energy efficiency, advancing the development and competitive deployment of renewable sources of energy and combined heat and power, and reducing the environmental impact of energy production and use, particularly in respect of greenhouse gas emissions. The Authority is charged with implementing significant aspects of the Green Paper on Sustainable Energy and the National Climate Change Strategy as provided for in the National Development Plan. SEI is funded by the government through the National Development Plan with programmes part financed by the European Union.

1.14 In September 2003, SEI commissioned a study on 'Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System' (referred throughout this report as the '*Wind and Operating Reserve Study*'). The objective of this study is to provide a detailed technical and economic analysis and quantification of the impact of increased wind penetration on the operation and provision for electricity system operating reserves in Ireland.

1.15 This final report describes the results from the wind and operating reserve study.

Structure of this report

1.16 In Chapter 2 we discuss the definition, role and provision of operating reserve in electricity systems and discuss how the growth of wind generation may impact on operating reserve.

1.17 We provide an overview of the *Wind and Operating Reserve Study* in Chapter 3, summarising the high-level scenarios that have been run and the background assumptions adopted.

1.18 Chapter 4 and Chapter 5 give the results of the study. Chapter 4 describes the impact of wind on the physical requirements for operating reserve. Chapter 5 describes the financial and environmental cost of this operating reserve provision.

1.19 In Chapter 6 we draw out the key conclusions from the study.

1.20 The report contains a series of technical annexes

- Annex A provides our acknowledgements and details of the consultation process undertaken for this study. It also includes short sections on the new Market Arrangements for Electricity, Grid Codes and the recent moratorium in wind connections in the RoI;
- Annex B describes the detailed modelling methodology adopted for this study;
- Annex C describes the scheduling and dispatch methodology adopted;
- Annex D gives the detailed results from the study; and

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9 CER, "Letter from CER to ESBNG, 3rd December 2003", CER/03/283.

10 CER, "Wind generator connection policy: direction by the Commission for Energy Regulation". CER/04/245, 9th July 2004.

- Annex E provides a detailed paper on the inertial response of wind turbine generators and on the models used to represent them in the dynamic system model.

About the authors

1.21 The *Wind and Operating reserve* study has been undertaken by a consortium of experts, led by ILEX Energy Consulting. This consortium, which has worked closely together on previous related projects comprises:

- ILEX Energy Consulting Ltd. (ILEX) – a leading independent energy markets consultancy, specialising in Europe's liberalised electricity, gas, carbon and renewables markets. ILEX is a member of Electrowatt-Ekono, part of the Jaakko Pöyry Group.
- The Electricity Research Centre (ERC) in University College Dublin (UCD) – the leading power systems research centre in the Republic of Ireland (RoI).
- The Electric Power and Energy Systems Research Group (EPESRG) in The Queen's University of Belfast (QUB) – the leading power systems research centre in Northern Ireland.
- Manchester Centre for Electrical Energy (MCEE), the University of Manchester Institute of Science and Technology (UMIST) – the leading power systems research centre in Great Britain.

Background to methodology and modelling

1.22 Much of the detailed scientific, analytical and modelling work that underpins this study has been developed in parallel by the researchers in University College Dublin, The Queen's University of Belfast and the University of Manchester Institute of Science and Technology.

1.23 The research work is being continually refined, modified and improved. Results from this research work are being applied to test power systems that have many similarities with the all-island power system.

1.24 Most of the research work completed by University College Dublin and the Queen's University of Belfast in this area is being funded through the Electricity Research Centre by the electricity industry in the Republic of Ireland.

1.25 Some of this research work has been published at conferences[11,12,13,14] and is in preparation for publication in prestigious journals. Two particularly relevant parts of this research have recently been submitted to the IEEE for publication[15,16]. These two papers are confidential until they are accepted for publication when they will become freely available. As much of this research work underpins the work in this study, we have shared these papers under confidentiality with SEI but for copyright reasons they cannot be included in this report.

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11 Lalor, G. and O'Malley, M.J., "Frequency control on an island power system with increasing proportions of combined cycle gas turbines", *IEEE Power Tech*, Bologna, Italy, June 2003.

12 Doherty, R. and O'Malley, M.J., "Quantifying reserve demands due to increasing wind power penetration", *IEEE Power Tech*, Bologna, Italy, June 2003.

13 Lalor, G., Ritchie, J., Rourke, S., Flynn, D. and O'Malley, M.J., "Dynamic frequency control with increasing wind generation", *IEEE PES General Meeting*, Denver, June 2004.

14 Doherty, R., Denny, E. and O'Malley, M.J., "System operation with a significant wind power penetration", *IEEE PES General Meeting*, Denver, June 2004.

15 Lalor, G., Ritchie, J., Flynn, D. and O'Malley, M.J., "The impact of combined cycle gas turbine short term dynamics on frequency control", *in review*, 2004.

16 Doherty, R. and O'Malley, M.J., "New approach to quantify reserve demand in systems with significant installed wind capacity", *in review*, 2004.

2. The Role of Operating Reserve

What is operating reserve?

2.1 System operators must constantly balance the demand for, and generation of electricity over time horizons from fractions of a second, through minutes, hours, days to weeks and even months ahead. System operators will plan to operate the system based on a forecast of demand and a schedule of planned power station operation. In Ireland, in common with most markets, the generation schedule is determined by the system operator (SO) from a merit order[17] of generating stations. However, in some markets, power plant self-dispatch and the SO's role is reduced to just that of balancing. Variations in the level of demand from that forecast, and generation from that scheduled, have to be covered from operating reserve if the system is to remain in balance.

2.2 On the island of Ireland, there are two interconnected electricity systems. ESB National Grid operates the system in the Republic of Ireland and System Operator for Northern Ireland (SONI) operates the system in Northern Ireland. The two SOs (ESBNG and SONI) coordinate the operation of the two systems and share resources, in particular operating reserve.

2.3 Operating reserve can be provided by electricity generators and interruptible electricity consumers. The appropriate form of operating reserve will depend on the time horizon being considered – from fractions of a second to hours ahead. Longer-term balancing is dependent on an appropriate level of generation capacity to meet anticipated system demand and operating reserve requirements. A study on the total generation capacity available on the all-Island system – examining system security issues – is outside the scope of this work.

2.4 If electricity demand and generation are not maintained in balance, then the frequency of the system will deviate from its statutory level. All power systems within the EU are required to maintain a frequency of 50 Hz, with an error tolerance of no more than $\pm$0.5 Hz (that is a range of 49.5 Hz to 50.5 Hz). However, most SOs manage their systems within narrower margins – for ESB National Grid this operating range is 49.8 Hz to 50.2 Hz[18]. If there is insufficient generation to meet demand at any time then the system frequency will fall (a low frequency event), whereas a surplus of generation over demand will lead to an increase in system frequency (a high frequency event). Low frequency events can be corrected through an increase in generation or a reduction in demand, whereas high frequency events require a reduction in generation (or increase in demand).

The effect of frequency excursions

2.5 The consequences of an unchecked frequency excursion are potentially severe and can *in extremis* result in a blackout across the entire electricity system. Electrical systems are designed to operate in accordance with the statutory requirements. Some manufacturing processes are intolerant of variations in frequency (and/or voltage), potentially leading to equipment damage. Accordingly, protection equipment is installed at some consumer premises, on the transmission and distribution systems and at power stations, which will disconnect load and generation when the frequency drops below or exceeds defined thresholds. The effect of a frequency incident that breaches these protection thresholds could lead to a rapid failure of the electricity grid as power stations and demand trip off the system.

2.6 The potential effect of unchecked frequency excursions were dramatically demonstrated on the eastern seaboard of the US and Canada on 14th August 2003. A transmission failure in Ohio isolated a number of power stations providing power to the Eastern States and the reduced inflow of power led to a severe low frequency incident. As further transmission lines and power stations tripped off in response to the falling frequency, power was lost to 50 million people in the US and Canada.

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17 A merit order is a ranking of generating plant from least cost to most expensive. In competitive power markets, the cost of generating stations is determined from bids received from the generator.

18 ESBNG, "Grid Code Version 1.1", CC.8.2.1, October 2002.

Types of operating reserve

2.7 Severe frequency excursions are normally avoided through the use of operating reserve to limit the extent of frequency divergence. Frequency excursions can take many forms, from slow-acting inaccuracies in the forecasting of demand, where demand and generation drift out of balance over time, to sudden shocks to the system following the loss of significant generation or demand due to a plant or network fault. Consequently, the provision of operating reserve has a number of aspects, related to the timeframe over which it is required to operate and the type of incident to which it responds. Hence, operating reserve requirements range from small short-term frequency variations to load-following over longer time frames, and further include the need to respond to sudden large imbalances following the loss of a major generating unit.

Figure 2.1 illustrates the type of reserve that may be utilised following a frequency incident, using the definitions adopted for the RoI system.

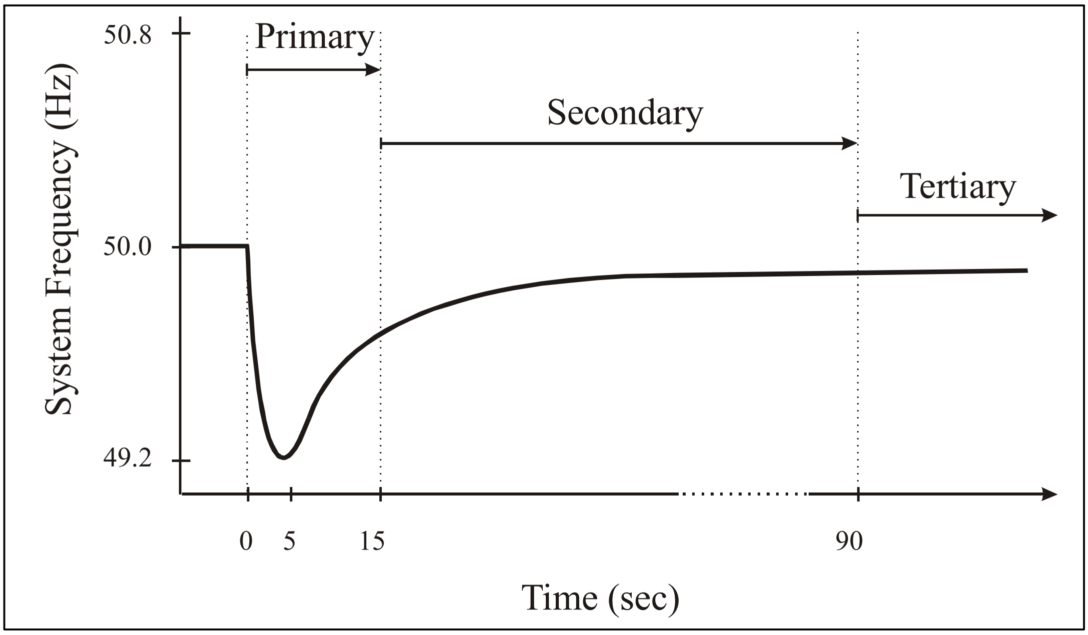

Figure 2.1 – Role of Primary and Secondary operating reserve in managing frequency excursions

Primary operating reserve (0 – 15 seconds[19])

2.8 Primary reserve is the most critical form of reserve for system security, as this acts in the very short timescales of a few seconds to stop the fall in frequency following an incident. There are two forms of primary response:

- Inertial response – the inherent response of synchronised generators to changes in the system frequency; and
- Fast response – the automated action to increase generation from scheduled plant – for example, in the case of steam cycle plant, by releasing the potential energy stored as steam pressure within the boilers.

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[19] The time frames presented in this report relate to the Irish electricity system. As Ireland is a small, island system dominated by a few medium-to-large conventional generators and one pumped storage facility (Turlough Hill), it is particularly sensitive to frequency excursions, and therefore the time frames within which reserve must function are considerably shorter than for larger or more interconnected electricity systems.

Inertial response

2.9 A generator or load can be considered to contribute to system inertia if a change in system frequency causes a change in its rotational speed and thus its kinetic energy. The power associated with this change in kinetic energy is fed to or taken from the power system and is known as the inertial response. An illustration of the inertial response of a thermal generating unit is shown in Figure 2.2, following the loss of a generator.

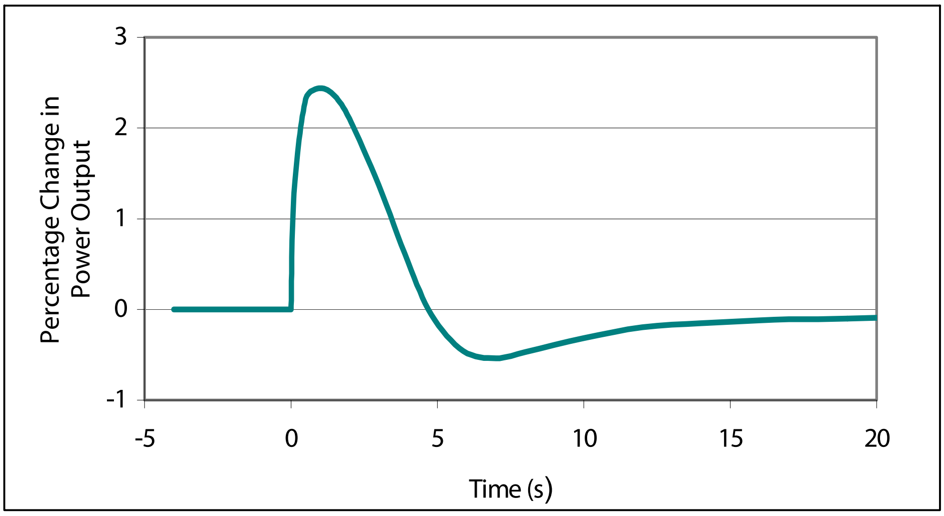

Figure 2.2 – Inertial response of a thermal generating unit to a sudden drop in system frequency

Fast response

2.10 Fast response is provided typically by automatic governor control, which increases the power delivered by conventional generators in proportion to the frequency drop. Fast response can also be provided by pumped-storage plant generating below maximum output, when the system frequency reaches a defined threshold. In extreme low frequency events demand blocks (including pumped storage pumps) can also be automatically tripped-off.

2.11 Steam cycle plant, providing fast response, can only maintain increased output for short periods, before the drop in steam pressure activates a pressure unloading stage. The boiler stored energy, and the ability of the unit to maintain output will vary significantly depending on fuel type, plant configuration, etc.

Secondary operating reserve (15 – 90 seconds)

2.12 The role of secondary response is to return system frequency to 50 Hz. Secondary response operates over the period from 15 seconds to 90 seconds after the initial incident. Secondary response can be provided by part-loaded generating plant that have been scheduled to operate below their full load by the SO, so that they can be ramped-up to full load in a matter of minutes following a low frequency event (or ramped-back further in a high frequency event).

2.13 Secondary response can also be provided by pumped storage plant, which are able to generate significant amounts of electricity very rapidly by releasing water stored in a high level reservoir through large capacity hydro-electric turbines. In pumped storage plant, the water used in this way is replaced by pumping it back to the high level reservoir at times of low energy prices, typically at night. This ability to pump can also be used to control high frequency incidents by increasing demand on the system. Pumping may also be a valuable tool for balancing excess generation, as steam cycle plant are ramped up in anticipation of a rapid increase in demand (such as the morning peak). Pumped-storage plant provide a unique asset for system operators and are a valuable source of operating reserve.

Tertiary response (90 seconds – onwards)

2.14 In the event of a major incident, the role of tertiary response is to replace the lost generation in the event of a plant outage, or to meet the unexpected demand from 90 seconds after the initial incident until such time that the plant can be returned to the system or demand returns to anticipated levels, or that replacement generating plant can be scheduled to operate. This may require tertiary reserve for a matter of minutes or several hours. ESBNG's Grid Code describes four types of tertiary response

- *Band 1 Tertiary Operating Reserve* – being sustained over periods of 90 seconds to 5 minutes;
- *Band 2 Tertiary Operating Reserve* – being sustained over periods of 5 minutes to 20 minutes;
- *Replacement Reserve* – over periods of 20 minutes to four hours; and
- *Contingency Reserve* that may be required to operate from up to 24 hours ahead of real time.

2.15 Tertiary response is generally provided by standing reserve plant that were not previously operating, but which are capable of fast start – such as hydro, diesel or gas turbine generators. In Ireland, due to the comparatively small nature of the power system, such plant may also be used to provide a secondary reserve response. These plant may also provide back-up generation at demand sites or black-start capability at power stations.

2.16 On a day-to-day basis, tertiary response provides the load-following ability to meet changes in the pattern of demand over the day and to ensure that peak demand can be met in the event of the loss of a major generating unit (either through genset or transmission outage).

Dynamic reserve

2.17 Dynamic reserve is characterised by a continuous response to frequency deviations, i.e. regulating. Units that are synchronised and on-line typically provide this type of operating reserve.

Static reserve

2.18 Static reserves include interruptible demand, reactors, interconnectors and pumped storage. It is characterised by being triggered by a frequency deviation e.g. the under-frequency relays controlling interruptible demand are currently triggered at 49.3 Hz in the ROI. Static reserves are called on at different frequency levels during a contingency. Therefore this type of reserve is not contributing towards regulation/load following. Static reserve has temporal characteristics, as its sources are not always available (see Annex C).

Providers of operating reserve

2.19 In the above text, we have identified the type of plant that typically provides each of the forms of operating reserve. However, operating reserve is generally not location specific[20], as frequency excursions will affect an entire interconnected network. Only where transmission constraints restrict the flow of power on a network, will the location of operating reserve providers be a factor. It is for this reason that operating reserve is presently managed on an all-island basis, with the electricity systems in RoI and NI providing mutual support. Primary reserve requirements are presently shared in the proportion 2/3 RoI and 1/3 NI. Other forms of reserve are presently carried separately in both systems but we anticipate increased co-operation between the two system operators, particularly if the growth in wind generation increases the requirements for operating reserve. An all-island electricity market is looking increasingly likely and a memorandum of understanding is currently being discussed between the regulators in the North of Ireland and the Republic of Ireland. For this reason, we have assumed that all operating reserve requirements are managed on an all-island basis throughout this study.

2.20 The provision of operating reserve is both an obligation on generators and a commercial service. Obligations on generators to provide operating reserve services are laid out in the Grid Code. In addition to these obligations, other operating reserve services are procured by the System Operator on a commercial basis.

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20 In this study the impact of network issues such as congestion are assumed to be negligible.

The impact of wind generation

2.21 A rapid growth in wind generation is expected in both the RoI and NI systems over the period to 2010. It is possible that this growth in wind generation could both increase the requirement for operating reserve – due to uncertainty over the level of wind output in any period – and reduce the number of available providers of operating reserve, as wind generation displaces conventional generation on the system.

2.22 This new wind generation is expected to comprise approximately equal capacities of distribution- and transmission-connected plant, with a large number of small developments connected at distribution voltages (i.e. embedded) and fewer but larger transmission-connected developments. Some of the large developments may be offshore[21,22].

2.23 Unlike an equivalent thermal generator, the inertia of a wind generator may, or may not, contribute to the system inertia, depending on the particular technology involved (this issue is examined in detail in section 4.25 and Annex E). A reduction in system inertia in periods of high wind generation may require more fast acting reserve to be deployed to maintain reliability standards.

2.24 Traditionally, wind generators do not provide reserve. They run at their maximum power output for a given wind speed, as the marginal costs of wind power are close to zero. If wind generation is displacing thermal plant then the sources of reserve available to the system will decline and fewer conventional units will be available to share the operating reserve burden. However, this decline does not apply to other sources of reserve, particularly reserve from interruptible load.

2.25 As output from wind generators may be difficult to predict, system operators need to maintain additional operating reserves in the event that generation levels are lower than anticipated. In the opposite scenario where more wind generation is available than expected, and under the assumption that wind power should always be used if possible, then the ability to reduce generation is required. This raises the possibility of wind being constrained off (i.e. prevented from generating) as thermal power plant can only reduce their output to a minimum level, assuming that for security reasons it is desirable to maintain a certain level of conventional plant on the system. This has recently become a very topical issue with the release of a consultation document[23].

2.26 CER's direction on wind connections[24] requires all new wind generators to be controllable by ESBNG or the Distribution System Operator (DSO), to enable their output to be constrained if necessary. This requirement may also be extended to existing connectees.

2.27 During large frequency events, there is a possibility that protection equipment on windfarms will disconnect the wind generation from the system[25]. This sympathetic tripping of wind generation, due to its very untimely nature, could have a very negative effect on system reliability and cause the need for large increases in system operating reserve levels.

2.28 As wind power penetration increases there will be an increased demand on generation units providing regulation (response through governor action) and load following due to increased variability of the wind power[26]. This issue is distinct from the setting of the required operating reserves in each category, as it relates to the actual amount of operating reserves called upon, as opposed to the amount that is required to be available.

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21 Department of Communications, Marine and Natural Resources, "Results of the sixth alternative energy requirement (AER VI) competition", July 2003.

22 Airtricity, "Arklow bank", [press release], June 2003.

23 ESBNG, "Options for operational rules to curtail wind generation", CER/04/247, 16 July 2004.

24 CER. "Wind generator connection policy: direction by the Commission for Energy Regulation". CER/04/245. 9 July 2004.

25 Persaud, S., Fox, B. and Flynn, D., "Impact of wind power variability on the dynamic operation of thermal power systems", UPEC 2000, Belfast, September 2000.

26 Persaud, S., Fox, B. and Flynn, D., "Modelling the impact of wind power fluctuations on the load following capability of an isolated thermal power system", Wind Engineering, Vol. 24, pp. 399-416, 2000.

2.29 The objective of the *Wind and Operating Reserve* study described in this report is to quantify the impact that the defined increase in wind generation (see Chapter 3) will have on the requirement and provision of operating reserve, and to estimate the economic and environmental costs involved.

Modelled operating reserve requirements

2.30 In our modelling of operating reserve requirements we have simplified the types of operating reserve into three categories, as these equate best to a combination of determinants and providers – fast reserve, slow reserve and replacement reserve. The time periods over which these apply and the ESBNG equivalent terms are summarised in Table 2.1.

Table 2.1 – Modelled operating reserve types

Operating reserve type	**Applicable time horizon** (modelled reserve)	**Equivalent ESBNG reserve definitions**
Fast	5-15 seconds	Primary operating reserve
Slow	15 seconds – 30 minutes	Secondary reserve and Tertiary operating reserve (Band 1 and 2)
Replacement	30 minutes – 4 hours	Replacement reserve

3. Overview of the Study

3.1 The objective of the study is to quantify technically and economically the impact that different levels of wind power will have on operating reserve requirements on the Irish electricity system.

3.2 To achieve this, the study has compared the operating reserve requirements on the system under a range of scenarios for variations in installed wind capacity and system operational modes. The study has been undertaken for two time horizons, 2006 and 2010. This chapter sets out the high-level assumptions and scenarios that have been adopted for the analysis. The selected scenarios and assumptions are the product of a lengthy consultation phase with a broad set of stakeholders from government bodies, system operators and the renewable and conventional generating sectors.

3.3 As described in the previous chapter, operating reserve is presently managed on an all-island basis, and our modelling reflects that.

Scenario analysis

Wind capacities

3.4 This study has been carried out for three future wind capacity scenarios, representing the two time horizons:

- Wind Scenario 1: Year 2006 with 845 MW (650 MW in RoI and 195 MW in NI) of wind capacity;
- Wind Scenario 2: Year 2010 with 1,300 MW (1,000 MW RoI and 300 MW NI) of additional wind power;
- Wind Scenario 3: Year 2010 with 1,950 MW (1,500 MW RoI, 450 MW NI) of additional wind power.

3.5 Wind Scenarios 1 and 2 are consistent with government targets for renewables in 2005 (500 MW in RoI) and 2010 respectively. Scenario 3 represents a more aggressive penetration by wind, but is consistent with the rapid growth in wind connection requests over the last year[27].

Wind generator assumptions

3.6 The following assumptions have been adopted for the size and location of new wind generating plant.

- Only a small proportion of wind capacity will be large offshore installations (10%).
- The majority of new wind capacity will be onshore and transmission connected (50%).
- Smaller, distribution connected wind generation will account for the remainder (40%).
- Where it is necessary to define the location of a wind generator, our assumed wind capacities are located in line with the location of wind connection requests to date (details of our assumed locations are provided in Annex B).

3.7 New wind generation, installed in future years, is assumed to be of variable speed design. Unlike fixed speed generators, which provide a natural inertial response, the provision of inertial response from variable speed generators is not a simple matter as it is dependent on the details of the control strategies of the particular wind turbine (considered further in Section 4.28 and Annex E).

3.8 Wind turbine technologies for 2006 and 2010 years to be studied will have the fault ride through capability that the new Grid Code requires.

27 ESB National Grid, "Interim policy on wind connections," CER/03/282, 28th November 2003.

3.9 In general, wind generators will not provide reserve. However, we have assumed that it will be possible to curtail wind production should this prove necessary, in line with the CER's direction on wind connections[28]. In these circumstances, if wind is constrained to operate at a level below the level it is capable of generating at, given the wind speed, then reserve would be available from wind generators.

Wind generation

3.10 In converting the above wind capacities into wind generation we have used actual metered generation data from the existing wind generators in Ireland to produce an annual profile of generation. This takes full account of increased diversity, the geographic spread of windfarms and technological development (described in full in Chapter 4 and Annex B). In determining the required level of operating reserve we have used this aggregate profile of wind generation to assess the extent of changes in wind generation that can occur over various time horizons and the predictability of those changes. Only unpredicted changes in wind generation will lead to an increase in operating reserve.

3.11 However, it is possible that our approach to developing an aggregate profile for wind generation, may not fully reflect all observed meteorological effects, particularly those affecting the whole of the all-island system. Further work may be required to review meteorological data to ascertain whether more rapid changes in wind speed across broad geographic areas are possible than that represented by the generation profile developed for this study. If more rapid unpredicted changes in the aggregate volume of wind generation are plausible and likely to occur at sufficient frequency to impact on generation security standards, operating reserve requirements could be higher than those reported in this study. Whilst it is worth noting that extreme weather conditions may not be fully represented in the dataset used for this study, only unpredictable effects affect operating reserve requirements. Within operating reserve timescales of a few hours or less, most meteorological effects are predictable (with varying error factors). In contrast, most unplanned outages at conventional power stations are random events and totally unpredictable.

3.12 We have utilised two wind profiles, representing high and low wind days appropriate for the season for each sample day (see section 3.22) analysed and a base case with no wind. This process is described within Annex C.

3.13 The operating reserve requirements under each of these Wind Scenarios have been compared with the operating reserve requirement where there is no wind available.

System operations

3.14 System operators strive to operate the system at least cost, subject to constraints. Operating reserve is a major constraint on any electricity system but it is particularly stringent for the all-island system because of its small size and weak interconnection with other systems (currently limited to the 500 MW Moyle dc interconnector with Scotland, which although capable of providing operating reserve, is not currently configured to do so).

3.15 Increasing operating reserve improves the reliability of the system. For meaningful comparison of electricity systems, with and without wind power, it is important to maintain consistent reliability standards. In operating a system with wind generation, system operators will have to decide how to accommodate wind in their scheduling decisions.

3.16 The study has considered a number of alternative System Operator schedule and dispatch strategies for managing an electricity system including a significant volume of wind generation, so as to be able to assess the sensitivity of operating reserve requirements both to wind levels and system operation modes. The modes considered are

- *No wind* (the base case);
- The *fuel saver* approach, whereby the system is scheduled without wind, but in real time conventional units are backed off to accommodate available wind generation;
- A *forecast* approach, where the expected levels of wind generation are included in the scheduling of the system.

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28 CER, "Wind Generator Connection Policy: Direction by the Commission for Energy Regulation". CER/04/245, 9th July 2004.

Fuel saver

3.17 In this operating mode, wind is neglected in operational planning and if the wind is available at the time of operation it displaces conventional thermal plant, i.e. fuel is saved. Conventional generation is backed-off, potentially down to the minimum level at which the plant can operate (minimum stable generation), starting from the most expensive plant operating in order to accommodate wind. This operational mode is expensive, as no plant is taken off the system completely, so dispatch may be sub-optimal, but does ensure that the reliability of the system is maintained or indeed improved. This operational mode may also cause wind to be curtailed unnecessarily, if conventional plant cannot be pulled back far enough to accommodate all available wind (either due to minimum stable generation, ramp-up or down rates or to maintain operating reserve requirements).

Forecast

3.18 For the *forecast* approach, wind generation is included in the operational planning time frame. The scheduling of plant includes an estimate for the level of wind generation that will be available, enabling a more optimal dispatch of conventional plant around the wind profile. However, it may be necessary to carry additional operating reserves to ensure that actual real time dispatch of plant is able to accommodate any changes in wind output between that forecast and that delivered.

3.19 As the amount of wind power increases this operational mode will require significant changes in the detailed operational methodologies, tools and training of personnel. Wind power forecasting will be of paramount importance.

3.20 The success of the *forecast* approach in the long term will be dependent on appropriate investment in plant that complement the nature of wind generation. This plant could be thermal generation, or dispatchable load, and the market will need to give the correct signals to encourage appropriate investment. Existing plant may also need to be upgraded in order to provide the necessary load following ability, e.g. combined cycle gas turbines (CCGTs) are normally designed for base loaded operation but may need to operate as mid merit units.

3.21 The *forecast* approach does not remove the potential requirement for wind curtailment, as it may be necessary to operate conventional capacity beyond that necessary for the optimal energy dispatch in order to ensure that sufficient operating reserve is available.

Sample demand days

3.22 With the help of the system operators, three sample days have been chosen to study the wind scenarios and the scheduling methodologies.

- Winter peak day;
- Summer valley day;
- Shoulder business day;

3.23 These sample days have been chosen to reflect the two extremes in system operation – peak demand during winter and minimum summer demand – together with a more representative operating day. The small number of days considered is limited by the complexity of the modelling required, but is considered to be representative of extreme (winter peak day and summer valley day) and more typical (shoulder business day) requirements for operating reserve.

Background assumptions

3.24 In order to keep the study focussed, several key assumptions have been made. These assumptions are based on consultations and a review of the background material provided by the industry (see Annex A).

- System reliability and security is to be maintained at current levels (see Annex B).
- The Moyle dc interconnector will not provide frequency control in 2006 but will provide limited functionality in 2010.

- There will be a new east/west dc interconnector by 2010 and it will provide limited frequency control[29].
- There will not be an all-island electricity market in 2006 but there will be by 2010.
- In 2006 and 2010 all operating reserve categories are assumed to be managed on an all-island basis.
- Most of the new additional thermal generation will be split between combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs)[30].
- Interruptible load will provide operating reserve in 2006 and 2010. The amount of interruptible load assumed is based on the results of the competition run by ESBNG for provision of this service (see Annex C).
- ESBNG and SONI generation adequacy methodologies[31] formed the basis for estimating system capacity (for conventional plant) and the nature of the plant to be added/retired from the system. The present system capacity, with the addition of presently planned additions is sufficient to meet system requirements through to 2010. Our assumed plant capacities are provided in Annex C.
- Turlough Hill, the pumped storage station, will not alter its operational methodology in 2006 or 2010[32].
- The new market for the Republic of Ireland and possible all-island arrangements will be compatible with the scheduling methodologies being investigated. The new market arrangements are discussed further in Annex A.

Modelling approach

Operating reserve requirement

3.25 This study has made use of highly sophisticated modelling techniques that have been developed over a number of years at UCD, QUB and UMIST. The analysis combines results from a number of modelling techniques:

- Wind and load modelling are used to determine load and generator fluctuations from forecast levels, and the frequency control requirements that they create.
- A dynamic frequency control model, which models the response of the system up to 20 seconds following a major contingency.
- Static year round response / reserve allocation and costing simulation tool with a stochastic wind generation model.
- The probabilistic reserve model, which assesses longer-term frequency control issues (20 seconds onward).

3.26 Our modelling approach is discussed in detail in Annex B. The results of the wind and load modelling, and the impact on operating reserve requirements are presented in Chapter 4.

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29 The correlation of wind generation between Great Britain and Ireland is not explicitly considered in this study. However, with greater levels of interconnection, this issue may become more relevant.

30 CCGTs are more efficient and produce significantly lower emissions, but have high capital costs. OCGTs have high marginal costs, due to their lower efficiencies, but lower capital costs, and are better suited to peaking operation in the energy markets and the provision of reserve.

31 ESBNG, "Generation Adequacy Report 2004 - 2010", November 2003.

32 The operation of Turlough Hill within the new market and with significant amounts of wind penetration may change; however, the manner of such a change is hard to predict and is outside the scope of this study.

Operating reserve costs

3.27 The financial and environmental costs of any requirement for additional operating reserve have been calculated by comparing the operation of plant providing operating reserve in the *no wind* base case with those in the various wind scenarios. Environmental and operating costs may arise from the increased use of fuel in additional plant start-ups and in the part-loading of generators, where plant are operated at sub-optimal efficiency.

3.28 Traditionally, conventional generating plant is used for providing operating reserve. In order for synchronised plant to provide operating reserve (and response), it must run part-loaded. Thermal units operate less efficiently when part-loaded, with an efficiency loss of between 10% and 20%, although losses in efficiency could be even higher, particularly for new gas plant. Since the flexible generating units will be part-loaded to provide the operating reserve, other units will need to be brought on the system to supply energy that was originally allocated to these flexible plant. This usually means that plant with higher marginal cost will need to run, and this is another source of cost associated with the provision of operating reserve.

3.29 In addition to synchronised reserve, that is provided by part-loaded coal and CCGT plant, the reserve task can be carried out by so called standing reserve, that is supplied by higher fuel cost plant, such as OCGTs and backup generation.

3.30 The allocation of operating reserve between synchronised and standing plant is a trade-off between the cost of efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with relatively high marginal cost. Cost of using storage[33] for this task will be primarily driven by its efficiency. The balance between synchronised and standing reserve could be optimised to achieve minimum overall operating reserve cost. Clearly, synchronous plant will be used to accommodate relatively frequent but comparatively small imbalances between generation and demand while standing reserve will be used for absorbing less frequent but relatively large imbalances. When considering this balance between synchronised and standing reserve, start up cost associated with committing part-loaded plant to provide response and reserve together with the cost of associated with plant inflexibility (particularly minimum up times) should be considered.

3.31 In contrast to other studies (such as SCAR[34]), this analysis is not based on the statistical assessment of system operation employing an analytical (closed form) solution technique, but on a more detailed simulation of the operation of the system. Using the concept of characteristic days we simulated operation of the all-island system taking into consideration daily and seasonal demand variations combined with variations in wind regime. One of the key advantages of this approach is the ability to take into account specific dynamic characteristics of plant and associated cost parameters (e.g. part load efficiency losses) and hence quantify more precisely the additional cost associated with accommodating wind generation.

3.32 The costs of providing operating reserve are presented in Chapter 5. This study has assessed the total requirement and costs for operating reserve in an all-island electricity market. We have not attempted to distinguish between whether these costs are incurred by market participants or by the system operator, but rather to calculate what the cost of the optimal provision of the operating reserve requirement would be.

3.33 The capital costs of conventional and renewable plant are outside the scope of this study and report. This study has not considered issues of the assimilation of wind generation into the wider electricity market.

33 SEI, "Study of electricity storage technologies and their potential to address wind energy intermittency in Ireland", May 2004.

34 ILEX and Strbac, G., '"Quantifying the [GB] system costs of additional renewables in 2020". DTI, October 2002. [www.dti.gov.uk/energy/developep/080scar_report_v2_0.pdf]

4. Impact of Wind on the Physical Requirements for Operating Reserve

Wind modelling results

4.1 Historical wind data was scaled up as described in detail in Annex B to produce 15-minute wind data for the future scenarios, i.e. 2006, 2010A, 2010B.

Wind forecasting

4.2 The impact that additional wind capacity will have on system operating reserve levels (as described in Section 2.7) will depend on the increased uncertainty generated by the wind power forecasting errors[35].

4.3 Recent work demonstrated that for time horizons of less than three to four hours, modern statistical techniques offer a slight improvement over conventional persistence based prediction methods[36]. However, for longer time horizons considerable improvements can be obtained by adopting more sophisticated forecasting techniques that would require meteorological forecasting tools.

4.4 Analysis of the wind data revealed that the wind forecast error was largely independent of wind production. Figure 4.1 illustrates that for wind outputs of between 20% and 80% of installed capacity the persistence error is approximately constant. This finding is also supported by the analysis in Watson & Landberg[37]. Therefore, in this study the wind forecast error was taken to be a function of the forecasting time horizon only.

4.5 The methodology used here can accommodate more advanced forecasting techniques using, for example, Meteo-Risk indices[38]. These techniques are particularly suited to examining longer time horizons.

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35 In this study, forecasting errors are quantified as standard deviations.

36 Persistence forecasting assumes that the observed output in the previous period is maintained in the subsequent period(s). By its nature, persistence forecasting is unable to forecast sudden short-term changes.

37 Watson, R. and Landberg, L., “Evaluation of the Prediktor power forecasting system in Ireland”, Proc. European Wind Energy Conference, Madrid, June 2003.

38 Pinson, P. and Kariniotakis, G., “On-line assessment of prediction risk for wind power production forecasts”, Wind Energy, Vol. 7, No. 2, 2004.

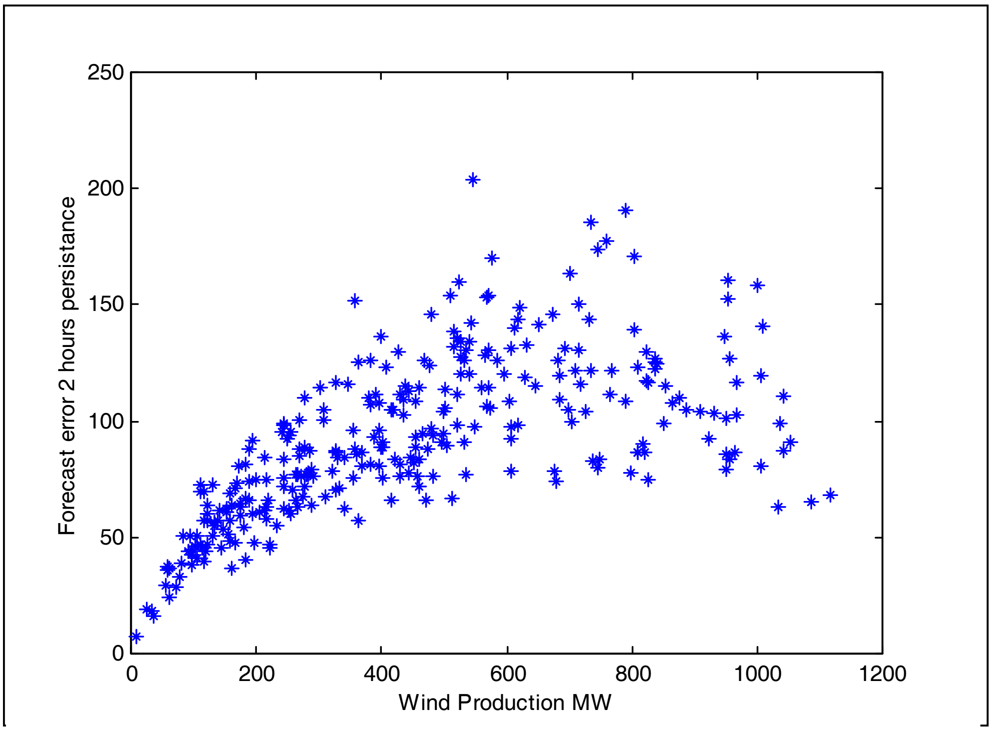

Figure 4.1 – Scatter plot of forecast error (based on 2 hour persistence) against MW output for 1,300 MW of installed wind capacity.

4.6 Correlation between individual windfarm forecast errors is an important issue, as it has the potential to significantly increase the overall uncertainty that the system is exposed to from increased wind capacity. Any error in the meteorological forecasts can cause the forecast errors of individual windfarms to become correlated. It should be noted that this correlation is distinct from the correlation between individual windfarm outputs, which do not expose the system to greater levels of uncertainty.

4.7 The correlation between wind power forecast errors, for different time horizons, of individual windfarms is strongly dependent on the distance between the windfarms. For this study, a model has been developed, which recognises the correlation of wind power forecast errors as a function of the distance between the windfarms (Annex B).

4.8 Figure 4.2 shows the correlation coefficient of one hour forecast errors as a function of distance between windfarms. Over a one hour period, persistence forecasting is assumed to be close to the best performance. The data is historical and the curve is a fit to the data. Further details are given in Annex B.

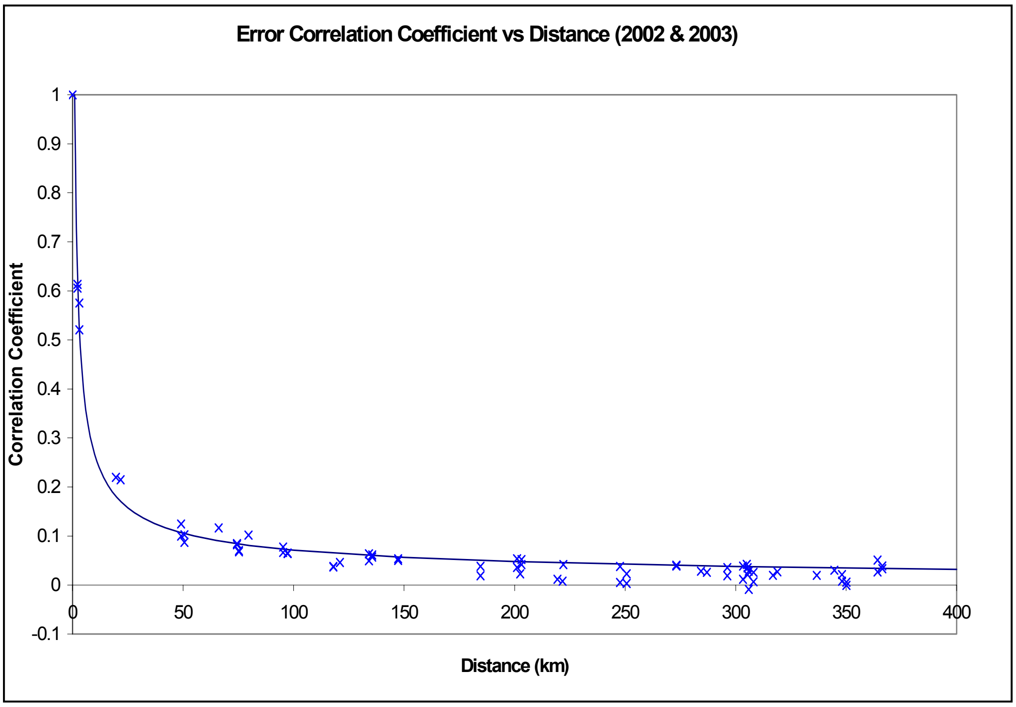

Figure 4.2 – Correlation of one hour forecast error as a function of distance

4.9

Figure 4.3 shows the correlation coefficient of forecast errors as a function of distance between windfarms. Four different forecast horizons are illustrated. The curves shown are fits to data. Forecasting for the 15 minute and for the 1 hour horizons utilise the persistence approach. Forecasting for 6 hours is taken from a modelling approach[39] applied to the Irish system. The four-hour forecasting is based on a combination of modelling techniques and data analysis (Annex B). Neglecting this correlation could result in an underestimation of the total wind forecast error.

39 Watson, R. and Landberg, L., "Evaluation of prediktor wind power forecasting system in Ireland," Proc. Madrid 2003 European Wind Energy Association Conference, June 2003.

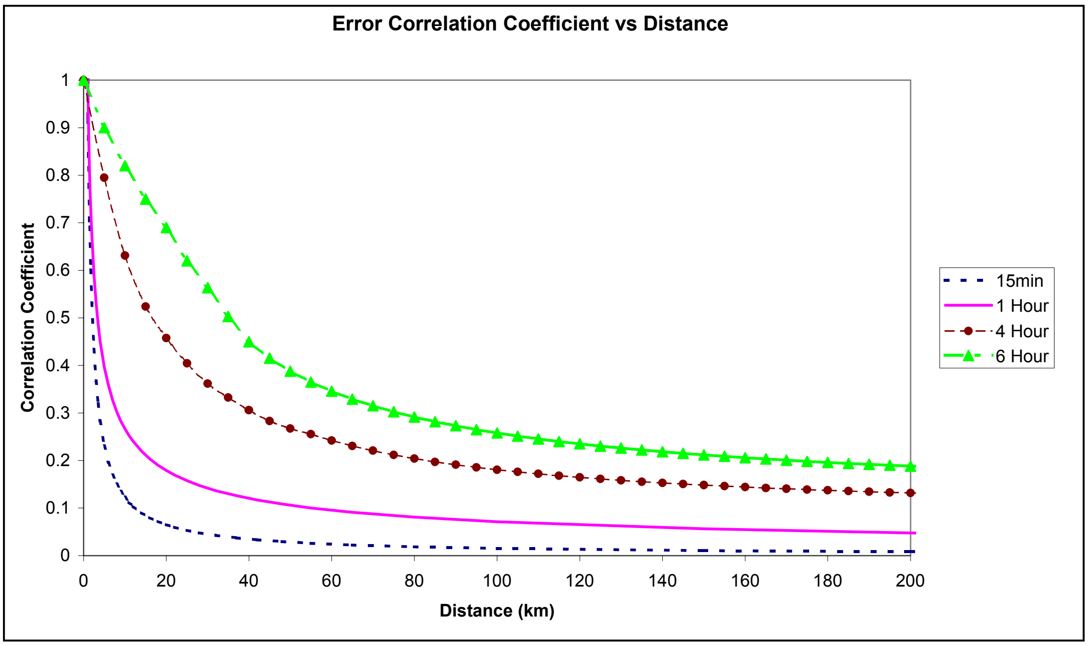

Figure 4.3 – Correlation of forecast error as a function of distance for different forecast horizons (15 minute, 1 hour, 4 hour, 6 hour)

4.10 Based on the literature and analysis of the historical data,
Figure 4.4 gives an approximation to the wind forecast error (normalised to capacity) for an individual windfarm on the all-island system.

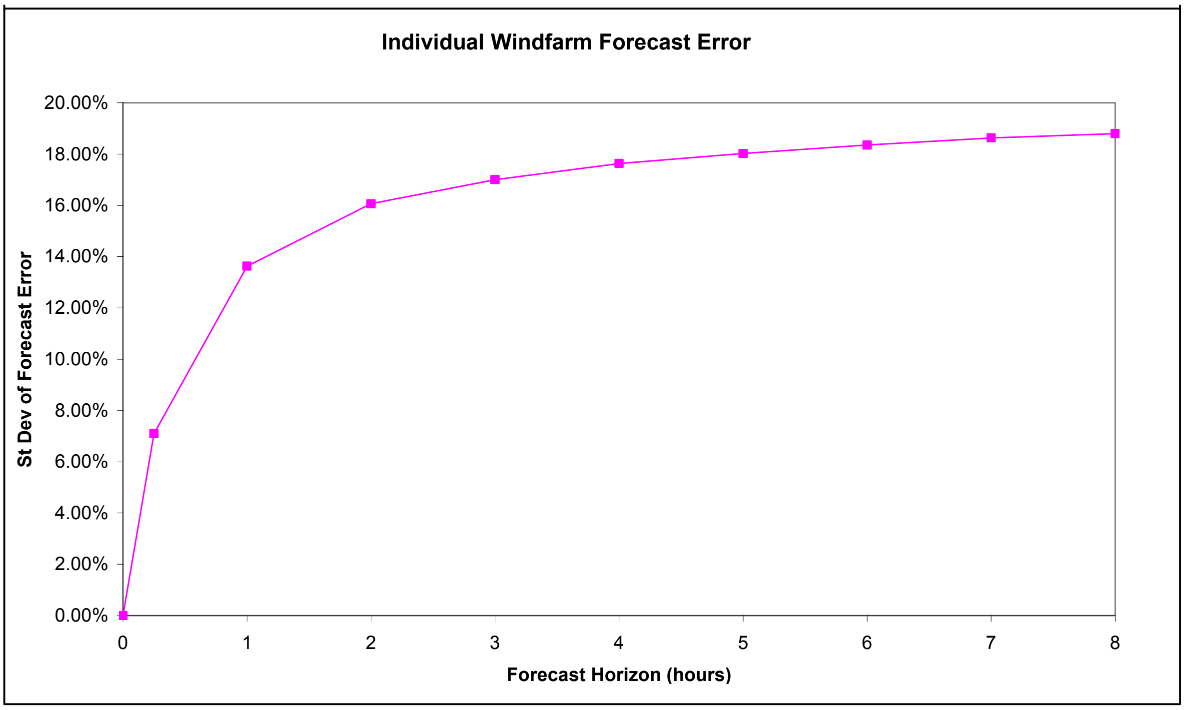

Figure 4.4 – Individual forecast error normalised to windfarm capacity

4.11 Combining the information in Figure 4.3 and Figure 4.4 in the manner described in Annex B allowed an estimate for the wind forecast error for the all-island system for future scenarios to be generated.

4.12 Figure 4.5 quantifies the wind forecast error for increasing forecast horizons for the different scenarios being studied here (2003[40], 2006, 2010A & 2010B). As can be seen the forecast error increases with forecast horizon and with higher wind capacity scenarios.

4.13 Figure 4.6 quantifies the wind forecast error for increasing wind capacities for a selection of forecast horizons. The lowest installed wind capacity is taken to be one windfarm (Figure 4.4). The horizons chosen are fast (1.25 minutes), slow (30 minutes), 1 hour and 4 hours. The forecast error is normalised to capacity in Figure 4.6. Figure 4.6 illustrates that, as a percentage of capacity, the forecast error decreases with installed capacity for all forecast horizons[41] but that this decrease is limited and may reach saturation. This phenomenon is a result of the assumed diversity (Annex B).

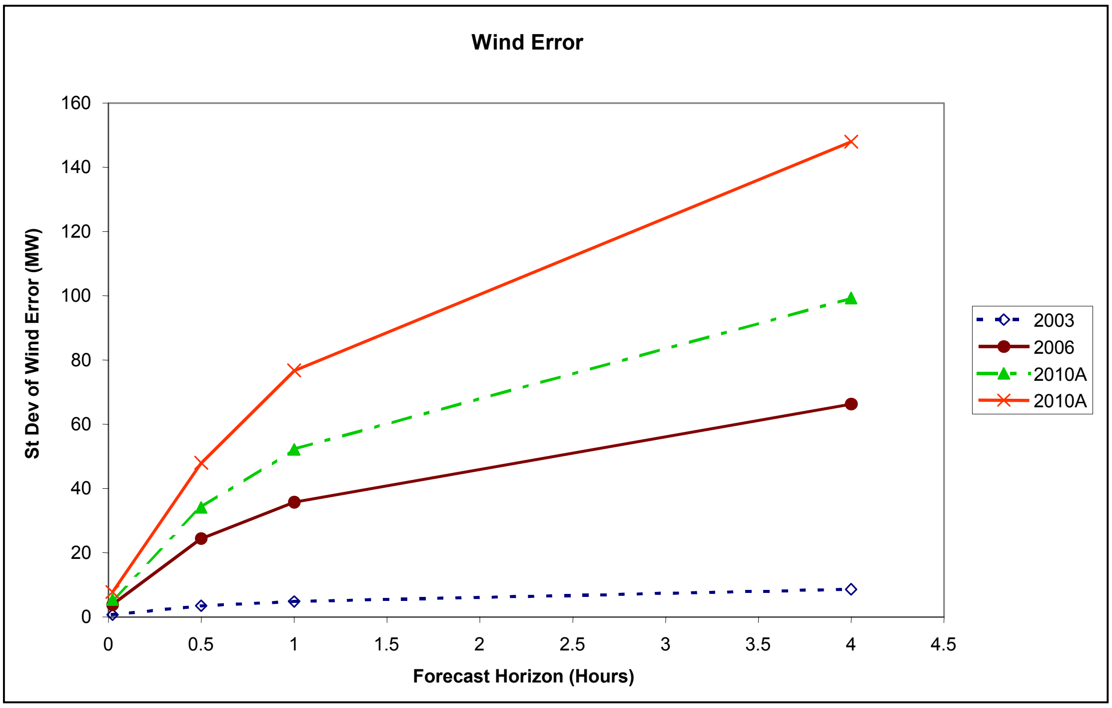

Figure 4.5 – Wind forecast error as a function of forecast horizon for 2003 and the 2006, 2010A & 2010B scenarios

40 While 2003 is not a future scenario, it is included as a baseline scenario for comparative purposes.

41 Not all horizons were tested and therefore this is an extrapolated assumption.

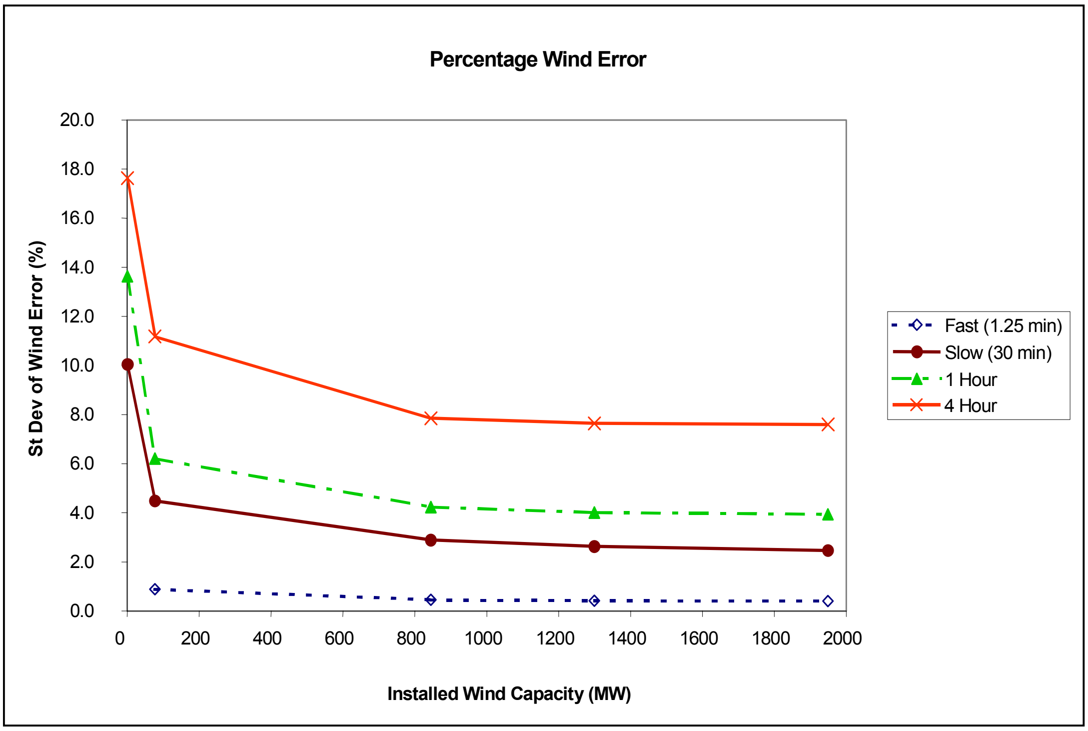

Figure 4.6 – Normalised wind forecast error as a function of installed capacity for different forecasting horizons (fast (1.25 minutes), slow (30 minutes), 1 & 4 hour).

Load forecasting

4.14 For the probabilistic assessment of operating reserve, load forecast error information is important. It is well known that load forecast errors are sensitive to the forecast horizon. Information gathered from the two system operators (ESBNG & SONI) indicated that 40 MW is a good approximation to the 1 hour load forecast error and that 60 MW is a good approximation to the 4 hour error. The estimates of the load forecast error are scaled appropriately to account for shorter horizons[42] (Table 4.1).

Table 4.1 – Load Forecast Error

Timeframe	Std Dev of Error (MW)
Fast (1.25 minutes)	5.8
Slow (30 minutes)	28.3
Replacement (1hour)	40.0
Replacement (4 hour)	60.0

[42] Doherty, R. and O'Malley, M.J., "Quantifying reserve demands due to increasing wind power penetration, *IEEE Power Tech*, Bologna, Italy, June 2003.

System errors

4.15 Load and wind forecast errors are combined for different time horizons to produce system forecast errors. The methodology used is that described by Doherty and O'Malley[43], and makes use of the following equation

$$\sigma_{system} = \sqrt{\sigma_{load}^2 + \sigma_{wind}^2} \quad (4\text{-}1)$$

where σ_{system}, σ_{load} and σ_{wind} denote the standard deviations of the system error, load error and wind error respectively. The resulting system forecast errors are plotted in Figure 4.7 and Figure 4.8.

4.16 Figure 4.7 shows the system (wind and load) forecast error as a function of forecast horizon. Four different wind scenarios are illustrated in Figure 4.7: 2003, 2006, 2010A & 2010B.

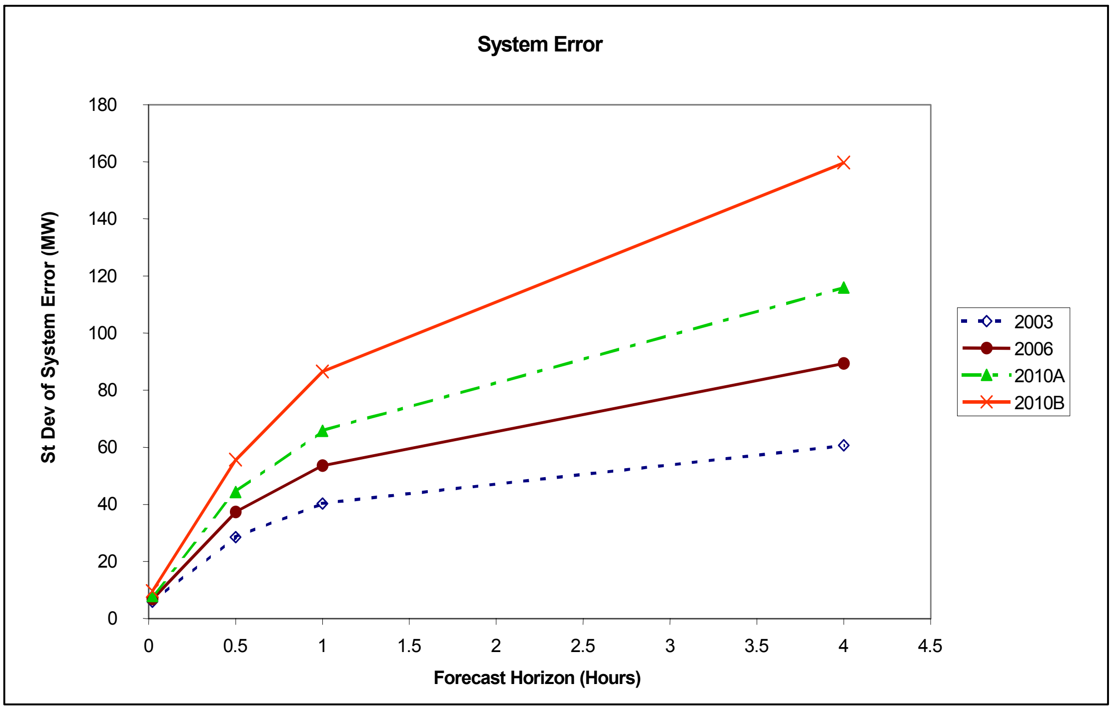

Figure 4.7 – System forecast error as a function of forecast horizon for different wind scenarios (2003, 2006, 2010A & 2010B).

4.17 Figure 4.8 shows the system (wind and load) forecast error as a function of wind capacity for four different forecast horizons. The four forecast horizons are fast (1.25 minutes), slow (30 minutes), 1 hour and 4 hours. The forecast error increases with wind capacity and the increase is more pronounced for the 4 hour horizon.

[43] Doherty, R. and O'Malley, M.J., "New approach to quantify reserve demand in systems with significant installed wind capacity", *in review*, 2004.

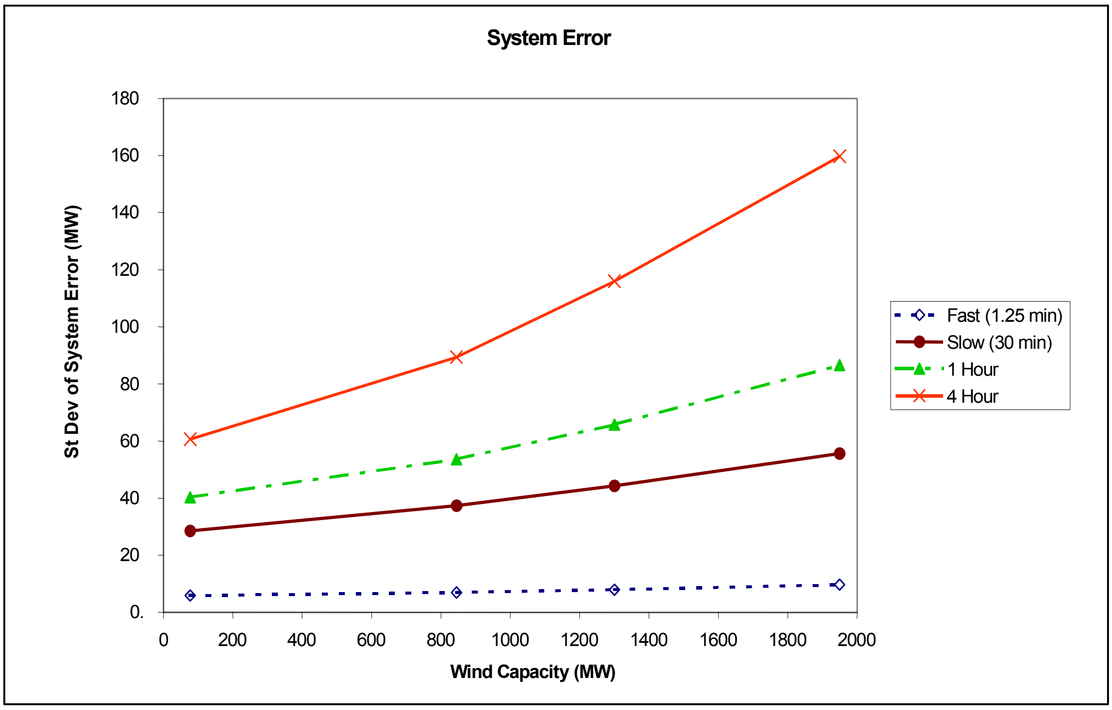

Figure 4.8 – System forecast error as a function of installed capacity for different forecasting horizons.

Operating reserve targets

4.18 For the sample days and wind scenarios, operating reserve targets need to be set. These operating reserve targets are a function of the largest credible loss (largest infeed typically), reliability of the generators, the level of system reliability required and in particular the system error (Figure 4.8). The relationships are complex and involved but can be calculated. A methodology for calculating the operating reserve targets has been developed. Further details are available in the literature[44,45,46] and in Annex B.

4.19 The operating reserve targets impact on the dispatches and the dispatches impact on the operating reserve targets. Therefore, the dispatches and the operating reserve targets should be dealt with simultaneously, if possible. A completely integrated algorithm of this nature is under development but is not yet fully available. What has been developed for this study is a look up table synopsis of a broad range of results[47] that is used to inform the operating reserve targets for the sample day dispatches.

4.20 The reliability criterion used in this study is load-shedding incidents per annum, i.e. the number of times an incident causes load (not interruptible) to be shed. The operating reserve targets are a function of this criterion. It was set in this study such that when applied to the current system the targets were virtually the same as the existing targets.

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44 Doherty, R. and O'Malley, M.J., "New approach to quantify reserve demand in systems with significant installed wind capacity", *in review*, 2004.

45 Doherty, R., Denny, E. and O'Malley, M.J., "System operation with a significant wind power penetration", *IEEE PES General Meeting*, Denver, June 2004.

46 Doherty, R. and O'Malley, M.J., "Quantifying reserve demands due to increasing wind power penetration", *IEEE Power Tech*, Bologna, Italy, June 2003.

47 Load and wind statistics, forecast horizon, largest infeeds, etc.

4.21 Figure 4.9 shows the operating reserve targets (fast, slow, 1 hour and 4 hour) as a function of wind capacity, which are dominated by the assumed largest infeed[48] (400 MW). This dominance by the largest infeed is only significantly impacted on for long time horizons at high wind penetrations. Only very small amounts of additional faster reserves are required even for large wind penetrations.

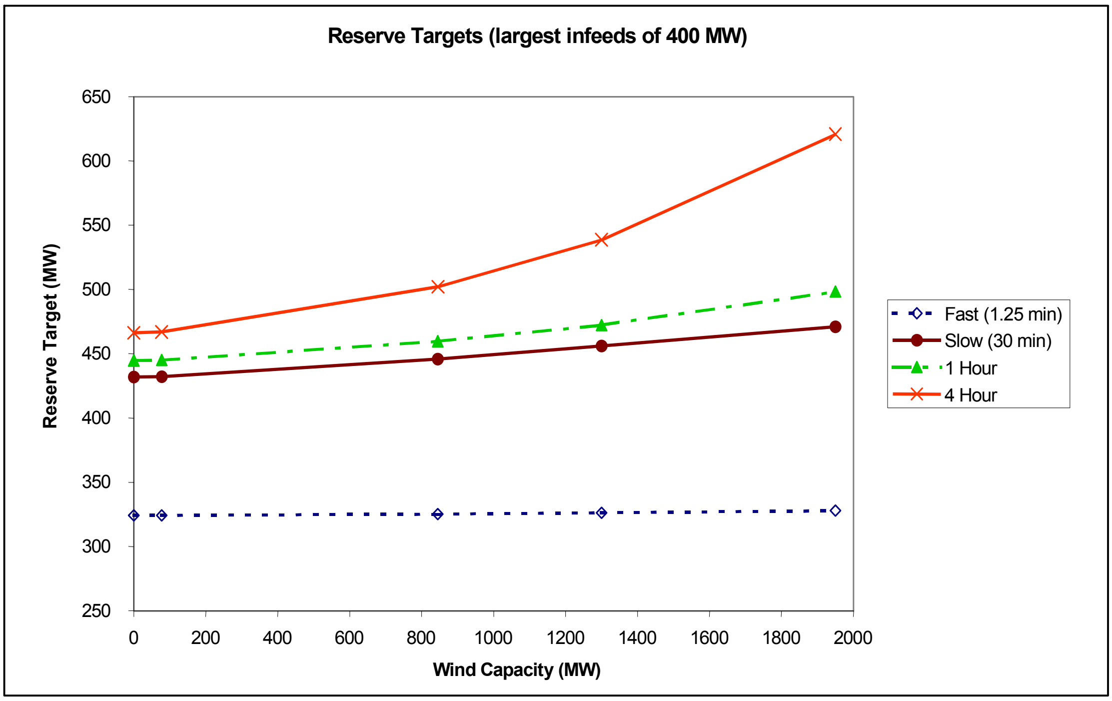

Figure 4.9 – Operating reserve targets, largest infeed 400 MW, as a function of wind capacity for different horizons (fast (1.25 mins), slow (30 mins), 1 hour & 4 hour).

4.22 Improvements in wind forecasting will reduce the system error (Figure 4.8), which will in turn reduce the amount of additional operating reserve required to accommodate wind.

4.23 Figure 4.10 shows the required levels of operating reserve as a function of forecast horizon for four different scenarios, with an assumed largest infeed requirement of 400 MW. Wind generation does not significantly increase the need for fast acting reserve (1.25 minutes) and only really starts to have an impact at the 30 minute horizon and beyond. For the high wind scenario (2010B), there is a substantial increase in the need for operating reserve over longer horizons.

48 The fast reserve target may look out of place here however it should be emphasised that the system operators on the island of Ireland only carry a percentage (80%) of the largest infeed as fast reserve.

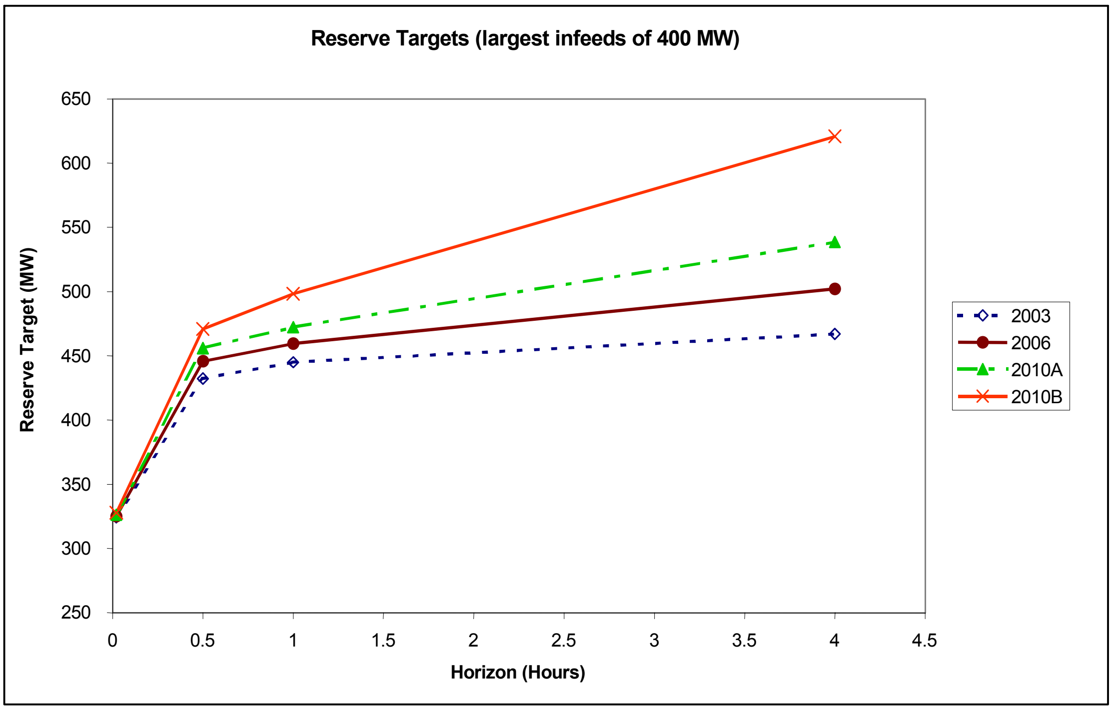

Figure 4.10 – Operating reserve targets, 400 MW largest infeed, as a function of forecast horizon for different wind scenarios (2003, 2006, 2010A & 2010B).

4.24 Operating reserve targets are a function of largest infeed and Figure 4.11 shows the slow reserve target as a function of wind capacity for varying levels of largest infeed. Figure 4.12 shows the 4-hour reserve target as a function of wind capacity for varying levels of largest infeed.

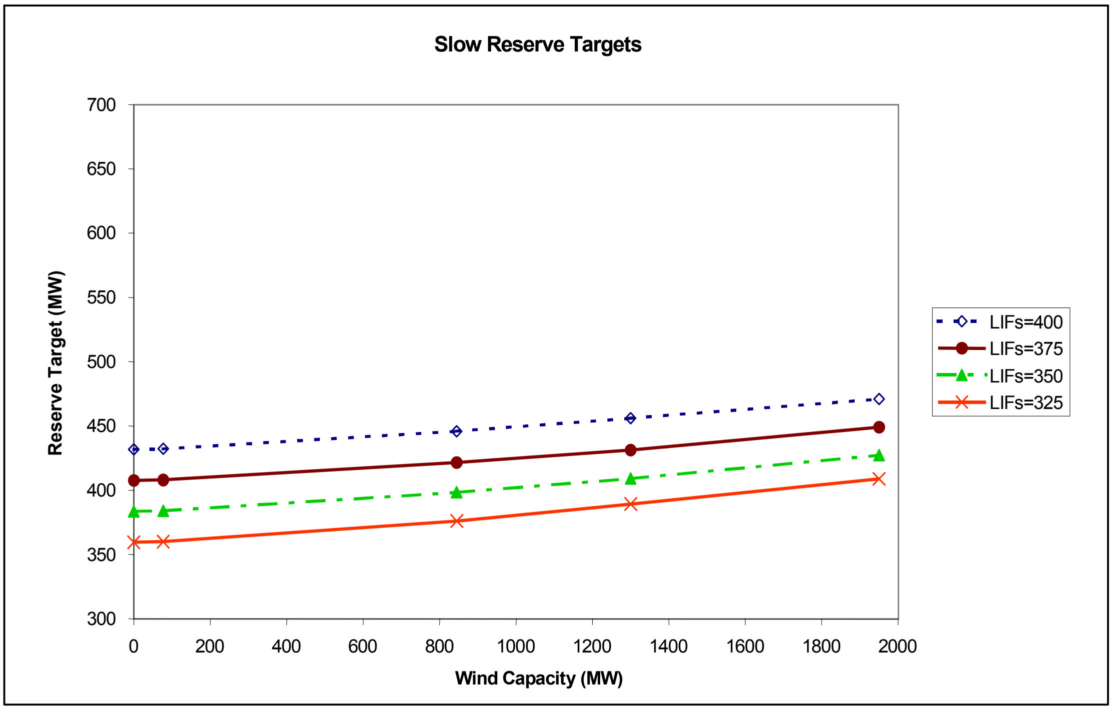

Figure 4.11 – Slow reserve target as a function of wind capacity for different largest infeeds (LIFs).

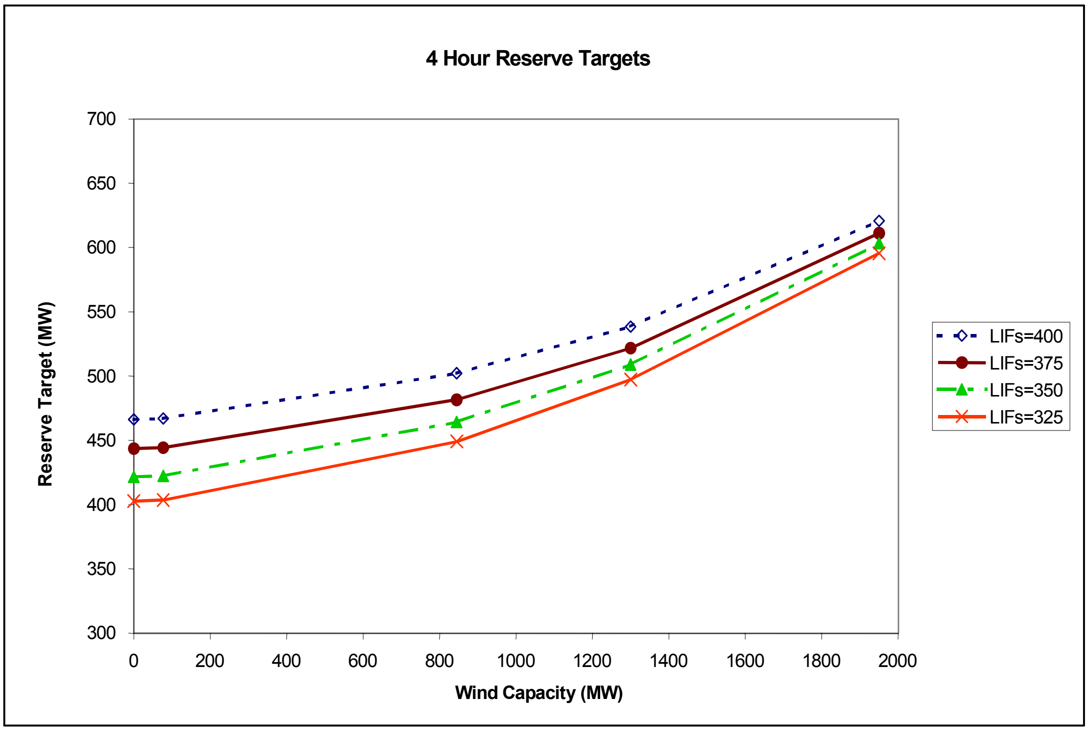

Figure 4.12 – 4 hour reserve target as a function of wind capacity for different largest infeeds (LIFs).

Short term frequency dynamics

4.25 Most of the fast-acting reserve being carried on the all-island electricity system is there to arrest the frequency fall in the event of a large contingency. Large contingencies include the loss of the largest infeeds – generators and interconnectors – and, typically, this represents a power loss in the region of 300 - 400 MW.

4.26 Following the loss of a large generator (or interconnector), the frequency will fall rapidly. This rapid fall in frequency will activate the operating reserves through governor action on generators (dynamic reserve), and frequency sensitive relays on pumped storage units, reactors and interruptible load (static reserve). The load is frequency sensitive and inherently provides a certain amount of the operating reserve in the event of a contingency[49].

4.27 Following a contingency, the initial rate of change of frequency is determined by the inertia on the system. There is a very complex relationship between this initial rate of change of frequency and the frequency nadir[50]. Reducing the inertia on the system will increase the need for operating reserve in order to maintain the frequency above the load-shedding region. The exact nature of the relationship between inertia and operating reserve is very complex and is outside the scope of this study.

49 O'Sullivan, J. and O'Malley, M.J., "Identification and validation of dynamic global load model parameters for use in power system simulation", *IEEE Transactions on Power Systems*, Vol. 11, pp. 851 - 857, 1996.

50 Lalor, G., Ritchie, J., Rourke, S., Flynn, D. and O'Malley, M.J., "Dynamic frequency control with increasing wind generation", *IEEE PES General Meeting*, Denver, June 2004.

4.28 The contribution of wind turbine generators to system inertia is an unresolved and somewhat controversial issue. Synchronous generators connected to the electricity system contribute to the system inertia in a reasonably straightforward and quantifiable manner. However wind turbine generators do not normally fall into this category (i.e. synchronous generators), and while they do have inertia, it is unclear how they contribute to the system inertia. To quantify this inertial contribution is non-trivial and requires detailed information relating the control strategies, steady-state operating point, wind levels, individual machine characteristics (e.g. fixed or variable speed operation) and dynamics. Much of this detailed information is simply not available and there is a need for this data to be gathered. This issue is analysed and discussed in detail in Annex E.

4.29 Representing the wind turbine generators in the short-term dynamic frequency model for the all-island electricity system requires development of some new model components. The development and details of these new components are described in Annex E. Tuning of such models across the entire range is virtually impossible because of the dearth of reliable dynamic data for a large range of operational scenarios and technologies.

4.30 The approach taken here is to investigate a small number of cases in order to identify the important issues regarding frequency control and the potential need for additional operating reserve.

Problematic schedule

4.31 The short-term frequency dynamic model developed by University College Dublin and The Queen's University of Belfast over the past ten years is used to investigate these two issues[51,52]. Experience gained over the years in developing this model is used to choose a problematic representative schedule from the multitude of future year dispatches generated in this study. This schedule is 10.30, Summer valley day 2010B scenario. It is chosen on the basis of plant mix, low system demand (3,582 MW), operating reserve sources, wind generation (1,294 MW) and the size of largest infeed (346 MW).

Case A

4.32 Annex E indicates that fixed speed wind turbines do contribute to system inertia. However, the contribution of wind turbines using doubly fed induction generators (DFIGs) is influenced by the control scheme.

4.33 The frequency excursion for the loss of the largest infeed (346 MW) is shown in Figure 4.13. Four different scenarios are considered.

- All wind generation technology is of the fixed speed type.
- All wind generation is of the variable speed type, i.e. doubly fed induction generators, and it is assumed they have no inertial contribution.
- All wind generation is of the variable speed type, i.e. doubly fed induction generators, and it is assumed that the speed controller is slow acting.
- All wind generation is of the variable speed type, i.e. doubly fed induction generators, and it is assumed that the speed controller is fast acting.

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51 Lalor, G., Ritchie, J., Rourke, S., Flynn, D. and O'Malley, M.J., "Dynamic frequency control with increasing wind generation", *IEEE PES General Meeting*, Denver, June 2004.

52 O'Sullivan, J. and O'Malley, M.J., "Identification and validation of dynamic global load model parameters for use in power system simulation", *IEEE Transactions on Power Systems*, Vol. 11, pp. 851 - 857, 1996.

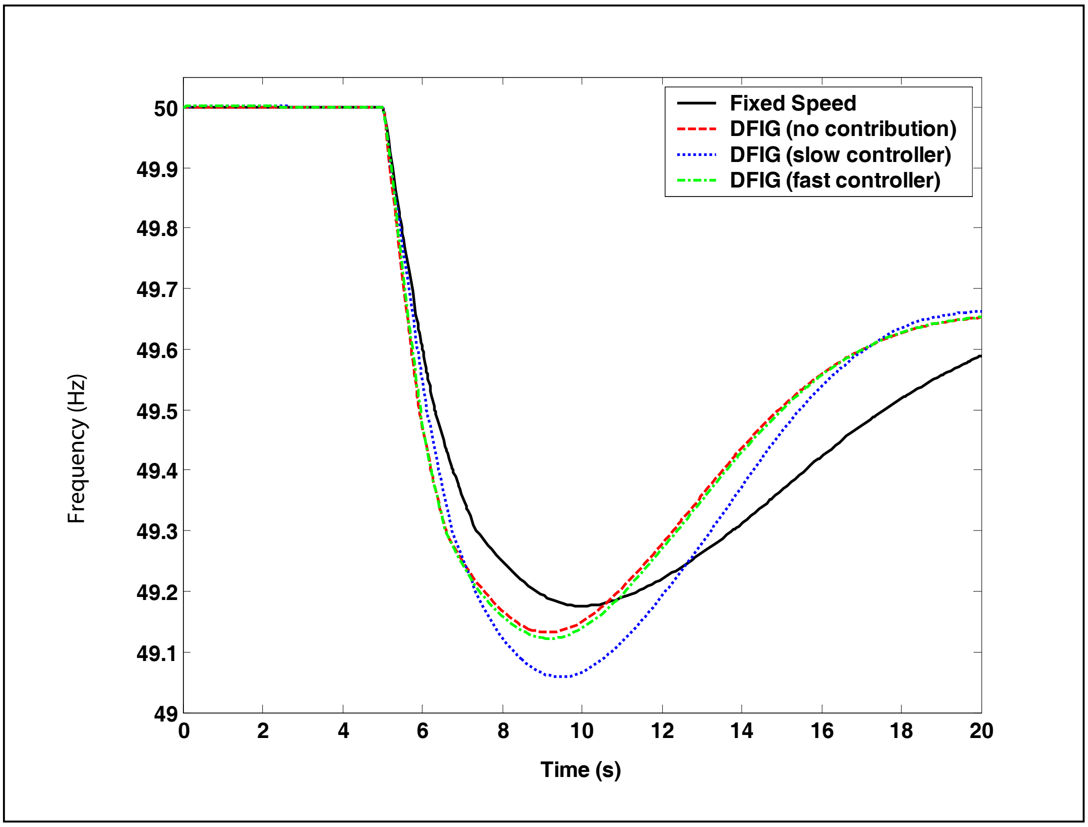

Figure 4.13 – Frequency transient following the loss of the 346 MW (medium wind speed distribution)

4.34 Of the wind turbines, 50% are assumed to be stall controlled and 50% pitch controlled. A medium wind distribution is assumed (see Table 4.2) which indicates that 1,938 MW of wind capacity is on line. Because of the medium wind speed assumption, the majority of wind turbine generators are assumed to be operating close to the peak of the C_P surface (in a region where the surface is relatively flat). Therefore, changes in rotational speed will have minimal impact on changing the power captured from the wind regardless of pitch/stall control (Annex E).

Table 4.2 – Wind-speed distribution

	Wind Distribution	
Wind Speed	*Medium*	*High*
7 m/s	6.5%	—
11 m/s	85%	10%
18 m/s	8.5%	90%

4.35 Figure 4.14 shows the corresponding responses for each of the wind technologies considered in case A, i.e. fixed, DFIG (no inertial contribution), DFIG (slow controller) and DFIG (fast controller).

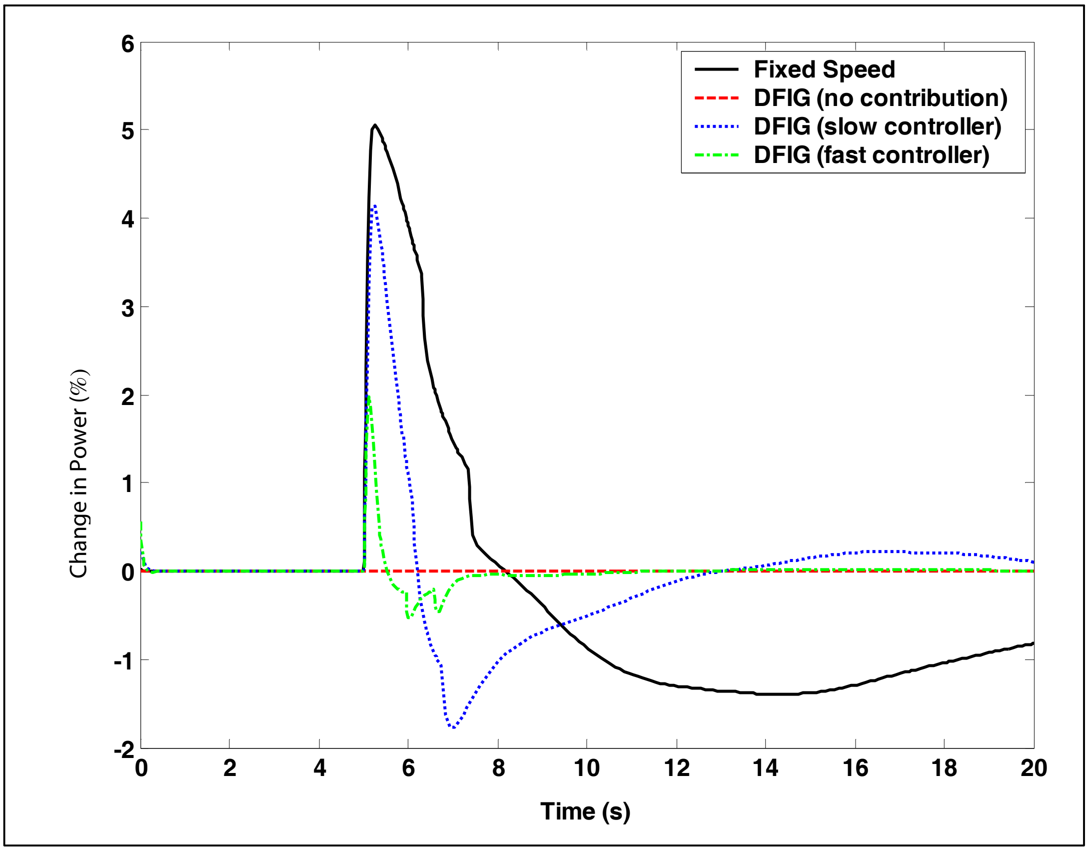

Figure 4.14 – Normalised response of the four scenarios in case A.

4.36 Fixed speed wind turbines contribute to system inertia in a similar fashion to conventional generation. With the assumption that DFIGs have no contribution to system inertia, it can be seen (
Figure 4.13) that the frequency initially falls at a faster rate than for the fixed speed case, and the resulting frequency nadir is lower. DFIGs with slower acting speed controllers initially contribute to system inertia, slowing the initial rate of fall. However, as the speed controller acts to restore the rotational speed to the set-point value, power is absorbed from the system, in this case prior to the nadir being reached, resulting in a lower nadir. The impact of DFIGs equipped with fast controllers is very similar to the no contribution case, as inertial contribution is almost negligible due to minimal change of rotational speed.

4.37 It is clear from the above that the tuning of the speed controller has significant effect on the inertial response of the DFIG following a contingency, and the resulting frequency nadir.

Case B

4.38 Analysis in Annex E indicates that if the action of the pitch control system is neglected, at high wind speeds, the response of installed wind turbines to a large system frequency event will be dependent on the ratio of pitch-controlled to stall-controlled turbines. To highlight the possible difference between pitch and stall regulated performance at high wind speeds, a high wind distribution is assumed (see Table 4.2), which indicates that 1,338 MW of wind capacity is on line. Figure 4.15 shows the frequency excursion for four different scenarios.

- 100% pitch controlled (fixed and variable speed technologies) with a trip of 346 MW (largest infeed)
- 100% stall controlled (fixed and variable speed technologies) with a trip of 346 MW (largest infeed)
- 100% pitch controlled (fixed and variable speed technologies) with a trip of 356 MW (largest infeed plus 10 MW)
- 100% stall controlled (fixed and variable speed technologies) with a trip of 356 MW (largest infeed plus 10 MW)

4.39 In this case a fixed to variable speed split of 30:70 was assumed.

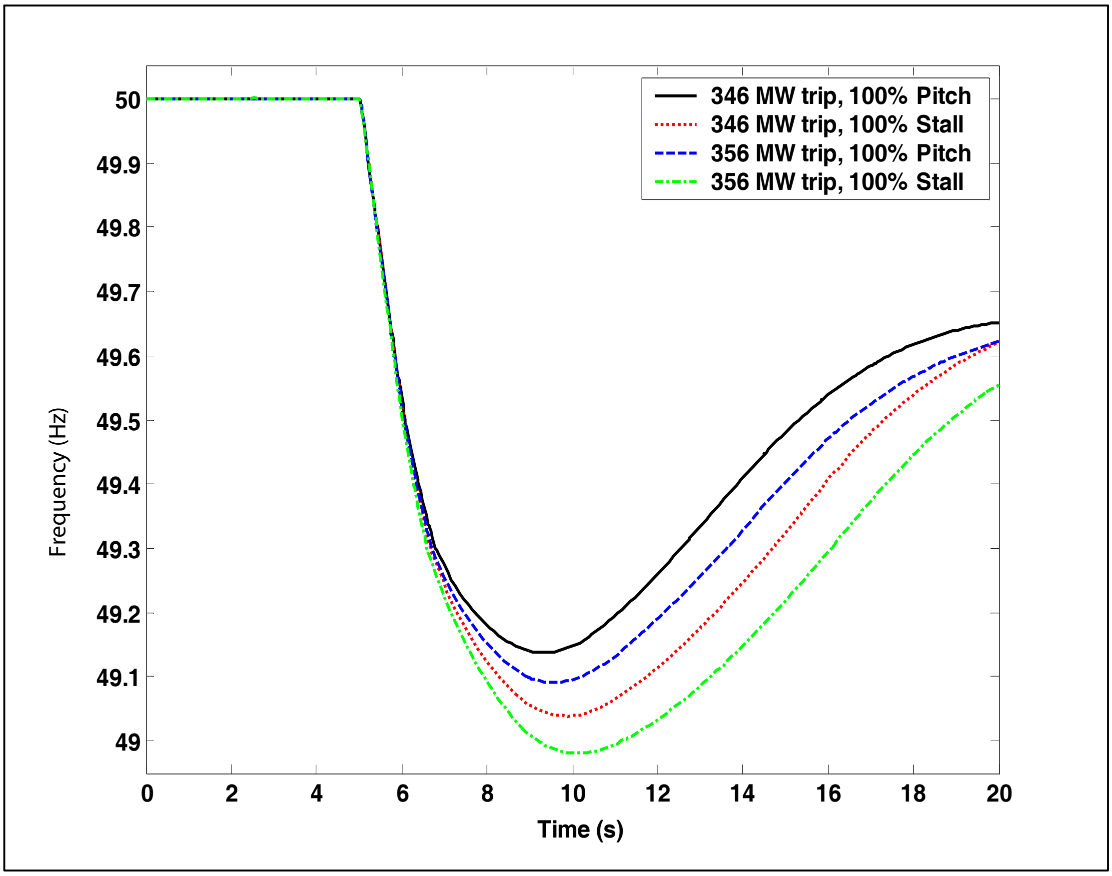

Figure 4.15 – System frequency transient for Case B (high wind speed distribution)

4.40 Assuming the action of the pitch control system is neglected, following the loss of 346 MW, the largest infeed, the frequency falls further for the case of stall regulated machines. This is due to the effect whereby, when operating at high wind speeds in the stall region, decreasing rotational speed results in a reduction in power capture from the wind. For the pitch control case, the turbine is operating in the lift region where a reduction in rotational speed will not result in reduced power capture.

4.41 When the size of the contingency is increased by 10 MW, mimicking a small load and/or wind variation at the time of the event, the frequency nadir drops to below 49 Hz, in the case where all wind turbines are stall controlled. Even with a 10 MW increase in the size of the contingency, the response in the case of pitch controlled wind turbines is less severe than for the stall control wind turbines in the event of the smaller contingency.

Case C

4.42 As illustrated in case B, assuming the action of the pitch control system can be neglected, the response of stall and pitch regulated wind turbine generators will differ at high wind speeds. As the performance of pitch and stall regulated wind turbine generators are comparable for below rated wind speeds (Annex E), it is important to examine the effect of different wind distributions on the performance of a stall regulated wind turbine generator. In this case, 100% of the wind turbine generation is assumed stall regulated and two different wind distributions are simulated: medium and high (see Table 4.2).

4.43 In this case a fixed to variable speed split of 30:70 was assumed. The system frequency response following a contingency is shown in Figure 4.16.

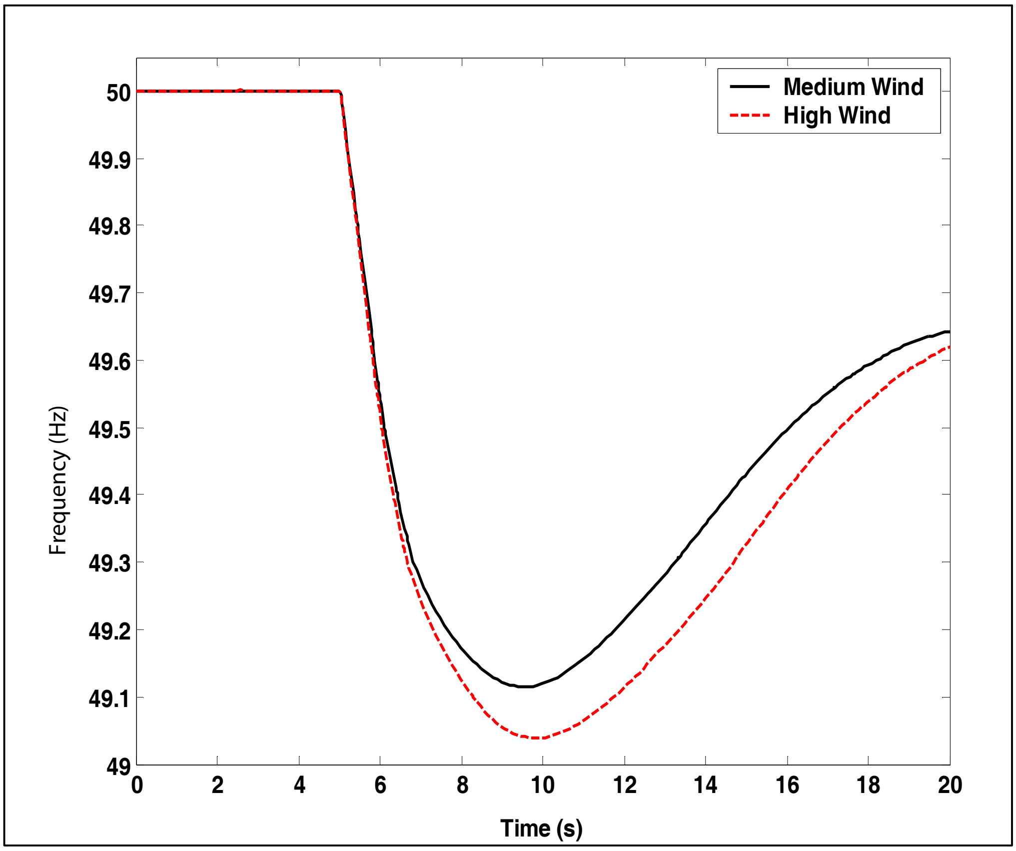

Figure 4.16 – System frequency transient for Case C (loss of 346 MW)

4.44 At the medium wind distribution, the majority of stall regulated wind turbine generators are generating with a wind speed of 11 m/s, and are therefore operating close to the peak of the C_P surface. In this region of operation, the slope of the C_P surface is relatively flat. Therefore, changes in rotational speed have minimal influence on changing the power captured from the wind. At high wind speeds, however, stall regulated wind turbine generators operate in the stall region, where a reduction in rotational speed will result in a reduction in power captured from the wind, thus causing the increased drop in the frequency nadir illustrated in Figure 4.16.

Summary

4.45 It is important to look at the frequency response of wind turbine generators, and there are two mechanisms at work. The first is the inertial response, which depends on the actual change in rotational speed of the wind turbine generator. The second is the subsequent effect of rotational speed variations on wind turbine generator power extraction from the wind. In Case A, the effect of inertial contribution on system frequency was examined, and the frequency falls faster when wind turbine generators provide no inertial contribution. The influence of the DFIG speed controller was also shown to affect both the frequency nadir and the initial rate of change of frequency.

4.46 In Case B, pitch and stall regulated wind turbine generators were compared at high wind speed, and due to the characteristics of stall regulation, pitch control wind turbine generators were found to result in a more favourable frequency response than stall controlled wind turbine generators. The effects of varying wind speed on the frequency response of stall controlled wind turbine generators were examined in Case C, showing a better response at lower wind speeds.

5. Impact of Wind on the Costs of Operating Reserve

5.1 In this chapter, we describe the impact that wind has on the environmental and economic costs of operating reserve provision. The impacts described are based on a simulated outturn position after wind errors and are shown for two alternative approaches of generator dispatch – *forecast* where wind is included in the schedule of generator to run, and *fuel saver*, where it is not.

5.2 This study has assessed the total requirement and costs for operating reserve in an all-island electricity market. We have not attempted to distinguish between whether these costs are incurred by market participants or by the system operator, but rather to calculate what the cost of the optimal provision of the operating reserve requirement would be.

Impact on generation patterns

5.3 The wind generation under all the scenarios analysed was accommodated within the all-island system without the need for additional new generation capacity (beyond that already announced and a 500 MW dc interconnector to Wales) and without the need to constrain-off or down any wind generation. By actively managing the conventional generation plant on the system, part-loading plant and interconnectors where necessary, it was possible to accommodate both our high and low wind days without constraining wind generation whilst maintaining system security. It should be noted that our high wind days were based on an aggregate wind generator capacity factor of 60%, which could be exceeded for short periods.

5.4 Figures 5.1 to 5.3 illustrate the generation mixes on the all-island system on each of the sample days considered. The *no wind* scenarios for 2006 and 2010 represent a system without wind generation – where demand is principally met from coal plant and CCGTs. Against this are shown generation volumes by technology for the various scenarios for wind generation. In the *fuel saver* operation modes, the total demand and generation volumes are exactly the same as the *no wind* cases, but with wind generation requiring deload on conventional plant. In the *forecast* operation mode, where the dispatch schedule is optimised for wind, fewer conventional plant are brought onto the system, reducing total demand and generation (as the in-house load from auxiliaries is not required).

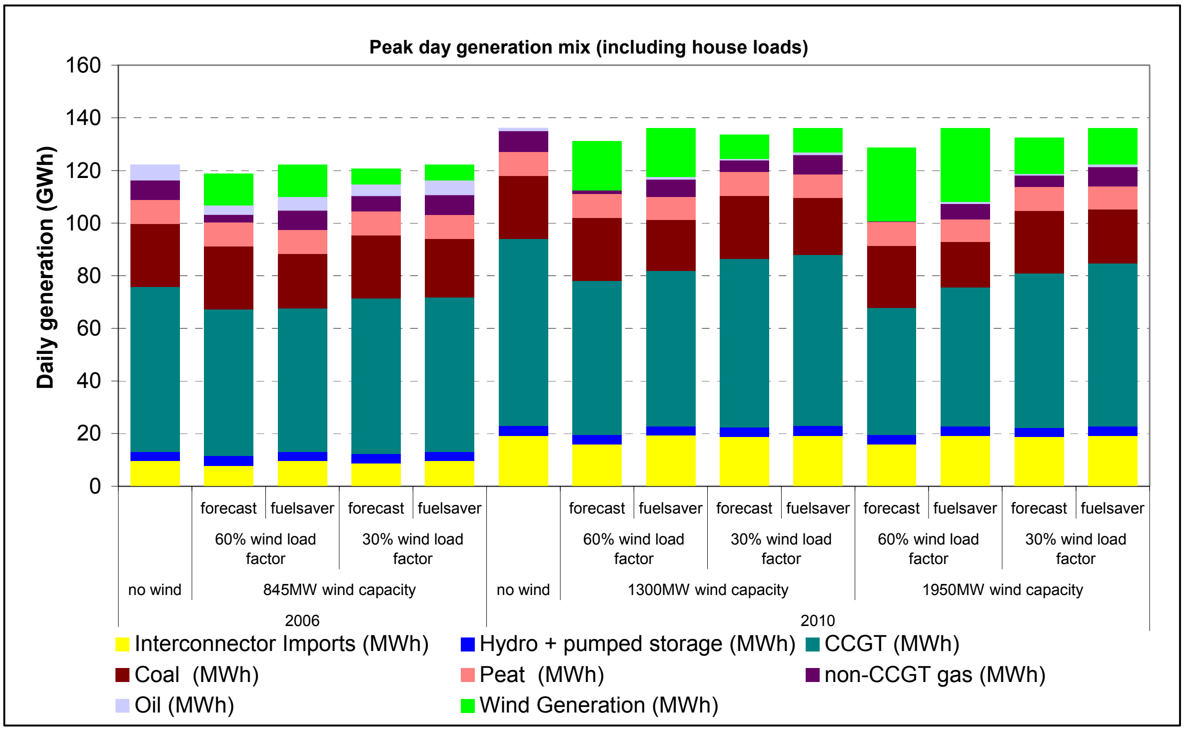

Figure 5.1 – Generation mix on winter peak sample day for all operation and wind capacity scenarios

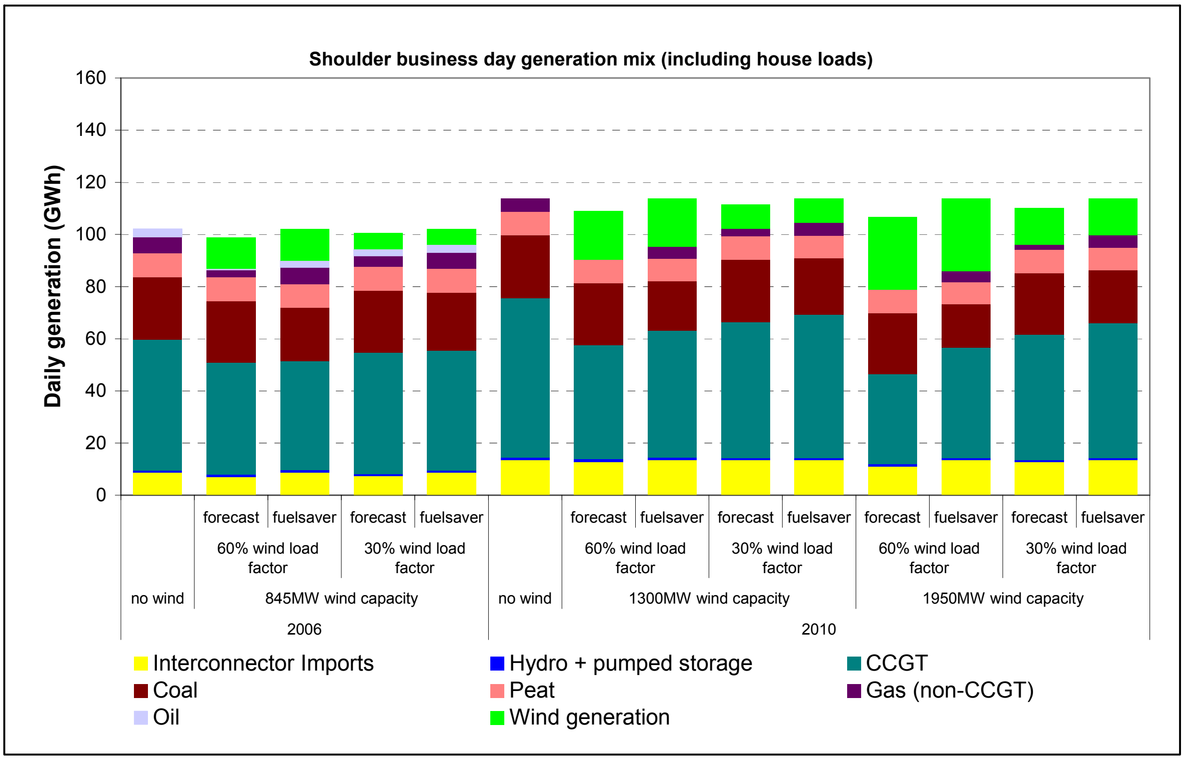

Figure 5.2 – Generation mix on a shoulder business sample day for all operation and wind capacity scenarios

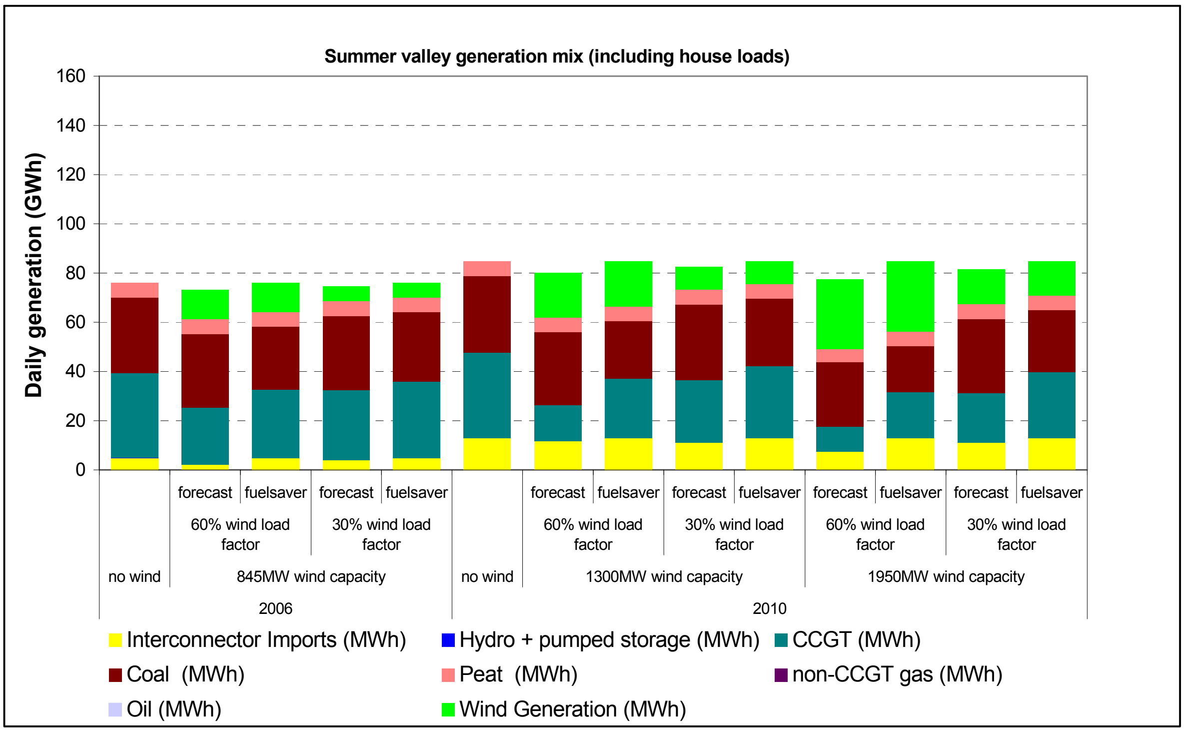

Figure 5.3 – Generation mix on summer valley sample day for all operation and wind capacity scenarios

Impact on generation sector fuel use and costs

5.5 The increased penetration of wind generation reduces total fuel use on the all-island power system. The extent of that reduction is dependent on the efficiency of the generation displaced and the effect that part-loading of plant may have - reducing the efficiency of operating plant. Figure 5.4 illustrates the reduction in fuel use for each of the sample days, wind profiles and wind capacities studied. Fuel savings are considerably greater in the *forecast* system operation mode, when a more optimal mix of generation can be obtained – compared to *fuel saver* where a large proportion of plant are part-loaded. However, even under the *fuel saver* approach, energy savings are in direct proportion to the penetration of wind generation – where wind generation comprises 5% or 20% of total generation, fuel burn is reduced by 5% or 22% respectively. In the *forecast* approach, where there is less part-loaded plant, fuel savings are greater for any given wind penetration, e.g. savings of 7% and 27% for wind penetrations of 5% and 20%.

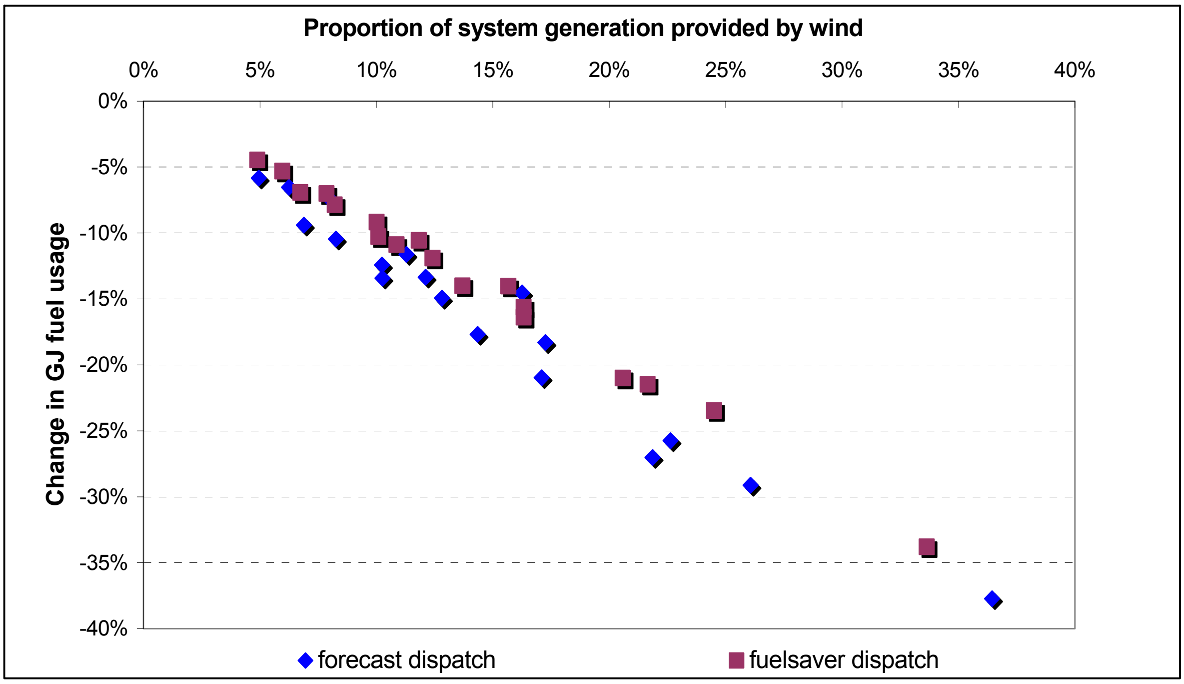

Figure 5.4 – Reduction in all-island fuel use by electricity generation sector as proportion of wind generation increases

5.6 The reduced fuel use arises from three separate factors – incremental fuel use in generation, no-load fuel use and start-up fuel use. In Figures 5.5 to 5.7 we illustrate the reductions in the cost of fuel use for each of the wind scenarios. Total savings are greatest in the *forecast* system operation mode, despite the use of some additional fuel in start-up in this mode.

5.7 Note that fuel cost calculations assume the same gas prices for all scenarios. Actual gas costs under the forecast and the fuel saver approaches might be higher, as unexpected changes in demand patterns would incur penalties on transport charges, which are often based on fixed volumes. This is particularly true if baseload gas plant (CCGTs) are being forced to run as mid-merit plant, as at times of low total system demand and high wind generation.

5.8 Wind variability may also affect the gas spot price. If wind generation on the all-island system is low overall, the general increase in demand for additional gas will result in short-term price spikes and overall higher gas costs. Conversely, the sale of surplus gas at times of high wind generation may drive prices (and revenues to affected plant) down.

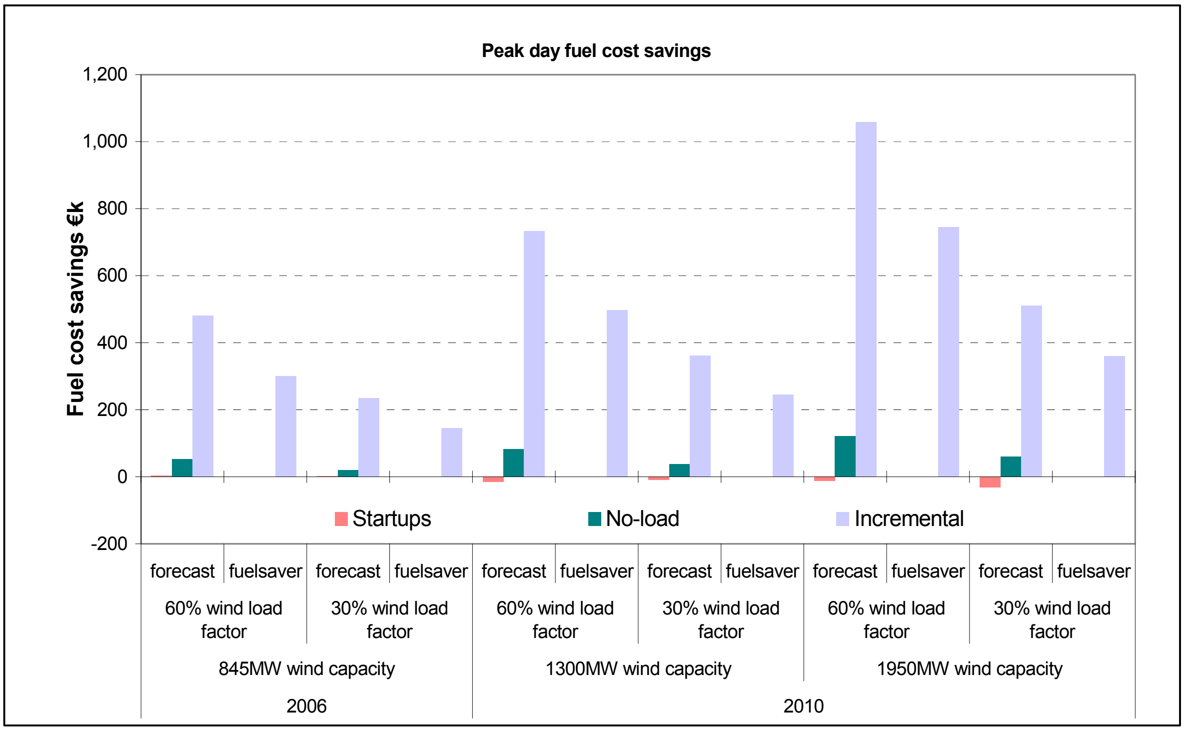

Figure 5.5 – All-island fuel cost savings for winter peak sample day

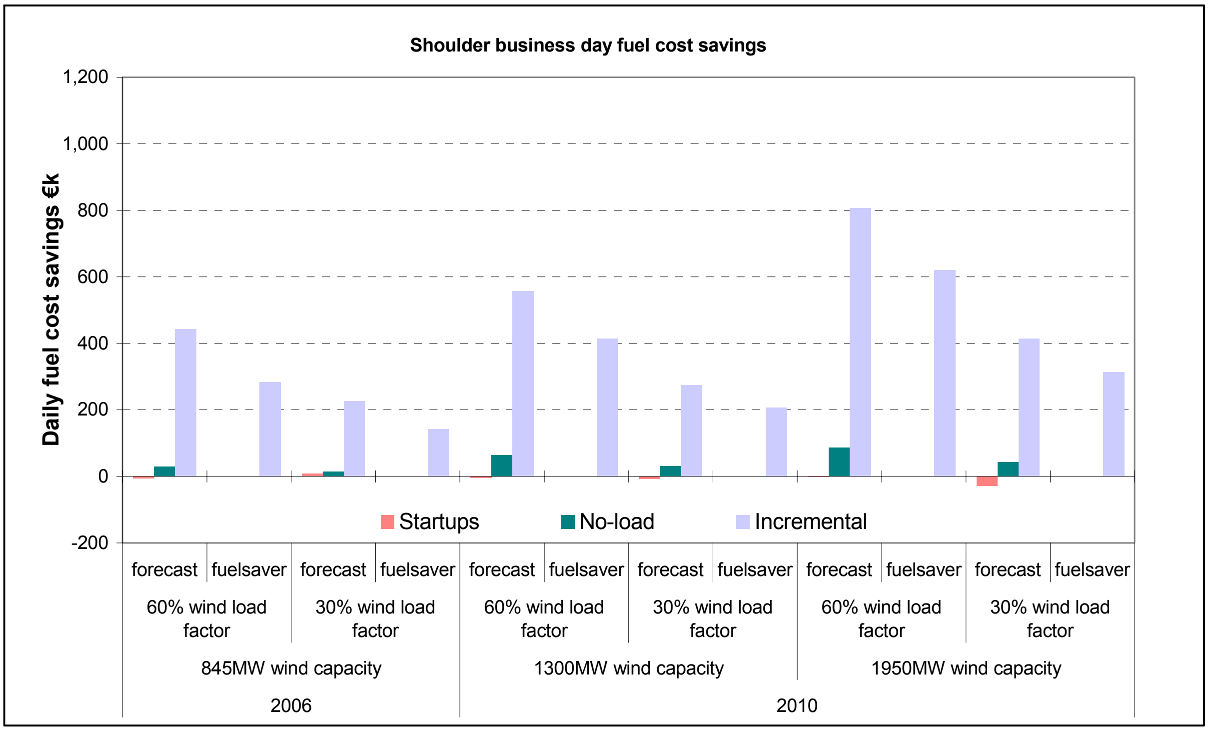

Figure 5.6 – All-island fuel cost savings for shoulder business sample day

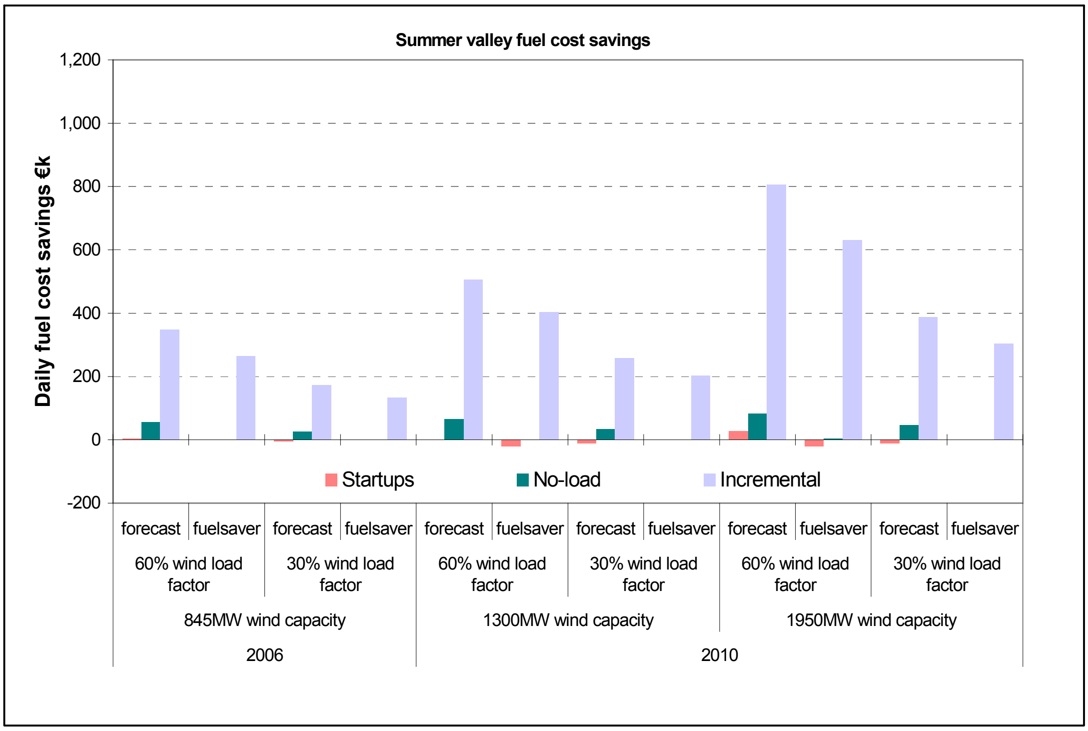

Figure 5.7 – All-island fuel cost savings for summer valley sample day

Impact on emissions reductions

5.9 Figure 5.8 illustrates the net reductions in CO_2 emissions from the wind generation, having taken full account of the increased requirement for operating reserve, and its impact on the part-loading and start-up of conventional generators. Interestingly the choice of system operation mode has little impact on CO_2 emissions. This is because in the higher wind penetration cases the scheduling and dispatch is being dominated by the requirement to provide operating reserve rather than economic energy dispatch. Under the *forecast* approach, the high carbon emitting coal plant are retained on the system to provide operating reserve, as they could not be brought back from warm or cold starts within sufficient time to provide operating reserve.

5.10 CCGT plant are more efficient and lower carbon-emitting than coal plant. However, CCGTs have a smaller operational range over which they are able to provide operating reserve (due in part to substantial increases in NO_x emissions when operating at low load factors[53]), and are therefore more restricted in their ability to be part-loaded. But CCGTs may be able to respond faster from cold than coal plant, to provide some replacement reserve (at least from their gas turbine units).

53 Future generations of gas turbine plant may be able to operate over a wide range of load factors without incurring excessive NO_X emissions. However, such plant are not likely to be available commercially by 2010.

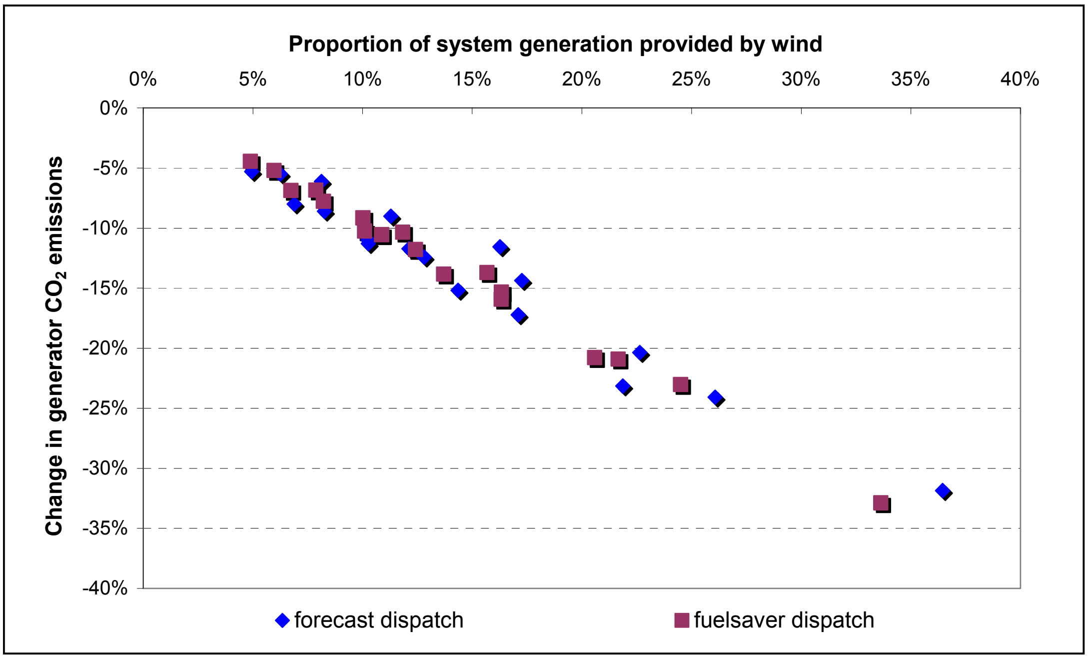

Figure 5.8 – Impact of wind on carbon emissions from the all-island generation sector

Impact on cost of providing operating reserve

5.11 Figure 5.9 illustrates the potential increase in the cost of providing operating reserve that may be due to the increased levels of wind generation. The nature of modelling a system that co-dispatches energy and operating reserve makes isolating a 'cost of operating reserve' from fuel savings due to wind generation somewhat arbitrary. To provide the figures presented in Figure 5.9 we have attempted to isolate the additional operating reserve costs by calculating the operating costs on the basis of a unit of conventional generation, and then presenting the additional operating reserve costs due to wind as the difference between the unit costs without wind and those with wind. At lower levels of wind penetration there may be savings in operating reserve costs under the *forecast* approach on peak days, whilst at higher levels of wind generation and on other sample days these costs increase.

5.12 Based on the *forecast* approach to scheduling wind and conventional generation, additional operating reserve costs are unlikely to exceed €0.6/MWh (in 2004 prices) on any of the sample days studied and indeed could return a benefit of €0.5/MWh on some days. The benefits occur consistently on winter peak sample days and the higher costs on the summer non-business sample days. This suggests that when the level of demand is high in winter and there is more generation operating, it is easier to accommodate wind in an optimal manner. However in periods of low demand the system operator has less flexibility in scheduling the system, and has to maintain a proportionately greater capacity of part-loaded plant.

5.13 However, if no account is taken of the level of wind generation when scheduling wind (the *fuel saver* approach) the costs could be greater, ranging from €0.30/MWh at low wind levels to €1.3/MWh at higher wind levels, and possibly €1.8/MWh in the extreme.

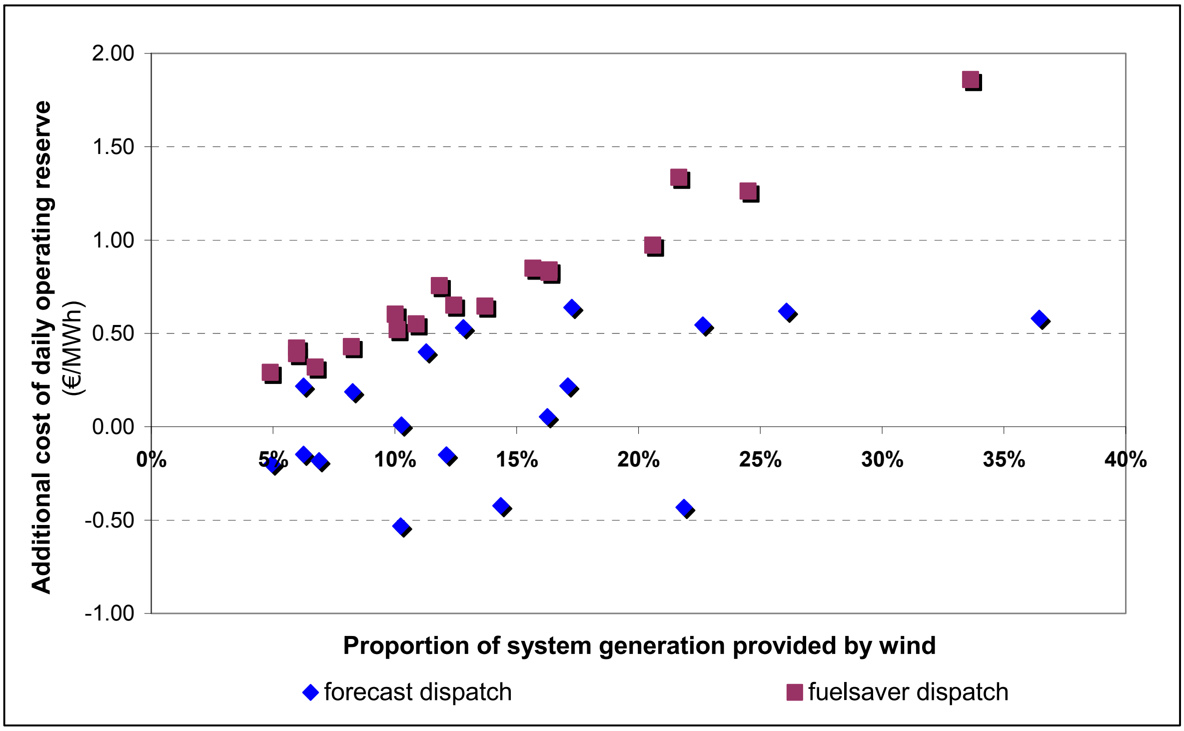

Figure 5.9 – Impact of wind on the daily costs of all-island operating reserve provision

5.14 The costs presented represent the unit costs of operating reserve provision over the sample days studied for each volume of wind generation. We have not been able to undertake this analysis over a sufficient number of sample days with varying levels of wind generation in order to extrapolate these results to provide annual costs with any great degree of confidence.

5.15 The summer valley day and winter peak day sample periods are extreme cases designed to test the maximum impact on operating reserve. Results for these sample days are not likely to be representative of more normal or an average period.

6. Conclusions

6.1 This study has projected the impact that substantial increases in connected wind capacity from 312 MW[54] at present to 845 MW in 2006, or 1,300 MW or 1,950 MW in 2010 would have on the requirement for operating reserve. This is a very narrow scope, which has been examined in detail. This study has not looked at any other potentially impacts[55] that the growth in wind generation may have on the electricity system.

6.2 Other studies[56] published recently have attempted to look at the wider effects that incorporating a greater capacity of wind generation could have on the wider electricity system in Ireland. Caution is advised in comparing directly the results of this study with others where a number of key assumptions may differ – including the assumed wind generation profiles, system operation scheduling methodologies and level of interconnection. In particular, the reader's attention is drawn to the manner in which the results of this study are presented – for specific sample days. No attempt has been made to extrapolate the detailed results obtained here for a small number of sample days to a set of annual costs.

6.3 This study has used historic metered generation from Irish windfarms. However, in common with all studies of this type, there is a severely limited quantity of high quality wind generation data. As the growth in wind represents increases in generation of several orders of magnitude over that presently on the all-island system, it has been necessary to adopt assumptions on the future profile of wind generation. In reviewing the results of this study (and all other studies of this type) readers should be aware that there is a degree of uncertainty in the wind generation data used and that this will constrain the level of confidence in some of the results. This uncertainty covers three principal areas:

- the level of diversity that wind generation will be able to achieve as the number of turbines and their geographic spread increases. The diversity assumed in this study may be conservative, potentially overstating the required operating reserve;
- the impact of unusual weather patterns that may affect all or a large proportion of Irish wind generators, that were not recorded in the wind generation data used in this study, or whose effect was reduced through the scaling process applied to the original data. If, over longer periods of study, such weather patterns are found to occur at sufficient frequency[57] to impact on the need for additional reserve, then this study may have understated the requirement for operational reserve; and
- The statistics of wind and load variations for short time-scales were derived from 15-minute data. Because there is insufficient high resolution data available, there is no experimental verification for the methodology used in Chapter 4 and Annex B.

6.4 There is a lack of high resolution windfarm data and in particular data during faults which would be very beneficial for the modelling and analysis of short term dynamic response of the wind turbine generators.

The physical requirement for additional operating reserve

6.5 This study indicates that the growth in wind generation will require additional operating reserve, but that this increase may not be substantial. Our findings are partly based on the assumption that system operators dispatch generation taking appropriate account of the expected wind generation (and the forecast error). This *forecast* approach represents a new paradigm in system operation, that to date has not been necessary, given the small capacity of wind generation presently connected to the system. Our findings in relation to the *forecast* approach may not be directly comparable with the results from other studies that have used more conventional dispatch techniques, such as the *fuel saver* approach also considered in this report.

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54 229 MW in RoI and 83 MW in NI.

55 It has variously been suggested that direct or indirect impacts could include: transmission and distribution network investment, operation and maintenance of conventional generators, fuel prices, requirements for back-up capacity, etc. These aspects are outside the scope of this study.

56 ESB National Grid. "Impact of wind power generation in Ireland on the operation of conventional plant and the economic implications", February 2004.

57 Very rare events that occur, for example, once every ten years or more, are unlikely to lead to the system operator carrying more reserve.

6.6 Conventional generation units are required to track both scheduled (expected) variation in the system demand, and errors arising in either the demand or wind generation forecast. Load variability can at times be high, dominated by the morning rise and evening fall off in demand. Wind output variability is considerably less, even for the 2010B scenario. Consequently, net demand (defined as system demand less wind generation) variation should not greatly exceed system demand variation. With additional generation plant expected before 2010, the all-island system has the potential to be highly responsive with improved load tracking capability.

6.7 *Fuel saver* and *forecast* operating modes have been considered here. From a load following perspective, the major difference between these options is that more units will be committed in *fuel saver* mode (due to an expectation of total demand, rather than net demand), implying that the load following burden on individual units should be reduced. Since wind variability is relatively low, any increased load following requirement should be small. Being the larger system, it is probable that the ESB system will provide the majority of this requirement, over the NIE system.

6.8 In *fuel saver* mode, unit outputs will be reduced from that scheduled (due to availability of wind generation) causing a reduction in the required operating reserve levels.

6.9 In *forecast* mode, any variation in the scheduled unit commitment will generally be less. For short time horizons, errors in the wind forecast should be small, such that reserve targets can normally be maintained without undue effort – assuming that scheduling of committed plant and monitoring of windfarm output is actively managed. For longer time horizons, wind forecast errors may cause operating reserve targets, on occasion, to be contravened. Available containment options will be dependent on circumstances and time of day.

6.10 Wind forecasting errors are correlated and this needs to be recognised by system operators. Assuming independent wind forecast errors for individual wind farms will underestimate the total wind forecast error which could be problematic for system operators, if they carry insufficient operating reserve as a result. This conclusion may also support the need for the centralised forecasting of Irish wind generation rather than wind farm-by-wind farm submissions of estimates to the system operator.

6.11 Additional benefits of diversity to the all-island system may be limited. It would appear that the existing wind farm distribution (2003) has captured a significant amount of the benefits of diversity. It is estimated that by 2006, with over 850 MW of wind capacity connected, most of the benefits of diversity will have been realised.

6.12 As a small island power system the total operating reserve targets are dominated by the largest infeed. Increasing wind penetration increases the need for operating reserve. However, with the scenarios investigated the largest infeed remains the dominant influence on operating reserve targets.

6.13 Only very small amounts of additional fast acting reserve (5-15 seconds) are required even for large wind penetration levels. However over longer time horizons, of 15 seconds to several hours) there is an increasing requirement for additional operating reserve as wind penetration increases.

6.14 Analysis of the future dispatches indicates that with a large wind penetration it may be beneficial to change the operation of the pumped storage station, Turlough Hill. Further detailed analysis is required in order to determine the optimal operational strategies for Turlough Hill.

6.15 In this study, it has been assumed that hydro generation units follow a scheduled profile for each day, and, therefore, do not contribute to the load following duty for the system. Hydro plant tend to be highly responsive with governor droops less than 4%. They therefore offer an untapped form of regulation.

6.16 Short-term dynamic results presented in this study indicate that there is a need for more detailed analysis of the response of wind turbine generators during large frequency events. This coupled with the recognised issues around fault ride through (i.e. voltage events) and the lack of data would indicate that wind turbine modelling and validation needs to be made a priority. This exercise would contribute to and enhance the development of a more robust wind turbine generator grid code.

6.17 Without more detailed data on the dynamic performance of wind turbine generators it would be difficult to make any conclusions about how they might impact the short term frequency dynamics in the future. However, a conservative view would be that in respect of contribution to system inertia, fixed speed wind turbine generators may be the technology of choice at this time.

The environmental and economic costs of additional operating reserve provision

6.18 The impact that the identified requirement for additional operating reserve has on costs and emissions varies substantially between whether the system operator is including wind in the schedule of generation (the *forecast* approach) or not (the *fuel saver* approach).

6.19 In the *forecast* approach, our findings are that:

- the total capacity of conventional plant that is scheduled is less than in the *no wind* and *fuel saver* cases;
- the total system generation required (from conventional and renewable generators) is lower than in the no wind and fuel saver cases[58];
- the total fuel burn is substantially lower than in the no wind case and also less than in the fuel saver cases[59];
- carbon dioxide (CO_2) emissions are substantially lower than in the no wind case. In comparison with the fuel saver cases however, savings are less clear-cut, due to a different mix of plant under the two approaches[60]. If the costs of carbon allowances under the EU emissions trading scheme were significantly higher than projected, this result might change; and
- the cost of providing the required operating reserve is less than under the fuel saver cases. In some instances it is lower than even the no wind case[61]. The additional cost of operating reserve is relatively small and likely to be to less than €0.20/MWh in 2010 if there is 1,300 MW of wind or €0.50/MWh with 1,950 MW.

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58 This is due to the in-house demand of some generator auxiliaries being avoided.

59 Fuel savings are, at the least, directly proportional to the penetration of wind generation and can be greater.

60 The *forecast* approach will try to deload the more flexible gas plant first, and leave the cheaper (but more carbon-intensive) coal plant fully loaded. The *fuel saver* approach will deload all plant in the merit order to an equal proportion, irrespective of fuel cost.

61 This is particularly the case at times of high demand, where the additional wind generation displaces expensive peaking plant, while reserve can still be provided by baseload units at little cost.

ANNEX A – Acknowledgements and Consultation

A.1 This study has only been made possible thanks to the contributions in time, effort and access to data provided by a large number of stakeholders.

Consultation

A.2 As part of the study, consultations with stakeholders was required. These meetings were primarily intended to inform interested parties of the study being undertaken and, in most instances, to seek their permission to use their data as an input into the modelling work. A copy of the proposal submitted to SEI in response to the tender was provided to all parties in advance of any meetings. From October 2003 to December 2003 the following organisations were met and consulted with on at least one occasion:

- Sustainable Energy Ireland
- ESB National Grid
- ESB Power Generation (ESBPG)
- Hibernian Wind Power
- The Commission for Energy Regulation
- System Operator Northern Ireland
- Northern Ireland Electricity
- Airtricity
- Irish Wind Energy Association
- ESB Networks

A.3 In addition to the consultation meetings, contact by phone and email requesting release of data and describing the study has been made with numerous other parties including: Viridian, B9 Energy and Scottish Power, Synergen, Edenderry Power, Saorgus, and Bord na Mona.

A.4 The consultation process continued for the duration of the study, in particular with ESBNG and SONI.

A.5 There was a consensus that a meeting of all stakeholders to discuss in detail the approach being taken would be a useful exercise, where many of the issues could be discussed openly, and the industry as a whole could educate itself about this important topic. A half-day workshop was held on January 23rd 2004 in Enterprise Ireland. This was attended by the entire team of consultants and by approximately twenty five industry representatives.

Results of consultation

A.6 In addition to data, much useful information was gathered during the consultation process. In particular, many of the decisions relating to some of the key assumptions being made in the study were informed by interaction with the stakeholders.

A.7 There was a consensus that the study being conducted was long overdue. Many of the issues raised at these consultations were relevant to this study but were outside the scope of the detailed modelling being undertaken. The stakeholders would welcome further and more detailed studies to be undertaken in this and closely related areas.

A.8 Several parties commented on the lack of high quality wind data. It is clear that a coordinated effort of defining and gathering such data is required. This is outside the scope of this study.

A.9 A broad range of views was expressed at these meetings, with a consensus on many issues but obvious areas of potential conflict were also identified. Many of the areas of potential conflict exist because of a misunderstanding of some of the issues involved. This highlights the need to educate all stakeholders in order for the results of this, and related studies to be accepted by as broad a range of participants as possible.

A.10 Any queries, and or questions, relating to the methodology being taken in the study were answered. It is our opinion that the stakeholders consulted have raised no fundamental objections or concerns about the approach being taken in the study.

A.11 There was great interest, and some amount of concern, expressed about the new electricity market being developed in the Republic of Ireland and how it may impact on wind generation.

Market Arrangements for Electricity (MAE)[62]

A.12 As part of the consultation and data gathering process, the consultants attended all of the relevant public and specialist workshops hosted by CER on the proposed new trading arrangements, known as the Market Arrangements for Electricity (MAE) in the Republic of Ireland. In early 2004, the MAE consultation process evolved into formal expert groups. Unfortunately, none of the consultants were asked to participate in these groups process and therefore the information reported here may be dated.

A.13 From attendance at these meetings we have identified several key features of the market, and the market for operating reserves in particular.

- The co-optimisation of energy and reserve will result in half hourly prices for all forms of reserve. This methodology implicitly compensates generators for any lost opportunity cost in the energy market as a result of providing operating reserve.
- These half hourly prices will, on many occasions, be tightly correlated to the energy prices and may be very volatile, making prices difficult to quantify and study.
- There is some consensus on how the price for operating reserve (and therefore the costs) will evolve after market opening.
- In the short term, it is expected that operating reserve prices will be high and this will encourage generators, and the load, to respond to these high prices and compete in the reserve market. Competitive forces, coupled with investment in technology and innovation, will then drive the price of reserve downwards.
- A counter argument to this scenario is based on the fact that since the power system at the moment is short of capacity, and many of the units are old and in need of investment, the high prices will persist for a long time.
- Detailed analysis would be required to resolve this issue. Some analysis is being proposed by CER, but the results are unlikely to be comprehensive and/or available in a short period of time.
- Gate closure will initially be four hours ahead, reducing to one hour ahead.
- All participants will be expected to provide indicative bids from one week out down to gate closure, on a rolling basis. These bids will enable the system operator to develop a series of indicative schedules for the dispatch of plant in the energy and reserve markets. Generators will respond to these indicative dispatches by changing their bids to obtain a more favourable outcome. On occasion, the dispatch will be infeasible; it is not clear how often this will happen and how it will be resolved. It is unclear how the issue of wind forecasting will be integrated into these indicative market runs.
- Reserve will be paid for on a 'causer pays' basis with both quantity and frequency of activation being important determinants. The methodology being proposed is the 'runway' method, which can easily handle the quantity issue, and can be adapted to account for frequency of activation.
- Different types of reserve products have yet to be defined, but with a causer pays methodology, there will, in the details of the definitions, be the potential to impact financially on generators of all types. The details of the runway method may also have a financial impact.
- Reserves will be required to cover the loss of single large generating plant (e.g. 400 MW), and, therefore, the cost of providing these reserves will be allocated mainly to large generating plant, with little or no allocation to smaller plant.
- Operating reserves will be needed to cover any forecast errors, and it is likely that wind generation will be a major contributor to these types of operating reserves. It will be expected, therefore, that, on a causer pays basis, wind generators will be allocated a significant proportion of the costs of these operating reserves, with most of the rest of the cost being attributed to the load.
- With large amounts of wind generation, it can be envisaged that there may be a large number of committed units on line, all capable of providing operating reserve, but the market clearing engine will not clear them for operating reserve[63].

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62 At a meeting in CER on June 8th 2004, the major players in the electricity industry all expressed concern about MAE. Following this meeting and subsequent submissions the CER have paused the process while additional modelling and consultation is carried out. The possibility of an all-island electricity market is also being actively pursued during this pause.

- In order to keep the market as transparent as possible it is probable that any additional measures that will be used to support wind generation will be achieved 'outside the market'. This offers the distinct advantage of not confusing what some believe to be an already complex market and will not place additional costs on the development of the market clearing engine.

A.14 CER have considered responses received to a consultation document dedicated to Renewables, CHP and Distribution-connected Generation in the proposed market[64].

A.15 This study does not explicitly represent any aspect of the new electricity market. However, the impact of the results and outputs on market participants will be largely determined by the performance of this new market. This is particularly true for participants in RoI. From this there emerges a number of issues.

- Should inertia be a product in the market? The alternative is that all units be forced to provide an inertial response by insisting on it in the Grid Code.
- With the co-optimisation of reserve approach, it is perfectly plausible that the operating reserve constraint can be met by reducing the size of the largest unit. Limiting the size of the largest infeed, to reduce the rate of change of frequency in the event of losing this infeed, may be the optimal approach to providing operating reserve with large amounts of 'no inertia' wind turbines operating. However, it is not clear that the proposed market design is able to accommodate this, which potentially could cause system reliability problems.
- The distinction between wind and load forecasting, and the sensitivity of wind forecasting to time horizons has not been considered.
- Under any conditions where wind curtailment is required, how will it be achieved – will there be a market in "wind curtailment"?[65]

Grid codes

A.16 ESBNG, in consultation with all stakeholders, has developed a set of proposed new grid codes specifically for wind turbine generators[66, 67].

A.17 A number of factors associated with the technical performance of the generating plant, particularly at times when the system experience disturbances, play a critical role in maintaining system integrity. The design characteristics of the conventional thermal and hydro plant are such as to enable the plant to contribute towards the provision of system support (dynamic voltage and frequency regulation) that is critical for stable operation of the system.

A.18 Wind generation is based on different technology and generally is not currently able to provide similar support to the system. At relatively small levels of wind penetration, this can usually be tolerated. However, operating the system with large amounts of such plant could pose major challenges in terms of sustaining system integrity, particularly in relatively small power systems, such as Ireland.

A.19 ESBNG sets out the requirements for connecting generation equipment to the transmission network and these are detailed in the Grid Code. In a number of countries, the Grid Codes have been reviewed to reflect the trend of increased levels of wind generation and the fact that they were written with conventional synchronous generation in mind. One of the key topics is associated with the ability of wind generation to stay stable through faults on the transmission network, in order to avoid the widespread tripping of wind generation and loss of substantial amount of active power generation (fault ride-through capability). Other important issues include frequency and voltage control and regulation, signalling, communication and dispatch.

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63 This will be particularly true for the *fuel saver* operation methodology.

64 CER, "Implementation of the market arrangements for electricity (MAE) in relation to renewables, CHP and distribution-connected generation", CER/03/253, October 2003.

65 ESBNG, "Options for operational rules to curtail wind generation", CER/04/247, 16 July 2004.

66 CER, "Windfarm power station grid code", CER/04/136, April 2003.

67 CER published the final version of the Windfarm Transmission Grid Code on 1st July 2004 (CER/04/237) and a proposed modification to the Distribution Grid Code has been put out to consultation (CER/04/273). The versions reviewed for this report were discussion documents and differ slightly from the final versions.

A.20 Recently proposed Grid Codes for Ireland are very similar to and consistent with a number of Codes reviewed lately (e.g. National Grid Transco, Scottish Transmission Operators, EoN, Spain). In two key areas, regarding value of retained voltage and the speed of post fault active power recovery, the ESBNG Grids Code is actually less demanding than that in the proposed UK Codes.

A.21 As indicated in paragraph 3.8, for the purpose of this study we have assumed that the issue of fault ride-through is successfully resolved.

Recent moratorium in wind connections

A.22 *On 3rd December 2003, CER published three documents on their website[68,69,70] and announced the temporary suspension of new wind connections until system security issues raised by ESBNG could be addressed. This action is partially related to the recent success of wind projects, with 534 MW of wind capacity having signed connection agreements, and almost 600 MW of further applications seeking connections[69,71].*

A.23 *In their document, ESBNG raise a number of arguments for halting wind development in the short term. Their concerns highlight the need for suitable studies to be carried out on a number of complex technical issues related to the integration of wind generation onto the system. CER agreed to ESBNG's request for a moratorium on new connection agreements, at least until it concluded a consultation process on the issues raised. CER requested inputs into the process by 19th December 2003. A public forum on this issue was hosted by ESBNG on 17th December 2003. CER has published a final direction on the issue[72].*

A.24 *ESBNG recognise the Northern Ireland dimension, and have proposed that wind generation policy for the whole island should be coordinated.*

A.25 *This study has tackled a number of the concerns raised by ESBNG, and should make a positive contribution to this debate.*

A.26 *This study is focussed on frequency control issues facing a system operator with significant amounts of wind generation. Issues such as fault ride through capability, grid codes and voltage stability are considered as input assumptions* to the study. There may well be a case for SEI to commission an additional study following on from this study, to address these important topics.

Data gathering

A.27 A very detailed list of data requirements was compiled and discussed with SEI, ESBNG and SONI in particular. It was recognised that some of the data required is not available and engineering judgement needed to be applied to obtain reasonable values.

A.28 Data required for the study included:

- Generating unit data: inertia, heat rate curve, droop, rating, emissions characteristics, etc.
- System data: historical dispatches, load data, frequency event data, etc.
- Wind data: 15-minute wind power output data from at least ten windfarms, some high resolution wind power output data, etc.
- Forecasting characteristics: forecast errors, correlations between forecasts, etc.

A.29 All organisations approached agreed to provide their data for the purposes of the study, and most of this data was successfully gathered. Nearly all the data required is held by the two system operators, ESBNG and SONI.

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68 Letter from ESB National Grid to CER, 1st December 2003, CER/03/281.

69 ESB National Grid, "Interim policy on wind connections," 28th November 2003, CER/03/282.

70 Letter from CER to ESBNG, 3rd December 2003, CER/03/283.

71 By July 2004 this number had increased to 1369 MW.

72 CER, "Wind generator connection policy: direction by the Commission for Energy Regulation". CER/04/245, 9th July 2004.

A.30 A confidentiality agreement has been signed between ESBNG, SEI and the ILEX consortium that allows all the data required to be released for the purposes of the study.

A.31 A confidentiality agreement has been signed with SONI.

A.32 Dedicated wind power output data gathering is not part of the scope of this project. However, there is a recognised lack of high quality, high-resolution data from wind turbines.

Interconnectors

A.33 The ESBNG and SONI systems are connected by three lines. The main interconnector between Louth and Tandragee is a 275 kV dual circuit 600 MW link, while two 110 kV links, with limited capacities, are used for support but not trading of energy.

A.34 Operationally, the 275 kV interconnector is typically limited to 300 MW north to south, and 0 MW south to north. There is a very complex operational/commercial interaction that can impact on these limits.

A.35 The Internal Market for Electricity (IME) group, consisting of all the major stakeholders in the electricity market in Northern Ireland, is currently completing the second part of a study on "Interfacing with the proposed RoI Market". Results of the first part have been published[73].

A.36 The two system operators (ESBNG & SONI) are carrying out a number of studies on an all-island system and all the indications are that an all-island electricity market and/or system is probable in the near future.

A.37 Currently, primary reserve is shared on the island as follows: one third is carried by NI and two thirds by RoI. There is no sharing of other categories of reserve. We understand that this arrangement is currently being reviewed. Therefore, we have assumed that reserve will be shared as at present for 2006 and will be fully shared on and all-island basis by 2010.

A.38 On 11th February 2004 the minister for Communications Marine and Natural resources announced a 1,000 MW East West dc Electricity Interconnector. On April 6th 2004 the CER published an invitation for submissions and meetings relating to an Ireland-Wales Electricity Interconnector[74].

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73 NERA, "Republic of Ireland interface study," August 2004.

74 CER, "Ireland-Wales electricity interconnection", April 6th 2004, CER/04/133.

ANNEX B – Detailed Modelling Methodology

B.1 This annex includes details of the modelling methodology. In particular, it includes details of the wind and load modelling, dynamic modelling and the probabilistic modelling of operating reserve.

B.2 The dynamic and probabilistic modelling chapters are not very extensive as a lot of this detail is published[75] or is currently in review for publication[76]. The wind modelling and to a lesser extent the load modelling chapter are more detailed as the methodology used has not been reported elsewhere.

Wind modelling

B.3 Wind power data in the form of a time series for entire future years (2006 & 2010A, 2010B[77]) are required for this study. This data was generated from historical time series data. What follows is a summary of the historical data that was used in the study and its characteristics. The methodology for scaling is then described and the future wind power time series for 2006 and 2010 are presented.

Historical wind power data

B.4 Historical wind power data was obtained for ten windfarms in the Republic of Ireland. The data consisted of 15-minute metered energy data (MWh) and covered a time period from 1999 to 2003 inclusively. Data was not available for all ten farms for all of the five years and in some cases partial data was only available. The total installed capacity of the ten windfarms is approximately 80 MW and was geographically well dispersed (Figure B.1). The data was of high quality with very few anomalies.

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75 Lalor, G., Ritchie, J., Rourke, S., Flynn, D. and O'Malley, M.J., "Dynamic frequency control with increasing wind generation", *IEEE PES General Meeting*, Denver, June 2004.

Doherty, R., Denny, E. and O'Malley, M.J., "System operation with a significant wind power penetration", *IEEE PES General Meeting*, Denver, June 2004.

Lalor, G. and O'Malley, M.J., "Frequency control on an island power system with increasing proportions of combined cycle gas turbines", *IEEE Power Tech*, Bologna, Italy, June 2003.

Doherty, R. and O'Malley, M.J., "Quantifying reserve demands due to increasing wind power penetration", *IEEE Power Tech*, Bologna, Italy, June 2003.

76 Lalor, G., Ritchie, J., Flynn, D. and O'Malley, M.J., "The impact of combined cycle gas turbine short term dynamics on frequency control", *in review*, 2004.

Doherty, R. and O'Malley, M.J., "New approach to quantify reserve demand in systems with significant installed wind capacity", *in review*, 2004.

77 2010A – 1300 MW installed wind scenario, 2010B – 1950 MW installed wind scenario.

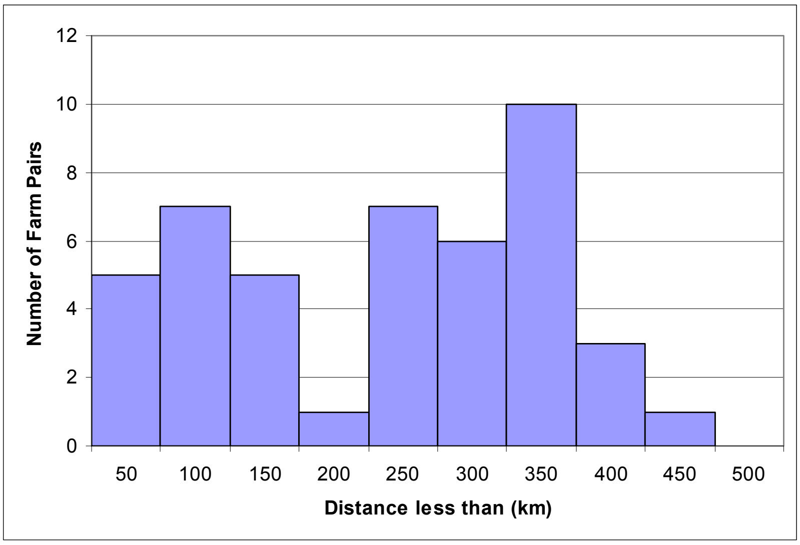


Figure B.1 – Distance between windfarms

B.5 This historical data was subjected to extensive analysis in order to test and verify its integrity and to find a number of crucial parameters that are needed in order to scale it up to produce time series data for future years.

B.6 The capacity factor for the k^{th} windfarm with a maximum capacity of $Capacity_k$ is given by (B-1) where $Energy_k(i)$ is the energy exported to the grid by the k^{th} windfarm in the i^{th} 15-minute interval. The capacity factor was calculated for each farm for every year of available data. With the exception of one farm the capacity factor was in the range 30 – 45% over the five years. No dramatic changes in capacity factors over the five years were noted. As data was available for all farms for 2002 and 2003, it was concluded that either of these years could form the basis of the scaling. The year 2003 was chosen as the base case for scaling.

$$\text{Capacity factor}_k = \frac{\sum_{i=1}^{35040} Energy_k(i)}{8760 \times Capacity_k} \qquad \text{(B-1)}$$

B.7 Wind power outputs from the ten windfarms are correlated as would be expected, Figure B.2

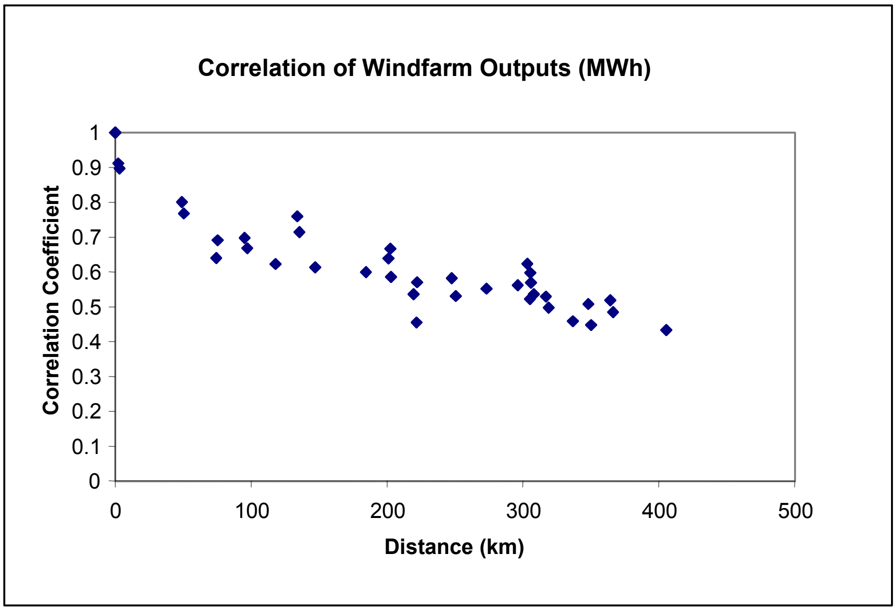


Figure B.2 – Correlation of wind power outputs (MWh) – for 2003

B.8 The standard deviation of 15-minute deviations for all individual windfarms was calculated for all years of available data. Expressed as a percentage of the windfarm capacity this standard deviation ranged from 5.7% to 8.6% and had an average value of 7.1%, Figure B.3.

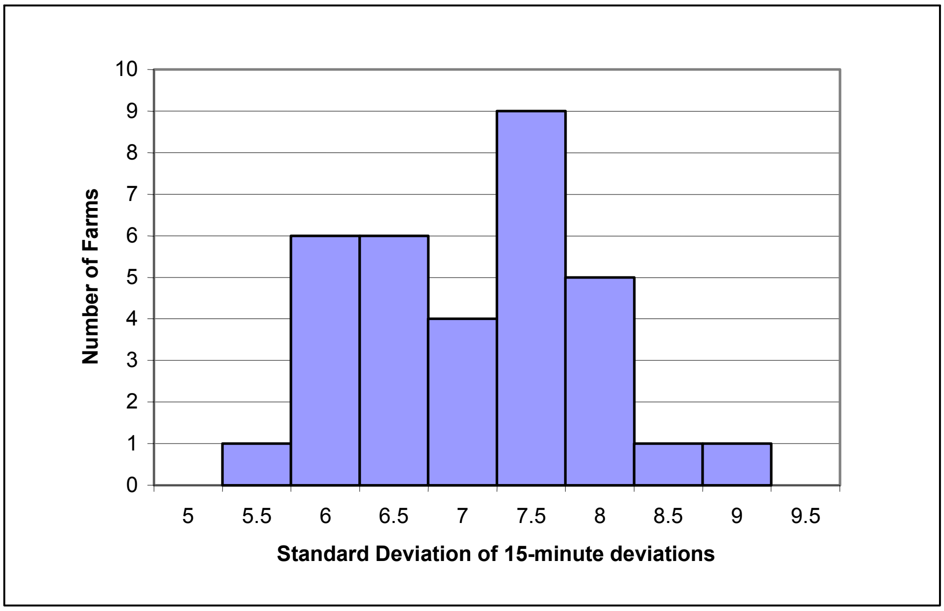


Figure B.3 – Standard deviations of 15-minute deviations for all available windfarms for five years

B.9 The standard deviation of 15-minute deviations for the cumulative wind data (sum of wind power data from all farms) for 2003 was calculated. Expressed as a percentage of the total windfarm capacity this standard deviation was 3%, illustrating the effect of diversity.

B.10 The correlation coefficients of the 15-minute deviations for all windfarms for all available data were calculated. These correlation coefficients are plotted against distance between the windfarms in Figure B.4. A log-log plot for this data[78] is shown in Figure B.5 and regression analysis was employed to fit a straight line to the data.

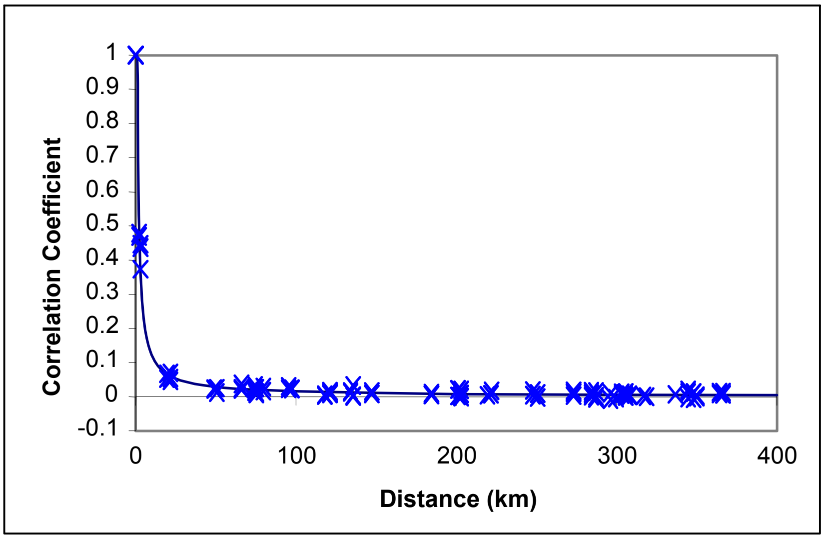


Figure B.4 – Correlation coefficients, 15-minute deviations against distance

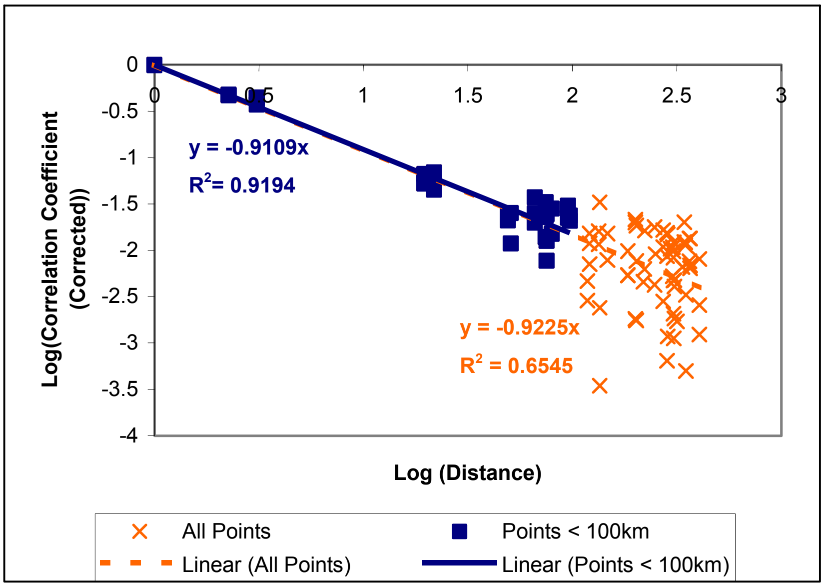


Figure B.5 – $\log_{10}$(Correlation Coefficient) 15-minute deviations against $\log_{10}$(Distance)

B.11 Limiting the regression analysis to windfarms that are < 100 km apart gave a statistically robust relationship ($R^2 = 0.9194$). Regression analysis applied to all the data gave virtually the same linear relationship but the fit was not as robust ($R^2 = 0.6545$). This linear regression when transformed gives the following relationship between correlation and distance

$$Correlation_{15\_minute\_deviations} = Distance^{-0.9109} \quad \text{(B-2)}$$

B.12 As the correlation falls to virtually zero above 100 km this relationship (B-2) was taken as a model for 15-minute deviation correlation with distance.

[78] Negative correlations are ignored.

B.13 The steps above were also applied to the one hour data (four 15-minute data points per hour) and the following relationship (B-3) was found

$$Correlation_{1\_hour\_deviations} = Distance^{-0.5986} \quad \text{(B-3)}$$

B.14 The differences in the relationships (B-2 & B-3) are important as they illustrate that while the wind power deviations are correlated and are a function of distance the relationships are also a function of interval i.e. they differ for 15-minute and one hour intervals. This has important implications when it comes to estimating wind forecast errors and how they will change over horizon.

Scaling methodology

B.15 15-minute 2003 data was scaled up for the 2006, 2010A & 2010B scenarios. The 2003 geographical onshore dispersion of windfarms was obtained from SEI[79], Figure B.6. The total installed capacity onshore and offshore was 263.725 MW. Based on available data[80,81], a 2010 future per county onshore distribution of installed wind power capacity was formed (see Figure B.7). The 2006 onshore distribution is taken to be the average of the 2003 and 2010 data.

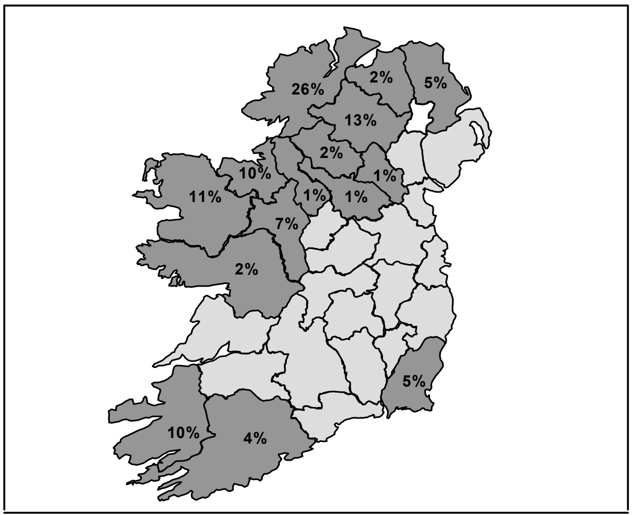


Figure B.6 – Per county distribution (%) of installed wind power capacity 2003.

[79] Sustainable Energy Ireland, "Windfarms in Ireland." http://www.sei.ie/uploads/documents/upload/publications/Wind_Farms_in_Ireland.pdf

[80] Hurley, T. and Watson, R., "An assessment of the expected variability and load following capability of a large penetration of wind power in Ireland," *Proc. Global Wind Energy Conference*, Paris, 2002.

[81] Department of Enterprise, Trade and Investment, "A study into the economic renewable energy resource in Northern Ireland and the ability of the electricity network to accommodate renewable generation up to 2010," June 2003, [Online]. Available: www.energy.detini.gov.uk.

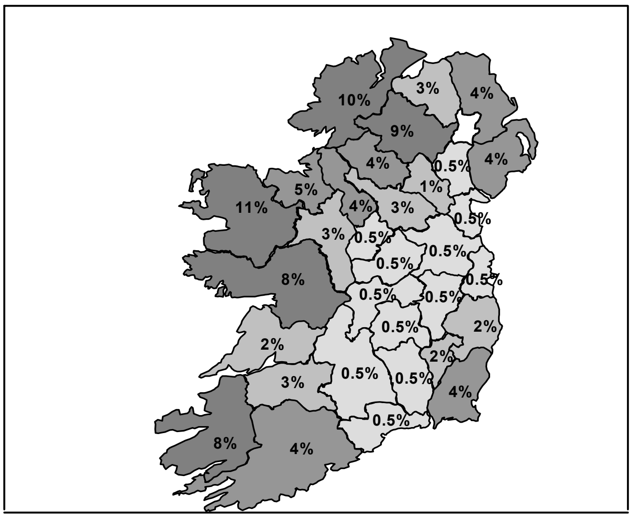


Figure B.7 – Per county distribution (%) of installed wind power capacity 2010.

B.16 Two offshore windfarms are considered in this study (see Table B.1) and are netted off the total capacities for future years before these capacities are allocated within each county.

Table B.1 – Offshore windfarms

	MW installed			
Location	*2003*	*2006*	*2010A*	*2010B*
Arklow	25	60	80	150
Tunes Plateau	0	25	50	50
Total	25	85	130	200

B.17 Sizes of future windfarms were chosen from a distribution that was formed by combining two truncated normal distributions. These distributions were truncated at 1 MW and had standard deviations of 6 and 42 MW respectively Figure B.8.

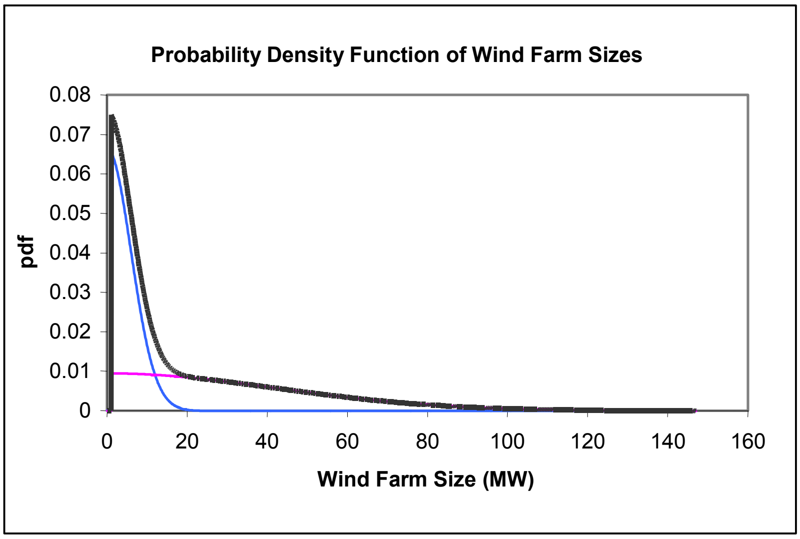


Figure B.8 – Windfarm capacity distribution

B.18 Future year targets for onshore wind capacity of 760 MW (2006), 1,170 MW (2010A), and 1,750 MW (2010B) are distributed geographically across counties (see Figure B.7 for the 2010 distribution). For each county windfarm capacities were chosen at random from the wind size distribution (Figure B.8) until the total capacity for the county was reached. The last farm to be placed in a county had its capacity truncated to obtain the correct total county capacity. The farms in each county are located randomly (uniform distribution) in a circular area, centred in the county, with a diameter of 90 km.

B.19 The correlation coefficient for 15-minute deviations between the m^{th} and n^{th} windfarms $\rho_{m,n}$ is calculated from Figure B.4 (and equation B-2). The standard deviation of the 15-minute deviations for the n^{th} windfarm σ_n is taken to be 7% which is the average value for the historical data (Figure B.3). The standard deviation σ_{wind} for the future wind power 15-minute deviations is given by (B-4) where *F* is the number of windfarms[82].

$$\sigma_{wind} = \sqrt{\sum_{m=1}^{F} \sigma_m{}^2 + 2\sum_{n=1}^{F} \sum_{m=n+1}^{F} \rho_{m,n}\sigma_m\sigma_n} \qquad \text{(B-4)}$$

B.20 The process of choosing windfarm sizes and locating them on a per county-by-county basis up to the prescribed capacity as described above was repeated several thousand times for each of the three future scenarios 2006, 2010A & 2010B. The average value of σ_{wind} was calculated for each scenario and was used as the target for the scaling up process, Table B.2.

Table B.2 – Average current & future year windfarm characteristics

	2003	2006	2010A	2010B
Average Number of Farms	10	76	97	127
Standard Deviation of 15-minute deviations as a percentage of total capacity	3.00%	1.56%	1.44%	1.37%

B.21 In order to benchmark these results the process described above was also carried out with no bias in favour of any particular county (in contrast with Figure B.7) and with a large number of windfarms. When this was done the average standard deviation for 15-minute deviations reduced to 1.1%, which can be taken to be the absolute minimum possible. Therefore, the future scenarios are approaching the maximum possible benefits of diversity for 15-minute deviations.

B.22 Future year wind time series data *W* was obtained by adding the 2003 W_{base} wind power time series to itself shifted by 15-minutes multiple times (*N*).

$$W = (1+\alpha)W_{base} + W_{base,-15\min} + W_{base,-30\min} + ...W_{base,-N*15\min} \qquad \text{(B-5)}$$

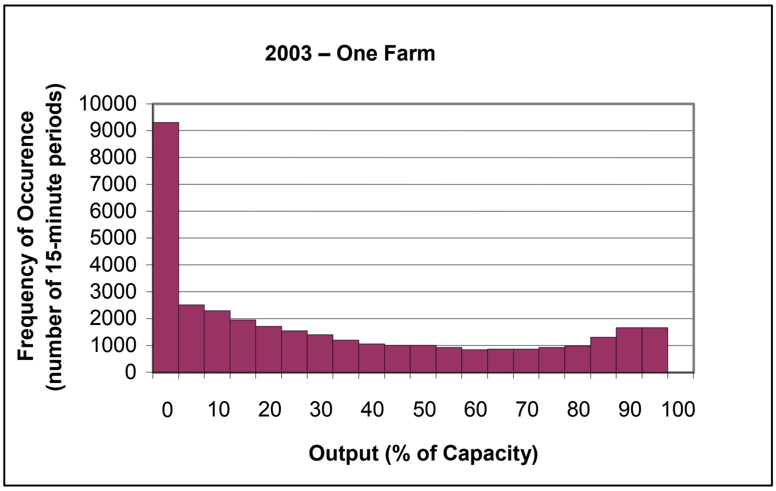
B.23 The coefficient α above (B-5) is used to fine-tune the result so as the resulting with statistics have the required 15-minute deviation statistics, Table B.2. Table B.3 illustrates the sensitivity of the results to the two parameters *N* and α.

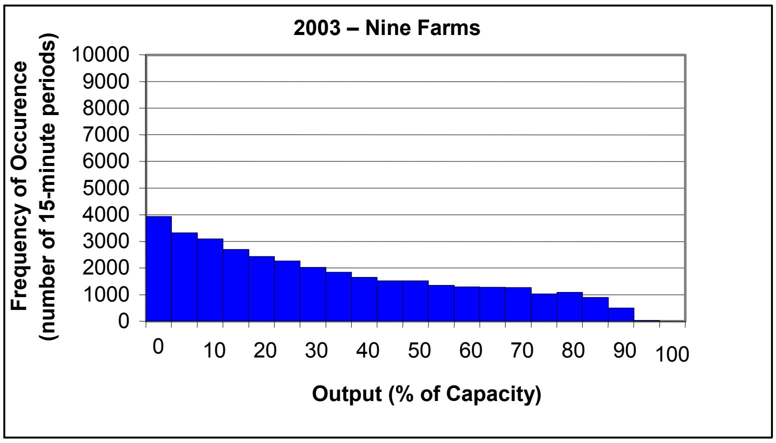
82 Doherty, R. and O'Malley, M.J., "New approach to quantify reserve demand in systems with significant installed wind capacity", in review, 2004.

Table B.3 – Future wind time series standard deviation of 15-minute deviations as a percentage of total capacity as a function of tuning parameters N and *α* (B-5)

Tuning coefficient	*Number of Series (N)*								
(α)	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
0	3.05	2.24	1.81	1.55	1.38	1.26	1.16	1.09	1.03
0.05	3.05	2.24	1.81	1.55	1.38	1.26	1.17	1.10	1.04
0.1	3.05	2.25	1.81	1.56	1.40	1.28	1.19	1.12	1.07
0.15	3.05	2.26	1.83	1.58	1.42	1.31	1.22	1.16	1.10
0.2	3.05	2.27	1.84	1.60	1.44	1.34	1.25	1.19	1.14
0.25	3.05	2.28	1.86	1.63	1.47	1.37	1.29	1.23	1.18
0.3	3.05	2.29	1.88	1.65	1.51	1.41	1.33	1.28	1.23

B.24 Figure B.9 shows a histogram of the 15-minute energy readings for (a) a single windfarm (2003 data), (b) nine windfarms (2003 data), and (c) a forecast of all windfarms in 2006. Figure B.10 shows a histogram for the 15-minute changes for the data shown in Figure B.9 and Table B.4 summarizes this data.





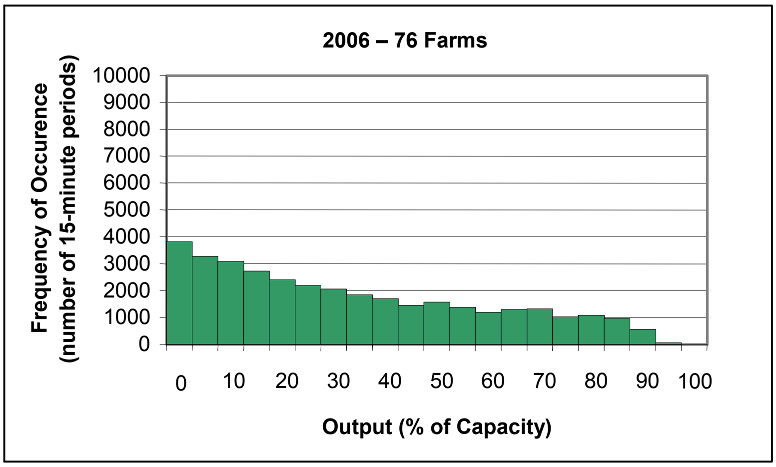
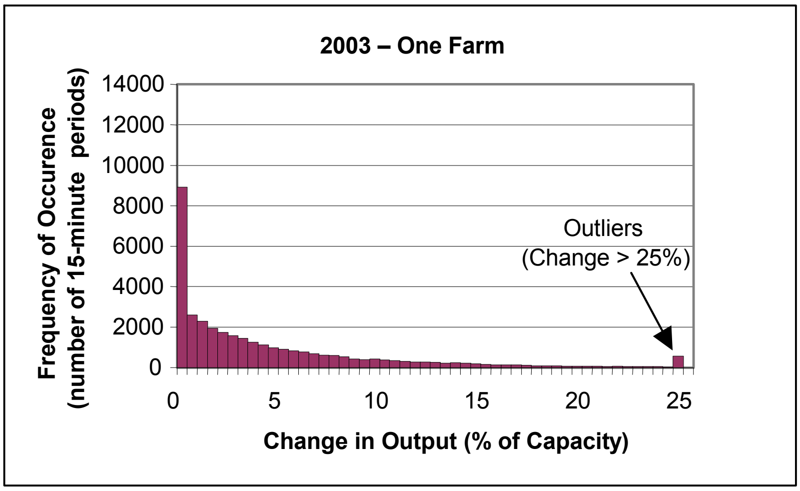
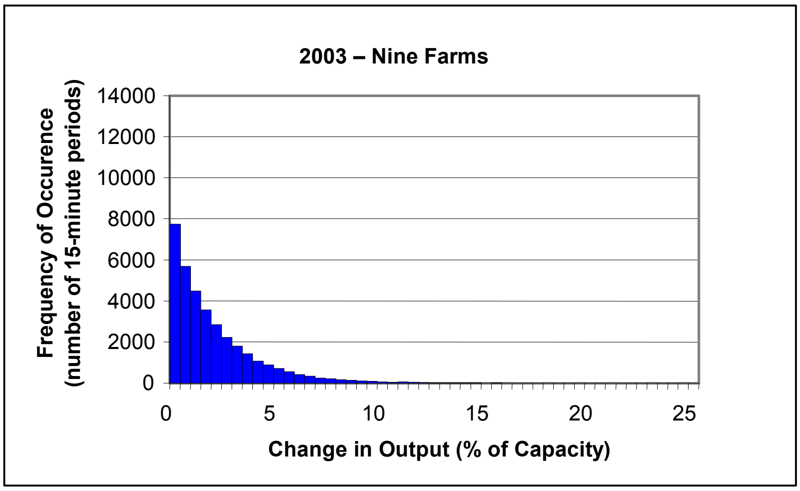


Figure B.9 – Histogram of 15-minute data (a) single farm (b) nine farms (c) 76 farms





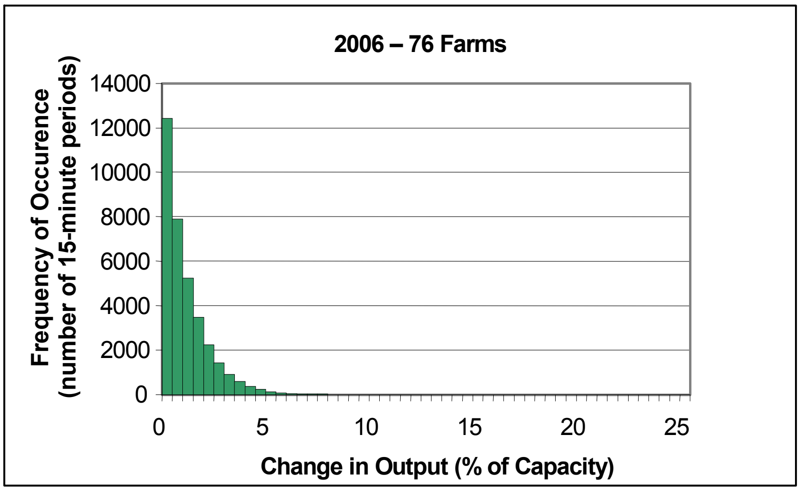


Figure B.10 – Histogram of 15-minute changes – (a) single farm[83] (b) nine farms (c) 76 farms

83 Note the outliers (since there are changes greater than 25% for the single wind farm – see Table B.6) are all grouped at the 25% level.

Table B.4 – Statistics of 15-minute changes in windfarm output

	One Farm[84] (2003)	Nine Farms (2003)	76 Farms (2006)	127 Farms (2010B)
Capacity (MW)	—	77.3	845	1950
Maximum change (max increase)	76%	21%	10.9%	7.9%
Minimum change (max decrease)	-69%	-24%	-9.8%	-8.9%
Mean change (absolute value[85])	4.6%	2.1%	1.1%	1.0%
Standard deviation of change	7.3%	3.0%	1.56%	1.37%
Number of times that 15-minute change exceeds a percentage of capacity				
%				
2	18895	13563	6021	4709
5	10609	3301	298	140
10	4332	341	2	0
15	1902	35	0	0
20	949	6	0	0
30	286	0	0	0
40	116	0	0	0
50	62	0	0	0
60	46	0	0	0
70	26	0	0	0
80	17	0	0	0
90	6	0	0	0
95	3	0	0	0
98	0	0	0	0

84 These are values for a typical windfarm – not necessary the same farm as in the Figures above.

85 The absolute value of the change is used, as the mean value of the change itself is zero.

Load modelling

B.25 Load data in the form of time series for entire future years (2006 & 2010A, 2010B[86]) are required for this study. This data was generated from historical time series data. What follows is a summary of the historical data that was used in the study and its characteristics. The methodology for scaling is then described.

Historical load data & pre processing

B.26 Historical load data (2002 & 2003) for both systems (Republic of Ireland and Northern Ireland) was obtained. Interconnector flows (Moyle and North/South) and details of demand reduction schemes were also available. The characteristics of this data differed in a number of respects. For example, half hour metered (energy) data was obtained for the NI generators (net of house load) and 15-minute generated spot data (power) was obtained for the ROI generators (inclusive of house load). The data was pre-processed to obtain two consistent sets of data i.e. half hour energy data exported (net of house load).

B.27 The original system load data was checked for bad or suspect data, which were corrected in line with typical values where appropriate.

Peak management schemes

B.28 On the Republic of Ireland system, peak management schemes have traditionally operated during the peak hours of winter (November to February) to reduce the peak capacity requirement on the system. A new peak demand reduction scheme (known as winter peak demand reduction scheme WPDRS) was introduced in the winter of 2003/2004 with considerable success. Since there was little peak reduction achieved during the winter of 2002/2003, it was necessary to adjust the demand figures for January and February of 2003 to simulate the demand reduction that would have occurred had WPDRS been in operation.

B.29 During January and February 2003, 40 MWh (80 MW) was subtracted from the half-hour demand for the dispatch periods between 17.00 and 19.00 on business days. A further reduction of 20 MWh was applied to the dispatch periods immediately before and after the peak reduction period as this mimics the observed pattern of demand reduction[87].

Load data analysis

B.30 Prior to scaling, this pre-processed data was analysed to gain insight into the appropriate scaling methodology[88]. In particular the issue of whether scaling for future years should be done on a uniform basis (i.e. same scaling factor for all periods) or whether it would be more appropriate to use different scaling for different periods. It was found that while there was some evidence of a non-uniform scaling it was not strong enough in the context of this study to warrant different scaling for different times (i.e. time of day/season). In particular, with the exception of outliers[89], the changes in percentiles between the two years displayed no patterns and were uniform (Table B.5).

Table B.5 – Percentile load change 2002 to 2003. Republic of Ireland Data.

Percentile (%)	95	90	75	50	25	10	5
Change 2002 to 2003 (%)	2.4	2.65	3.26	2.57	2.71	3.10	3.09

86 2010A – 1300 MW installed wind scenario, 2010B – 1950 MW installed wind scenario.

87 More information regarding WPDRS has become available which indicates that this method could be slightly improved see ESB National Grid, "Results of the winter peak demand reduction scheme (WPDRS) 2003/04", May 2004.

88 This analysis was limited to 2002 and 2003 data.

89 Maxima and minima are very sensitive to weather and other localised phenomena and therefore cannot be taken to be representative of underlying load growth.

Scaling

B.31 Pre-processed 2003 data was taken as a base case for scaling. Republic of Ireland data was adjusted to account for recent changes in the demand reduction schemes. Load growth in the Republic of Ireland and Northern Ireland differ and this was accounted for by growing the load differently for the two systems (1.8% per annum NI and 3.2% per annum for ROI)[90].

B.32 Future load profiles for 2006 and 2010 were generated and were used as data inputs to the other parts of the study.

Dynamic system model

B.33 The dynamic system model, which represents the frequency response of the all-island electricity system, was developed. The model is a single busbar representation of the current system[91].

B.34 The model has been extensively adapted to allow a broad range of scenarios and sensitivity analyses to be performed relatively easily.

B.35 Each individual element on the system model has been tuned with data that has been made available to the Electricity Research Centre at University College Dublin and to colleagues in the Queen's University Belfast for their academic work. Agreement was reached for this data to be used in this study. For this particular study, the models were fine tuned and updated to account for the particular future year scenarios.

B.36 During the tuning process, it was discovered that many of the units that should respond, as indicated by their droop characteristics, failed to do so during many of the historical events examined. ESB Power Generation had anticipated a number of power station closures around 2003 with the advent of market opening and the entry of independent power producers. Due to capacity limitations, there was a lack of overhaul opportunities from 2000 to 2002. Consequently, plant was a sub-optimal condition (e.g. boiler fouling, air ingress, fan limitations, etc.) which necessitated use of load-limiters occasionally. ESBPG are currently in the process of restoring optimal plant condition and would expect to see a significant improvement in spinning reserve performance by 2006, with the balance of improvement by 2010. Therefore, it was conservatively assumed that the unit responses are unchanged for the 2006 scenario, but unit responses will be assumed to be ideal in 2010 and are tuned accordingly.

B.37 The study was conducted on future years and the existing base model was adapted to account for this. In particular:

- any decommissioned plant will be removed from the model; and
- auplicating one of the existing plants will represent any newly commissioned plant. It is envisaged that all new plant will be CCGTs or OCGTs.

Wind turbine models

B.38 Details of the wind turbine models are given in Annex E

Combined cycle gas turbines[92]

B.39 Emphasis has been placed on the development of models of combined cycle gas turbine (CCGT) units on the system, which have particular frequency response characteristics that make them prone to potentially exacerbating any initial frequency disturbance.

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90 ESB National Grid, "Generation Adequacy Report, 2004 - 2010", November 2003.

ESB National Grid, "Forecast Statement, 2003 - 2009", June 2004.

91 Lalor, G. and O'Malley, M.J., "Frequency control on an island power system with increasing proportions of combined cycle gas turbines", IEEE Power Tech, Bologna, Italy, June 2003.

92 Lalor, G., Ritchie, J., Flynn, D. and O'Malley, M.J., "The impact of combined cycle gas turbine short term dynamics on frequency control", in review, 2004.

B.40 Following the tripping of a unit on the system the frequency falls. This will reduce the speed of the compressor on a CCGT. Consequently, the output pressure of the compressor is reduced, and there is also a reduction in airflow. Reduced output pressure of the compressor leads to a decrease in the pressure ratio across the gas turbine and hence a lower power output from the gas turbine. The reduction of airflow into the combustor increases the fuel to air ratio, leading to a rise in temperature. However, due to operational constraints on the machine, the upper temperature at which the turbine may operate is limited. This limit can be exceeded for short periods of time but can impact on the lifespan of the machine. The temperature controller comes into play in such a situation and the fuel flow is reduced accordingly. So, clearly, the maximum power output of the gas turbine element of the CCGT during a low frequency event will be constrained by temperature control. This results in a further reduction in power output by the CCGT. During a frequency transient, CCGTs may also suffer from compressor surge, which can adversely affect the power output.

B.41 If a CCGT is operating at base load (i.e. maximum rated output), the unit is not capable of producing and maintaining any increase in power output. In fact, if the frequency falls, the temperature controller will actually reduce fuel demand and the power output of the gas turbine will drop. Consequently, the output of the unit remains at a value less than its rated output until the frequency of the system returns to normal.

B.42 There are now four large CCGTs on the system, with at least one more large unit being planned for 2005. Therefore, a major and recent addition to the dynamic model is the inclusion of a combined cycle gas turbine (CCGT) representation, which is based on existing gas turbine models with the addition of a heat recovery steam generator (HRSG) and steam turbine. The steam turbine may be neglected in this case, apart from its contribution to the system inertia, by assuming that its response is negligible up to 20 seconds following a frequency event.

B.43 Open cycle gas turbines (OCGTs) tend to have a less adverse effect on the system frequency following a disturbance for two reasons. Firstly, as they generally operate as peaking plant, they are not often base loaded. Secondly, the turbine exhaust temperature limit is usually far less stringent than for CCGTs. These two factors mean that OCGTs can respond quite rapidly to frequency deviations, and are therefore often used as a source of spinning reserve.

Load dynamic model tuning[93]

B.44 The system load was represented using a single model, accounting for the frequency sensitivity and inertial response of the load[94]. Validation was undertaken using measurement-based techniques that combined data from system tests and generator tripping events occurring on the system, and consultation with both ESB National Grid and System Operator Northern Ireland.

Probabilistic model

B.45 When quantifying the required system operating reserve level, deterministic security criteria are usually applied in practice. These often take the form of requirements to satisfy the performance standards of system operation, i.e. to maintain the system frequency within statutory limits for a number of pre-defined (credible) events, such as the sudden loss of the largest infeed to the system. Furthermore, the system must maintain a sufficient amount of response in order to deal with continuous changes in demand and generation outputs. The amount of response required is usually determined empirically, so that the number of occasions when the frequency deviates from operating targets is considered acceptable.

93 This refers to the tuning of the load model used in the dynamic simulations and should not be confused with the load modelling methodology, which was used to scale up historical load data.

94 O'Sullivan, J. and O'Malley, M.J., "Identification and validation of dynamic global load model parameters for use in power system simulation", IEEE Transactions on Power Systems, Vol. 11, pp. 851 - 857, 1996.

B.46 In our approach we have adopted a more rigorous approach to determining required operating reserves to deal with generation outages and unforeseen load variations, and we can appraise the reliability of the system as an objective measure to assess required operating reserve under different conditions. This approach provides a consistent framework within which it is be possible to compare operating reserve requirements for various scenarios on an objective basis. This is used to quantify the additional amount of operating reserve necessary to accommodate large amounts of wind generation on the all-island system[95].

B.47 The probabilistic methodology developed considers the uncertainty in the load and wind power forecasts along with the probability of losing generation, enabling the required system operating reserve level for a specified level of system reliability to be quantified. This methodology is applied to the all-island system with significant quantities of wind capacity, taking into consideration the characteristics of the latest wind power forecasting techniques.

B.48 Many different reliability criteria are used in power systems analysis[96]. Most system reliability analyses focus on generation adequacy calculations, which consider the probability of load and generation *being* out. The methodology developed, which is suited to system operation and dispatch, considers the probability of generation and load *going* out. This subtle difference in approach allows the effect of wind and load variations to be included in the operating reserve calculations. In our approach, the reliability criterion *LSI* is defined as being the expected number of load shedding incidents tolerated per year, where a load shedding incident is defined as an incident when there is insufficient operating reserve to meet a generation shortfall.

B.49 The methodology developed relates the operating reserve level on the system in each hour to the reliability of the system over the year. The operating reserve requirement in every hour will vary as the generator dispatch and forecast errors vary. Therefore, the operating reserve level must be related to the reliability of the system over one hour. It is assumed that the operating reserve is allocated in such a way during the year so as to maintain the average risk of having a load shedding incident in each hour at the same value for all hours (i.e. each hour is operated such that if the year was comprised of 8760 such hours then the expected number of load shedding incident would be *LSI*). This is a reasonable assumption and is one that is generally adopted in many power systems.

B.50 The approach assumes a load shedding incident may occur in 3 ways:

- A generator outage (full or partial) and an unforecast wind and load variation greater than the system operating reserve level.
- A generator outage and an unforecast wind and load variation some time directly after a previous generator outage.
- An unforecast wind and load variation greater than the system operating reserve level.

B.51 The number of load shedding incidents per year will correspond to the sum of the probabilities of having a load shedding incident in each hour. Due to the low generator outage rates, the probability of having three or more generator outages in a short period of time is small and will not meaningfully contribute to the number of load shedding incidents experienced over a year, and has therefore been neglected.

95 Doherty, R. and O'Malley, M.J., "New approach to quantify reserve demand in systems with significant installed wind capacity", in review, 2004.

96 Billinton, R. and Allan, R., "Reliability evaluation of power systems", Plenum Press, 1984.

ANNEX C – Scheduling and Dispatch Methodology

C.1 This Annex describes the methodology used for determining the scheduling and dispatch of conventional and wind generation to meet both the requirements of the energy and reserve markets. This was a two-step process.

- Scheduling was undertaken using ILEX's in-house economic dispatch and pricing model of the all-island energy market to determine an optimal schedule for plant operation based on expected wind generation and demand profiles and projected requirements for operating reserve.
- Dispatch modelling was undertaken by QUB and UMIST to determine actual dispatch of generation (where this may differ from the schedule) in real time based on probabilistic changes to the wind and/or demand profiles.

C.2 Actual dispatch of generation can be expected to vary from the forecast schedule operation due to any combination of:

- forced outages in generators or on the transmission or distribution system;
- unexpected changes in demand; and
- unpredicted changes in wind generation.

C.3 The system operator must schedule sufficient operating reserve to be able to ensure that the required real time dispatch can be met. The extent to which the actual dispatch may vary from the scheduled plant operation may be affected by:

- The gate-closure period – the time period between the schedule being set and the real time delivery of power. The shorter the period the less opportunity there is for forecast errors. We assumed a one-hour gate-closure period.
- The accuracy of wind forecasting – over short time periods of an hour or less, persistence is likely to be the most accurate wind forecasting tool, however over longer time periods more sophisticated wind forecasting techniques become an important determinant of the operating reserve requirement. Recent developments in the improvement of wind forecasting techniques may assist in reducing the volume of operating reserve required to accommodate wind generation.
- Weather patterns – extreme weather days increase the potential extent for variances, as demand and conventional (particularly CCGT) generation is sensitive to temperature, and both wind generation and demand are sensitive to wind speed.

Scheduling of energy and operating reserve

C.4 The dispatch schedule for each sample day was generated by simultaneously optimising energy and operating reserve schedules in the most economic manner. Key inputs to this process were the profiles of demand and wind generation over the sample days modelled.

Sample demand days

C.5 For both 2006 and 2010, and for each of the wind capacity scenarios, scheduling was undertaken for three sample days – a winter peak day representing peak demand, a summer valley day representing the lowest annual demand and a shoulder business day – representing a day of normal operation. The sample days were selected using the 2003 demand profile for RoI:

- the winter peak day selected was the day in which the half-hour of annual maximum system demand occurred;
- the summer valley day was the day in which the half-hour of annual minimum system demand occurred; and
- the shoulder business day selected was the day with total demand closest to the average daily demand across the spring and autumn months, so as to typify a normal business day over the shoulder periods.

Daily wind profiles

C.6 The demand profile for each of these sample days were then combined with a wind generation profile – representing either a high wind day or low wind day, typical of the season applicable to that sample day. The wind days were selected by examining the annual wind profile for 2003 as scaled to the appropriate total wind capacity (845 MW, 1,300 MW or 1,950 MW – see Annex B).

- The high wind day corresponds to a 60% capacity factor (total daily generation is equivalent to 60% of the total installed wind capacity generating at full rated capacity throughout the 24 hour period).
  - The winter high wind day was selected as the day during the winter period with daily generation closest to the 60% capacity factor.
  - The summer high wind day was selected as the day during the summer period with daily generation closest to the 60% capacity factor.
  - The shoulder high wind day was selected as the day during the spring and autumn periods with daily generation closest to the 60% capacity factor.
- The low wind day corresponds to a 30% capacity factor.
  - The winter low wind day was selected as the day during the winter period with daily generation closest to the 30% capacity factor.
  - The summer low wind day was selected as the day during the summer period with daily generation closest to the 30% capacity factor.
  - The shoulder low wind day was selected as the day during the spring and autumn periods with daily generation closest to the 30% capacity factor.

Forecast energy schedule

C.7 A comprehensive data set of generation plant capabilities[97] and cost data for 2006 and 2010 was developed from several existing sources[98]. This data set was used for two purposes. Firstly, it was used to form the dispatch schedules for the sample days and wind scenarios. Secondly, it was used to fine-tune the short term frequency dynamic model.

C.8 Plant forecast dispatch is generated separately for each sample day. For each half-hour in the sample day, the plant is dispatched to meet energy requirements.

C.9 For this purpose, plant are sorted in an energy merit order, i.e. according to their short-run marginal costs of providing energy to the system. A plant's position in the energy merit order will be determined by:

- the relative cost of its fuel; and
- its efficiency in converting that fuel to electricity.

C.10 Plant are scheduled to run according to their position in the energy merit order – the most efficient/cheapest baseload plant are lower in the merit order and will be dispatched first. The less efficient mid-merit and peaking plant are situated higher in the merit order and will only be dispatched if there is sufficient energy demand.

C.11 The merit order is built to meet energy requirements for both Northern Ireland and the Republic of Ireland – the only constraint being the maximum permitted flow on the North-South Interconnector.

97 Maximum power output, minimum power output, reserve capabilities, etc.

98 Includes similar data sets from the two system operators (ESBNG & SONI).

Table C.1 – North-South Interconnector assumptions

	2006	2010
Maximum capacity North-South	300 MW	400 MW
Maximum capacity South-North	-	200 MW

C.12 A number of units were considered to be operating according to predetermined profiles, outside the merit order.

- Wind turbines were generating according to predetermined patterns. Three profiles were considered for each wind capacity scenario:
  - no wind;
  - low wind (a profile chosen to represent a 30% load factor); and
  - high wind (a profile chosen to represent a 60% load factor).
- Hydro plant and the Turlough Hill pumped storage plant were operating in accordance with historic profiles on the days chosen as the basis for sample days.
- The Moyle and East-West dc Interconnectors are importing at predetermined rates.
- Both pumped storage and the two external interconnector profiles were later adjusted in order to ease operating reserve and operational constraints.
- Coal plant (Kilroot in Northern Ireland and Moneypoint in the Republic of Ireland) are assumed to always run at baseload (unless outaged), even though they might not be in merit for some of the periods.

Pumped storage

C.13 Turlough Hill is a pumped storage station on the system and is so fundamentally important to the provision of reserve on the system that it requires special attention.

C.14 Turlough Hill consists of four units, each capable of three distinct modes of operation: generating, spinning in air, and pumping. In the generating mode of operation, the units can provide all categories of operating reserve. When spinning in air (also known as synchronous condenser turbine mode), the units consume approximately 1 MW and can provide all categories of operating reserve except primary. When pumping, each unit consumes 73 MW and can be tripped instantaneously thus providing 73 MW of reserve. Each pump will trip off at a different preset frequency, providing the reserve in a staggered manner.

Plant availabilities

C.15 In order to produce representative results for the sample days realistic snapshots of plant availabilities are generated. A plant can be unavailable for two reasons - scheduled outage or forced outage.

C.16 The outages are such that system availability is close to the forecast/desired system availability for the future years. For the ESB system, the outage rates are based on historical data and data published in the Generation Adequacy Report[99]. For the NIE system, the forced outage rate is based on the contracted values supplied by SONI/NIE while the scheduled outage rates are assumed to be the same as for the ESB system. In line with the Generation Adequacy Report, an increase in availability is assumed going forward (ESB system availability for 2006 is 85%, while for 2010 it is 87%).

99 ESBNG, "Generation Adequacy Report 2004 - 2010", November 2003.

Table C.2 – ROI plant capacity assumptions

Plant	Capacity[100] (MW)	Plant fuel/ type	Comments
Aghada 1	258	Gas/ST	
Aghada Turbine 1	90	Gas/OCGT	(ST)
Aghada Turbine 2	90	Gas/OCGT	(ST)
Aghada Turbine 4	90	Gas/OCGT	(ST)
Ardnacrusha 1	24	Hydro	
Ardnacrusha 2	24	Hydro	
Ardnacrusha 3	21	Hydro	
Ardnacrusha 4	22.5	Hydro	
Aughinish	150	Gas/CCGT	
Carrigadrohid	8	Hydro	
Cathleen's Fall 1	22.5	Hydro	
Cathleen's Fall 2	22.5	Hydro	
CCGTx[101]	390	Gas/CCGT	(2010)
Cliff 1	10	Hydro	
Cliff 2	10	Hydro	
East-West Interconnector	400	Interconnector	(2010)
Edenderry	117.6	Peat	
Emergency Generation AD8	52	Gas/OCGT	(ST)
Emergency Generation PK8	104	Gas/OCGT	(ST)
Emergency Generation TW5	52	Gas/OCGT	(ST)
Golden Falls	4	Hydro	
Great Island 1	57	Oil	(ST)
Great Island 2	57	Oil	(ST)
Great Island 3	112	Oil	
Huntstown	343	Gas/CCGT	
Inniscarra 1	15	Hydro	
Inniscarra 2	4	Hydro	
Lanesboro 8	91	Peat	
Leixlip	4	Hydro	
Marina	112.3	Gas/CCGT	
Moneypoint 1	285	Coal	
Moneypoint 2	285	Coal	
Moneypoint 3	285	Coal	
Northwall 1-4	163	Gas/CCGT	
Northwall 5	109	Gas/OCGT	
Pollaphuca 1	15	Hydro	
Pollaphuca 2	15	Hydro	
Poolbeg 1	114.5	Gas/ST	
Poolbeg 2	114.5	Gas/ST	
Poolbeg 3	257	Gas/ST	
Poolbeg CCGT	460	Gas/CCGT	
Shannonbridge 4	137	Peat	
Dublin Bay Power	390	Gas/CCGT	
Tarbert 1	57	Oil	
Tarbert 2	57	Oil	
Tarbert 3	240.7	Oil	
Tarbert 4	240.7	Oil	
Turlough Hill 1	73	Pumped Storage	
Turlough Hill 2	73	Pumped Storage	
Turlough Hill 3	73	Pumped Storage	
Turlough Hill 4	73	Pumped Storage	
Tynagh	390	Gas/CCGT	

(2010) only assumed to be present in 2010
(ST) plant considered as standing reserve[102]

100 Export capacity (generated output minus house load).

101 This is a new CCGT, which is assumed commissioned by 2010.

Table C.3 – NI plant capacity assumptions

Plant	Capacity (MW)	Plant fuel/ type	Comments
Ballylumford 1	110	Gas/ST	
Ballylumford 10	103	Gas/CCGT	
Ballylumford 2	510	Gas/CCGT	
Ballylumford 6	190	Gas/ST	
Ballylumford GT 1	58	Distillate/OCGT	(ST)
Ballylumford GT 2	58	Distillate/OCGT	(ST)
Ballylumford GT 3	29	Distillate/OCGT	(ST)
Ballylumford GT 4	29	Distillate/OCGT	(ST)
Coolkeragh	390	Gas/CCGT	
Kilroot 1	180	Coal	
Kilroot 2	180	Coal	
Moyle	400	Interconnector	(1)

(1) unable to provide reserve in 2006
(ST) plant considered as standing reserve[103]

Fast reserve requirement

C.17 Both fast reserve (5-15 seconds) and slow reserve (15 seconds - 30 minutes) are co-dispatched with energy under the proposed new Market Arrangements for Electricity (MAE). Fast and slow reserve targets were developed under the methodologies described in Annex B. However, it is the fast reserve target that is critical, as the scheduling of sufficient capacity to meet the fast reserve target was sufficient to also satisfy the slow reserve target in almost all periods.

C.18 The size of the four largest infeeds to the system in each half-hour determines the total fast reserve requirement in each half-hour.

C.19 In 2006, fast reserve targets are met independently by Northern Ireland and the Republic of Ireland. Northern Ireland carries one third of the total requirement, while the Republic carries two thirds.

C.20 In 2010, fast reserve is shared on an all-island basis, irrespective of geographic location.

Static reserve

C.21 A number of static sources of fast reserve are netted off the total operating reserve requirements:

- contribution from pumped storage;
- interruptible demand;
- reactors overnight; and
- the Moyle and East-West Interconnectors.

C.22 Turlough Hill: when pumping, Turlough Hill operates at a fixed set point and therefore cannot provide dynamic reserve. The sets are equipped with under-frequency relays, which trip them out at staggered setpoints. The sets can then switch into generating mode if necessary providing additional operating reserve.

C.23 Interruptible demand: not all of the interruptible demand is consuming energy at the time of an event; the contribution to operating reserve is taken to be a fraction of the total contracted. This operating reserve is available 07.00 – 00.00, except during the winter peak hours, when the winter peak demand reduction scheme (WPDRS) is active, i.e. 17.00 to 19.00. Interruptible demand is assumed to provide 50 MW of fast reserve in both 2006 and 2010.

102 Total standing reserve in the Republic of Ireland: 592 MW.

103 Total standing reserve in Northern Ireland: 174 MW.

C.24 Shunt reactors connected to the cable network are activated by under-frequency relays. These reactors reduce demand by depressing the voltage. For system stability reasons these relays are only active from 00.00 until 07.00. The amount of operating reserve they provide is estimated as 1% of system demand.

C.25 Interconnectors: the existing Moyle interconnector and the proposed east/west interconnector are both capable of providing operating reserves. They are however static operating reserves as they are likely to be triggered by a frequency deviation. Each interconnector (for the 2010 cases only) is assumed to provide a single block of static operating reserve of 25 MW.

C.26 The contribution from these static sources of fast operating reserve was capped at a level equivalent to the total operating reserve requirement less 150 MW, and was shared equally between the two systems.

Determination of operating reserve provision and iteration

C.27 Within the forecast energy dispatch, a separate operating reserve merit order is created for the units in the energy merit order. The operating reserve merit order is based on:

- the maximum capacity of fast reserve a plant is able to provide;
- the efficiency of the plant at providing fast reserve; and
- the lost opportunity revenue from not providing energy to the market.

C.28 Plant are deloaded to meet total fast reserve requirements. The total amount deloaded is added back on to the energy requirements, resulting in a new energy merit order.

C.29 This process is iterated until fast reserve requirements are met in each half-hour, with the following considerations in mind:

- the new energy merit order might result in changes to the four largest infeeds, and consequently changes to the fast reserve requirements;
- the North-South interconnector flow constraints (see Table C1) must not be breached;
- the number of required plant start-ups in a day should be minimised.

C.30 Should fast reserve requirements in either of the two systems not be met after several iterations, pumped storage and/or interconnector import profile assumptions are adjusted to bring additional units onto or off the system.

C.31 The final forecast dispatch schedule is analysed to extract the contribution of units to slow reserve targets.

Dispatch

System demand variability

C.32 If net system demand is defined as the total system demand less the contribution from wind generation, then the load following capability of conventional plant is required to track both scheduled variation in the net system demand and from errors arising in either the forecast value for the total system demand or wind generation. Scheduled variation in net system demand is met by pre-determination of individual unit setpoints, while forecast errors are distributed across all synchronised plant dependent on their individual governor droop characteristics.

C.33 Net system demand will be independent of whether wind generation forms part of the unit commitment procedure or not. Depending on the wind profile for a particular day, the net system demand may look significantly different to the system demand, and the load following requirements for conventional plant may be similarly altered. Figure C.1 illustrates probability distributions of the 15-minute variation in system demand, net demand and wind generation for 3 sample days – 2006 summer valley day (low wind), 2010B shoulder business day (low wind) and 2010B winter business day (high wind).

C.34 For the 2006 scenario, while the system demand distribution is skewed negatively indicating that the demand is slightly more likely to decrease than increase, the net demand characteristic appears more uniform with $\pm$ 80 MW variations over 15 minutes being equally probable. For the 2010B shoulder business day the maximum net demand variation (294 MW) is greater than the maximum system demand variation

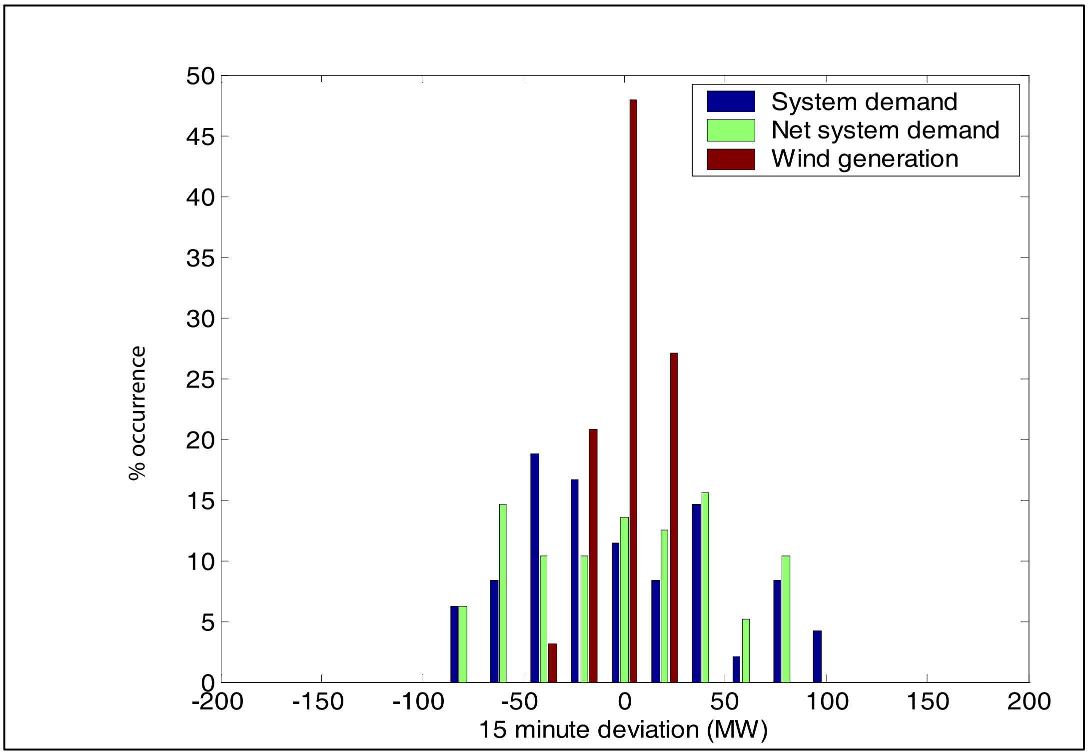
(244 MW) and occurs, in this case, because a fall in wind generation coincides with the morning rise in demand. Finally, for the 2010B winter business day, the system demand and net system demand are of similar shape.

C.35 The variability in wind output is considerably less than that of the demand – the latter is dominated by the morning rise and evening fall off in demand. For the three considered scenarios the maximum variation in wind output is 39 MW (2006), 52 MW (2010A) and 80 MW (2010B). Consequently, even with significant wind generation the extremes in net demand variation would not normally be expected to significantly exceed the system demand variation.

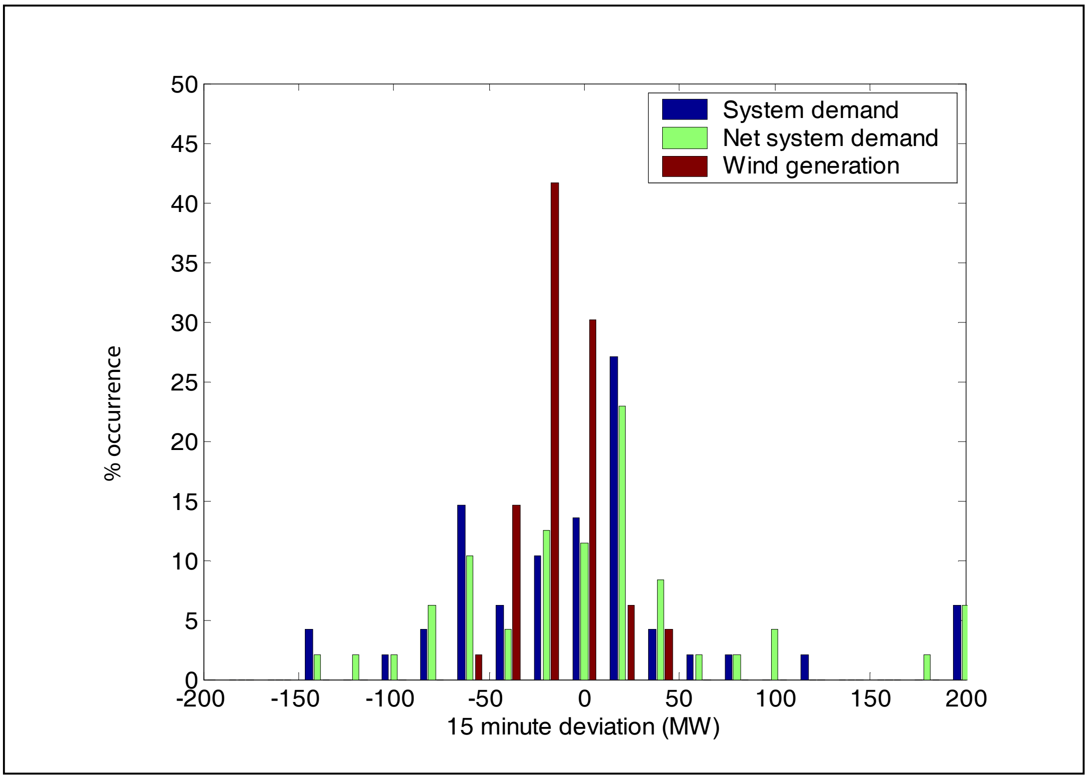
C.36 Table C.4 summarises the standard deviation, maximum and minimum of the observed variation over 15-minute periods in the system demand, net system demand and wind generation. Data are presented for 2006, 2010A and 2010B for low and high wind scenarios covering the winter business day, shoulder business day and summer valley day. Net system demand variability tends to be higher than that of the system demand for the winter business day scenarios, while the reverse tends to be true for the summer valley days. Indeed, although wind variability is highest for the 2010B summer valley day (high wind) scenario, the effect is to reduce the load following requirements for the system. On this particular day, total wind output rises from ≈300 MW to ≈1,600 MW between 04.00 and 11.00, thus negating much of the normal morning rise in demand.

Table C.4 – Total demand, wind and net demand 15-minute variability for 2006, 2010A and 2010B scenarios

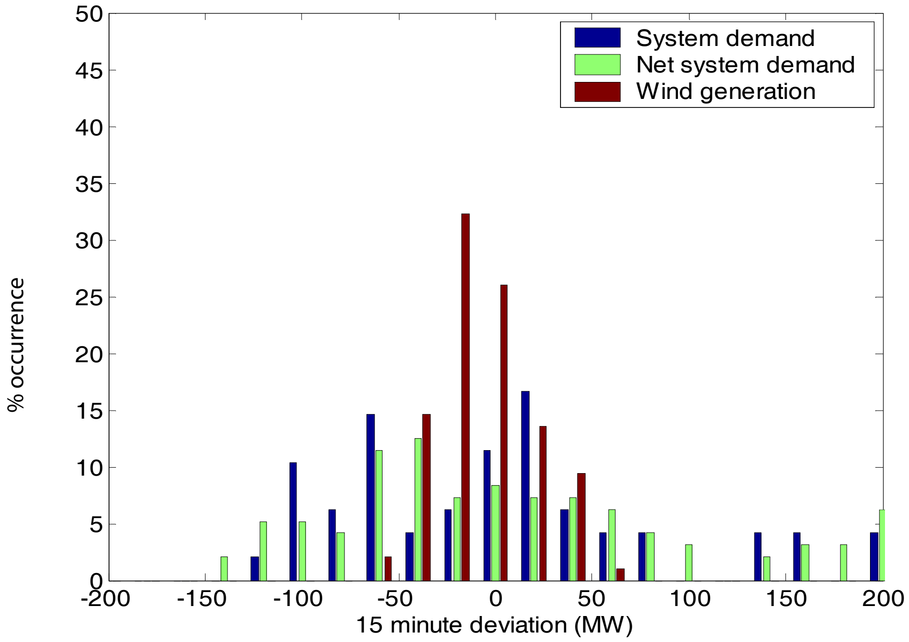
		Total demand			Wind			Net demand		
		SD	Max	Min	SD	Max	Min	SD	Max	Min
2006 low	Winter	75.4	217	-104	12.7	32	-22	83.9	230	-133
	Shoulder	70.3	222	-125	8.9	15	-27	69.4	206	-127
	Summer	47.5	97	-80	14.9	26	-33	48.1	88	-83
2010A low	Winter	84.1	241	-116	18.8	50	-32	97.1	259	-160
	Shoulder	78.1	244	-139	19.2	33	-41	83.6	252	-144
	Summer	53.1	107	-88	20.7	35	-46	54.7	103	-93
2010B low	Winter	84.1	241	-116	22.2	43	-55	95.8	284	-144
	Shoulder	78.1	244	-139	19.4	38	-59	88.9	294	-131
	Summer	53.1	107	-88	28.9	50	-62	57.1	114	-108
2006 high	Winter	75.4	217	-104	12.3	19	-39	75.5	232	-103
	Shoulder	70.3	222	-125	18.2	34	-32	71.7	232	-149
	Summer	47.5	97	-80	15.7	37	-35	42.7	86	-77
2010A high	Winter	84.1	241	-116	19.6	45	-41	90.3	252	-122
	Shoulder	78.1	244	-139	25.3	49	-50	81.1	258	-179
	Summer	53.1	107	-88	23.0	52	-48	46.7	90	-85
2010B high	Winter	84.1	241	-116	27.5	63	-59	94.5	261	-131
	Shoulder	78.1	244	-139	28.3	52	-63	84.2	249	-153
	Summer	53.1	107	-88	29.5	80	-77	40.4	81	-77



(a)2006 summer valley day – low wind



(b) 2010B shoulder business day – low wind



(c) 2010B winter peak day – low wind

Figure C.1 – System demand, wind and net demand probability distributions

Load-following model

C.37 The dynamic model of the all-island system (Annex B) forms the basis for an investigation of the load following requirements on conventional plant. The existing model is only intended for 20 second time frames, but by removal of the existing boiler dynamics for conventional plant, exhaust temperature control of CCGTs, etc. and inclusion of unit output setpoint controls (unit commitment schedule), greatly extended time horizons can be considered. CCGTs are fully represented, such that the HRSG and steam turbine can assist in load following, as well as being a potential source of slow reserve. Ramping rate restrictions have been placed on all units, and units are also ramped up and down during start-up and shutdown procedures.

C.38 For the 2006 scenario, specified governor droops have been based on an analysis of steady-state unit responses following loss of generation events during the period 1998 to present. A number of units have been observed to have poor frequency response (see Section B.36) and in some cases may not be considered to possess a load-following capability. In the 2010 scenario, all units are assumed to be able to contribute to load following. The governor droops of existing units have been improved towards a target figure of 4%, while all new additions to the system are assumed to have a 4% droop characteristic. Turlough Hill, the Moyle dc interconnector and the proposed East-West dc interconnector are all assumed to provide no load following capability, although it is recognized that they have the capability to do so.

C.39 Time series models of the actual wind generation and actual system load (rather than the predicted values used for unit commitment purposes) enable the regulating behaviour of individual generators, subject to ramping rate restrictions, and the subsequent impact on the system frequency to be examined every 15-minutes. In addition, available fast and slow reserve are compared against scheduled targets (based on original unit commitment) and actual required targets (based on the actual output of the four largest infeeds). The scheduled and actual targets will differ due to forecast errors in both the system demand and wind generation, causing an error in the net demand (system demand – wind generation) supplied by conventional generation.

C.40 Unit commitment has been performed for a number of sample days, and requires half-hourly predictions of both the system demand and wind generation (for *forecast* mode). When considering the load following requirements of the scheduled generation, the predicted system demand and wind generation require to be converted into actual demand and actual generation profiles for each sample day, updated every 15 minutes rather than every half-hour. It then becomes the role of the generation plant to follow scheduled changes in unit setpoints and errors in both forecast demand and wind levels.

C.41 The conversion between predicted and actual outputs is achieved by filtering 15 minute demand and wind input signals. This consists of a combination of time-shifted low pass filters (of high and low order to respectively provide high and low signal smoothing of the original input) and the addition of a low frequency noise signal. The output signal is determined as a weighted output of the individual components – the weighting is separately adjusted for the demand and wind time series, and for the 2006 and 2010 scenarios. Errors, between the predicted and actual signals, can present themselves as a time-shifting (backwards and forwards) of the inputs and a variation in signal magnitude (positive and negative).

C.42 The standard deviation of errors in both the demand and wind forecast are established on a time horizon of 5-10 minutes. The targets are 11.6 MW for the system demand for both 2006 and 2010, Figure 4.7, while the wind targets are 9.2 MW (2006), 13.0 MW (2010A) and 18.6 MW (2010B), Figure 4.5. These can be roughly translated into a maximum absolute system demand error of ±35 MW. Equivalent approximate figures for wind prediction errors are ±30 MW (2006), ±40 MW (2010A) and ±50 MW (2010B).

Generation output variability

C.43 The timing and magnitude of the morning rise and evening fall, as part of the load shape, can be accurately predicted. Units will accordingly be scheduled to come on-line and switch off at appropriate times. The ramping up and down of these committed / decommitted units will, therefore, tend to reduce the required load following capability of the remaining synchronized units.

C.44 The load following capability of individual units will depend on their permissible ramping rates and the governor droops of the units. In the 2006 load following model, unit parameters have been based on observed data following frequency transients on the all-island system. A number of ESB plant are considered to be unresponsive, and only provide an inertial response following a loss of generation on the system (see Section B.36). With the addition of new plant, mainly in the form of CCGTs, these under-performing generators have tended to be pushed up the merit order such that their underperformance has become less critical.

C.45 By 2010, all plant are assumed to have the potential to be highly responsive, with excellent load tracking capability.

C.46 For the same three scenarios as earlier, namely 2006 summer valley day (low wind), 2010B shoulder business day (low wind) and 2010B winter business day (high wind) the 15-minute variation in output of ESB generation and NIE generation is compared against the variability of all units over the sample days in Figures C.2 - C.4. Results are presented when wind is both *forecast* and unforecast (*fuel saver* mode). Variation in output due to start-up and shutdown of units has been excluded from all calculations. Consequently, taking the 2010B winter business day as an example, the maximum net system demand variation of 261 MW has been reduced to 194 MW for the committed plant in *fuel saver* mode and 173 MW in *forecast* mode.

C.47 From a load following perspective, the major difference between *fuel saver* and *forecast* mode is that more units will tend to be committed in *fuel saver* mode (due to an expectation of total system demand rather than net system demand). With actual wind potentially approaching 2,000 MW for the 2010B scenario, this can mean a difference in commitment of 7+ units. An increased number of scheduled units (under *fuel saver* mode) implies that the load following burden on individual units should be reduced. However, note has to be taken that a scheduled increase / decrease in a unit output does not coincide with a decrease / increase in (unforecast) wind generation causing the system load following requirements to actually increase. This effect can be seen between 03.00-04.00 and 20.00-21.00 on 2006 summer valley day (see Figure C.2).

C.48 The NIE system is increasingly composed of a small number of large units and a dc interconnection to Scotland. Additionally, in 2010 it is assumed that the Moyle link will provide a limited increase in power transfer should the system frequency fall beneath a defined threshold.

C.49 For the 2006 scenario, individual operating reserve targets are set for both the NIE and ESB systems. From an NIE system point of view this will imply that a comparatively high number of plant will be scheduled to generate[104] – NIE generation capacity will tend to exceed NIE demand and hence power will be exported to ESB. Consequently, when switching from *fuel saver* to *forecast* mode, the reduction in predicted net system demand will tend to be achieved by rescheduling ESB generation.

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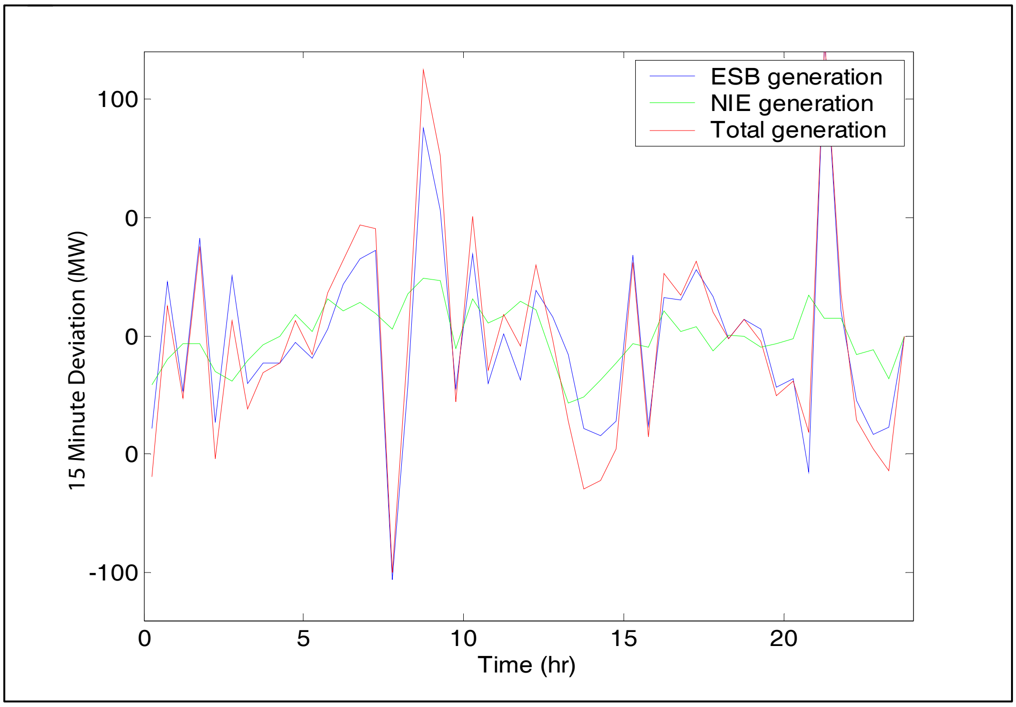
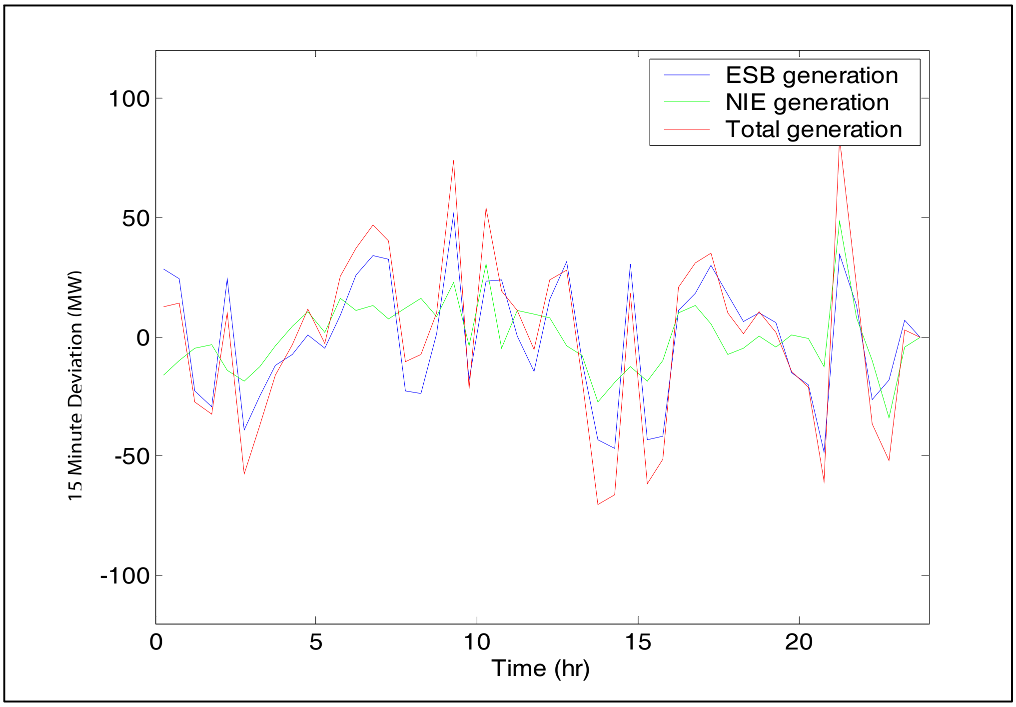
104 Kilroot power station will tend to operate at (or near) maximum output on coal, although even at this level both units can provide significant operating reserve.

C.50 For the 2010 scenario, a single operating reserve target is defined, which will reduce excess scheduled NIE capacity. Further, given that all generating units will be expected to be responsive, the ESB system will still provide the majority of the load following requirement.

C.51 Consequently, in *fuel saver* mode ESB units will tend to provide the majority of the fuel save requirement, see Figures C.2(a) - C.4(a). The 15-minute variation in NIE generation rarely exceeds 50 MW, while a comparable figure for ESB generation would be 80 MW in 2006 and 100 MW in 2010.

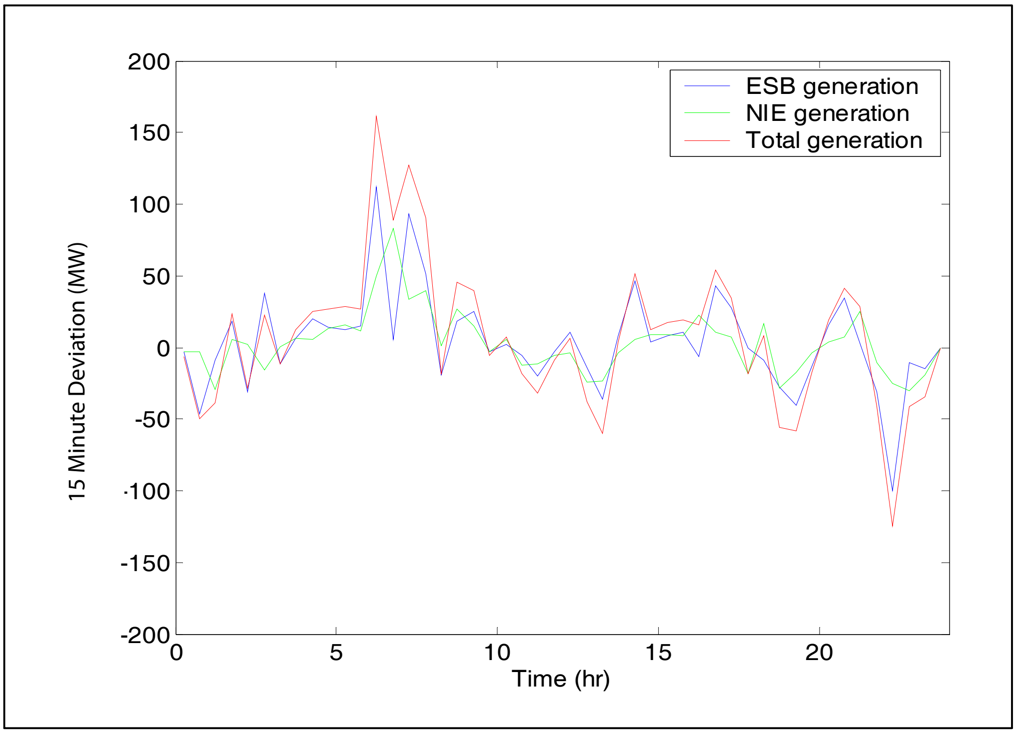


(a) fuel saver mode – low wind

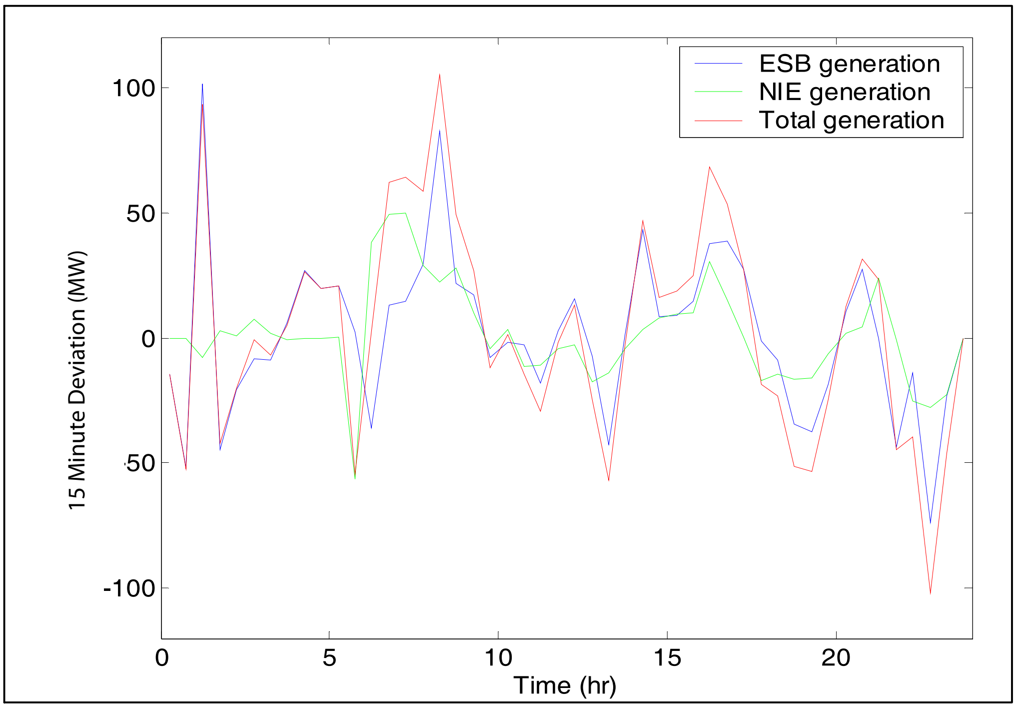


(b) forecast mode – low wind

Figure C.2 – 2006 summer valley day 15-minute deviation of ESB and NIE generation

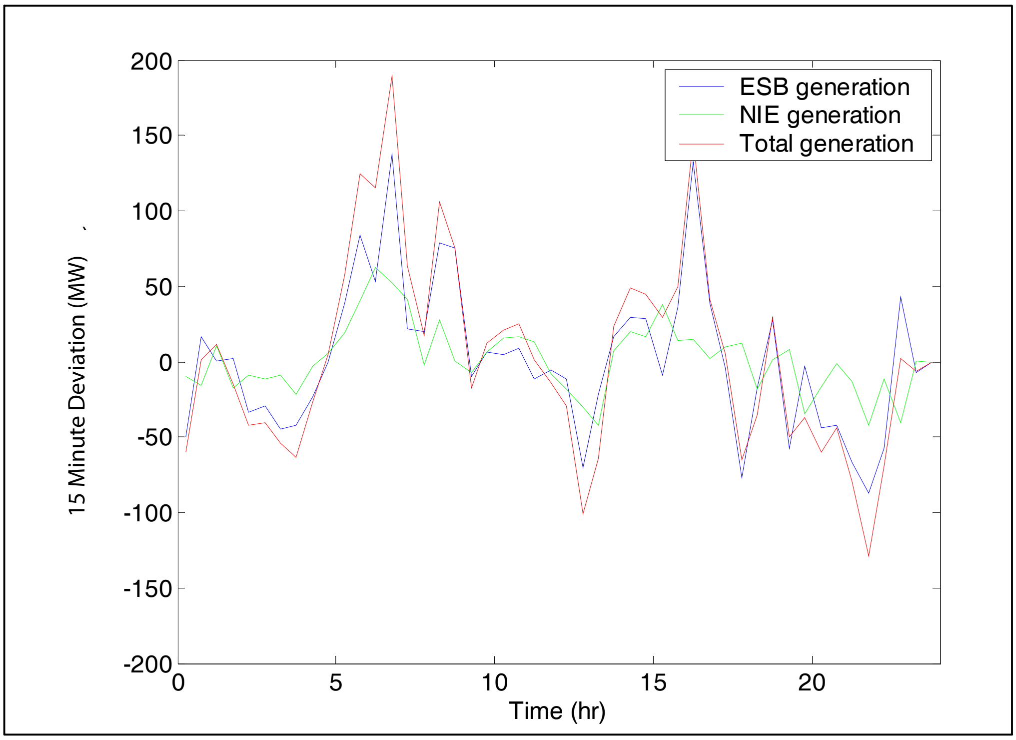


(a) fuel saver mode – low wind

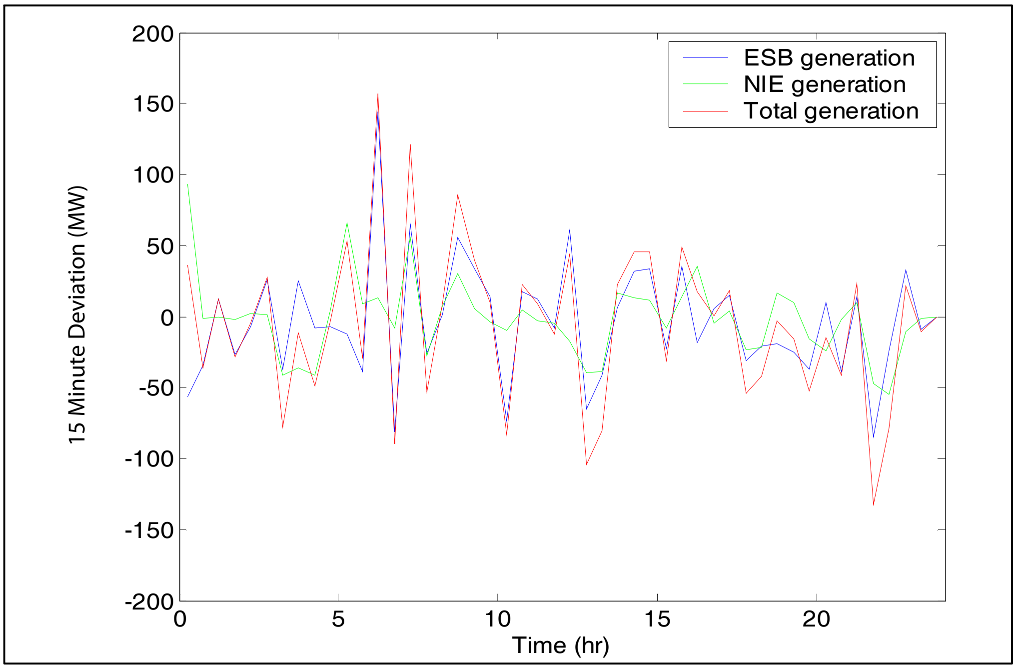


(b) forecast mode – low wind

Figure C.3 – 2010B shoulder business day – 15-minute deviation of ESB and NIE generation



(a) fuel saver mode – high wind



(b) forecast mode – high wind

Figure C.4 – 2010B winter peak day – 15-minute deviation of ESB and NIE generation

Individual unit responses

C.52 For each scenario, individual units are subject to positive / negative ramping restrictions. Comparison can be made between *fuel saver* and *forecast* modes for each unit, although given that the original schedules for both modes may be significantly different, a direct comparison can not be easily achieved.

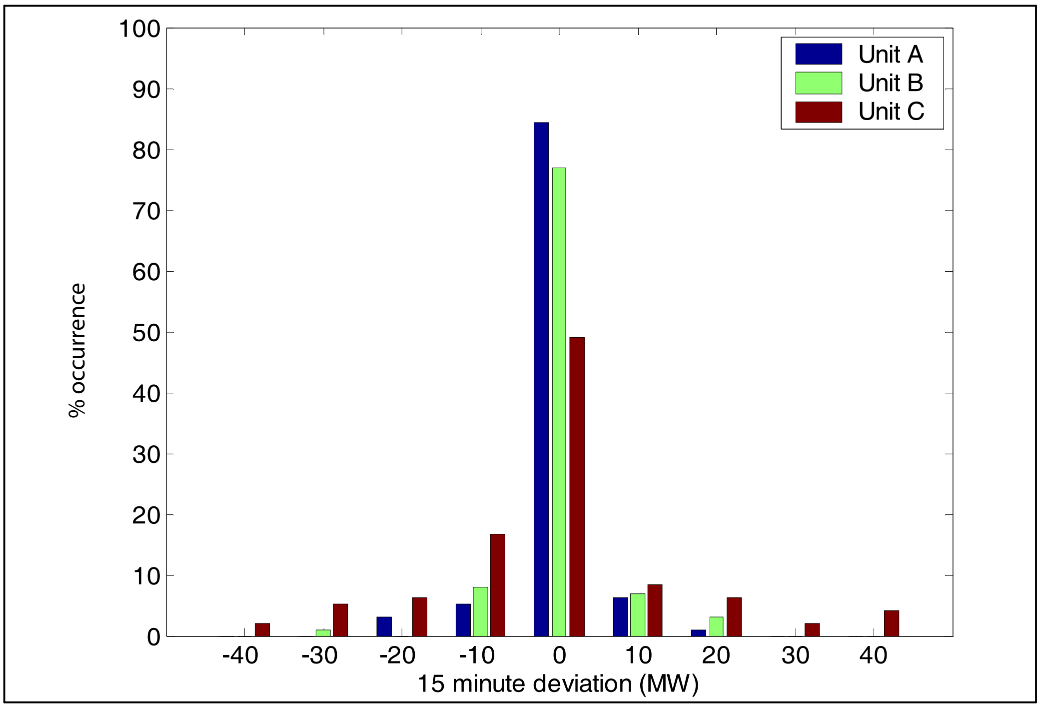
C.53 Figures C.5 - C.6 illustrate the probability distributions for three, unidentified power stations, operating in both *fuel saver* and *forecast* mode for 2006 summer valley day (low wind), 2010B shoulder business day (low wind) and 2010B winter business day (high wind). Unit C was not operational during the 2006 summer valley day.

C.54 The histograms illustrate the 15-minute deviation in unit outputs, rather than the variation in unit output itself. Consequently, the dominance of the zero deviation columns merely indicates that unit outputs are changing slowly rather than that the unit commitment schedule is being followed.

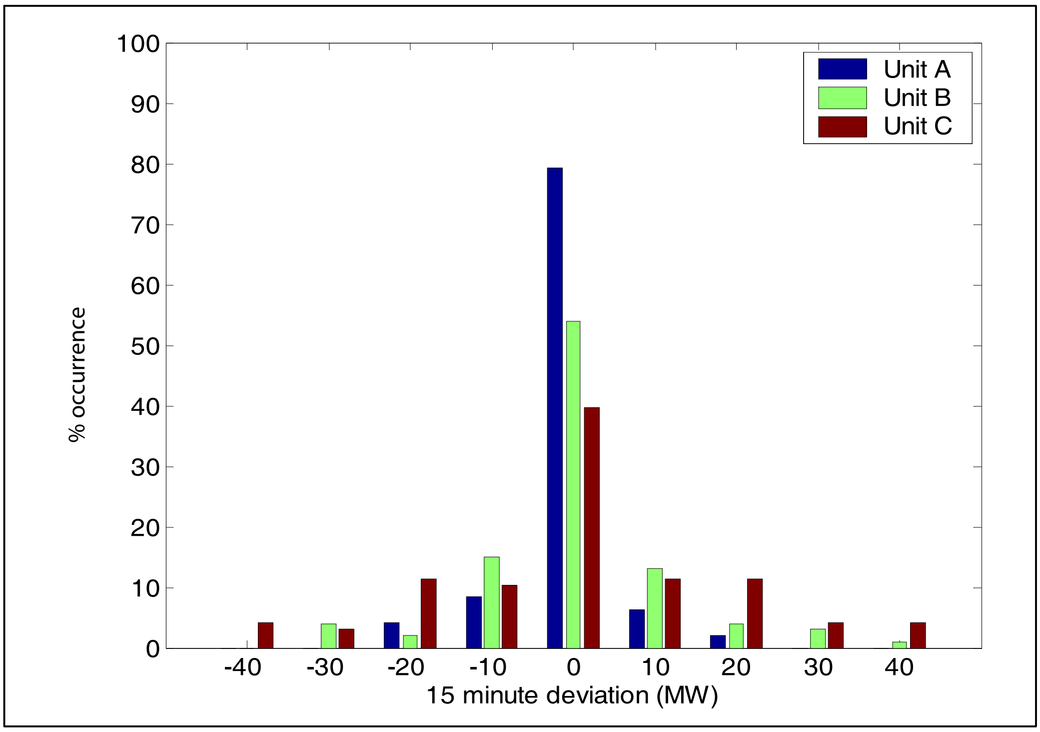
C.55 In *fuel saver* mode unit outputs will reflect the (unpredicted) variation in wind generation. However, as Table C.4 confirms, the additional burden that this introduces is relatively small. For the 2006 summer valley day the observed 15-minute variation in wind output ranges between −33 to +26 MW, while for the 2010B shoulder business day and 2010B winter business day the equivalent figures are −59 to + 38 MW, and −59 to +63 MW.

C.56 Extremes in unit load following are largely a result of scheduled changes, or a combination of a scheduled increase / decrease in unit output with an accompanying decrease / increase in wind output. The permissible ramp rates for all the generators, and in particular Units B and C, illustrated here are comparatively high, and over the 3 events shown the peak variation over 15 minutes represents 32%, 24% and 20% of the stated maxima.

C.57 If comparison is made between *fuel saver* and *forecast* modes, then in all three cases the variation in unit output tends to be greater in *forecast* mode relative to *fuel saver* mode. This difference occurs for two reasons. In *fuel saver* mode there will tend to be a larger number of scheduled generation plant available for load following (reducing the requirements for individual units), and the load following requirement will be shared across all plant according to their droop characteristics. In contrast, in *forecast* mode, a number of plant may be scheduled to operate at fixed (maximum) output, while the remainder will be required to track load and wind variation.

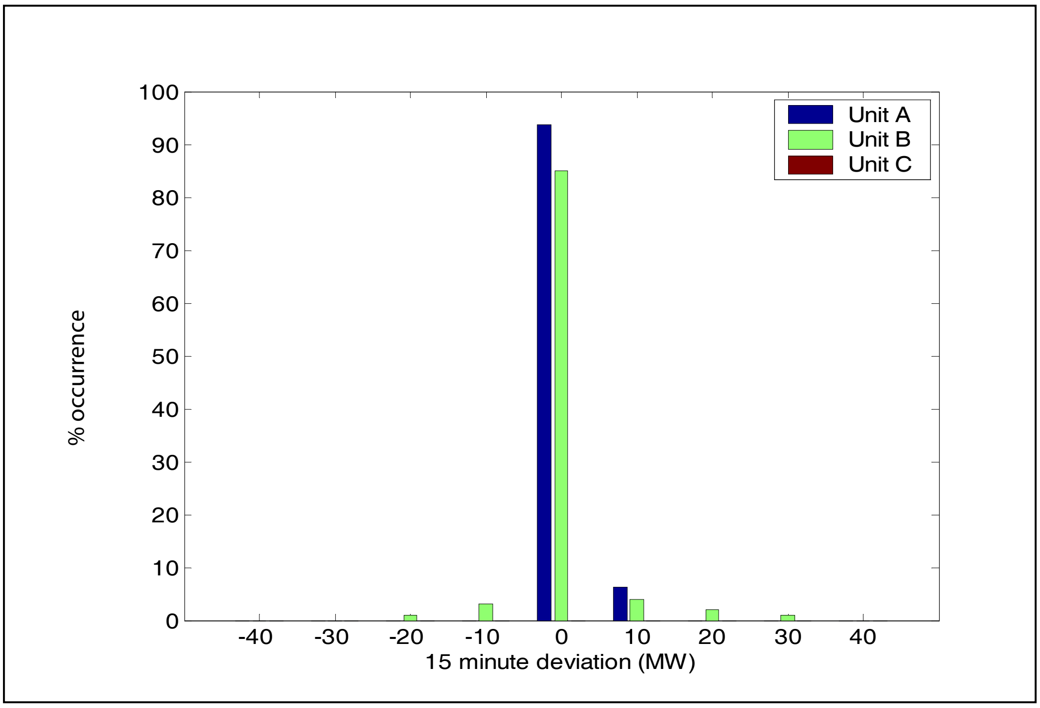


(a) fuel saver mode – low wind

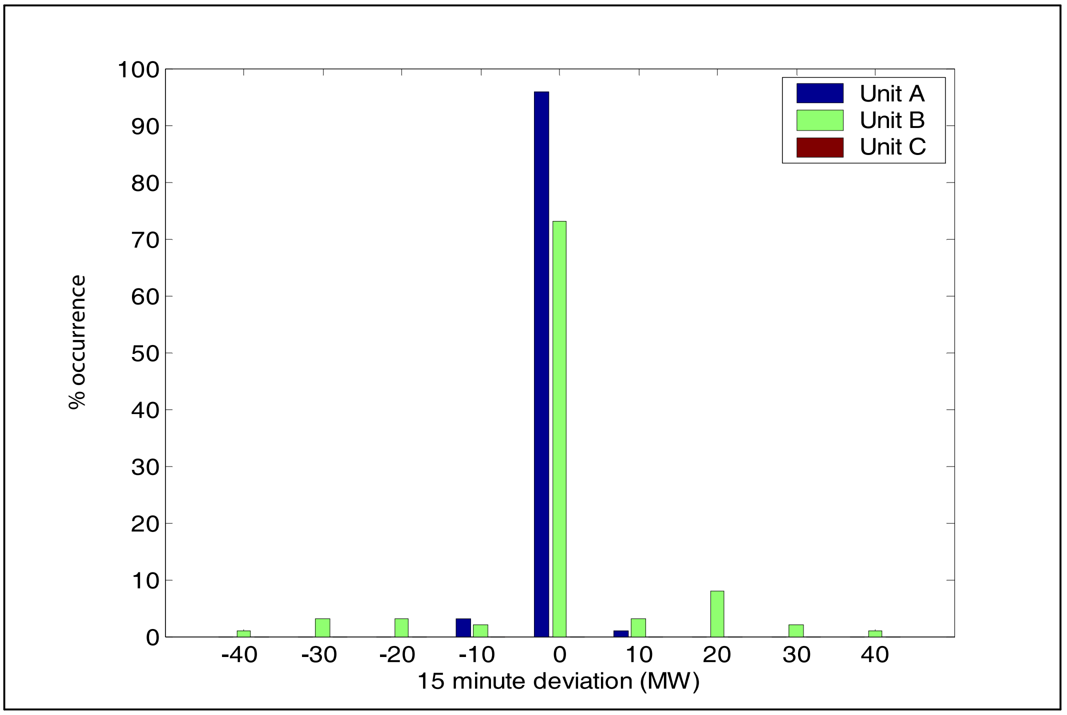


(b) forecast mode – low wind

Figure C.5 – 2006 summer valley day 15-minute deviation in ESB units

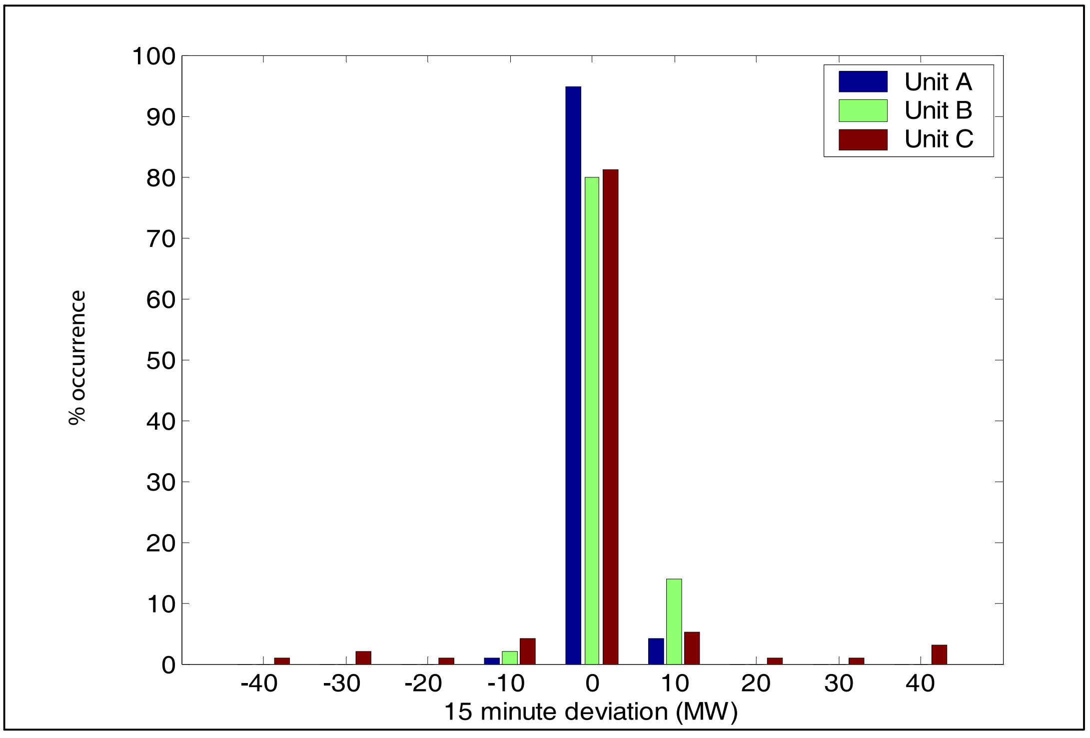


(a) fuel saver mode – low wind

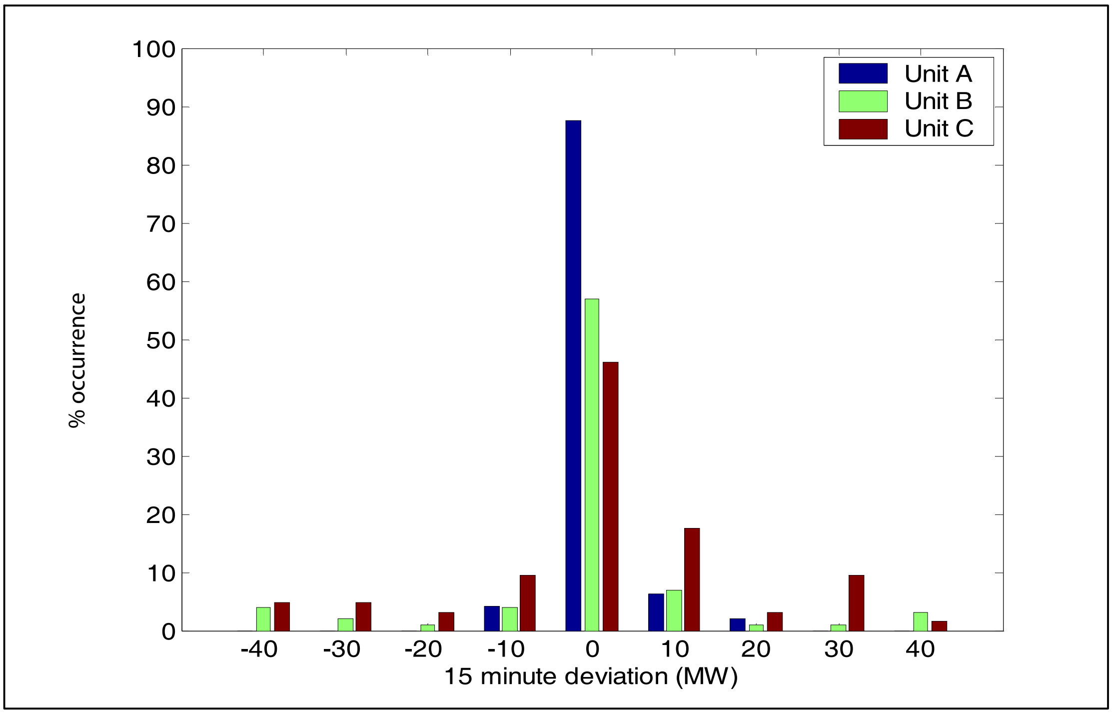


(b) forecast mode – low wind

Figure C.6– 2010B shoulder business day – 15-minute deviation in ESB units



(a) fuel saver mode – high wind



(b) forecast mode – high wind

Figure C.6 – 2010B winter peak day – 15-minute deviation in ESB units

Provision of fast and slow reserve

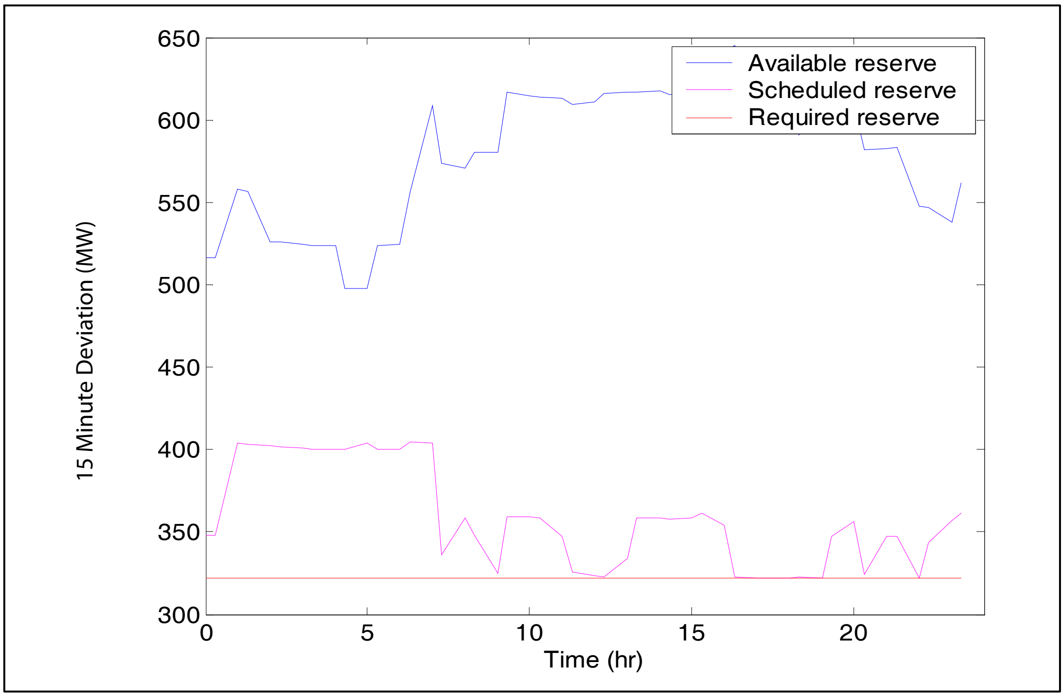
C.58 Fast and slow reserve targets are selected based on the loading of the largest infeeds to the system. Due to errors in the forecast demand and wind generation, the loading on the largest infeeds may be affected causing a change in the required fast and slow reserve targets. In *fuel saver* mode, unit outputs will be reduced causing a reduction in the required operating reserve levels, and a probable increase in the available reserve provision. However, if wind generation is sufficiently high and generation units are not decommitted, then unit outputs may fall sufficiently low to affect both the fast and slow reserve capability.

C.59 For the 2010B winter business day (high wind) scenario the variation in fast and slow reserve provision is compared for *fuel saver* and *forecast* modes in Figure C.7 and Figure C.8. The scheduled reserve target is determined from the original unit commitment for the sample day, while the actual reserve target is dependent on the actual distribution of demand across the scheduled generation. In *forecast* mode the two figures may be expected to be similar while in *fuel saver* mode they will be significantly different.

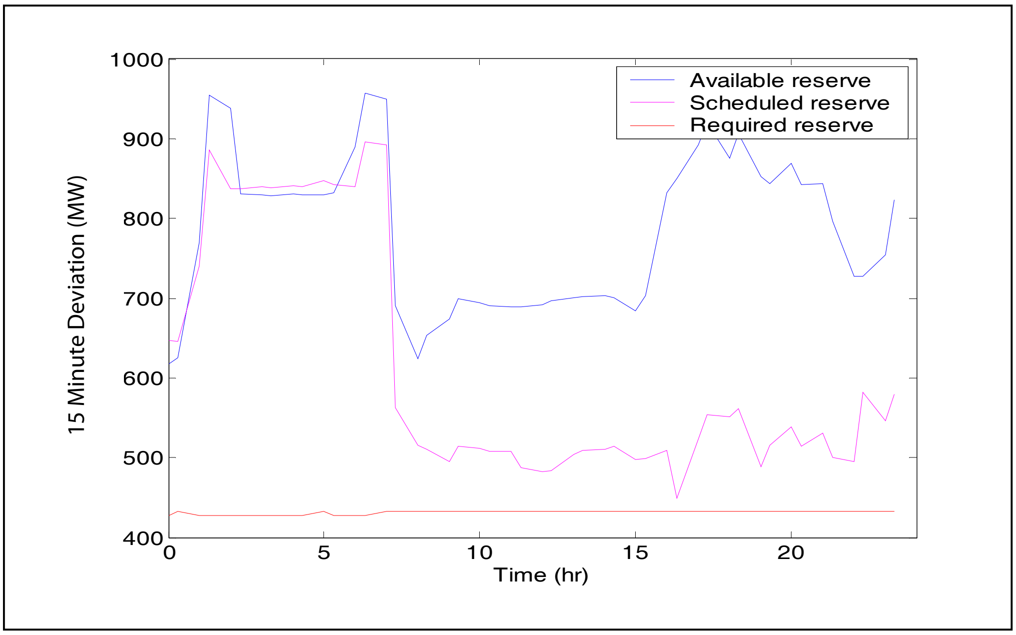
C.60 By examining the scheduled reserve targets in *fuel saver* mode, Figure C.8, it is possible to first assess the ability of the system to provide operating reserve on a day without wind. The most challenging time periods are during the morning rise when the system demand is rapidly increasing, and during periods of high demand relative to available capacity (e.g. winter peak or maintenance periods).

C.61 A sensible balance must be achieved between static and spinning reserve sources, but the operation of Turlough Hill in pumping mode at night tends to imply that there will be a natural excess of static reserve – each unit can provide 73 MW of fast reserve and 146 MW of slow reserve when in pumping mode. During the 17.00-19.00 period, it is conservatively assumed that 50 MW of interruptible load is not available. In practice, this assumption may be slightly pessimistic. Further, any growth in embedded generation (connected to the NIE system between 17.00-19.00) may imply that the system load is slightly less than expected, and the operating reserve available increased. The presence of embedded generation has been recognized in the preparation of the system demand profiles (Annex B).

C.62 In *fuel saver* mode, units are backed off such that the fast and slow reserve targets are always easily met. In *forecast* mode, some difficulties are encountered mid-morning during the morning rise. A deficit in forecast wind, coupled with the increase in system demand, causes both an increased load following requirement on scheduled generation and an increase in both the fast and slow reserve targets. For the remainder of the day, available fast and slow reserve generally exceeds the on-line targets. Although similar in shape, the available and scheduled reserve characteristics differ due to errors in both the forecast demand and wind. There are, consequently, brief periods when the largest infeeds are slightly greater than expected and the operating reserve targets are contravened.

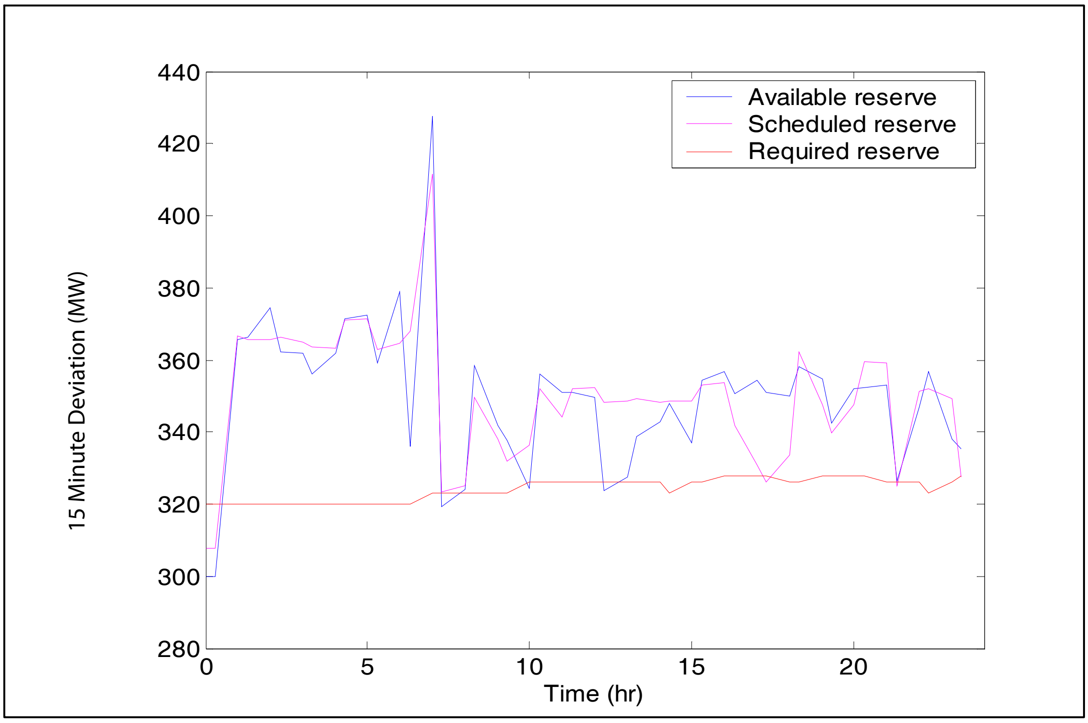


(a) high wind – fast reserve

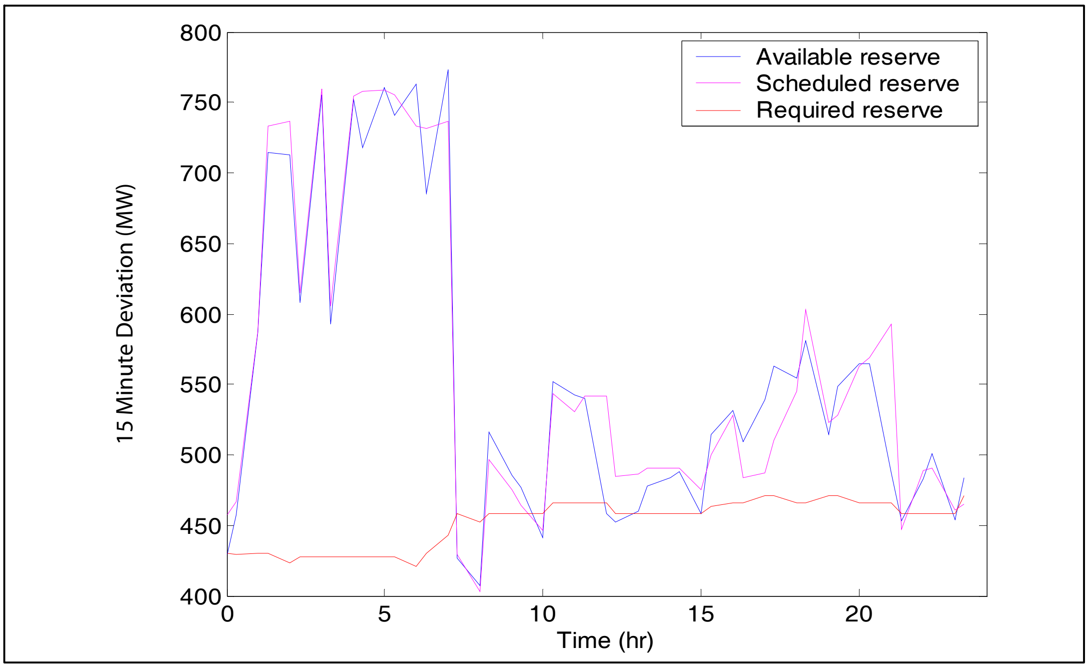


(b) high wind – slow reserve

Figure C.7 – 2010B winter peak day, *fuel saver* mode – scheduled and available reserve



(a) high wind – fast reserve



(b) high wind – slow reserve

Figure C.8 – 2010B winter peak day, *forecast* mode – scheduled and available reserve

Standing reserve requirement

C.63 For short time horizons, errors in the wind forecast will tend to be small. Consequently, fast reserve targets, and to a lesser degree, slow reserve targets can normally be safely maintained without undue effort – assuming that scheduling of committed plant and monitoring of windfarm output is actively managed.

C.64 When assessing the requirement for, and utilisation of, standing reserve, the load following model of the all-island system can be applied by extending the time horizons for both demand prediction and wind forecast towards a 4 hr period.

C.65 It has been assumed here that a wind shortfall (causing fast and slow reserve to be critically depleted) will be met by either delaying the shutdown of currently committed units or introducing OCGTs for a short period of time. Dependent on circumstances and time of day, the OCGTs may be primarily utilised as a source of spinning reserve, or as a source of energy.

C.66 If wind generation significantly exceeds the forecast, then one or more units could be safely decommitted from the system. Here, a more cautions approach is applied, and unit outputs are ramped down to accommodate the wind.

C.67 The utilisation of standing reserve will strongly depend on how accurate the wind forecast is for a particular day. The 2010B winter business day (high wind) is considered, and based on the forecast wind profile for the day, two alternative actual wind profiles are generated following the procedure outlined in section C.41. A target for the standard deviation of the wind forecast error is based on Figure 4.5. A forecast horizon of 2 hr assumes that reserve levels are actively monitored, but that unscheduled plant cannot be committed at short notice.

C.68 Figure C.9 illustrates high wind profile 1. The standard deviation of the forecast error is 89 MW, while the actual error ranges from –152 MW (under-prediction) to +204 MW (over-prediction). Periods when wind is under-predicted are likely to deplete reserve and require intervention by the system operator. Potential problem periods according to Figure C.9 are between 04.00-06.00, 10.00-11.00 and 18.00-21.00. It is, however, the combination of wind forecast errors and demand forecast errors that will prove important.

C.69 In order to preserve available fast and slow reserve targets a number of actions have been taken.

- OCGT switched on between 10.00 - 11.00.
- oil/gas-fired unit shutdown delayed from 19.00 to 20.30.
- oil/gas-fired unit shutdown delayed from 18.00 to 19.30.

C.70 During the period 04.00-06.00, system operating reserve levels are naturally high, primarily due to Turlough Hill operating in pumping mode, and no intervention is applied. Care must be taken, however, that a sensible balance between static and spinning sources of fast reserve is maintained.

C.71 Figure C.10 shows the variation in fast and slow reserve provision following the above actions. Brief periods still remain when the targets are not met. If considered of importance, redistribution of demand across a small number of units would eliminate these problem periods.

C.72 Figure C.11 illustrates an alternative high wind profile 2. The standard deviation of the forecast wind error is 97 MW, and the actual forecast error ranges from −181 MW (under-prediction) to +168 MW (over-prediction). Potential problem periods now lie between 04.00-07.00 and 12.30-16.00.

C.73 For wind profile 2 the following actions have been taken to maintain fast and slow reserve levels.

- OCGT switched on between 05.00 - 08.00.
- OCGT switched on between 06.00 - 07.00.
- second gas turbine of a multi-shaft CCGT kept on between 12.30 - 15.30.

C.74 Figure C.12 shows the variation in fast and slow reserve provision. Again, the brief periods when reserve levels remain low can be minimized by reallocating load across a small number of generators.

C.75 Errors in net demand (system demand – wind) will increase / decrease monotonically over time. Consequently, significant mismatches between forecast and actual values will only gradually become apparent. For the considered two wind profiles, alternative actions could potentially be applied to reduce the requirement for OCGTs.

C.76 At particular times, it may also be possible to advance the start-up of a unit (by say 30 minutes) which was scheduled to come on-line, instead of introducing an OCGT. Alternatively, unit outputs can be moved towards the breakpoints on their operating reserve characteristics as a means of releasing untapped reserve potential. Neither option has been pursued here.

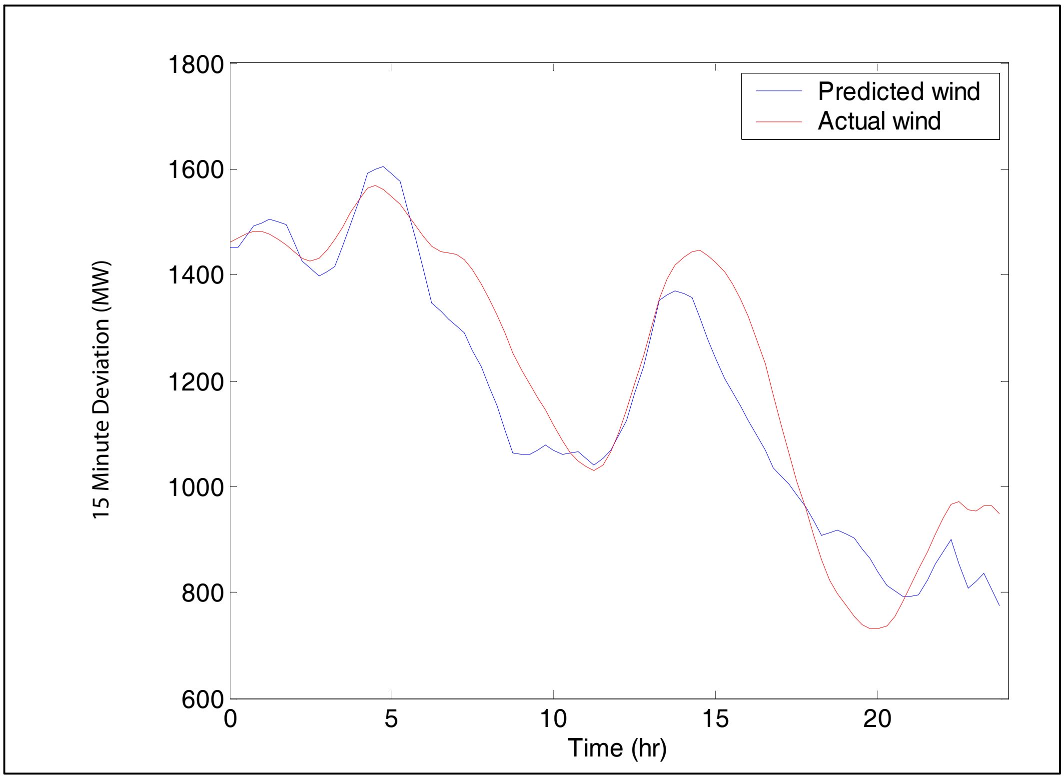
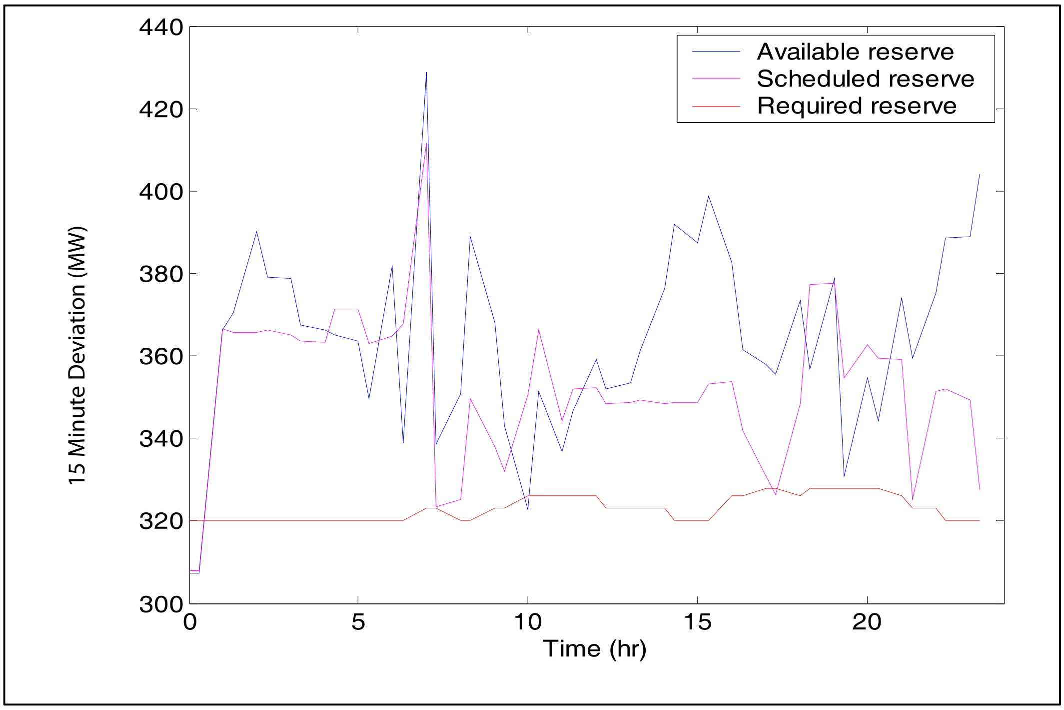
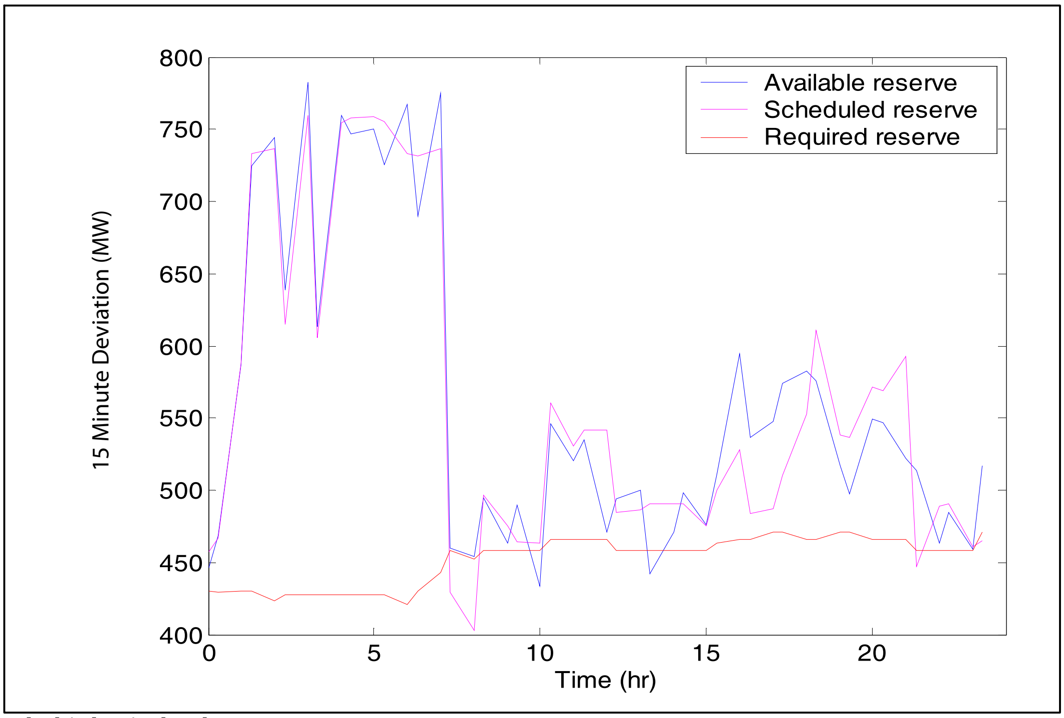


Figure C.9 – 2010B winter business day, *forecast* mode – high wind profile 1



(a) high wind – fast reserve



(b) high wind – slow reserve

Figure C.10 – 2010B winter business day, *forecast* mode – scheduled and available reserve, according to high wind profile 1

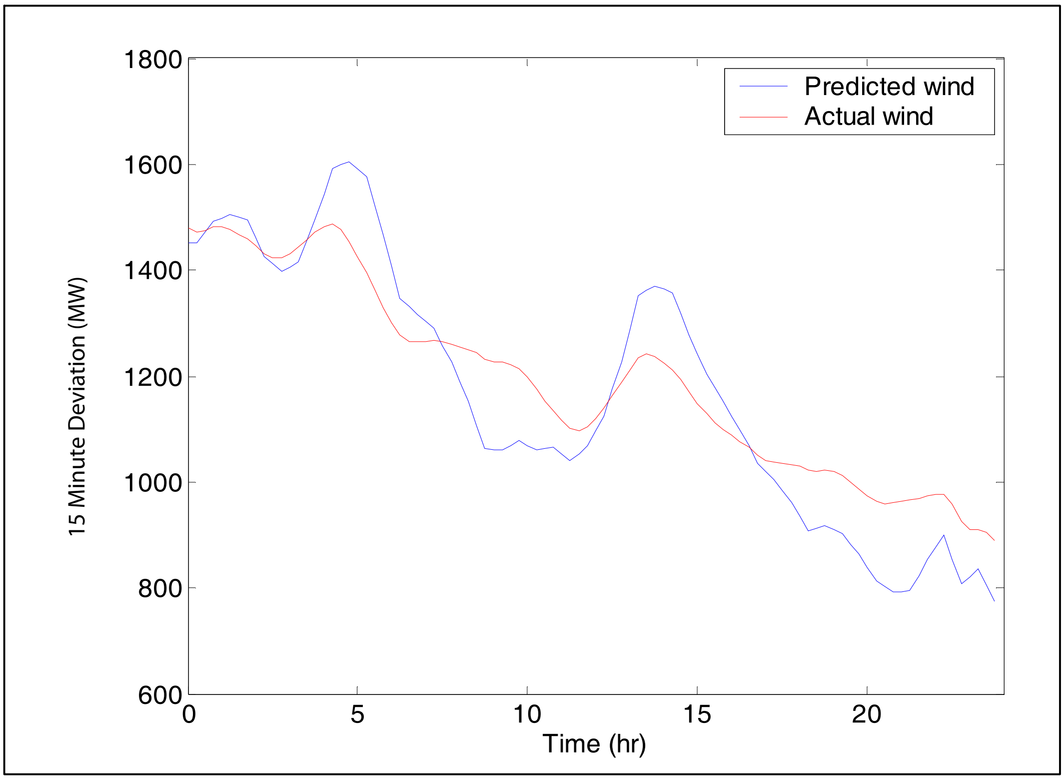
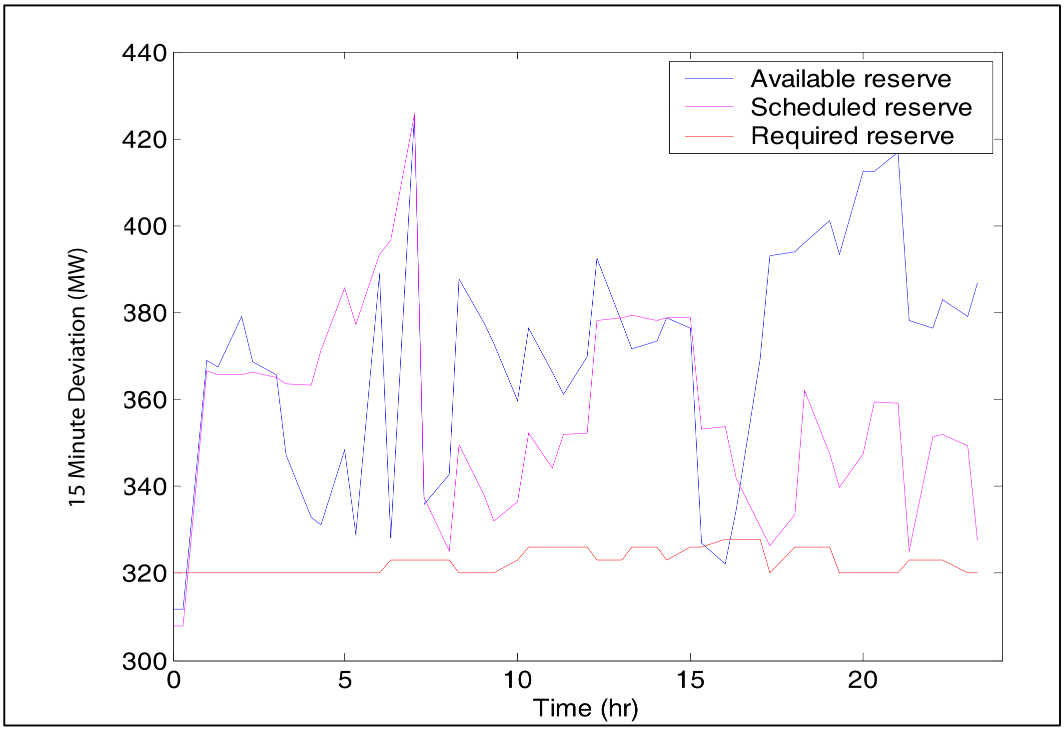
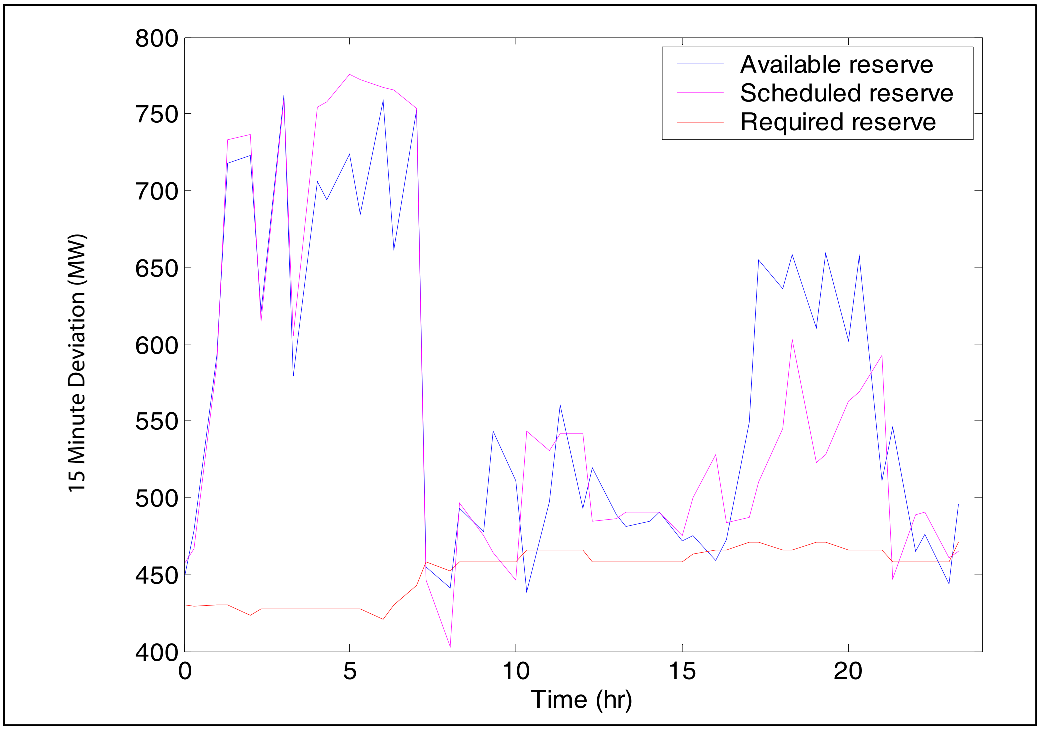


Figure C.11 – 2010B winter business day, *forecast* mode – high wind profile 2



(a) high wind – fast reserve



(b) high wind – slow reserve

Figure C.12 – 2010B winter business day, *forecast* mode – scheduled and available reserve, according to high wind profile 2

ANNEX D – Detailed Results

D.1 This section contains tables summarising key dispatch results from the modelling process.

Reserve targets and achieved reserve levels

Table D.1 – All-island daily average reserve targets and reserve provided (MW)

no wind case	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Avg fast reserve target (MW)	323	279	322	324	311	322	324	311	322
Avg fast reserve (MW)	336	325	343	358	339	354	358	339	354
Avg slow reserve target (MW)	420	364	418	431	397	416	431	397	416
Avg slow reserve (MW)	560	651	648	525	591	606	525	591	606

forecast case 30% wind load factor	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Avg fast reserve target (MW)	321	268	317	325	285	315	326	267	311
Avg fast reserve (MW)	337	310	342	354	318	362	347	321	366
Avg slow reserve target (MW)	423	366	420	451	391	428	459	400	441
Avg slow reserve (MW)	567	627	640	522	579	633	528	599	641

forecast case 60% wind load factor	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Avg fast reserve target (MW)	316	254	307	324	273	311	324	254	303
Avg fast reserve (MW)	338	291	327	351	307	344	349	320	335
Avg slow reserve target (MW)	418	358	410	444	381	422	452	394	422
Avg slow reserve (MW)	560	599	623	551	596	609	553	605	597

fuel saver case 30% wind load factor	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Avg fast reserve target (MW)	321	255	307	322	298	299	323	292	294
Avg fast reserve (MW)	411	365	409	482	411	461	480	420	493
Avg slow reserve target (MW)	420	364	418	431	397	416	431	397	416
Avg slow reserve (MW)	675	670	749	719	688	765	702	702	801

fuel saver case 60% wind load factor	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Avg fast reserve target (MW)	320	240	301	322	286	294	322	291	290
Avg fast reserve (MW)	464	383	452	565	421	544	578	415	546
Avg slow reserve target (MW)	420	364	418	431	397	416	431	397	416
Avg slow reserve (MW)	750	696	817	829	708	859	782	633	788

Modelled generation levels

Table D.2 – Total daily all-island generation (MWh gross)

***no wind* case**	**2006**			**2010A**			**2010B**		
		Summer	**Shoulder**		**Summer**	**Shoulder**		**Summer**	**Shoulder**
	Peak	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**
CCGT (MWh)	62,543	34,541	50,131	71,174	34,783	61,271	71,174	34,783	61,271
Coal (MWh)	23,968	30,747	23,967	23,989	31,195	23,989	23,989	31,195	23,989
Peat (MWh)	9,072	6,000	9,072	9,071	6,000	9,071	9,071	6,000	9,071
non-CCGT gas (MWh)	7,553	0	6,340	7,935	0	5,102	7,935	0	5,102
Oil (MWh)	5,837	0	3,128	1,052	0	0	1,052	0	0
GasOil (MWh)	0	0	0	0	0	0	0	0	0
Wind Generation (MWh)	0	0	0	0	0	0	0	0	0
Hydro + pumped storage (MWh)	3,592	84	833	3,658	34	890	3,658	34	890
Interconnector Imports (MWh)	9,600	4,740	8,680	19,200	12,800	13,480	19,200	12,800	13,480
Total generation (MWh gross)	**122,165**	**76,112**	**102,152**	**136,079**	**84,812**	**113,802**	**136,079**	**84,812**	**113,802**

***forecast* case**	**2006**			**2010A**			**2010B**		
30% wind load factor		**Summer**	**Shoulder**		**Summer**	**Shoulder**		**Summer**	**Shoulder**
	Peak	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**
CCGT (MWh)	59,021	28,502	46,437	63,966	25,264	52,178	58,499	20,020	48,122
Coal (MWh)	23,950	30,163	23,885	23,969	30,762	23,899	23,913	30,273	23,628
Peat (MWh)	9,072	6,000	9,072	9,069	6,000	9,070	9,069	5,982	9,068
non-CCGT gas (MWh)	5,898	0	4,249	4,487	0	2,767	4,320	0	1,727
Oil (MWh)	4,293	0	2,508	513	0	0	765	0	0
GasOil (MWh)	0	0	0	0	0	0	0	0	0
Wind Generation (MWh)	5,971	6,056	6,285	9,202	9,316	9,204	13,596	14,032	14,113
Hydro + pumped storage (MWh)	3,705	-102	853	3,689	81	778	3,534	-87	684
Interconnector Imports (MWh)	8,680	3,950	7,280	18,730	11,080	13,480	18,730	11,080	12,800
Total generation (MWh gross)	**120,591**	**74,568**	**100,569**	**133,624**	**82,504**	**111,375**	**132,427**	**81,299**	**110,142**

***forecast* case**	**2006**			**2010A**			**2010B**		
60% wind load factor		**Summer**	**Shoulder**		**Summer**	**Shoulder**		**Summer**	**Shoulder**
	Peak	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**
CCGT (MWh)	55,736	23,208	42,981	58,514	14,838	43,647	48,267	10,078	34,390
Coal (MWh)	23,963	29,792	23,608	23,921	29,600	23,853	23,467	26,214	23,509
Peat (MWh)	9,072	6,000	9,072	9,067	6,000	9,067	9,064	5,417	9,068
non-CCGT gas (MWh)	3,052	0	2,830	1,266	0	0	184	0	0
Oil (MWh)	3,401	0	575	0	0	0	0	0	0
GasOil (MWh)	0	0	0	0	0	0	0	0	0
Wind Generation (MWh)	12,170	11,881	11,986	18,825	18,140	18,641	28,149	28,245	27,827
Hydro + pumped storage (MWh)	3,657	-28	889	3,651	-24	1,016	3,586	106	849
Interconnector Imports (MWh)	7,800	2,210	6,980	15,920	11,580	12,800	16,030	7,440	11,080
Total generation (MWh gross)	**118,851**	**73,064**	**98,921**	**131,165**	**80,134**	**109,025**	**128,746**	**77,499**	**106,723**

***fuel saver* case**	**2006**			**2010A**			**2010B**		
30% wind load factor		**Summer**	**Shoulder**		**Summer**	**Shoulder**		**Summer**	**Shoulder**
	Peak	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**
CCGT (MWh)	58,541	31,133	45,999	64,982	29,547	55,043	61,997	26,984	51,844
Coal (MWh)	22,327	28,175	22,202	21,734	27,233	21,477	20,505	25,173	20,161
Peat (MWh)	9,072	6,000	9,072	8,847	6,000	8,822	8,725	6,000	8,691
non-CCGT gas (MWh)	7,535	0	6,340	7,427	0	4,855	7,308	0	4,756
Oil (MWh)	5,556	0	2,956	1,000	0	0	1,025	0	0
GasOil (MWh)	0	0	0	0	0	0	0	0	0
Wind Generation (MWh)	5,974	5,989	6,095	9,166	9,221	9,352	13,734	13,847	14,124
Hydro + pumped storage (MWh)	3,616	76	790	3,695	21	790	3,558	15	740
Interconnector Imports (MWh)	9,600	4,740	8,680	19,200	12,800	13,480	19,200	12,800	13,480
Total generation (MWh gross)	**122,221**	**76,113**	**102,133**	**136,050**	**84,822**	**113,817**	**136,052**	**84,819**	**113,796**

***fuel saver* case**	**2006**			**2010A**			**2010B**		
60% wind load factor		**Summer**	**Shoulder**		**Summer**	**Shoulder**		**Summer**	**Shoulder**
	Peak	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**	**Peak**	**valley**	**bus. day**
CCGT (MWh)	54,449	27,837	41,926	58,966	24,406	48,559	52,849	18,611	42,187
Coal (MWh)	20,663	25,532	20,499	19,563	23,249	19,237	17,316	18,722	16,827
Peat (MWh)	9,072	6,000	9,072	8,632	6,000	8,599	8,408	6,000	8,360
non-CCGT gas (MWh)	7,482	0	6,340	6,598	0	4,471	5,959	0	4,199
Oil (MWh)	5,123	0	2,706	870	0	0	781	0	0
GasOil (MWh)	0	0	0	0	0	0	0	0	0
Wind Generation (MWh)	12,237	11,925	12,080	18,639	18,367	18,589	28,007	28,532	27,889
Hydro + pumped storage (MWh)	3,552	64	830	3,599	-1	883	3,573	160	881
Interconnector Imports (MWh)	9,600	4,740	8,680	19,200	12,800	13,480	19,200	12,800	13,480
Total generation (MWh gross)	**122,178**	**76,097**	**102,134**	**136,066**	**84,820**	**113,819**	**136,094**	**84,823**	**113,822**

Table D.3 – Proportion of wind generation (% of daily total generation)

Proportion of wind generation (%)	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
forecast case 30% wind load factor	5.0%	8.1%	6.2%	6.9%	11.3%	8.3%	10.3%	17.3%	12.8%
forecast case 60% wind load factor	10.2%	16.3%	12.1%	14.4%	22.6%	17.1%	21.9%	36.4%	26.1%
fuel saver case 30% wind load factor	4.9%	7.9%	6.0%	6.7%	10.9%	8.2%	10.1%	16.3%	12.4%
fuel saver case 60% wind load factor	10.0%	15.7%	11.8%	13.7%	21.7%	16.3%	20.6%	33.6%	24.5%

Fuel use

Table D.4 – Total daily fuel burn (GJ)

***no wind* case**	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
Gas (GJ)	568,121	277,023	458,045	634,013	273,950	523,841	634,013	273,950	523,841
Coal (GJ)	242,852	312,964	241,282	243,036	317,375	241,472	243,036	317,375	241,472
Peat (GJ)	105,151	73,652	105,151	105,141	73,652	105,140	105,141	73,652	105,140
Oil (GJ)	62,725	0	32,494	12,993	0	0	12,993	0	0
GasOil (GJ)	0	0	0	0	0	0	0	0	0
Imports (Gas - GJ)	74,056	40,730	67,747	148,580	104,378	109,041	148,580	104,378	109,041

***forecast* case 30% wind load factor**	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
Gas (GJ)	527,168	232,039	409,962	546,107	200,915	433,676	504,191	161,438	397,294
Coal (GJ)	242,698	307,251	240,540	242,852	313,151	240,591	242,305	308,373	237,944
Peat (GJ)	105,151	73,652	105,151	105,121	73,652	105,131	105,123	73,415	105,117
Oil (GJ)	46,683	0	26,610	7,585	0	0	10,073	0	0
GasOil (GJ)	0	0	0	0	0	0	0	0	0
Imports (Gas - GJ)	67,747	35,313	58,147	145,357	92,583	109,041	145,357	92,583	104,378

***forecast* case 60% wind load factor**	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
Gas (GJ)	472,660	189,734	372,534	471,710	118,374	342,679	383,288	78,049	274,987
Coal (GJ)	242,797	303,729	238,185	242,390	301,750	240,159	238,032	269,953	236,788
Peat (GJ)	105,151	73,652	105,151	105,107	73,652	105,108	105,071	66,154	105,109
Oil (GJ)	36,614	0	9,416	0	0	0	0	0	0
GasOil (GJ)	0	0	0	0	0	0	0	0	0
Imports (Gas - GJ)	61,713	23,381	56,090	126,089	96,012	104,378	126,843	67,623	92,583

***fuel saver* case 30% wind load factor**	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
Gas (GJ)	542,411	254,717	431,553	588,741	238,972	481,054	567,835	221,829	459,358
Coal (GJ)	227,535	288,685	224,901	221,984	279,985	218,163	210,511	260,550	205,949
Peat (GJ)	105,151	73,652	105,151	103,020	73,652	102,778	101,864	73,652	101,540
Oil (GJ)	60,124	0	30,909	12,525	0	0	12,748	0	0
GasOil (GJ)	0	0	0	0	0	0	0	0	0
Imports (Gas - GJ)	74,056	40,730	67,747	148,580	104,378	109,041	148,580	104,378	109,041

***fuel saver* case 60% wind load factor**	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
Gas (GJ)	515,852	233,164	405,743	541,892	206,137	436,358	496,038	167,004	392,888
Coal (GJ)	211,997	263,736	209,107	201,714	242,385	197,379	180,734	199,596	175,013
Peat (GJ)	105,151	73,652	105,151	100,978	73,652	100,670	98,865	73,652	98,403
Oil (GJ)	56,095	0	28,616	11,339	0	0	10,539	0	0
GasOil (GJ)	0	0	0	0	0	0	0	0	0
Imports (Gas - GJ)	74,056	40,730	67,747	148,580	104,378	109,041	148,580	104,378	109,041

Table D.5 - Reduction in fuel burn (excluding imports) compared to the *no wind* case (%)

Fuel use reduction (%)	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
forecast case 30% wind load factor	-5.8%	-7.6%	-6.5%	-9.4%	-11.6%	-10.5%	-13.4%	-18.3%	-14.9%
forecast case 60% wind load factor	-12.4%	-14.5%	-13.3%	-17.7%	-25.7%	-21.0%	-27.0%	-37.7%	-29.1%
fuel saver case 30% wind load factor	-4.5%	-7.0%	-5.3%	-6.9%	-10.9%	-7.9%	-10.3%	-16.4%	-11.9%
fuel saver case 60% wind load factor	-9.2%	-14.0%	-10.6%	-14.0%	-21.5%	-15.6%	-21.0%	-33.8%	-23.5%

Costs

Table D.6 – Total daily fuel costs (€)

***no wind* case**	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Total incremental fuel costs (€)	3,253,012	1,824,765	2,640,228	3,736,704	2,024,314	2,730,551	3,736,704	2,024,314	2,730,551
Total startup costs (€)	59,192	14,185	36,763	64,268	28,439	38,525	64,268	28,439	38,525
Total no-load costs (€)	438,352	259,170	366,863	467,398	242,373	351,572	467,398	242,373	351,572
Total fuel costs (€)	**3,750,557**	**2,098,120**	**3,043,854**	**4,268,370**	**2,295,126**	**3,120,648**	**4,268,370**	**2,295,126**	**3,120,648**

***forecast* case 30% wind load factor**	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Total incremental fuel costs (€)	3,018,748	1,651,908	2,413,930	3,374,744	1,765,479	2,456,130	3,225,394	1,636,713	2,315,729
Total startup costs (€)	57,431	19,407	28,910	74,147	39,373	45,324	96,618	39,369	66,729
Total no-load costs (€)	418,600	233,556	351,763	429,480	208,815	321,157	406,574	196,241	309,265
Total fuel costs (€)	**3,494,779**	**1,904,872**	**2,794,603**	**3,878,371**	**2,013,667**	**2,822,611**	**3,728,585**	**1,872,323**	**2,691,722**

***forecast* case 60% wind load factor**	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Total incremental fuel costs (€)	2,771,184	1,476,936	2,197,072	3,003,542	1,516,894	2,172,511	2,677,533	1,218,449	1,924,500
Total startup costs (€)	54,792	10,726	41,844	80,148	28,099	42,697	76,911	0	40,101
Total no-load costs (€)	386,008	202,880	336,686	384,712	176,353	287,156	345,357	159,464	264,907
Total fuel costs (€)	**3,211,985**	**1,690,542**	**2,575,602**	**3,468,402**	**1,721,346**	**2,502,364**	**3,099,802**	**1,377,912**	**2,229,508**

***fuel saver* case 30% wind load factor**	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Total incremental fuel costs (€)	3,107,000	1,691,816	2,498,090	3,491,841	1,821,830	2,523,401	3,375,826	1,719,978	2,417,260
Total startup costs (€)	59,192	14,185	36,763	64,268	28,439	38,525	64,268	28,439	38,525
Total no-load costs (€)	438,352	259,170	366,863	467,398	242,373	351,572	467,398	242,373	351,572
Total fuel costs (€)	**3,604,545**	**1,965,171**	**2,901,715**	**4,023,507**	**2,092,642**	**2,913,498**	**3,907,491**	**1,990,790**	**2,807,358**

***fuel saver* case 60% wind load factor**	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
Total incremental fuel costs (€)	2,951,394	1,560,267	2,356,961	3,239,605	1,621,090	2,316,886	2,991,130	1,393,530	2,110,074
Total startup costs (€)	59,192	14,185	36,763	64,268	49,096	38,525	64,268	48,915	38,525
Total no-load costs (€)	438,352	259,170	366,863	467,398	241,483	351,572	467,398	238,668	351,572
Total fuel costs (€)	**3,448,939**	**1,833,623**	**2,760,587**	**3,771,271**	**1,911,669**	**2,706,983**	**3,522,796**	**1,681,113**	**2,500,172**

Table D.7 – Additional fuel cost compared to *no wind* case (€/MWh non-wind generation)

Additional fuel cost (€/MWh)	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
forecast case 30% wind load factor	-0.21	0.24	-0.16	-0.20	0.45	0.20	0.01	0.77	0.61
forecast case 60% wind load factor	-0.59	0.06	-0.17	-0.49	0.71	0.26	-0.55	0.91	0.84
fuel saver case 30% wind load factor	0.31	0.46	0.42	0.34	0.62	0.47	0.58	0.99	0.74
fuel saver case 60% wind load factor	0.67	1.01	0.86	0.75	1.71	1.00	1.23	2.80	1.67

Table D.8 – Total daily additional cost of reserve (€)

Additional cost of reserve (€)	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
forecast case 30% wind load factor	-24,155	16,245	-14,801	-24,340	33,113	20,900	1,238	51,982	58,450
forecast case 60% wind load factor	-63,181	3,957	-14,827	-55,354	43,710	23,885	-55,605	45,028	66,054
fuel saver case 30% wind load factor	35,676	32,132	40,038	43,535	46,781	48,882	70,746	70,202	74,199
fuel saver case 60% wind load factor	73,660	64,642	77,232	87,958	113,348	95,623	132,457	157,781	143,757

Table D.9 – Additional cost of reserve (€/MWh generation)

Additional cost of reserve (€/MWh)	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
forecast case 30% wind load factor	-0.20	0.22	-0.15	-0.18	0.40	0.19	0.01	0.64	0.53
forecast case 60% wind load factor	-0.53	0.05	-0.15	-0.42	0.55	0.22	-0.43	0.58	0.62
fuel saver case 30% wind load factor	0.29	0.42	0.39	0.32	0.55	0.43	0.52	0.83	0.65
fuel saver case 60% wind load factor	0.60	0.85	0.76	0.65	1.34	0.84	0.97	1.86	1.26

Emissions

Table D.10 – Total daily all-island CO_2 emissions, excluding UK import emissions (t CO_2)

Emissions (tCO2)	2006			2010A			2010B		
	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day	Peak	Summer valley	Shoulder bus. day
no wind case	65,780	48,332	57,303	65,638	48,541	58,464	65,638	48,541	58,464
forecast case 30% wind load factor	62,299	45,371	54,151	60,380	44,167	53,435	58,220	41,569	51,208
forecast case 60% wind load factor	58,548	42,746	50,587	55,676	38,656	48,397	50,443	33,075	44,390
fuel saver case 30% wind load factor	62,858	45,027	54,324	61,130	43,417	53,915	58,917	40,811	51,571
fuel saver case 60% wind load factor	59,762	41,706	51,379	56,555	38,393	49,499	51,998	32,578	45,001

Table D.11 – UK import (Interconnectors) daily CO_2 emissions (t CO_2)

Interconnector emissions (tCO2)	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
no wind case	4,068	2,237	3,722	8,162	5,734	5,990	8,162	5,734	5,990
forecast case 30% wind load factor	3,722	1,940	3,194	7,985	5,086	5,990	7,985	5,086	5,734
forecast case 60% wind load factor	3,390	1,284	3,081	6,927	5,274	5,734	6,968	3,715	5,086
fuel saver case 30% wind load factor	4,068	2,237	3,722	8,162	5,734	5,990	8,162	5,734	5,990
fuel saver case 60% wind load factor	4,068	2,237	3,722	8,162	5,734	5,990	8,162	5,734	5,990

Table D.12 – CO_2 emissions reduction compared to the *no wind* case, excluding UK import emissions

CO2 emissions reduction (%)	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
forecast case 30% wind load factor	-5.3%	-6.1%	-5.5%	-8.0%	-9.0%	-8.6%	-11.3%	-14.4%	-12.4%
forecast case 60% wind load factor	-11.0%	-11.6%	-11.7%	-15.2%	-20.4%	-17.2%	-23.1%	-31.9%	-24.1%
fuel saver case 30% wind load factor	-4.4%	-6.8%	-5.2%	-6.9%	-10.6%	-7.8%	-10.2%	-15.9%	-11.8%
fuel saver case 60% wind load factor	-9.1%	-13.7%	-10.3%	-13.8%	-20.9%	-15.3%	-20.8%	-32.9%	-23.0%

Table D.13 – Avoided CO_2 emissions through wind generation (t CO_2/MWh wind generation)

CO2 saved (tCO2/MWh wind generation)	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
forecast case 30% wind load factor	0.58	0.49	0.50	0.57	0.47	0.55	0.55	0.50	0.51
forecast case 60% wind load factor	0.59	0.47	0.56	0.53	0.54	0.54	0.54	0.55	0.51
fuel saver case 30% wind load factor	0.49	0.55	0.49	0.49	0.56	0.49	0.49	0.56	0.49
fuel saver case 60% wind load factor	0.49	0.56	0.49	0.49	0.55	0.48	0.49	0.56	0.48

Table D.14 – Implied CO_2 abatement cost through wind generation (€/t CO_2)

CO2 abatement cost (€/tCO2)	2006 Peak	2006 Summer valley	2006 Shoulder bus. day	2010A Peak	2010A Summer valley	2010A Shoulder bus. day	2010B Peak	2010B Summer valley	2010B Shoulder bus. day
forecast case 30% wind load factor	-0.36	0.48	-0.31	-0.34	0.96	0.37	0.02	1.56	1.18
forecast case 60% wind load factor	-1.00	0.14	-0.30	-0.93	1.29	0.49	-1.02	1.67	1.66
fuel saver case 30% wind load factor	0.63	0.83	0.85	0.70	1.11	0.96	1.18	1.77	1.53
fuel saver case 60% wind load factor	1.36	1.81	1.75	1.54	3.09	2.08	2.52	5.01	3.47

ANNEX E – The Provision of Inertial Response from Wind Turbines

Do current designs provide inertia to the system and if so how much?

E.1 The basic technology consists of fixed speed wind turbine generators (WTGs) with pitch control and using induction generators. The induction generators have a fairly linear speed vs. torque characteristic, with slip ranging from zero (100% speed) at no load to around 1% slip (101% speed) at full load. A 1% fall in frequency (0.50 Hz) with the WTG at full load would therefore almost double torque and hence electrical output. Assuming no change in captured wind power, the WTG would decelerate, releasing kinetic energy in electrical form to the network. The extent of this inertial response depends on the WTG stored energy.

E.2 A useful indicator of a generator's inertial response is provided by the so-called 'inertia' constant *H*. The *H* constant is actually generator stored energy divided by generator rating, and hence is measured in seconds. It may be interpreted as the time in seconds a generator can generate full power output from its own kinetic energy.

E.3 Typical WTG *H* values from the literature are 3.5 s[105] and 3.0 s comprising 0.5 s for the generator and 2.5 s for the turbine[106]. These are similar to *H* values for conventional generation[107].

E.4 The relationship of frequency to accelerating power and stored energy is governed by basic rotational mechanics:

accelerating torque = inertia × acceleration

E.5 This may be elaborated to give the following equation using power system quantities:

$$\frac{df}{dt} = \frac{\Delta P}{2 \times stored\ energy}$$

E.6 Here *f* denotes per-unit frequency, ΔP accelerating power. Power and stored energy can be expressed in MW and MWs or the per unit equivalents – the choice is immaterial since power cancels. This equation relates equally to an entire system or to a generator within it.

E.7 The equation above may be used to obtain the initial rate of change of frequency following a generator trip on the all-island system. Consider the generating capacity to be 2,000 MW, corresponding to a (low) demand of 1,500 MW, and the generator infeed to be 200 MW. Taking the 'system' *H* value to be 3.0 s, we obtain

$$\frac{df}{dt} = \frac{-200}{2 \times 3 \times 2000} = -0.0167\, p.u./s = -0.833\, Hz/s$$

E.8 This excludes demand-side kinetic energy. It also ignores the effect of frequency governing, which would increase the mechanical power output of remaining turbines and hence help to restore system frequency. However, governor response takes a few seconds to get underway.

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105 Ekanayake, J B, Holdsworth, L, Wu, X and Jenkins, N., "Dynamic modelling of doubly fed induction generator wind turbines", IEEE Transactions on Power Systems, vol. 18, no. 2, 2003, pp. 803 – 809.

106 Slootweg, J G and Kling, W L., "The impact of large scale wind power generation on power system oscillations", Electric Power Systems Research, no. 67, 2003, pp. 9 – 20.

107 Grainger, J J and Stevenson, W J., "Power system analysis", Wiley, 1994.

E.9 The same equation may now be used to assess the inertial response of a WTG with a *H* of e.g. 3 s, this time with a given rate of change of frequency:

$$\Delta P = 2 \times H \times \frac{df}{dt} = -2 \times 3 \times 0.0167 = -0.10\,p.u.$$

E.10 The accelerating power is mechanical less electrical power. The negative sign indicates an increased electrical power generation for the same wind power. Thus a WTG would be expected to increase its power output by 10% of rating while the frequency continues to fall. The stored energy, and rotor speed, would then be slowly restored as frequency recovers.

E.11 The inertial response from a fixed speed wind turbine can be observed by simulating the operating principle of the induction machine found in fixed speed WTGs. The machine operates on the principle whereby the electromagnetic torque produced by the machine depends on the difference in rotational speed of the rotor and the stator magnetic field. If there is a large difference in rotational speed, large currents are induced in the rotor and high levels of electromagnetic torque result. As the difference in speed reduces so too does the electromagnetic torque produced. This operating principle is described by the well established induction machine equations:

$$\text{slip} = \frac{\omega_s - \omega_r}{\omega_s}\ ,\ T_G = f\left(\text{slip}\right),\ 2H\dot{\omega}_r = T_G + T_L$$

where ω_s is the pu synchronous speed, ω_r is the pu rotor speed, T_G is the electromagnetic torque and T_L is the load torque (positive for a WTG) .

E.12 The power at the stator terminals is given by $P_S = \dfrac{T_G \omega_r}{1 - \text{slip}}$.

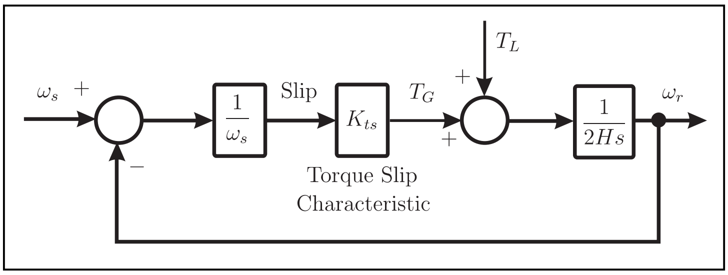

Figure E.1 – Induction machine block diagram

E.13 Figure E.1 shows a simplified representation of an induction machine found in a fixed speed WTG which due to the nominal slip of fixed speed WTGs of typically 1-2%, can be linearised about the synchronous speed ω_s and then represented by a gain K_{ts}.

E.14 Referring to Figure E.1, the overall operation of the block can be likened to a system with a highly tuned speed controller. As the load torque T_L changes, the rotational speed ω_r is held close to the synchronous speed ω_s. Consider now the response of the machine when operating as a generator to a drop in synchronous speed ω_s. Due to the inertia of the rotating mass, the rotational speed ω_r will not change instantaneously. The slip and resulting decelerating electromagnetic torque T_G instantaneously become more negative. Assuming T_L remains constant, the imbalance in accelerating and decelerating torque acts to quickly slow the machine with the increased power at the stator terminals resulting from the associated reduction of kinetic energy.

E.15 The response of an induction machine to a sample drop in system frequency as shown in Figure E.2 is shown in Figure E.3.

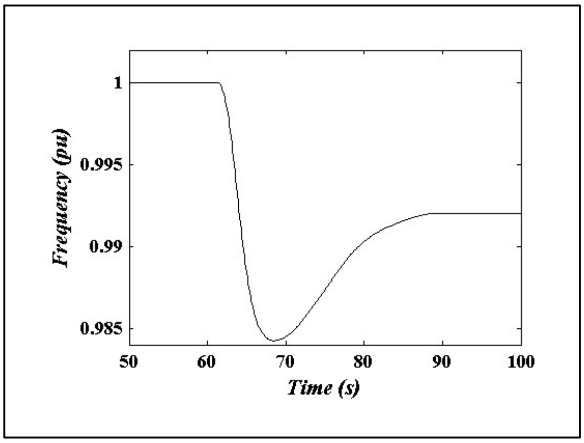

Figure E.2 – Sample frequency trace

E.16 It can be seen from the left hand plot in Figure E.3 that the rotational speed closely follows the system speed with the increased level of power generation due to the release of kinetic energy seen in the right hand plot. It should be noted in this figure that negative power implies generation. It should also be noted that the stator power does not return to -1pu after the frequency because the system frequency itself does not return to 1pu in the timeframe shown in the plots.

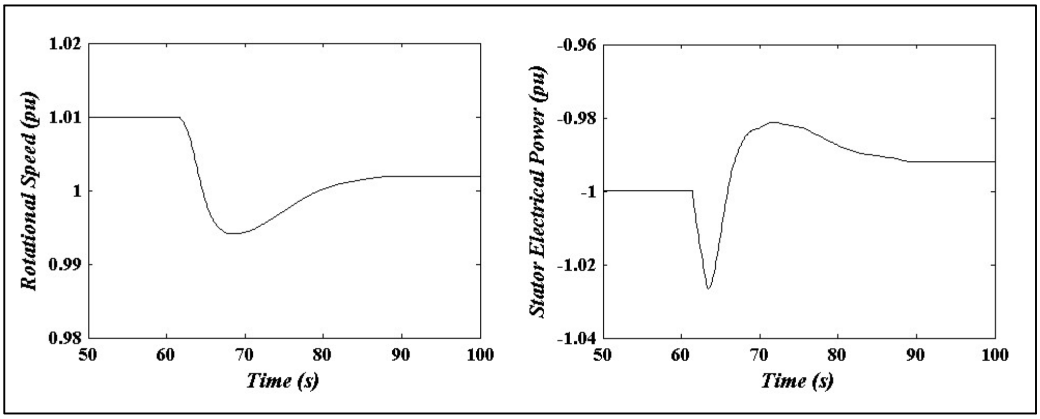

Figure E.3 – Rotational speed & stator power

E.17 It should be noted that the published *H* values for WTGs are similar to the values for conventional generation. Hence WTGs will contribute *pro rata* to system inertia.

E.18 Although the WTG design described above has proved reliable in many operational wind-farms, it has certain drawbacks.

E.19 Referring to Figure E.1, as a result of the close matching of the accelerating torque T_L and the decelerating electromagnetic machine torque T_G, electrical power, which is a function of T_G, will vary rapidly with fluctuations in the turbine torque. The very limited speed variation of the fixed-speed system allows for some absorption of gusts but with a typical speed variation of less than 2%, large torque variations are nonetheless transmitted through the drive-train and tower. The drive-train of a fixed-speed wind-turbine is usually over designed to deal with the torque transients which occur during gusts.

E.20 The fixed-speed wind-turbine also has the disadvantage of a large reactive power requirement and due to the operation of the WTG rotor optimal energy capture may only be achieved at one particular wind-speed.

Will future designs provide inertia and if so how much?

E.21 The disadvantages of the fixed speed design (particularly in respect of the drive train and tower stresses) has led to the development of variable speed WTGs. The dominant design for new windfarms is the doubly-fed induction generator (DFIG), providing limited variable-speed operation. The advantages are:

- Wind energy capture is increased
- Tower stresses are decreased, reducing capital cost
- Reactive generation is controllable, obviating the need for capacitive compensation

E.22 The mechanism by which the above three advantages are realised is through limited control of the rotational speed using a power converter connected to the rotor circuit.

E.23 The power converter connected to the rotor circuit allows for the addition and removal of induced rotor current. If induced current is removed from the rotor circuit then the relative speed of the rotor and stator has to increase in order to regain the lost electromagnetic torque and again reach a steady state speed condition. Likewise, if current is added to the rotor induced current then the relative speed will decrease. Using this principle of addition or removal of induced current, the slip and hence the speed of rotation may be controlled. This operation can be thought of as an offsetting of the torque slip characteristic shown in Figure E.1 resulting in the simple model of a DFIG shown below.

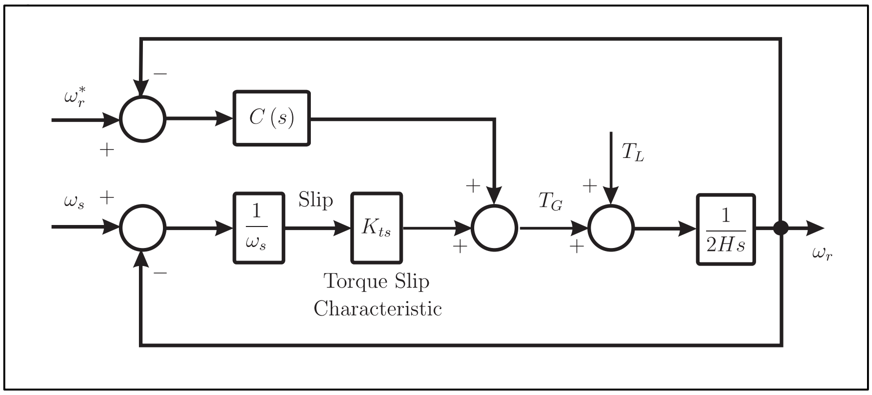

Figure E.4 – DFIG block diagram

E.24 Controllable speed allows for increased energy capture at low wind speeds when compared with a fixed speed design by allowing the turbine rotor to operate with high efficiency for a wide range of wind speeds.

E.25 Decreasing the tower stresses is achieved by loosening the coupling between T_L and T_G analogous to de-tuning the speed control loops in Figure E.1. If this is achieved then, unlike the fixed-speed case, the machine-torque T_G need not closely match the turbine-torque and as a result when the accelerating torque T_L changes, the turbine speed will increase at a rate largely determined by the WTG inertia. The large inertia of a WTG will act to filter out the variations in the turbine torque and as a result, rapid variations in T_L will not be reflected in the rotational speed. The deviation in rotational speed however will cause the machine torque T_G to increase in order to return the system to a steady state operating point. The rate of increase of machine torque can be designed to be much lower than that inherent in the fixed-speed design. Therefore in response to a gust, or fluctuations in turbine-torque, the electrical power which is a function of both ω_r and T_G will be smoothed when compared with the captured aerodynamic power.

E.26 Considering the objective of decreasing the coupling between T_L and T_G and referring to Figure E.4 it can be seen that for the DFIG case, the torque slip characteristic remains part of the speed control loop. In order to achieve the power-smoothing objective WTG based DFIGs would be expected to have a less steep torque slip characteristic than for a squirrel cage design. This effectively means that with a short circuited rotor a WTG based DFIG would be expected to have a larger nominal slip than the 1-2% level of its squirrel cage counterpart. The low nominal slip of a squirrel cage design is mainly due to the fact that rotor power, which increases with nominal slip, is not extracted from the machine. The DFIG configuration however allows rotor power to be extracted so increased levels of nominal slip will not have a detrimental effect on the overall level of power capture.

E.27 The sample frequency deviation used for model shown in Figure E.1 was applied to the DFIG model shown in Figure E.4 where the linearised torque slip characteristic was halved and the frequency deviation applied for increasingly fast speed controllers. Figure E.5 shows the inertial response of the DFIG with a short circuited rotor where it can be seen that during the frequency event there is a considerable speed deviation and as a result a considerable inertial response.

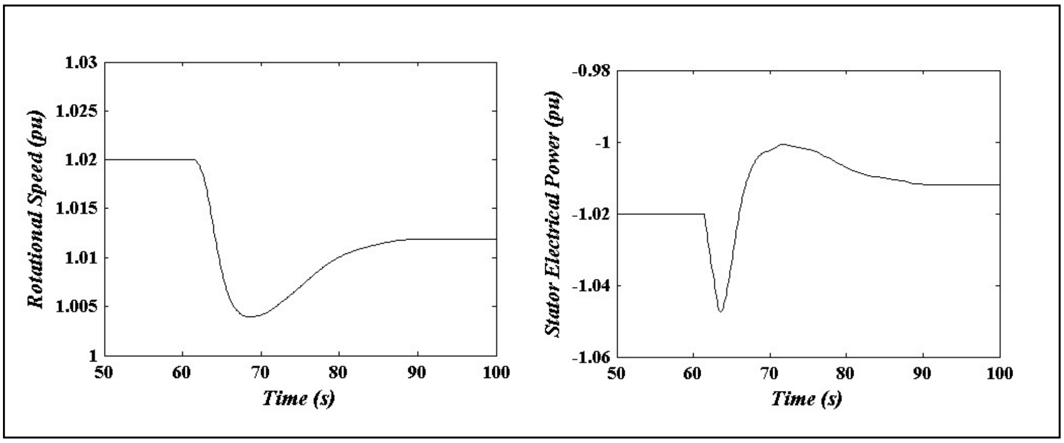

Figure E.5 – DFIG inertial response (short circuited rotor)

E.28 A speed controller is now added with a set-point of 1.02 pu and tuned such that the bandwidth of the speed control loop is similar to the short circuited rotor case. The response of the DFIG to a change in system frequency is shown in Figure E.6 where it can be seen that the shape of the speed response has changed little except that the speed is returned to the reference value. The inertial responses in both cases are very similar.

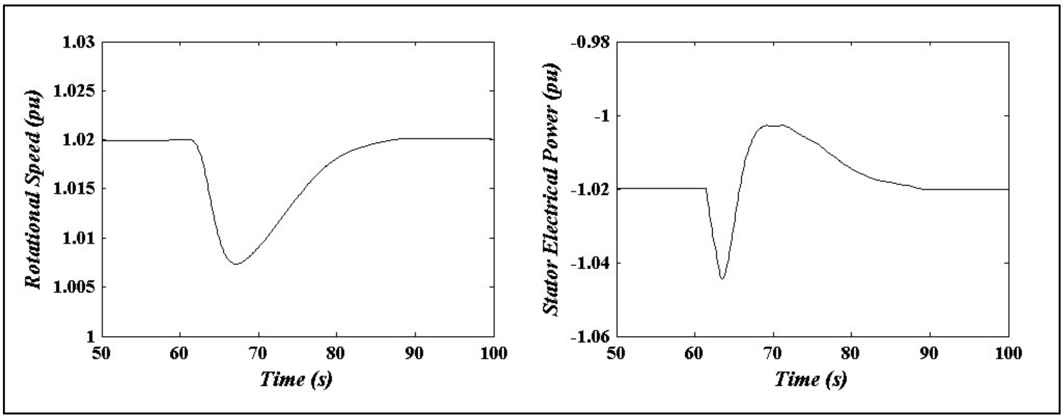

Figure E.6 – DFIG inertial response slow speed controller

E.29 The gain of the speed control loop is now increased by a factor of 10 and the inertial response again examined. It can be seen from Figure E.7 that with the increase in the gain of the speed controller, the rotational speed is maintained closer to the set-point and as a result less of an inertial response is observed.

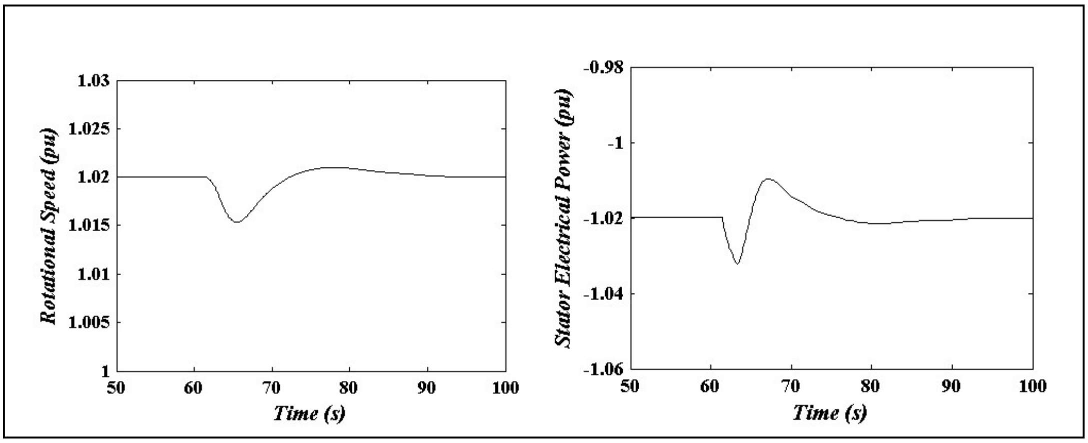

Figure E.7 – DFIG inertial response faster speed controller

E.30 For a further 10 fold increase in speed controller gain, it can be seen from Figure E.8 that the rotational speed barely changes during the frequency event and thus the inertial response is greatly reduced.

E.31 It can be concluded from these observations that the inertial response of a DFIG is wholly dependant on the bandwidth of the speed control loop. Considering that reduction of the bandwidth of the speed control loop is the primary reason for employing variable speed technology, it is thought that the inertial response form an operational DFIG in reality would be closer to the response observed in Figure E.6 than that observed in Figure E.8. The exact response however is dependant on the implemented speed controller, which could change considerably from manufacturer to manufacturer. A comprehensive DFIG measurement programme would be required to fully characterise the response of operational units.

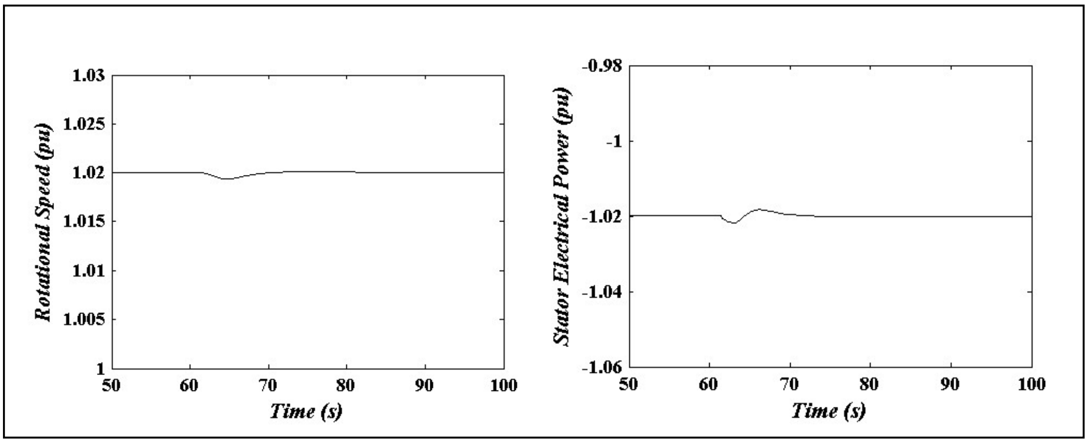

Figure E.8 – DFIG Inertial Response Really Fast Speed Controller

E.32 As can be seen in Figure E.8, appropriate configuration of the speed controller of a DFIG allows for adjustment of the rotor speed largely independent of the system frequency. Given this capability the rotor speed could also be configured to reduce dramatically upon detection of a frequency dip. Using this capability a much greater inertial response could be attained from a DFIG by decelerating the WTG rotor by a large amount during a dip.

E.33 A method for so doing has been suggested[108, 109]. It is only necessary to reinstate the inertial torque by adding to the torque set point a term

$$\Delta T = \frac{\Delta P}{\omega_r} = -2\frac{H}{\omega_r}\frac{df}{dt}$$

where ω_r is the rotational speed. The negative sign is to ensure increased torque and power for decreasing system frequency.

E.34 WTGs also exist using synchronous generators, rectification and inversion to achieve full variable speed operation, often without a gearbox. Such a system will not respond naturally to a system frequency transient. The desired inertial response may be reinstated by actively decelerating the WTG during a frequency dip.

Effect of rotational speed variation on inertial response

E.35 In addition to a reduction or increase of kinetic energy due to inertial response, power flowing from the prime mover to the power system may also change with the changing rotational speed. In order to quantify how a wind turbine generator (WTG) responds to a dip in system frequency, it is necessary to examine individually the main WTG topologies that are found today not only in terms of the influence of system frequency on their rotational speed, but also the subsequent effect of rotational speed variations on their power extraction from the wind.

E.36 The accelerating power of a Wind turbine generator (WTG) changes with the rotational speed of the wind-turbine rotor shaft ω_t , wind speed v_w , WTG rotor radius R and blade pitch setting β. The sensitivity of the accelerating aerodynamic power to changes in these variables is characterised by a set of curves, which describe the steady-state performance of a WTG rotor. The shape of the surface defined by these curves will change for each rotor design. Two possible surfaces are represented in Figure E.9 where C_p relates the amount of power in the wind to that captured by the rotor of the WTG.

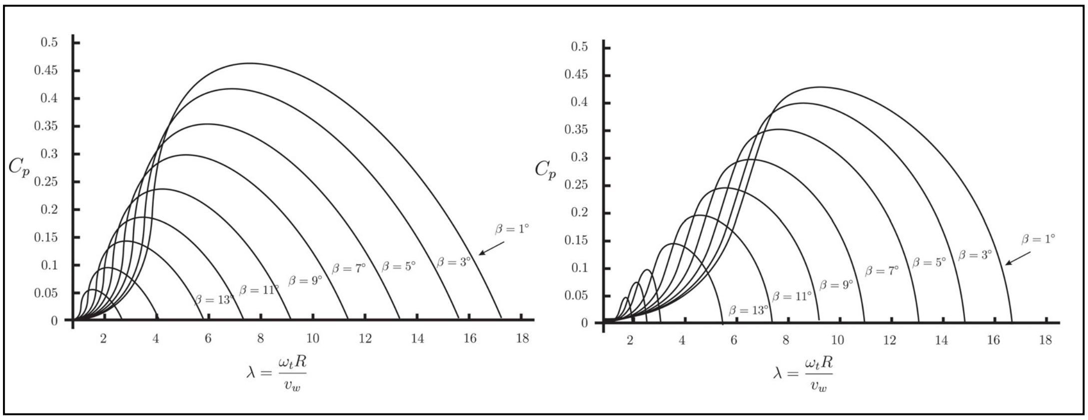

Figure E.9 – Possible Cp vs. tip-speed curves for two WTGs at various pitch angles β

E.37 It can be seen from the Figure E.9 that C_p varies with the tip-speed ratio, $\lambda = \frac{\omega_t R}{v_w}$ and blade pitch setting.

The portion of a C_p curve to the right hand side of the peak represents the lift region while the portion to the left hand side represents the stall region. Generally speaking as the wind-speed increases from the cut in wind-speed a WTG will operate in the lift region and the C_p operating point will move up the surface as the

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108 Ekanayake, J, Holdsworth, L and Jenkins, N., "Control of DFIG wind turbines", *Power Engineer*, vol. 17, no.1, 2003, pp. 28 - 32.

109 Holdsworth, L, Ekanayake, J and Jenkins, N., "Power system frequency response from fixed speed and doubly fed induction generator based wind turbines", *Wind Energy*, no. 7, 2004, pp. 21 - 35.

WTG extracts increasing power from the wind according to the relationship $P_a = \frac{1}{2}\rho A C_p v_w^3$, where P_a is the captured aerodynamic power. Once the rated power level of the wind turbine is reached and in order to maintain constant power output, increases in v_w must be offset by a reduction in C_p. There are three primary means of achieving this objective namely passive stall regulation, pitch regulation and active stall regulation.

Passive stall regulation

E.38 In passive stall regulated wind turbines there is no facility for blade pitching, the WTG rotor performance is characterised by a single C_p curve such as that shown in Figure E.10. The WTG rotor is designed such that higher wind speeds cause increasing levels of turbulence on the low-pressure surface of the WTG rotor, reducing lift and the associated power extraction form the wind.

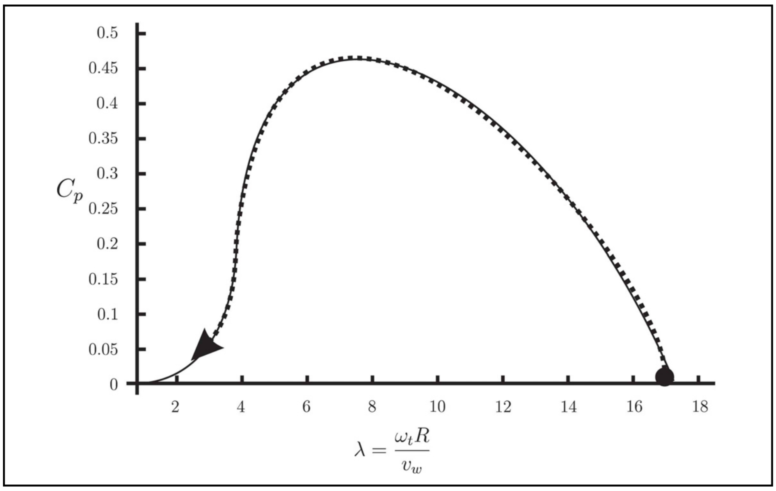

Figure E.10 – Possible C_p vs. tip-speed ($\frac{\omega_t R}{v_w}$) curve for stall regulated WTG including trajectory for fixed speed operation.

E.39 This type of power regulation has traditionally appeared in fixed-speed designs where the speed of rotation changes little with increasing wind-speed. Therefore at low wind-speeds the WTG operates in the lift region to the right hand side of the curve at a low value of C_p. As the wind speed increases λ reduces, moving the operating point up the curve resulting in increased energy capture from the wind. At above rated wind speed the operating point has moved over the peak of the curve and now operates to the left of the peak resulting in decreasing values of C_p with increasing wind speed.

E.40 The speed of a fixed speed WTG ω_t will change with changes in system frequency. If a passive stall regulation scheme is employed, changes in ω_t will result in changes in C_p corresponding to a change in T_L in Figures E.1 and E.4. The result of this interaction is that during a frequency event, the accelerating torque will change resulting in a change in power captured from the wind. This change will offset the extra power obtained due to the reduction in kinetic energy.

E.41 It should be noted that if the operating point is to the right of the peak corresponding to below rated operation, then a reduction in ω_t will result in an increase in T_L, while at above rated wind speeds corresponding to operation to the left of the peak, then a reduction in ω_t will result in an increase in T_L. The exact sensitivity of T_L to changes in ω_t will depend on the exact design of the WTG rotor but for a fixed speed passive stall regulated system the general response described here would be expected.

Pitch regulation

E.42 Figure E.11 shows a series of C_p curves at different blade pitch settings for a pitch regulated WTG. The pitch regulation system operates on the principle whereby at wind-speeds increasing above rated, the blades are pitched in order to reduce lift and the associated power extraction from the wind. A pitch regulated WTG thus operates in the lift region (to the right of the peak of the curves) over its entire range of operational wind-speeds.

E.43 The exact trajectory over the C_p surface will vary depending on whether a fixed or variable speed WTG is used but in general it would be expected that if the rotational speed reduces during a frequency event the operating point will move up the surface resulting in an increase in T_L and increasing the power during a frequency dip.

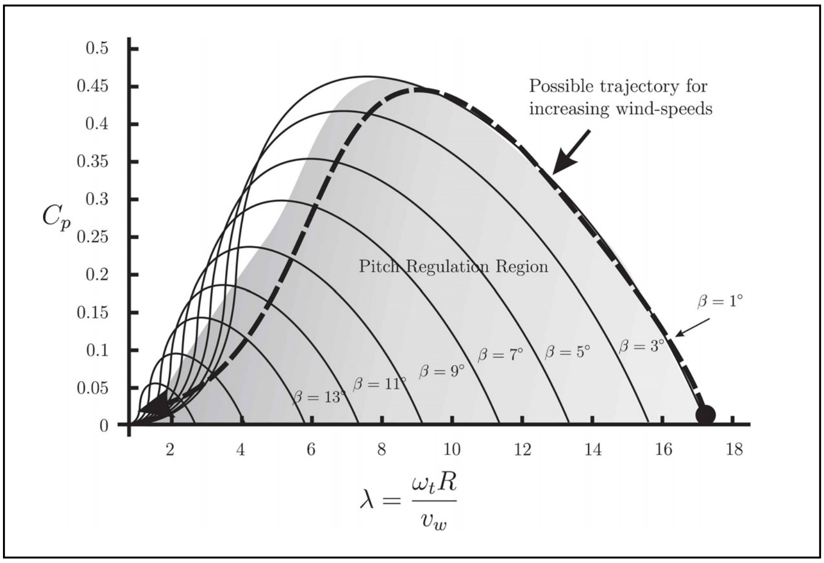

Figure E.11 – Possible C_p vs. tip-speed ($\frac{\omega_t R}{v_w}$) curves for a pitch regulated WTG at various pitch angles β

Active stall regulation

E.44 Figure E.12 shows a series of C_p curves at different blade pitch settings for an active stall regulated WTG. The stall regulation system operates on the principle whereby at wind-speeds increasing above rated, the blades are pitched in the opposite direction to that used in pitch regulation systems. This action actively induces stall, increasing levels of turbulence on the low pressure surface of the WTG rotor, reducing lift and the associated power extraction form the wind. An active stall regulated WTG thus operates in the lift region (to the right of the peak of the curves) at low wind speeds but operates to the left of the peak of the curves in the stall region for above rated wind-speeds.

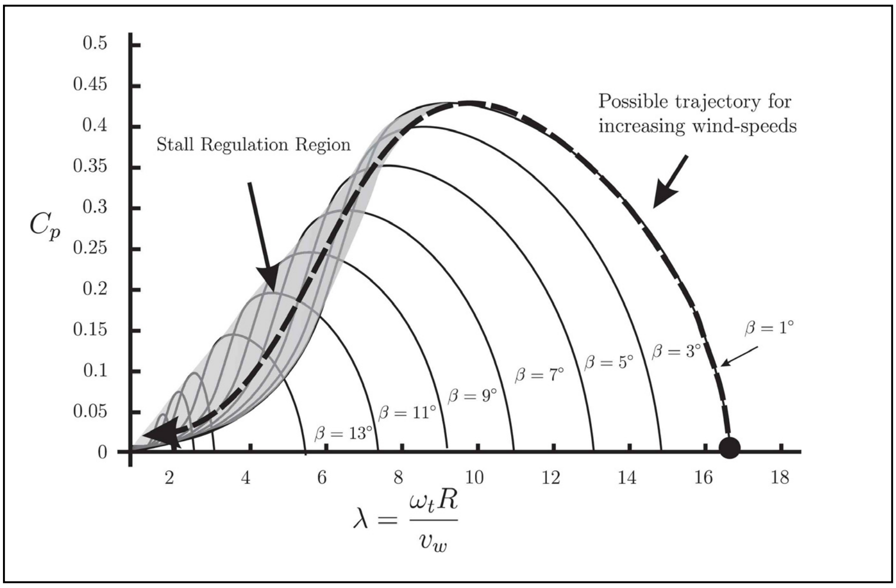

Figure E.12 – Possible C_p vs. tip-speed ($\frac{\omega_t R}{v_w}$) curves for an active stall regulated WT at various pitch angles β

E.45 The exact trajectory over the C_p surface will vary depending on whether a fixed or variable speed WTG is used but in general it would be expected that for a reduction in rotational speed at below rated operation, the power captured would be expected to increase whereas for a reduction in rotational speed at above rated wind-speed, the power would be expected to decrease. The extent of the increase or reduction in power during a frequency event is dependant on the shape of the C_p surface in the region close to the operating point on the surface.

E.46 It should be noted that during a frequency event if the rotational speed and hence electrical power change, the power regulation system may act to change the blade pitch in order to counteract the increase or decrease in electrical power. The speed at which this happens is limited by the bandwidth of the power control loop and the speed of the actuators that turn the WTG blades. It is important to consider this action when examining operation at above rated wind-speeds but for below rated operation the WTG typically operates in the lift region with the blade pitch at its minimum setting.

Measurement and validation

E.47 The response of a WTG to a change in system frequency is sensitive to the exact design of each WTG and the controllers employed within it. This is particularly true in respect of the speed control loop but as has been discussed, the influence of the power controller and the aerodynamic characteristics of the WTG are also important.

E.48 In order to validate the exact response of a WTG to a change in system frequency, a comprehensive measurement programme is required. Dedicated wind power output data gathering is not part of the scope of this project. However, there is a recognised lack of high quality, high-resolution data from wind turbines. Monitoring equipment was installed on one of the wind turbines at Elliot's Hill, Co. Antrim, which consists of 10 x 500 kW (fixed-speed) induction machines. System frequency and power output were monitored at a frequency of 10 Hz, with recording being triggered when the frequency fell beneath 49.7 Hz. The equipment was installed in February 2004, since when there has been a number of events, due to loss of generation, on the NIE-ESB system. It is clear that the turbines are providing an inertial response, with an estimated H value of 3 - 3.5 s, not that different from conventional plant.

E.49 In Summer 2004, the same monitoring equipment will also be installed on a windfarm employing DFIGs, in order to similarly confirm that such machines have the potential to provide an inertial response. It is recognized that the response of variable-speed machines is dependent on the turbine's C_p characteristic and the implemented control strategies. Consequently, it is the intention to record both wind speed and blade pitch angle in addition to system frequency and power output.

ILEX

Quality Control Check Sheet

"Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System"

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