# GENERATION AND TRANSMISSION ADEQUACY EVALUATION OF POWER SYSTEMS WITH WIND GENERATION

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# Abstract

In response to the challenge of proposed reductions to greenhouse gas emissions outlined in international agreements such as the Kyoto Protocol, countries are considering supplying a significant share of their future energy requirements from renewable energy sources. Wind power, both on and offshore, is the principal commercially available and scaleable renewable energy technology. It is expected to remain the dominant technology in the medium-term future by delivering the majority of the required growth in renewable energy.

The unique characteristics of wind power generation raise issues for its integration into the existing power systems. This thesis explores three specific issues, namely, wind generation's limited capacity value, its remoteness from demand centres and the appropriateness of the regulatory framework governing its integration.

The first issue was addressed by examining how the presence of flexible generation sources like hydro power affects the capacity value of wind in an assessment of overall system generation capacity. Wind capacity credit is interpreted from a planning perspective, and also as a component of the economic value of wind. The results illustrate that hydro power can compensate the variability of wind generation thereby augmenting its capacity value.

The second issue required the development of a transmission planning methodology to evaluate the sufficiency of transmission network capacity to accommodate wind generation and to manage security of supply. The methodology was used to assess, over the long term investment horizon, the requirement for additional transmission network capacity driven by wind generation. The assessment found that wind generation drives less transmission network capacity than conventional generation and that wind and conventional generation should share the same transmission network capacity.

Finally, the thesis looked into the establishment of regulatory framework that could recognise the realistic contribution of wind generation characteristics to transmission security and capture this contribution within the network pricing structure. The current

transmission security standards were reviewed to evaluate whether they are capable of recognising the different operation characteristics and output of wind generation. Standards for assessing transmission adequacy were found to lead to under-investment in capacity for importing areas and over-investment in exporting areas. Consequently, a set of 'contribution factors' capturing the interaction between wind and system characteristics were derived to augment the standards. At the same time, a modification of the present TNUoS charging mechanism in order to discriminate between generation technology types and to devise cost-reflective pricing regimes is proposed. This is particularly important when transmission investment is driven by reliability, as in exporting areas the cost reflective charges for wind were uniformly found to be lower than the charges for conventional generators.

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# List of abbreviations

| | | |
|---|---|---|
| BEER | – | Department for Business, Enterprise and Regulatory Reform |
| CBA | – | Cost Benefit Analysis |
| CEGB | – | Central Electricity Generating Board |
| COPT | – | Capacity Outage Probability Table |
| DTI | – | Department of Trade and Industry |
| EENS | – | Expected Energy Not Supplied |
| FOR | – | Forced Outage Rate |
| GB | – | Great Britain |
| GB SO | – | Great Britain System Operator |
| GB SQSS | – | Great Britain Security and Quality of Supply Standard |
| GB SYS | – | Great Britain Seven Year Statement |
| ISCPT | – | Interconnected System Capacity Probability Table |
| LOLP | – | Loss of Load Probability |
| LOLE | – | Loss of Load Expectation |
| LP | – | Linear Programming |
| MAR | – | Maximum Allowed Revenue |
| NG | – | National Grid |
| NGET | – | National Grid Electricity Transmission |
| NZ | – | New Zealand |
| Ofgem | – | Office of Gas and Electricity Markets |
| RMS | – | Root Mean Square |
| SEDG | – | Sustainable Electricity and Distributed Generation |
| TEC | – | Transmission Entry Capacity |
| TNO | – | Transmission Network Operator |
| TNUoS | – | Transmission Network of Use of System charges |
| TO | – | Transmission Owner |
| UK | – | United Kingdom |

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# Chapter 1

# Introduction

## 1.1 Sustainability of the modern electricity systems

Sustainable development offers a comprehensive and critical model of development anchored in the integration of three principles: economic development, social development, and environmental protection (World Commission on Environment and Development 1987). The Brundtland Commission Report, Our Common Future (1987) defined sustainable development as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs". The provision of adequate and reliable energy services at affordable costs, in a secure and environmentally benign manner, and in conformity with social and economic development needs, is an essential element of sustainable development.

In a world where the human survival depends on a continuing energy supply, the need for ever-increasing amounts of energy poses a dilemma; how can one provide the benefits of energy to the population of the globe without damaging the environment, negatively affecting social stability, or threatening the well-being of future generations? The solution will lie in finding sustainable energy sources and more efficient means of converting and utilising energy in a secure and affordable manner (Tester et al., 2005).

Electricity is a clean and reliable form of energy. It can be used to provide many essential services in domestic, commercial and industrial sectors. At present there is no other form of energy that is equally efficient, versatile, and environmentally benign in its use as electricity. However, its production from most of the existing sources inevitably results in producing emissions which degrades the environment. There is very little argument that fossil fuels used in power generation contribute substantially to global carbon dioxide emissions. Most of the current patterns of energy supply are unsustainable (UN, 2002).

The global decline in environmental quality and the ensuing climate change impacts started emerging as a serious concern about four decades ago (United Nations

Conference on Human Environment, 1972). The world community, realising the intensity of the issue, raised it on the international scene in the Rio Earth Summit with the adoption of an international treaty, United Nations Conference of the Framework Convention on Climate Change (UNFCCC), aimed at reducing emissions of green house gases (GHGs). Subsequently, the countries that ratified the UNFCCC declared the Kyoto Protocol in 1997 (UN, 1997). Under this Protocol the developed countries agreed to cut their collective GHGs by 5% below their levels of 1990 during the period 2008 to 2012 (Robertson et al., 1989). Although it is a collective goal different countries have been allocated different allocated targets. The European Union (EU) targets are set at an 8% reduction, of which UK is responsible for 12.5% reduction in her GHGs emissions.

The UK government developed its Climate Change Programme, aimed at reducing the UK emission of GHGs, by introducing policies in all sectors of the economy in order to meet its binding target to the Kyoto Protocol. It also endeavours a further reduction in GHGs emissions by setting a national goal of 20% reduction in $CO_2$ by 2010 (DEFRA, 2000), which presently is considered unlikely to be reached.

The UK Energy White Paper, "Meeting the Energy Challenge", released by the Department of Business Enterprise and Regulatory Reform (BERR) in May 2007, is one of the key policy documents encompassing all sectors of the UK energy prospect. It outlines directions for the energy policy of the UK that would lead to 60% reduction in greenhouse gas emissions by 2050, while ensuring reliable energy supplies, promoting competitive energy markets and alleviating fuel poverty (BERR, 2007).

Currently, UK is responsible for about 3% of the Global GHGs emissions, of which 85% is Carbon Dioxide ($CO_2$) (DTI and Ofgem, 2007). Over a third of this $CO_2$ is emitted from power stations (DTI, 2004a). Due to this, targets are set in all existing policies for generating 10% of electricity from renewable sources by 2010, which has now been raised to 15% by 2015. The Energy White Paper states that the government remains committed to achieving these targets and has set an aspiration of 20% electricity from renewable sources by 2020.

It is evident that international public and political pressure for the energy sector and energy-intensive industries to address climate change is mounting, forcing them to look

at all available options for reducing $CO_2$ emissions. Nuclear energy, renewable energy sources, carbon dioxide capture and storage of emissions from fossil fuel plant, and demand reduction from increased end-use efficiency have all been touted as a means to reduce emissions in the electricity industry (IEA, 2002). Each of these measures, however, comes with associated challenges.

## 1.2 Renewable energy

The electricity industry has been identified specifically as having potential for emissions reduction (Helm, 2005). Increasing the proportion of electricity generated by renewable sources is cited as a means to reduce greenhouse gas emissions and reduce the reliance on fossil fuels (Zervos, 2003; Neuhoff, 2005). The European Union has lead the way on this with the establishment of a directive obliging all member states to achieve a given percentage of their electricity consumption from renewable sources (EU, 2001).

The range of renewable technologies is wide and varied. Tidal stream, wave energy, on and off-shore wind generation, hydro, photovoltaic, various types of biomass and biogas projects are all forms of renewable generation currently being developed. Hydro generation is probably the most competitive and well-established renewable technology and it has played an important role in the early days of many electricity systems (ESB, 2005). The potential for future development of hydro projects is limited in many countries due to the lack of suitable sites. Of the remaining renewable technologies wind power is generally seen as the most competitive (SEI, 2004a).

Wind power generation technology has emerged as one of the potential renewable technology that is believed to deliver the low carbon requirements of the medium term future. To date, the research community has concentrated largely on improving the reliability and cost economics of this technology. However, the present state of electricity systems demands addressing the issues that arise due to the large scale integration of this source on the development and operation of the power system.

## 1.3 Wind power generation

Wind power generation has developed rapidly over the last decade, with an annual growth rate of around 30% each year (EWEA, 2004). Almost three quarters of the total

installed capacity worldwide is in Europe and turbine technology and site construction continues to develop at pace. Studies (EWEA and Greenpeace, 2002) suggest that wind power can supply 12% of the global electricity demand, assuming that global demand doubles from 2002 by 2020.

Wind generation is fundamentally different to generation from conventional fossil fuel plants in many ways. It does not utilise conventional synchronous generators, which has implications for voltage control, and the wind generators' ability to stay connected during system disturbances. It has been described as 'non-dispatchable' as its generation output is limited by the wind available at the time. The limited extent to which wind power can be forecasted also has significant implications for system scheduling and operation. The unique nature of wind generation has led to difficulties in foreseeing how it will impact on systems. Present power system operation and planning methods have evolved to accommodate conventional fossil fuel generation and many are now found to be inadequate in systems with large penetrations of wind generation.

The unique nature of wind generation requires new methods of system planning and operation which encapsulate wind generation's characteristics, as well as those of conventional plant. These methods should be generic in nature, compatible with modern liberalised electricity systems and should relate fairly the generation characteristics to the fundamental system objectives without being biased by previous methods.

## 1.4 Integration of wind power into modern electricity systems

The integration of wind generation will have benefits and cost implications in both the development and operation of the electricity systems. For instance, adding wind power to power systems will have beneficial impacts by reducing the emissions of electricity production and reducing the operational costs of the power system as less fuel is consumed in conventional power plants. On the other hand, the investment costs of wind generation are greater than that of conventional gas or coal plant.

The possible impacts associated with the integration of wind power in system operation and development are depicted in Figure 1-1. These impacts can be grouped according their timescales and also how far into the network the impacts stretch. There are three main categories of impact and associated cost for system wide impacts (Holttinen et al.,

2007). The first, so called system 'balancing impacts', relates to relatively rapid short term adjustments needed to manage fluctuations over the time period from minutes to hours. The second, defined as 'network impacts', relates to the effect that the location of the wind farms relative to load and the correlation between wind power production and load have on network security, efficiency, and system stability. The third, which is termed 'reliability impacts', relates to the extent to which one can be confident that sufficient generation will be available to meet peak demands. The following sub-sections examine the three categories of impact in greater detail.

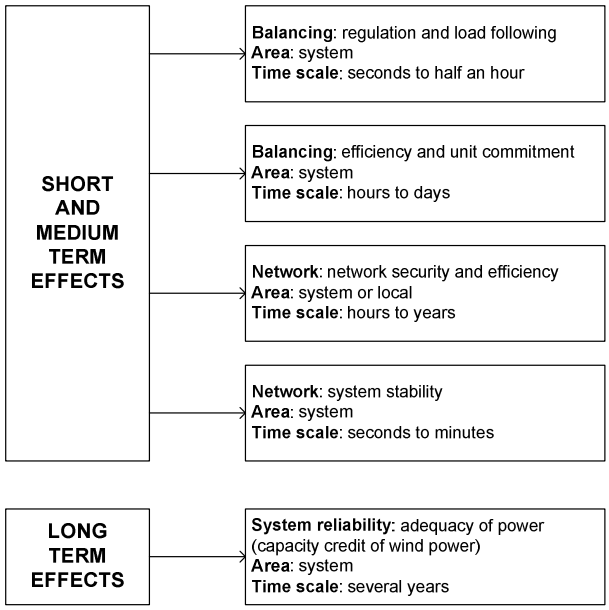



**Figure 1-1: Power system impacts of wind power causing integration costs**[1]

### 1.4.1 Balancing impacts: regulation and load following, efficiency, and unit commitment

One impact of the integration of wind power will be in the area of system balancing, a process that covers the impacts on allocation and use of short term reserves (time scale: from seconds to half an hour) and efficiency and unit commitment of existing power capacity (time scale: from hours to days). For instance the variability and uncertainty introduced by wind power will affect the allocation and use of reserves in the system. Analysing and developing methods of incorporating wind power into existing planning tools is important in order to take into account wind power uncertainties and existing

[1] Based on H. Holttinen, 2003, 'Hourly wind power variations and their impact on the Nordic power system'.

flexibilities in the system. Prediction errors of large area wind power should be combined with any other prediction errors the power system experiences, like prediction errors in load. General conclusions on the increase in balancing requirements will depend on the size of region undertaking balancing, initial load variations and how concentrated/distributed wind power is sited. The added costs of balancing will depend on the marginal costs of providing regulation or mitigating methods used in the power system for dealing with the increased variability and uncertainty.

Quantifying the effect of wind power generation is difficult particularly within a market context. Variability and prediction errors for wind power impact how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment, including both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). Likewise, in the time scale of hours to days the impacts of wind power can also be seen, reducing the use of fossil fuels thus saving the operational costs of the power system as well as decreasing the emissions.

### 1.4.2 Network impacts: network security, efficiency and system stability

The geographical remoteness of many wind power installations will also impact upon the system, particularly in the areas of security, efficiency and system stability. The significance of the effect will depend upon the correlation between wind power production and load consumption. Wind power affects the power flow in the network. It may change the power flow direction, reduce or increase power losses and bottlenecks situations. While there are a variety of means to maximise the use of existing transmission lines, like the use of online information (temperature, loads), FACTS (flexible AC transmission system) and even appropriate control of the wind power plants themselves, network reinforcement may be necessary to maintain network security.

The presence of wind power generator though will affect the calculation of network security. When determining security of the network, both steady-state load flow and dynamic system stability analysis are needed. Accordingly, different wind turbine types having different control characteristics and also different possibilities to support the system in normal and system fault situations. These differences must be considered. At present, for system stability reasons operation and control properties similar to central

power plants may be required for wind plants depending on penetration and power system robustness. Nonetheless, with current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage and participating in SCADA (supervision control and data acquisition) system operation with output and ramp rate control. These changed behaviours would affect the calculation of network security.

### 1.4.3 Reliability impacts: adequacy of power generation, and capacity credit of wind generation

A considerable amount of work has been done on the adequacy and reliability assessment of generation systems that are primarily based on conventional generation technologies. However, the inherent characteristics of wind power generation coupled with the influence of various factors such as wind source diversity, load factor, correlation with load requirements, demand new approaches in evaluating the sufficiency and reliability of future systems.

For instance, network adequacy, which relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraints (Billinton and Allan, 1984) will be affected by the presence of wind generation due to the changed nature of the power plant capacity necessary to generate sufficient electricity. Generation capacity adequacy manages the risk of supply deficits at an acceptable level by determining the amount and timing of new generation plant requirements. Under peak demand conditions a measure of the ability of the plant to contribute to demand and therefore to contribute to the adequacy of the system is provided by its ‘capacity credit’. When wind generation is present in the network, the assessment of its capacity credit must take into account geographical dispersion of the wind resource and interconnection. Intuitively, the capacity credit of wind generation will generally decrease as wind power penetration increases, but new methodologies are needed to quantify this impact.

## 1.5 Research question, aims and objectives

Broadly then, this thesis addresses the ‘reliability impacts’ associated with the integration of wind power in power system operation and development. In particular,

this study focuses on a central aim of evaluating the ability of the generation to meet the demand (generation adequacy) and the ability of transmission system to carry the power from the generation plants to the consumption areas (transmission adequacy) in the future sustainable power system featuring significant penetration of wind generation. This should be achieved in two key ways: (i) through the development of new methods of system planning which encapsulate wind generation's characteristics and promote an understanding on how wind generation affects the generation and transmission system development; and (ii) through the development of standards and regulatory arrangements associated with the transmission system to facilitate the cost effective integration of wind generation technologies.

Specifically this problem can be divided into five research questions and areas for research, each with individual objectives:

**RQ1. What is the impact of the presence of a flexible generation source such as hydro power on the capacity value of wind generation?**

This requires the development of a new methodology to quantify the capacity value of wind generation in the presence of a flexible generation source such as hydro power. This evaluation involves the assessment of the adequacy of the overall generation capacity of a system to serve a given demand with a set reliability target. The specific points to consider in response to this question include:

- the development of a methodology to quantify the additional capacity credit of wind power due to the presence of hydro power generation;
- the identification of what characteristics of wind power impact the overall system adequacy and capacity credit of wind generation in wind-hydro-thermal systems; and
- the identification of the key drivers of hydro power generation on the overall system adequacy and capacity credit of wind generation in wind-hydro-thermal systems.

**RQ2. What is the impact of interconnectors on capacity adequacy and capacity value of wind generation in systems with hydro generation?**

This area of research expands the methodology developed as an answer to the previous research question for application on an interconnected system. This enables one to quantify the role of interconnectors on adequate generation capacity requirements in systems having wind, hydro and thermal generation. The specific objectives of this area are to:

- evaluate how the interconnector can help to improve the reliability performance of the overall system;
- quantify the additional capacity costs attributed to wind power when this technology penetrates into the hydro-thermal system.

**RQ3. What is the impact of wind generation on the need for transmission network capacity and on systems' security of supply?**

This section of research details the development of a methodology for derivation of optimum levels of transmission network capacity driven by reliability considerations for interconnected systems including wind generation. The approach considers the impact of intermittent wind generation on the transmission network over the long term investment horizon and it determines the requirement for additional capacity driven by wind power generation. The objectives in this research area are to:

- explore how reliability standards can drive transmission network investment, and to highlight how transmission contributes to system risk;
- explore how important is the capacity value of wind generation in transmission network planning;
- evaluate the transmission system transfer capability requirements between the interconnected systems; and
- identify what characteristics of wind power decide the need (if any) for additional transmission requirements.

**RQ4. What are the main challenges facing the continued use of the present transmission security standards in systems with wind generation? What should be the main features of transmission security standards when applied to systems with wind generation and how should the technical framework be implemented?**

This section of research determines whether the current GB transmission security standards are suitable for application in the future system with wind generation, in the context of long term development of the transmission network. This section also presents the development of a new transmission planning method for investment in transmission. This new method, described as the 'contribution factors method', is presented as a basis to update the design criteria of the GB main interconnected transmission systems. The objectives developed to serve this assessment are the:

- review of both the principles on which the transmission security standards were developed and the assumptions underpinning existing application procedures;
- identification and examination of the strengths and weaknesses of the existing transmission planning standards according to their ability to accommodate growing levels of intermittent wind generation; and
- identification of critical parameters and procedures to be incorporated in the development of new transmission planning standards for a system with wind generation and the evaluation of the new approach in terms of the impact on system security of supply.

**RQ5. How should the network costs be allocated in a cost reflective manner to all network users in future low-carbon power systems with significant penetration of wind generation?**

This area of research builds upon the outcomes from the previous two research questions to develop a methodology to quantify and allocate reliability driven transmission costs to network users. The specific objectives of this area are to:

- determine the distinct contributions that individual generation technologies and demand have on transmission network capacity; and

– recognise the diverse contributions of individual generation technologies and demand to transmission network costs in order to provide cost reflectivity charges to network users.

## 1.6 Scope and methodology

### 1.6.1 Scope of the research

The title of this research thesis is "Generation and transmission adequacy evaluation of power systems with wind generation". The research and analysis that this requires is bounded in five key ways:

One of the key issues with wind generation is its limited capacity value i.e., its contribution to the overall system capacity and reliability is considerably lower than most of the conventional technologies (Grubb, 1991), (Sinden, 2004a), (RAE, 2004). However the presence of flexible generation sources in the system such as hydro power (with reservoir/storage capability) can mitigate the variability of wind generation and enhance the capacity value of wind generation. There is a need to evaluate the impact of the presence of a flexible generation source such as hydro power, on the capacity value of wind generation. There is also a need to identify and quantify the impact of various factors that affect the capacity value of wind generation.

In interconnected systems, interconnectors play a vital role in maintaining the supply and demand balance. Therefore in future systems with substantial amount of wind presence, the interconnectors can play a major role in mitigating the increased risk of security of supply due to the presence of wind power. This necessitates investigating the potential role of interconnectors in maintaining the risk to provision of supply at appropriate level in systems with large wind penetration. Such an investigation would lead to insights as to how the interconnectors can help to improve the reliability performance of the overall system.

The best conditions for the development of wind farms are in rural, remote areas, far from the load centres. Thus the location of wind generation sources in relation to demand centres as well as the correlation between wind power production and load consumption will be of considerable importance in assessing the impacts on the transmission network infrastructure. It is then required to evaluate how much

transmission network capacity should be built in order to transport large volumes of wind power from generation sources in remote areas to the centres of demand. Furthermore, the impact of wind power characteristics and conventional generating units' characteristics on the need (if any) for additional transmission network capacity must be understood and quantified.

In practice, network investment planners tend to use deterministic planning guides (also called network planning standards) that constitute a proxy of comprehensive reliability and economic assessments to make decisions about the adequate amount of transmission network capacity to build against a background of demand and generation. The information provided by the probabilistic method for transmission network expansion in system with generation is utilised to devise a deterministic planning criterion (set of practical rules) that defines the minimum required level of transmission network capacity in systems with wind generation.

The current technical, commercial and regulatory arrangements associated with the transmission system are fit for the purpose for which they were designed, namely the pricing of the transmission network to support a power system dominated by conventional, large-scale, centralised generation plant. However, movement towards a more sustainable, low carbon power system will bring with it a broader mix of generation technologies of varying size, generation profile and controllability. Location and time of use factors play a key role in the impact of these technologies and this is not aligned with the traditional methodologies for transmission network pricing in the system. Thus, it is necessary to recognise the diverse contributions of individual generation technologies, such as wind, to transmission network costs and hence to provide efficient, non-discriminatory and cost reflective charges for network users in general and wind generators in particular.

### 1.6.2 Research methodologies

The specific research methodologies adopted for the research were selected to allow coverage of a broad and interdisciplinary topic. Each chapter has its own methodological structure which centres on quantitative research methods, although in Chapter 7 there is an analysis and interpretation of the developed quantitative studies. The approach for each chapter is outlined in more detail below.

Chapter 2 develops a methodology to evaluate the generation capacity adequacy and capacity credit of wind in wind-hydro-thermal generation systems. The methodology to determine the adequacy of generation capacity is composed of two distinct models: a linear programming (LP) based optimisation model for generation dispatch and an analytical technique based on Markov model to determine the probability or long-term availability of the various capacity states of total thermal capacity considered in the system (COPT – Capacity Outage Probability Table). The two models are then combined allowing the computation of reliability indices such as loss of load expectation (LOLE) and expected energy not supplied (EENS), and the capacity credit of wind generation. The methodology respects the chronological behaviour of wind as well as any correlations that may exist among wind, demand and hydro generation. The methodology is enhanced to quantify the impact of various factors such as; system reliability level, wind resource diversity, wind load factor, wind penetration level, hydro penetration level, different hydro conditions and hydro storage size on the capacity credit of wind generation. Considering an equivalent NZ electricity system and using historical wind generation data (scaled up to represent various levels of wind capacity), the capacity credit of wind generation is determined in systems with hydro generation.

Chapter 3 extends the methodology developed in Chapter 2 to quantify the generation capacity adequacy with wind-hydro-thermal generation in interconnected systems. The linear programming (LP) based optimisation model for generation dispatch is enhanced to include the presence of the interconnector and to compute the generation dispatch for each of the interconnected regions. The analytical technique based on Markov model is also improved to determine the combined reserve capacity states and respective probabilities of the interconnected systems (ISCPT – Interconnected System Capacity Probability Table). Loss of load expectation (LOLE) and expected energy not supplied (EENS) indices are quantified as result of the combination of the two models.

Chapter 4 proposes a transmission planning methodology based on reliability evaluation of interconnected systems. The methodology evaluates the optimum transmission network capacity levels between the interconnected systems as well as the adequacy of transmission network capacity in systems with wind generation. The developed model is based on analytical techniques and employs Markov models to simulate the random failures of the thermal generators. Wind generation is represented through modelling the

key parameters of wind generation using a Markov model. The adequacy assessment of transmission network capacity uses the loss of load probability (LOLP) criterion. Comprehensive sensitivity studies are performed to study the effect of various factors on the optimum level of transmission network capacity. The factors studied include wind power characteristics (wind penetration level, wind resource diversity and wind load factor) and conventional generating units' characteristics (average unity availability and unit size). The proposed methodology is applied to a case study presented in the context of a simplified GB transmission system. In addition this chapter refers to a cost benefit analysis, applied to the same case study, to ensure the economic optimality of the transmission planning process.

Chapter 5 expands the methodology developed in Chapter 4 to evaluate the capacity contribution of the different generation technologies and demand to the required transmission network capacity. The developed methodology, described as the 'contributions factors method', is based on analytical techniques and it is derived from an exhaustive analysis of the ISCPT table. The contribution factors method seeks to provide a relatively simple function to characterise the required transmission network capacity for any given background of demand and generation. The application of the contribution factors method is further extended to analyse the impact of key factors on the contribution of wind generation to transmission network capacity. The key factors include wind penetration level, diversity of wind resource, wind load factor, conventional plant availability and conventional unit size. The contributions factors method is applied to the GB electricity grid for three wind scenarios developed by the GB system operator (SO) for this purpose.

Chapter 6 presents a methodology for allocation of reliability driven transmission network investment costs to network users based on the evaluation of the transmission network capacity requirements between the interconnected regions. Transmission network capacity requirements and the capacity contribution of the different generation technologies and demand to the required transmission network capacity are determined through the methodologies developed in Chapters 4 and 5 respectively. The proposed methodology is applied to a case study presented in the context of a simplified GB transmission system.

### 1.6.3 Contribution and originality of the research

This research has made significant and novel contributions, both conceptual and methodological, in the area of generation and transmission adequacy of power systems with wind generation.

A rigorous new methodology is developed to compute generation capacity adequacy and capacity credit of wind in wind-hydro-thermal generation systems. The developed methodology allows quantifying and understanding the impact (if any) of the presence of a flexible generation source such as hydro power on the capacity credit of wind generation. The method is further applied to evaluate and comprehend the influence of various characteristics of wind generation (wind resource diversity, wind load factor, wind penetration level) and hydro (hydro penetration level, different hydro conditions and hydro storage size) on the capacity value of wind generation.

The adequacy of generating capacity in a power system is normally improved by interconnecting the system to another power system. Thus the previous methodology is extended to allow its use on interconnected systems. This enables the quantification of the role of interconnectors on adequate generation capacity requirements in systems having wind, hydro and thermal generation. The methodology is further enhanced to allow the quantification of the additional capacity costs attributed to wind power when this technology penetrates into the hydro-thermal system. The methodology explores the effect of different hydro conditions (dry, average, wet) and the spatial distribution of wind resource on the overall system's capacity adequacy and the effect of wind forecasting errors on the capacity value of wind generation.

A new methodology is developed to evaluate the sufficiency of transmission network capacity to accommodate wind generation and to manage security of supply. The method determines the need for transmission network investment in systems with mixes of conventional and wind generation technologies. It permits the identification of the importance of the capacity value of wind generation in transmission network planning and provides insights into which characteristics of wind power drive the need (if any) for additional transmission requirements. The methodology is also extended and used to analyse the impact of characteristics of wind and conventional generation (average unity availability and unit size) on the need for transmission network capacity.

A new methodology, described as the 'contribution factors method', is developed to determine the adequate level of transmission network capacity based on the characterisation of simple functions. The 'contribution factors method' devises practical rules for the application in transmission planning procedures by transmission planners. The methodology is further applied to explore the effect of various sensitivity factors, i.e. wind power characteristics and generation units' characteristics, on the contribution factors of the different generation technologies and demand to the inter-area transmission network capacity.

In the context of electrical power systems and charging for network use, cost reflectivity of charges is required to send accurate price signals to individual users of the network with respect to the costs they impose on network development. The 'contribution factors method' is further enhanced to quantify the allocation of reliability driven transmission network investment costs to network users. The developed methodology proposes a simple modification of the present Great Britain's Transmission Network Use of System (TNUoS) charging mechanism in order to recognise the different contributions of individual generation technologies to transmission network costs and hence to achieve cost reflectivity.

## 1.7 Organisation of the thesis

Each chapter is focused on responding to one of the research questions outlined earlier. When combined, these sections serve to meet the thesis aim of evaluating generation and transmission adequacy of the future sustainable power system featuring significant penetration of wind generation. This will be achieved through the development of new methods of system planning which encapsulate wind generation's characteristics, and through the development of standards and regulatory arrangements associated with the transmission system to facilitate the cost effective integration of wind generation technologies.

Firstly, to do this requires an understanding of how wind generation affects the generation and transmission system development. Chapter 2 is concerned with the evaluation of capacity credit of wind generation which involves the assessment of the generation capacity of the overall system. The capacity credit of wind is interpreted from a planning perspective, and also as a component of the economic value of wind

energy. Chapter 3 assesses the effect of the presence of interconnectors on the capacity credit of wind generation, involving the computation of generation capacity adequacy in interconnected systems. Chapter 4 explores the impact of wind generation on transmission network over the long term investment horizon and determines the requirement for additional transmission network capacity driven by wind generation.

Secondly, the present standards and regulatory arrangements associated with the transmission system are reviewed and examined according to their ability to accommodate wind generation and alternative approaches to incorporate wind generation's characteristics are proposed. Chapter 5 reviews the philosophy and assesses the performance of the present transmission security standards in systems with wind generation and proposes a new method as the basis to update the design criteria of the GB main interconnected systems as stated in the GB SQSS. Chapter 6 presents a high level review of the main viewpoints of the GB Transmission Network Use of System (TNUoS) charging methodology in the context of wind generation and proposes a simple modification of the present TNUoS charging mechanism in order to recognise the different contributions of individual generation technologies to transmission network costs and hence to achieve cost reflectivity.

Chapter 7 presents some discussions on the main points raised and draws together the conclusions from the previous chapters. This chapter also presents the research findings and scope, and presents areas for further work.

# Chapter 2

# Capacity adequacy and capacity credit of wind generation in systems with hydro generation

## 2.1 Introduction

The rapid increase of wind generation in many power systems raises potential concerns regarding the reliability of future systems due to the intermittent nature and limited capacity value of this source. The capacity value of wind generation, assessed from its ability to displace conventional (thermal) generation while maintaining reliable supply of electricity, is termed as the capacity credit of this source. Evaluation of the capacity credit of wind generation is necessary for utility planners, system operators, wind farm developers and other decision makers in order to plan future power systems that meet the desired reliability standards and are economically efficient. This evaluation involves the assessment of the adequacy of the overall generation capacity of a system with and without wind generation to serve a given demand system with a set reliability target.

The capacity credit of wind generation varies across different regions due to the difference in the characteristics of the wind output and different compositions of the incumbent generation systems. The presence of other flexible generation sources in a system such as hydro power (with reservoir/storage capability) can mitigate the variability of wind generation. This will lead to require reduced thermal capacity in the system which is necessary to maintain system security, and thus enhances the capacity value of wind generation. However, the presence of such generation sources besides wind generation in a system further complicates the determination of the capacity adequacy and capacity credit of wind generation.

There has been some useful previous work in this area (Soder and Bubenko, 1987; Soder, 1988) which applies equivalent load duration curve for reliability assessment of the system while minimising the production costs. Wind generation is expressed as a multi-state unit characterised by the probability density function of wind power output. The wind capacity credit is calculated using three different indices; effective load

carrying capability, equivalent firm capacity and equivalent conventional capacity. Wind representation in this approach loses the chronological behaviour of wind as well as any correlations that may exist among wind, demand and hydro generation. Furthermore, the multi-state representation of wind results in specific levels of wind output being available all the time with certain probability which differs from actual wind behaviour. Also due to a focus on production costing, these approaches do not fully utilise the flexibility potential of hydro to mitigate variability of wind power in order to minimise thermal capacity requirements.

This chapter presents a new methodology based on loss of load expectation (LOLE) to quantify the impact of the presence of a flexible generation source such as hydro power, on the capacity value of wind generation. A linear programming (LP) based optimisation model for generation dispatch is developed. It optimally allocates wind, hydro and thermal generation during each time period (half-hour) throughout a year to meet demand such that the thermal capacity requirements are minimised within the given constraints. This approach is different from peak-shaving based approaches (Billinton and Harrington, 1978; Malik et al., 1999) and equivalent load duration curve methods (Baleriaux et al, 1967; Booth 1972) and it preserves the chronological behaviour and correlations among hydro energy, wind generation and demand.

An analytical technique based on Markov model is also employed to determine the probability or long-term availability of the various possible capacity states of the overall thermal capacity considered in the system. The optimal thermal dispatch required in each time period (assessed by the optimisation model) is applied to the analytical model in order to determine the loss of load probability (LOLP) in the corresponding period. These periodical LOLP values are aggregated to determine the annual LOLE. Subsequently, thermal capacity is added or removed iteratively from the system as required to match the computed LOLE with the target LOLE which was set as the system's desired reliability level.

The chapter then evaluates the additional system capacity costs attributed to wind power to maintain system reliability at a desired level. The additional system capacity costs due to wind power are quantified through the methodology developed by Strbac and Shakoor (Strbac and Shakoor, 2006). It assesses the ratio of capacity and energy that is displaced by a secondary technology (e.g. wind power) as it penetrates into an

incumbent system. The disproportion between the capacity and energy that is displaced by wind power is the cause of these additional capacity costs.

Using the developed methodology several studies are performed to evaluate the impact of various factors associated with wind and hydro power on the capacity credit of wind generation and on the capacity credit benefit due to the presence of hydro generation in system. The factors studied include the system reliability level, wind resource diversity, wind load factor, wind penetration level, hydro penetration level, different hydro conditions and hydro storage size.

## 2.2 Generation adequacy

Electricity system reliability assessment has been traditionally divided into two basic aspects: system adequacy and system security. Adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraint (Billinton and Allan, 1984). These include the power plant capacity necessary to generate sufficient electricity and the associated transmission and distribution facilities to transport electricity to consumer load points. Adequacy is therefore associated with static conditions, which do not include system disturbances. Security relates to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever perturbation it is subjected (Billinton and Allan, 1984).

From a planning point of view, adequacy is a long (mid)-term planning process in which the main objective is to give early warning signals concerning system reliability and highlighting opportunities or necessities to invest in generation and transmission. On the other hand, the ability of a generation system to respond to fluctuations of the system demand, unforeseen outages of both generating units and transmission components is a short-term planning process whose main objective is to provide balancing of the system demand and supply on second by second basis.

Adequacy of the power system depends on two factors: the ability of the generation to meet the demand (generation adequacy) and the ability of the transmission system to carry the power from the generation plants to the consumption areas (transmission adequacy). Chapter 2 and Chapter 3 only focus on generation adequacy while

transmission adequacy will be addressed in Chapter 4 and Chapter 5. The key drivers of generation capacity adequacy are shown in Figure 2-1. The damaging consequences of electricity supply shortages (deficits) on the economy and society are immediate and significant. There is no doubt that risk of supply deficits can be eliminated through extreme levels of uneconomic investment in generation plant. However, the accepted industry practice, worldwide, is to manage the risk to an acceptable level by determining the amount and timing of new plant requirements. The risk is often quantified by taking a probabilistic approach, which accepts that for a defined period of time, demand will not be fully met. The annual generation adequacy standard is used to benchmark the risk. If the level of risk is greater than standard, then additional power generation is required (EirGrid, 2007).

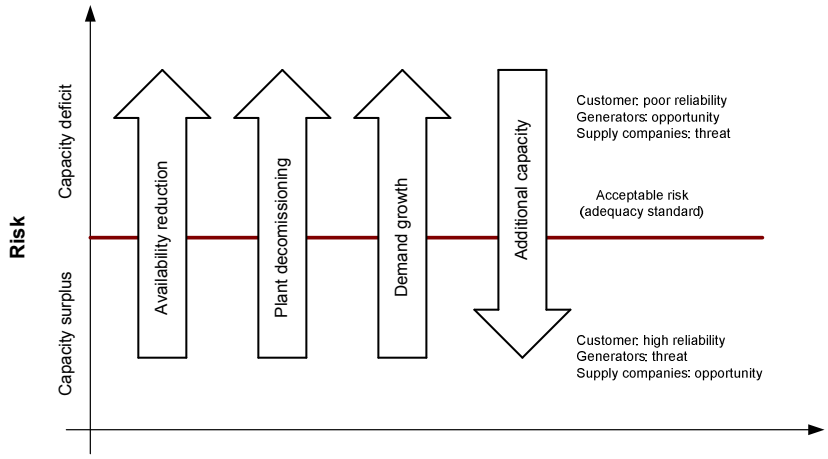



**Figure 2-1: Capacity adequacy – key drivers (ITSO, 2002)**

The adequacy standard in Ireland proposes that expectation of failure should not be larger than 8 hours per year. It should be emphasised that this does not mean that all customers will be without supply for 8 hours per year, but rather that there is an expectation that for 8 hours of the year there will be some supply deficits. The adequacy index used in this standard is the Loss of Load Expectation (LOLE), which is a mathematical expectation of having supply deficits over the period of one year (hours/year). This adequacy index is a measure of supply deficits duration and it cannot be used to measure magnitude of supply deficits.

The transmission system operator in France needs to submit a multi-annual Generation Adequacy Report, no less than once every two years and subject to the scrutiny of the State (RTE, 2007). In principle, this report suggests prospective short and long term

diagnostics of the balance between electricity supply and demand and evaluates the new generation capacity required to maintain security of supply in the long-term. The level of supply deficits accepted for the Generation Adequacy Report in France is mathematical expectation of less than three hours per year (LOLE < 3 hours/year).

The Union for the Co-ordination of Transmission of Electricity (UCTE) co-ordinates the interests of transmission system operators in 20 European countries. Their common objective is to guarantee the security of operation of the interconnected power system. The remaining capacity is used as a measure of generation adequacy for the UCTE. Remaining capacity can be interpreted as the capacity that the system needs to cover the 'margin against monthly peak load' (differences between synchronous peak load and sum of non synchronous peak loads) and, at the same time, exceptional and longer-term unplanned outages which the power plant operators are responsible to cover with additional reserves (often estimated at 5% of installed capacity) (UCTE, 2008).

## 2.3 Capacity contribution of wind generation

The quantification of the amount of a power system's generating capacity that can ensure an adequate supply is an important task in the power system planning process. The power system should be planned with a certain capacity margin to guarantee that the system's supply risk is kept at appropriately low levels. The capacity margin represents the magnitude of installed electricity generating capacity that is greater than the system peak demand. This margin is necessarily present in the system to deal mainly with random failures of generators and uncertainty in demand.

With the addition of new forms of generation sources, such as intermittent wind and solar power technologies, uncertainties inherent to the power generation systems are growing. Intermittent sources may be available at times when demand is high and many other units have failed, so they may reduce the overall risk of supply and allow the conventional plant margin to be reduced. Wind generation is considerably more variable than conventional generation and therefore less reliable during peak demand periods. Therefore, the capacity value of wind generation is not the same as conventional plant. In addition to the variable nature of this source there are several other factors like resource diversity, achievable load factor, level of penetration, correlation of demand and wind generation etc. that influence its capacity value.

One of the principal measures for the assessment of the capacity worth of wind generation is the capacity credit of this source. The term is defined by the British Wind Energy Association (BWEA, 1982) as:

"The reduction, due to the introduction of wind energy conversion systems, in the capacity of conventional plant needed to provide reliable supplies of electricity."

Capacity credit is generally expressed as a percentage of the installed capacity of the intermittent source (wind). At one extreme, if it is certain that a wind energy plant would produce its full rated power during peak demand hours; its capacity value would be relatively very high, approaching its rated power. At the other extreme, if it is assumed that the wind system would never be producing electricity during peak hours then its capacity value would be zero. However, generally, the capacity value of a wind generation is between zero and the capacity factor of wind plants. It is also dependent upon the correlation of wind power output and demand patterns and the composition of the incumbent system in which it is being added.

Capacity credit is generally interpreted in two ways. Firstly, from a planning perspective, capacity credit should indicate the replaceable conventional capacity in order to set targets for energy policy. Secondly, capacity credit is interpreted as a component of the economic value of wind energy. Traditionally the capacity credit has been used to determine the capacity cost of avoided or replaced conventional generators and subsequently used in determining the cost of electricity generation from wind power technology.

## 2.4 Capacity adequacy of thermal systems

The following sections present the developed methodology to quantify the overall system's capacity adequacy and capacity credit of wind generation in wind-hydro-thermal systems. The methodology to assess the adequacy of generation capacity was developed in three distinct phases. Initially the methodology is described for an entirely thermal based generation system. Hydro generation was then introduced to the thermal system and finally wind generation was added to achieve a combined wind-hydro-thermal system.

The amount of generation capacity in a power system is considered to be adequate if it meets the electricity demand with desired level of system reliability. The reliability criterion applied in this analysis is the Loss of Load Expectation (LOLE) which is defined as the number of hours per year when load is expected to exceed the available generation. The developed capacity adequacy model is also capable of evaluating Expected Energy Not Supplied (EENS) as a reliability index, however, the more widely applied LOLE criterion is used in this work.

### 2.4.1 Capacity model

The thermal generation system model is based upon Markov model and assumes statistically independent, stationary and exponential distribution of the failure and repair time of the generating units. The thermal capacity model was created using the recursive algorithm presented by Billinton and Allan (Billinton and Allan, 1984) and computes the probability or long-term availability of various capacity states of the generation system.

Each unit in the system is characterised by its maximum rated capacity and its operating capacity states with associated probabilities. All generating units are assumed to be connected in parallel and are added to the capacity model one by one. Each possible combination of units in either fully up, derated (consistent with a minimum stable generation) or down state defines a capacity state of the system. The resulting states are characterised by their available capacities and the associated probabilities. Identical states are merged to yield only unique capacity levels. The collection of all possible capacity states of the system expressed in the form of capacity outage states is termed as the capacity outage probability table (COPT).

In modelling the generation system it is further assumed that there is no correlation between the availabilities of conventional units i.e. the failure of one does not increase the risk of failure of others in the system.

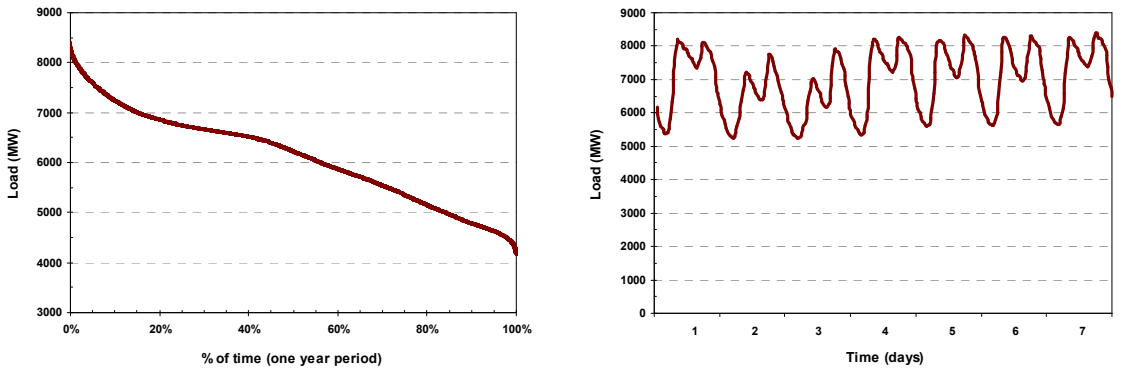
The cumulative probability '*P(X)*' of a particular capacity outage state of the system, say '*X*' MW on addition of a unit of capacity '*C*' MW, is given by equation (2.1).

$$P(X) = \sum_{i=1}^{n} p_i \cdot P'(X - C_i) \tag{2.1}$$

'$n$' represents the number of capacity states of the thermal generator being added to the capacity model, '$p_i$' is the probability of the unit's state '$i$' and '$P'(X\text{-}C_i)$' is the probability of system's capacity state of '$(X\text{-}C_i)$' size before addition of the unit.

### 2.4.2 Load system representation

The load model constitutes a time series of half-hourly peak loads '$L_t$' over a one year time horizon '$T$'. The load system used is based upon the half-hourly electricity demand profile of New Zealand. The available annual load profile was scaled up to represent the demand levels (8.4GW peak demand) and energy requirements (53TWh) expected for the year 2020. The individual half-hourly peak loads can be arranged in descending order to form a cumulative load duration curve (LDC). The load duration curve as well as the load system demand during the peak demand week are presented in Figure 2-2a and Figure 2-2b respectively.




**(a) Load duration curve** **(b) Load demand during peak demand week**

**Figure 2-2: Load system characteristics**

This load representation corresponds to an annual energy demand of 53TWh, part of which is deemed to be served by wind generation and the rest by hydro generation and conventional generation.

### 2.4.3 Computation of risk indices

#### Loss of load expectation (LOLE)

The individual half-hourly peak loads can be used in conjunction with the capacity outage probability table to compute the expected number of hours, over a one year time period in which the half-hourly peak load will exceed the available generation. The index in this case is designated as the loss of load expectation (LOLE).

A loss of load situation is considered to occur when the load exceeds the expected available generation. For each half hour time slot '$t$' the probability of all the capacity states of the system that lead to insufficient available generation in meeting concurrent load is added to determine the LOLP during that period, as given by equation (2.2).

$$LOLP_t = \sum_{i=1}^{n} p\left(X_i < L_t\right) \tag{2.2}$$

'$n$' is the number of the generation system capacity states, and '$X_i$' is the capacity level of the generation system state '$i$'. The annual loss of load expectation (LOLE in hours/year) is then determined by summing the LOLP values of each half hour period of the year as given by equation (2.3).

$$LOLE = \frac{1}{2}\sum_{t=1}^{T} LOLP_t \tag{2.3}$$

The adequacy of the generation capacity present in the system is determined through computation of the annual LOLE. If the computed LOLE matches the benchmark reliability level set for the system, the amount of capacity present in the system is considered adequate. Otherwise capacity is iteratively added (or removed) until the computed LOLE matches the target LOLE level.

#### Expected energy not supplied (EENS)

A loss of load situation also implies the existence of load energy curtailed due to deficiencies in the generation system. The load energy curtailed can be calculated by comparing a capacity outage state with a remaining capacity $C_i$ with all half-hourly load

values $L_t$ in all situations that lead to loss of load ($C_i<L_t$). The load energy curtailed is expressed in MWh and can be computed as follows:

$$LEC_i = \frac{1}{2}\sum_{t=1}^{T} L_t - C_i \tag{2.4}$$

This index can be extended in order to determine the expected energy not supplied (EENS) by the generation system due to outages of the generating units. The load energy curtailed due to a certain generation capacity out of service multiplied by the probability of occurrence of the outage state translates into the expected energy not supplied for that particular outage state. The particular values are summed up to calculate the expected energy not supplied by the generation system according to the following relationship:

$$EENS = \sum_{i=1}^{n} LEC_i \cdot p_i \tag{2.5}$$

## 2.5 Capacity adequacy of wind-hydro-thermal systems

The methodology described in section 2.4 for evaluating the capacity adequacy of a thermal system alone is extended to apply for a system containing wind, hydro and thermal generation.

A linear programming based optimisation model for generation dispatch is developed (section 2.5.1). It optimally dispatches the wind, hydro and thermal generation during each time period of the simulation horizon such that the requirements of thermal capacity in the system are minimised. The optimisation includes several constraints including the production constraints associated with wind, hydro and thermal power plants.

The COPT of the total thermal capacity considered in the system is determined in the same way as explained earlier for thermal systems alone. The optimal thermal generation dispatch and reserve hydro capacity obtained from the dispatch model are then combined with the COPT of the total thermal capacity to evaluate the system's reliability (LOLE) as described in section 2.4.3.

The adequacy of the overall system capacity is finally assessed by comparing computed LOLE with the LOLE standard. The thermal capacity is iteratively added (or removed) followed by recalculation of the LOLE until the required reliability level is attained.

A schematic representation of the capacity adequacy assessment model in wind-hydro-thermal systems is shown in Figure 2-3.

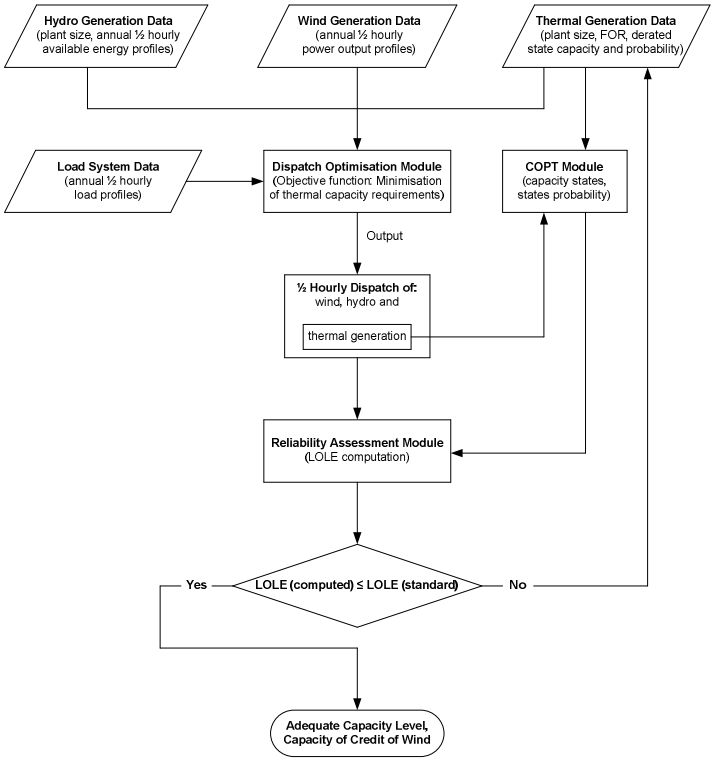



**Figure 2-3: Capacity adequacy model in wind-hydro-thermal systems**

### 2.5.1 Optimisation model: generation dispatch

For a system having wind, hydro and thermal generation a linear programming based optimisation model for generation dispatch is developed which can be implemented using any optimisation software. This work uses Dash Xpress optimisation tools (Dash Optimisation, 2008).

The optimisation formulation optimally allocates the wind, hydro and thermal generation during each time slot of analysis such that the requirements of the total thermal capacity in the system are minimised for given levels of wind and hydro generation in the system.

**Objective function**

The objective is to optimally dispatch all generators in the system (wind, hydro and thermal generators) over the simulation period '*T*' such that the utilisation of wind and hydro energy is maximised and the cumulative output from all thermal generators is minimised. Mathematically, the objective is expressed by the following objective function, equation (2.6).

$$\text{Minimise} \quad Z = MaxP^{th} + Wshed + Hshed \tag{2.6}$$

'$MaxP^{th}$' is the maximum of the cumulative power outputs from all thermal generators across all time periods of the simulation horizon determined by equation (2.7).

$$MaxP^{th} \geq \sum_{i=1}^{I} P_i^{th}(t), \quad \forall t \in T \tag{2.7}$$

'$P_i^{th}(t)$' is the power output of the thermal generator '*i*' during period '*t*'; and '*I*' is the number of thermal generators considered in the system.

'*Wshed*' is the cumulative wind energy curtailed from all wind generators across all time periods of the simulation horizon determined by equation (2.8).

$$Wshed = \sum_{t=1}^{T}\left[\sum_{w=1}^{W}\left[\left(W_w(t) - P_w^{wd}(t)\right)\cdot\tau\right]\right] \tag{2.8}$$

Where '$W_w(t)$' is the wind power available in each time period '*t*' (obtained from historical wind data); '$P_w^{wd}(t)$' is the wind power output of wind generator '*w*' in period '*t*'; '*W*' is the total number of wind generators; and '$\tau$' is the duration of the time period i.e., half-hour as considered in this work.

The model attempts to maximise the use of wind energy, however in a situation of wind energy surplus which cannot be utilised later in the simulation horizon period (one year), for example, due to subsequent surplus wind occasions and/or in low load conditions, wind can be curtailed.

'*Hshed*' is the cumulative hydro energy curtailed from all hydro power plants during the simulation horizon determined as follows:

$$Hshed = \sum_{t=1}^{T}\left[\sum_{h=1}^{H}\left[E_{ror}(t) + E_{rsvr}(t) - P_h^{hd}(t)\cdot\tau\right]\right] \tag{2.9}$$

Where '$E_{ror}(t)$' is the available hydro run-of-river energy in each time period '$t$'; '$E_{rsvr}(t)$' is the available hydro reservoir energy in each time period '$t$'; '$P_h^{hd}(t)$' is the power output of hydro generator '$h$' in time period '$t$'; and '$H$' is the total number of hydro generators.

The model attempts to maximise the use of hydro energy, nevertheless, water spillage due to energy storage in the hydro reservoirs is allowed when low load and/or excess available energy conditions exist.

The objective function is minimised subject to a number of constraints and auxiliary equations that are derived from the need to satisfy electricity demand in each period and to maintain the specific characteristics of each power plant.

#### Demand

In order to balance demand and supply in each time period, the power output from all generators in each time period equals the demand in the same time period as represented by equation (2.10).

$$\left[\sum_{i=1}^{I} P_i^{th}(t)\right] + \left[\sum_{h=1}^{H} P_h^{hd}(t)\right] + \left[\sum_{w=1}^{W} P_w^{wd}(t)\right] = d(t), \quad \forall t \in T \tag{2.10}$$

Where '$d(t)$' is the system load demand to be met during period '$t$' during the simulation horizon, i.e., one year as considered in this work.

**Thermal power plants**

The generation output level of each thermal power plant is constrained in each time period by the minimum stable generation level '$P_{mini}^{th}$' and the maximum (rated) capacity '$P_{maxi}^{th}$' of the generator '$i$', according to equation (2.11).

$$P_{\min_i}^{th}(t) \le P_i^{th}(t) \le P_{\max_i}^{th}, \quad \forall i \in I, \ \forall t \in T \tag{2.11}$$

**Wind power plants**

Wind power is modelled as a non-dispatchable energy source. The model attempts to maximise its use unless it is restricted by surplus available energy conditions such as during low load periods and minimum stable generation level constraints. Therefore, all wind power available '$W_w(t)$' in each time period (obtained from historical wind data) is used towards meeting demand unless its curtailment is necessary. This is expressed by equation (2.12).

$$P_w^{wd}(t) \le W_w(t), \quad \forall w \in W, \ \forall t \in T \tag{2.12}$$

**Hydro power plants**

All hydro generators are aggregated in the form of a single plant characterised by an equivalent capacity (i.e. the sum of the rated capacity of all hydro generators) and a certain amount of available hydro energy. The equivalent hydro capacity and the available hydro energy within a simulation horizon (one year) are categorised in accordance to the type of hydro plant, i.e., run-of-river '*ror*' and reservoir '*rsvr*'.

The hydro power output is also aggregated by type, run-of-river and reservoir. Thus the hydro output level in each time period is expressed as the sum of the power output of the hydro generators of run-of-river type and reservoir type according to equation (2.13).

$$P_h^{hd}(t) = P_h^{ror}(t) + P_h^{rsvr}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.13}$$

Where '$P_h^{ror}(t)$' is the power output of hydro generator '$h$' of run-of-river type in the time period '$t$'; and '$P_h^{rsvr}(t)$' is the power output of hydro generator '$h$' of reservoir type during the same time period.

The run-of-river hydro component is treated as a must-run part of the aggregated hydro plant. All available hydro run-of-river energy during each time period is modelled to be fully used unless constrained by the load or other generator's conditions. The power output of the hydro generators of run-of-river type are constrained, in time period '$t$', by the available hydro run-of-river energy as follows:

$$P_h^{ror}(t) \cdot \tau \le E_{ror}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.14}$$

The hydro output level in each time period is constrained by the minimum hydro generation level '$P_{minh}^{hd}(t)$', defined as the power output of the hydro generators of run-of-river type, and by the maximum hydro generation level '$P_{maxh}^{hd}(t)$' defined as the total rated capacity of the hydro plants in the system. Equation (2.15) defines the power output limits of the hydro generators.

$$P_{\min_h}^{hd}(t) \le P_h^{hd}(t) \le P_{\max_h}^{hd}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.15}$$

An energy balance constraint is applied to the run-of-river and reservoir hydro generation, equation (2.16) and (2.17) respectively, such that the total energy produced by the two types of hydro power plants does not exceed their respective available hydro energy during the simulation horizon (one year).

$$\sum_{t=1}^{T}\left[\eta_h \cdot P_h^{ror}(t) \cdot \tau\right] \le \sum_{t=1}^{T} E_{ror}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.16}$$

$$\sum_{t=1}^{T}\left[\eta_h \cdot P_h^{rsvr}(t) \cdot \tau\right] \le \sum_{t=1}^{T} E_{rsvr}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.17}$$

'$\eta_h$' is the efficiency of the hydro generator.

Energy balance during each time period '*t*' in the hydro reservoir is modelled through two constraints. Equation (2.18) gives the energy level of the reservoir at the end of first time interval '*t* = 1'.

$$E_h^{rsvr}(t) = rsvr_{InSt} \cdot E_{\max}^{rsvr} - \eta_h \cdot P_h^{hd}(t) \cdot \tau + E_{rsvr}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.18}$$

'$E_h^{rsvr}(t)$' is the stored energy in the reservoir of the hydro generator at period '*t*'; and '$rsvr_{InSt}$' is the initial condition of the hydro reservoir (expressed as percentage of maximum energy storage level '$E_{max}^{rsvr}$' of the reservoir).

Equation (2.19) represents the energy balance in the reservoir for all other time periods (i.e. for all $t > 1$). At the end of a period '*t*', the stored energy in the reservoir is the stored energy at the end of previous period '$E_h^{rsvr}(t\text{-}1)$', minus the energy produced by the plant in period '*t*', plus the available hydro reservoir energy during the same period.

$$E_h^{rsvr}(t) = E_h^{rsvr}(t-1) - \eta_h \cdot P_h^{hd}(t) \cdot \tau + E_{rsvr}(t), \quad \forall h \in H, \ \forall t \in T \tag{2.19}$$

In order to ascertain that the reservoir energy in all time periods '*t*' is within the limits, equation (2.20) is applied.

$$E_{\min_h}^{rsvr}(t) \le E_h^{rsvr}(t) \le E_{\max_h}^{rsvr}, \quad \forall h \in H, \ \forall t \in T \tag{2.20}$$

'$E_{minh}^{rsvr}(t)$' and '$E_{maxh}^{rsvr}(t)$' are respectively the cumulative minimum and cumulative maximum energy storage limits of the reservoir representing the aggregated hydro generator. The minimum energy storage limit of the reservoir is determined according to expression (2.21).

$$E_{\min_h}^{rsvr}(t) = rsvr_{\min} \cdot E_{\max}^{rsvr}, \quad \forall t \in T \tag{2.21}$$

Where '$rsrvr_{min}$' is the minimum storage level of the reservoir expressed as a percentage of the maximum energy storage level '$E_{max}^{rsvr}$' of the reservoir.

Hydro energy stored in the reservoir in the earlier time periods '*t*' of the simulation horizon can be utilised in any other period of the simulation horizon (one year). This

behaviour is translated by equation (2.22) where the total energy produced by the hydro power plants of reservoir type does not exceed the total available hydro reservoir energy during the simulation horizon.

$$\sum_{t=1}^{T}\left[P_h^{rsvr}(t)\cdot\tau\right]\le\sum_{t=1}^{T}E_{rsvr}(t),\quad \forall h\in H,\ \forall t\in T \tag{2.22}$$

The available hydro capacity reserve '$P_{reserve}^{hd}(t)$', for each half hour, is the difference between the total hydro capacity and the dispatched hydro power, subject to the available hydro energy in the reservoir. The available hydro capacity reserve is determined according to expression (2.23).

$$P_{reserve}^{hd}(t)=Min\left[\frac{E_h^{rsvr}(t)-E_{\min_h}^{rsvr}(t)}{\tau},\ \left(\sum_{h=1}^{H}P_{\max_h}^{hd}(t)-\sum_{h=1}^{H}P_h^{hd}(t)\right)\right],\quad \forall h\in H,\ \forall t\in T \tag{2.23}$$

### 2.5.2 Thermal capacity requirements in wind-hydro-thermal system

First, the thermal capacity requirement to meet a given demand considering only a thermal based system using its COPT and annual LOLE requirements is determined by applying the approach mentioned in section 2.4.

Subsequently, given quantities of wind and hydro power are added to the same system and the thermal power output in each time period is assessed by applying the LP dispatch model explained in the previous sub-section. The half-hourly thermal power output obtained from the model is then combined with the COPT of the thermal capacity considered in the system and the annual value of LOLE is then computed. This generally results in a significantly low value of LOLE. Therefore, thermal capacity is gradually reduced from the system and corresponding COPTs are prepared for each new thermal capacity level to re-evaluate the LOLE. This process is repeated unless the amount of thermal capacity in the system in combination with given wind and hydro capacities provides the required level of LOLE.

## 2.6 Evaluation of capacity credit of wind generation

The capacity credit of wind generation is generally defined as the reduction in the capacity of thermal plant needed to provide a reliable supply of electricity, due to the introduction of wind generation. It can be measured by comparing the amount of thermal capacity required in two systems; one with and the other without wind generation. The commonality of the two systems to be maintained is their ability to serve the same level of demand with the same reliability level. The capacity credit of wind generation in a wind-thermal or in a wind-hydro-thermal system is evaluated by first assessing the overall adequate capacity levels in these systems.

### 2.6.1 Wind capacity credit in wind-thermal system

The system is first modelled without the generation technology for which the capacity credit is pretended to be evaluated, i.e. wind generation. Thus, the starting point is to determine the amount of thermal generation capacity that is adequate to supply a given demand with a desired level of LOLE. Wind generation is then added to the system and the generation adequacy evaluation model is re-run for the same demand. This provides the new thermal capacity in the wind-thermal system that provides the same level of LOLE as in the only thermal based system. The difference in the total amount of thermal capacity between the thermal system alone and the wind-thermal system represents the capacity credit of wind generation in the wind-thermal system. The capacity credit of wind '$W_{CC}$' is generally expressed in percentage terms as the ratio of the thermal capacity displaced by wind generation and the wind capacity in the system.

### 2.6.2 Wind capacity credit in wind-hydro-thermal system

Wind capacity credit in wind-hydro-thermal systems represents the difference in the thermal capacity requirements between hydro-thermal and wind-hydro-thermal systems. Using the dispatch model and COPT the amount of thermal capacity necessary to supply a given demand with desired level of LOLE in both hydro-thermal and wind-hydro-thermal systems is determined. The difference in the thermal capacity requirement between the two systems is the capacity credit of wind generation in the wind-hydro-thermal system.

$$W_{CC_{WHT}} = \frac{C_{HT}^{th} - C_{WHT}^{th}}{C_{WHT}^{wd}} \tag{2.24}$$

Where '$W_{CCWHT}$' is the wind capacity credit in the wind-hydro-thermal system, '$C_{HT}^{th}$' and '$C_{WHT}^{th}$' are the thermal capacity requirements in hydro-thermal system and wind-hydro-thermal system respectively and '$C_{WHT}^{wd}$' is the installed wind capacity in the wind-hydro-thermal system.

### 2.6.3 Additional capacity credit of wind due to hydro generation

The energy storage capability of hydro generation can be used to manage the variability in wind generation output. Earlier work (Shakoor, 2005) indicates that low or no availability of wind power during peak demand days significantly reduces the capacity credit of wind power, reducing it to more than half the annual value if no wind power is available for about five days during peak demand period of the year. During periods of high wind power output, hydro output levels can be reduced and hydro energy stored for later use during periods of low/no wind output or during peak demand. Therefore, the presence of hydro generation enhances the capacity value of wind generation and reduces the amount of thermal capacity that would be required to maintain system security.

In order to quantify the benefit of the presence of the hydro generation in the system, the capacity credit of wind generation is determined in both the wind-thermal and wind-hydro-thermal systems. The difference of these two indicates the overall capacity benefit (added value) due to the presence of hydro generation in the system. For the purposes of simplicity, in this work the overall advantage of wind, hydro and thermal coordination has been attributed to wind power.

## 2.7 Evaluation of the additional system capacity costs attributed to wind generation

Although wind generation will displace a significant amount of energy produced by conventional plant, its ability to displace capacity of conventional generation will be limited. This is important as systems with significant wind penetration generally need

some form of capacity, either conventional plant or any alternative backup option such as energy storage or responsive demand, to ensure that the security of supply is maintained at peak demand times. Due to the disproportion in the displacement of capacity and energy in a system by wind, additional system capacity costs incur which are attributed to wind generation. The key source of these costs is the impact on the utilisation of the retained plant in the system required to maintain system security.

The methodology used to quantify the additional system capacity costs attributed to wind power, developed by (Strbac and Shakoor, 2006), assesses the ratio of capacity and energy that is displaced by a secondary technology (e.g. wind power) as it penetrates into an incumbent system. The disproportion between the capacity and energy that is displaced by wind power is the cause of these additional capacity costs. Therefore, the additional system costs are dependent upon the characteristics of the incumbent system to which wind power is being added. The additional capacity costs attributed to wind power are determined using the following formulation:

$$\Delta C_{Sec} = \left(1 - \frac{D_{Pr}^{C}}{D_{Pr}^{E}}\right) \cdot C_{Pr}^{I_0} \tag{2.25}$$

Where '$\Delta C_{Sec}$' additional per-unit system costs of secondary technology; '$D_{Pr}{}^{C}$' is the percentage displaced capacity of primary technology (due to penetration of secondary technology); '$D_{Pr}{}^{E}$' is the percentage displaced energy of primary technology (due to penetration of secondary technology); and '$C_{Pr}{}^{I0}$' is the per-unit cost of capacity of primary generation technology (£/MWh) in the original system when supplied with the primary technology only.

In order to provide a like-for-like comparison, these additional capacity costs due to wind are then compared with the corresponding costs of a thermal substitute. The additional capacity costs for wind generation are then expressed as the difference between the wind and thermal augmented systems.

### 2.7.1 Additional capacity costs in wind-thermal systems

Having assessed the capacity credit of wind power for a specific level of wind penetration in the wind-thermal system, the additional capacity cost attributed to wind

power is determined by the application of equation (2.25). The percentage displaced capacity of thermal plant due to the penetration of wind power is simply the ratio between the thermal capacity displaced by wind in the wind-thermal system and the thermal capacity requirement in the only thermal based system. The percentage displaced energy of thermal plant due to the penetration of wind power is expressed by the ratio between the energy generated by the wind power plants in the wind-thermal system and the energy produced by thermal power plants (i.e. annual energy demand requirements) in the only thermal based system. The per-unit cost of capacity of thermal generation (£/MWh) in the only thermal based system is simply equal to the annuitised investment capacity cost of the only based thermal system (£/annum) divided by the total annual energy produced (MWh/annum).

### 2.7.2 Additional capacity costs in wind-hydro-thermal systems

The additional capacity costs attributed to wind power are now quantified when wind generation is added to the hydro-thermal system. The penetration of wind generation into the incumbent system does not affect the utilisation of the hydro power plants as the system will continue to maximise the use of these zero/very low marginal cost sources. However, the utilisation of thermal plant will be affected by wind as these plants will be required to maintain system reliability at different levels of wind generation besides providing energy. Hence, in the wind-hydro-thermal system the key source of these costs is the impact on the utilisation of the thermal plants retained in the system to maintain system security.

## 2.8 Case study: adequacy and additional cost of generation capacity

### 2.8.1 System description and modelling assumptions

The developed methodology is applied to a system equivalent to New Zealand's electricity systems which depicts a good combination of thermal and hydro generation with an expected rapid deployment of wind power in near future. The brief description of the system considered and the range of various parameters studied are given in Table 2-1.

**Table 2-1: System description**

| |
|---|
| **System Demand:**<br>Peak demand: 8400MW<br>Electricity demand: 53TWh |
| **Thermal Generation (generic plants):**<br>Unit size: 100MW<br>Unit availability: 85% (FOR = 15%) |
| **Wind Generation:**<br>Penetration level (% of energy demand): 5% to 30%<br>Load factor: 30% to 50% |
| **Hydro Generation:**<br>Penetration level (% of energy demand): 10% to 30%<br>Load factor: 60%<br>Hydro conditions: average, dry, wet |
| **System Reliability Level:**<br>LOLE ≤ 4, 8, 12 hours/year |

### Demand

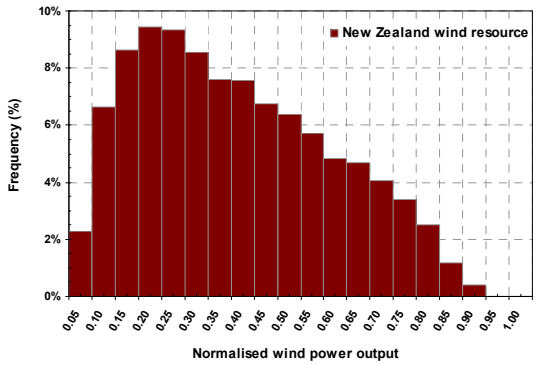
The system demand is modelled as a half-hourly annual load profile based on the historical electricity demand profile data of the NZ, as presented in section 2.4.2.

### Thermal power plants

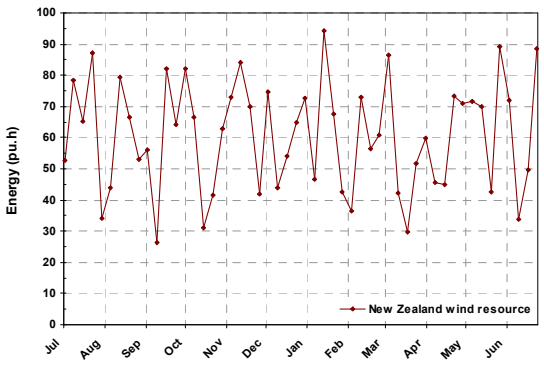
Thermal generation is composed of identical thermal units of generic capacity 100MW each with a forced outage rate (FOR) of 15%. A standard two state operation mode (fully up and fully down) of these units is applied. All generating units are assumed to operate independently. For example, it is assumed that an outage of one generator will not directly affect the operation of the other units in the system.

### Wind power plants

The reliability of the wind generators is assumed to be 100% i.e. these are available all the time. Half-hourly aggregated wind power output profiles representative of various levels of wind penetration in the system are prepared from historical wind data that represent a long-term average wind load factor of 40%. The frequency distribution of such wind profiles as well as their normalised wind energy output per week are presented in Figure 2-4a and Figure 2-4b respectively.




**(a) Frequency distribution of the normalised wind output**




**(b) Normalised wind energy output per week**

**Figure 2-4: Wind power characteristics**

It can be observed in Figure 2-4a that the most likely output level of wind power is between 15%-45% of the installed wind capacity. Figure 2-4b shows that the wind energy output ranges from a minimum of 26pu.h to a maximum of 94pu.h of the installed wind capacity. The annual wind energy is equal to 3,153pu.h of the installed wind capacity. For instance, at 20% wind penetration level, 3GW of installed wind capacity correspond to annual wind energy of 9,459GWh (=3x3,153).

### Hydro power plants

Hydro generators are considered to be fully reliable i.e. these are assumed to be available all the time and constrained only by their rated capacities and available hydro energy. The hydro inflow energy available per week is obtained from historical data for the different (dry, average, wet) hydro conditions in NZ as illustrated in Figure 2-5.

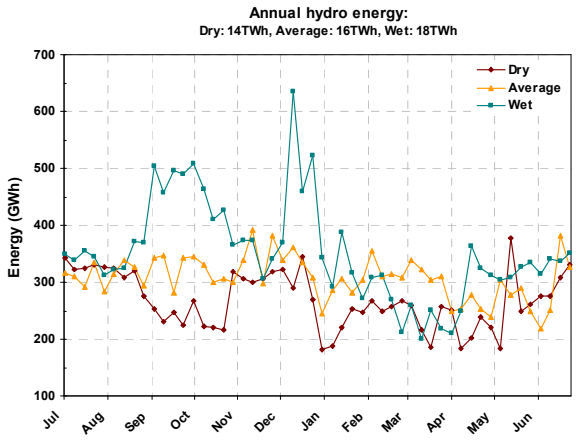



**Figure 2-5: Available hydro energy per week**

It can be seen in Figure 2-5 that different hydro conditions can lead to about ±25% variation in the annual hydro energy.

### System reliability level

The adequacy assessment of the generation capacity applies a reliability standard of LOLE ≤ 8 hours/year to determine the adequate capacity level in the system. Similar standards are exercised in power systems such as France (LOLE: 3 hours/year) (RTE, 2007) and republic of Ireland (LOLE: 8 hours/year) (EirGrid, 2007). Reliability standard of LOLE ≤ 4 hours/year and 12 hours/year are also used in the study to assess their impact on the capacity value of wind generation.

### Capacity credit of wind generation

The capacity benefit due to wind-hydro coordination in the system has been attributed to wind generation. This assumes that the hydro generation displaces the same amount of thermal capacity in hydro-thermal and wind-hydro-thermal systems.

### Additional capacity cost attributed to wind generation

In the additional capacity cost assessment, the thermal plant used for comparisons are assumed to operate as base load plant with a load factor of 85% and has a 100% capacity credit.

### 2.8.2 Thermal system

The developed methodology is employed to calculate the amount of thermal capacity necessary to meet the system load (shown in Table 2-1) with a loss of load expectation (LOLE) of 8 hours/year. Starting with an initial estimate of thermal capacity requirement (higher than the system peak demand) the optimisation model developed for generation dispatch optimally allocates the thermal generation during each time period of analysis to meet demand. In an only thermal based generation system this equals the load requirement in each period. This thermal dispatch in each time period is then combined with the COPT of the thermal capacity considered in the system to determine the LOLP in the corresponding period.

For a given thermal capacity of a system, the COPT describes the likelihood of having a certain certain level of generating capacity in service. This is shown in Figure 2-6 for a total installed capacity of 10.3GW.

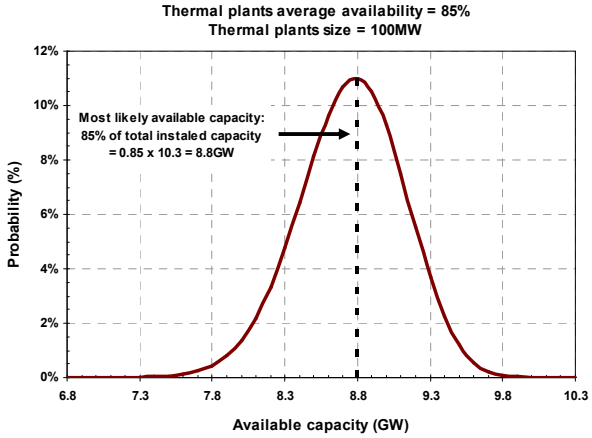



**Figure 2-6: Frequency distribution of the total available capacity**

It can be seen that the most likely combination is to have 88 units in service (85% of 10.3GW). On the other hand, for the same system the probability of having less than 78 units (75% of 10.3GW) or more than 98 units (95% of 10.3GW) in service is very small.

The yearly distribution of LOLP for this system is shown in Figure 2-7. The LOLP is observed to be significant during winter (high demand in New Zealand) season, i.e. from June to August.

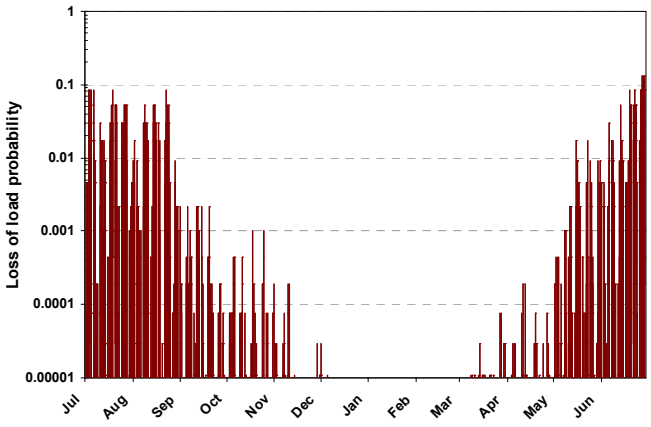



**Figure 2-7: Yearly distribution of LOLP (thermal system)**

The LOLP of all periods is added to determine the annual LOLE. This computed LOLE value was compared with the standard (8 hours/year) level and the thermal capacity was increased (or removed) unless it matches the standard LOLE requirement. This resulted in an overall thermal capacity requirement of 10,300MW.

### 2.8.3 Hydro-thermal system

Hydro generation is introduced to the above thermal system as an aggregated hydro plant with an energy penetration level of 30% (16TWh) representing 3,500MW hydro capacity. The share of the run-of-river energy in the total available annual energy is considered to be 48% (7.7TWh) and is assumed to vary daily but to be constant over each day of the year. The reservoir energy constitutes 52% (8.2TWh) of the total available annual energy and is assumed to vary weekly but to be constant over each week of the year. Also at the beginning of the simulation it was assumed that the reservoir level is at 50% of its total storage capacity. The reservoir capacity of the aggregated hydro plant (in terms of energy of hydro generator's full output) is assumed to be 0.8TWh. The minimum reservoir level is considered to be 10% of its total storage capacity.

The optimisation model allocates hydro and thermal generation during each period (half hour) of the simulation horizon, such that the requirements of thermal capacity in the system are minimised. Such a dispatch for the peak demand week period is depicted in Figure 2-8.

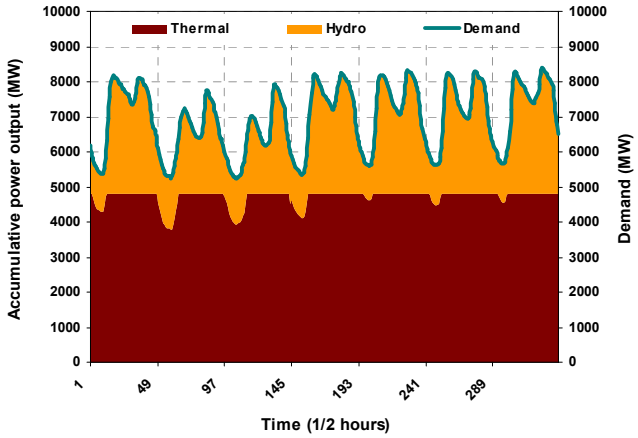



**Figure 2-8: Optimal output of hydro and thermal generation during peak demand week**

During daily peak load periods hydro power can be seen to supply demand. While, during daily off-peak periods the power output from hydro generator reduces to conserve energy for subsequent peak periods while demand is met by thermal generation. It can also be observed that during this peak demand week the total power output of thermal plants remains almost constant (4,800MW) except during some off-peak periods. This is the result of the thermal capacity minimisation process.

In this case, the amount of thermal generation required in the system to serve demand with 8 hours/year LOLE is determined to be 6,100MW. The presence of hydro generation in the system is also found to reduce the risk of loss load during peak demand season as shown in Figure 2-9.

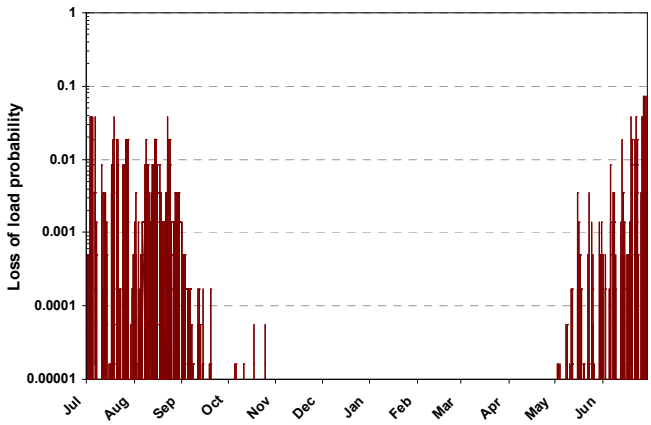



**Figure 2-9: Yearly distribution of LOLP (hydro-thermal system)**

### 2.8.4 Wind-hydro-thermal system

A wind energy penetration level of 20% (wind capacity of 3,000MW) was added to the hydro-thermal system examined in the previous sub-section. To assess the adequate level of total capacity, thermal generation is gradually reduced from the system in order to match the computed LOLE with the target LOLE level (8hours/year). This results in a thermal capacity requirement of 5,100MW to securely meet the same demand in the wind-hydro-thermal system.

A snapshot of the optimal wind-hydro-thermal output for the peak demand week is shown in Figure 2-10. It can be observed that during periods of relatively high wind power output, hydro output is reduced to conserve hydro energy for use during periods of low/no wind output coinciding with high demand periods. It can also be observed that during periods when high wind power output coincides with low demand conditions, the power output from thermal generators can be further reduced.

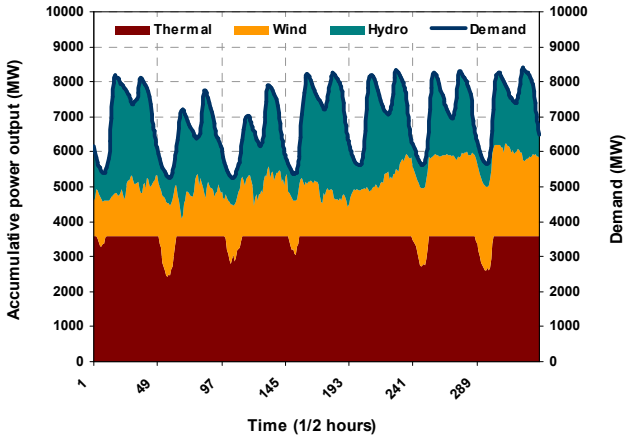



**Figure 2-10: Optimal output of wind, hydro and thermal generation (peak demand week)**

The optimal coordination between wind, hydro and thermal generation also flattens the LOLP distribution across the year as presented in Figure 2-11. The values of LOLP are small and are widely spread through different periods of the year.

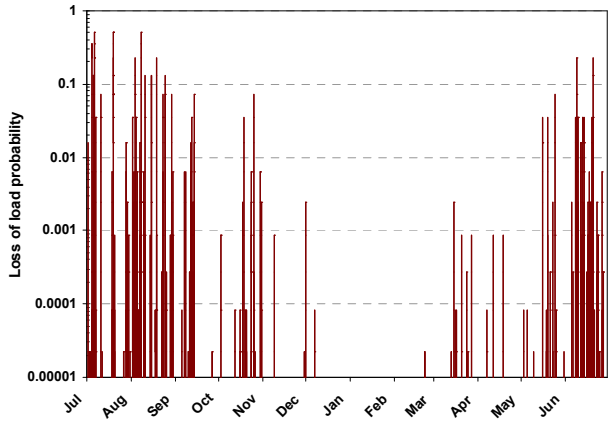



**Figure 2-11: Yearly distribution of LOLP (wind-hydro-thermal system)**

As a result of the above described wind, hydro and thermal output optimization, overall thermal capacity requirements are decreased resulting in enhancing the capacity value of wind generation.

### 2.8.5 Capacity credit of wind generation

Studies were performed to evaluate the capacity adequacy and capacity credit of wind power for various levels of wind penetration in the system. Figure 2-12 shows the capacity credit evaluations for both wind-thermal system and wind-hydro-thermal system.

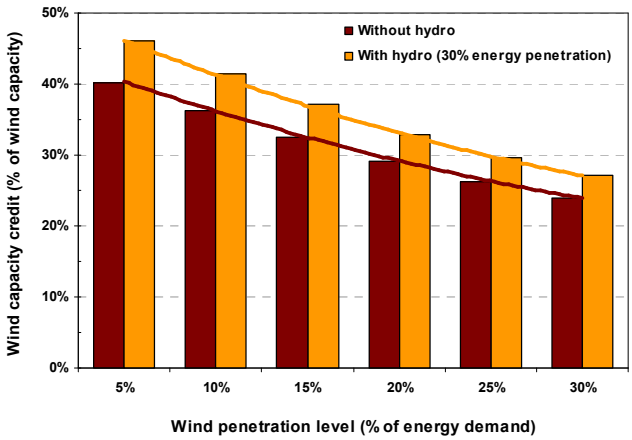



**Figure 2-12: Capacity credit of wind power at various penetration levels of wind**

For both the wind-thermal and wind-hydro-thermal systems at small levels of wind penetration the capacity credit of wind is close to its load factor. But, as the wind penetration in the system increases, its capacity credit tends to decline and saturates.

Figure 2-13 demonstrates that hydro generation in the NZ system will considerably enhance the capacity value of wind. However, the marginal contribution of hydro generation to the capacity credit of wind declines with increasing penetration of wind in the system. This is because, for a given level of hydro plant in the system it will be able to mitigate the wind variability up to a certain extent. If wind variability exceeds the mitigation limits of the hydro reserve available in the system then thermal plant will be required to provide capacity reserve to maintain system reliability. Also during rainy seasons, the hydro capacity reserve may also be limited due to the presence of a large run-of-river component of hydro plant in the system.

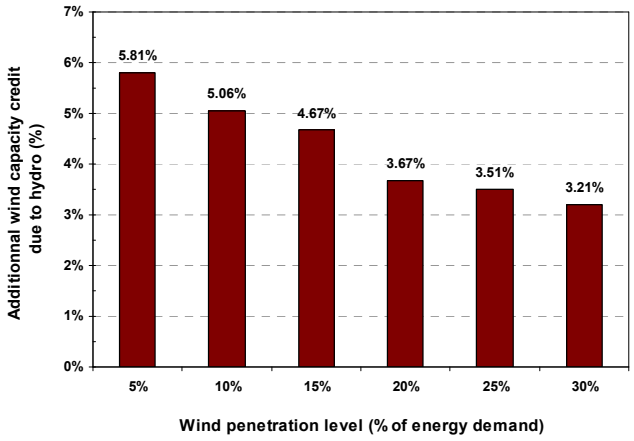



**Figure 2-13: Additional capacity credit of wind due to hydro generation**

### 2.8.6 Additional system capacity costs attributed to wind generation

System capacity costs attributed to wind generation are computed for each wind penetration level as given in Figure 2-14. These costs are expressed in comparison to a thermal plant that will substitute the same amount of energy as wind while operating as a base load plant. For each penetration level of wind the additional costs are expressed as a range. The lower limit of the range correspond to investment cost of 40 £/kW/yr, while the upper value corresponds to higher investment cost of 60 £/kW/yr for the base load thermal plant.

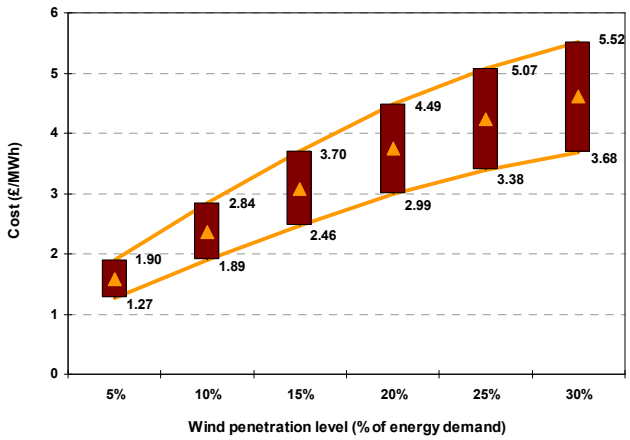



**Figure 2-14: Ranges of additional capacity costs of wind generation**

It is noted that at wind penetration of 5% to 10% the additional capacity costs attributed to wind are considerably lower which increase with further increase in wind penetration to 20% and above. This is mainly due to a significant drop in the capacity credit of wind at its high penetrations.

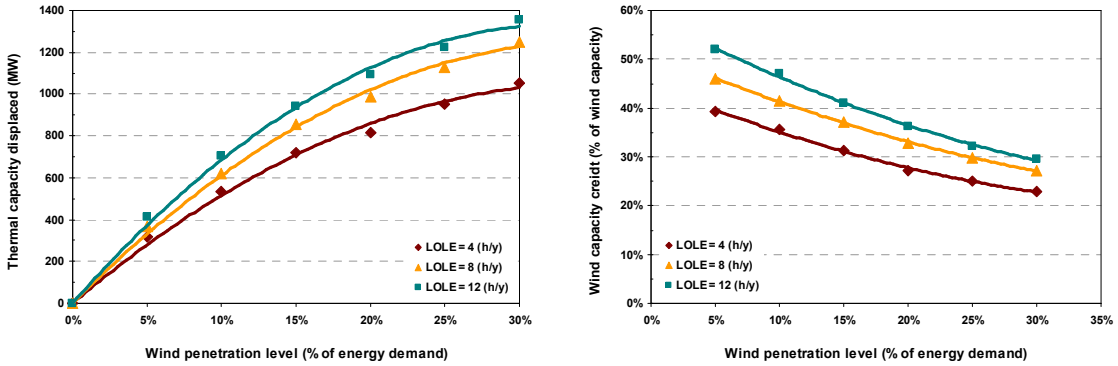
Cost estimates for other countries reveal similar levels. For example, in Great Britain the relevant cost estimates (UKERC, 2006) range between 3 £/MWh to 5 £/MWh corresponding to 5% and 20% wind penetration respectively.

## 2.9 Effect of key factors on capacity contribution of wind generation

The developed methodology is applied to quantify the impact of various key factors on the capacity value of wind generation. The factors studied include system reliability level, wind resource diversity, wind load factor, wind penetration level, hydro penetration level, different hydro conditions and hydro storage size, and are investigated for the same demand system as given in Table 2-1.

### 2.9.1 Effect of the system reliability level

To study the effect of system reliability level on capacity credit of wind generation, studies were performed considering 4 hours/year to 12 hours/year range of the system's reliability criterion, the loss of load expectation (LOLE). Figure 2-15 displays the effect of the elasticity of the system's reliability criterion (LOLE).




**(a) Conventional capacity displacement** **(b) Capacity credit of wind generation**

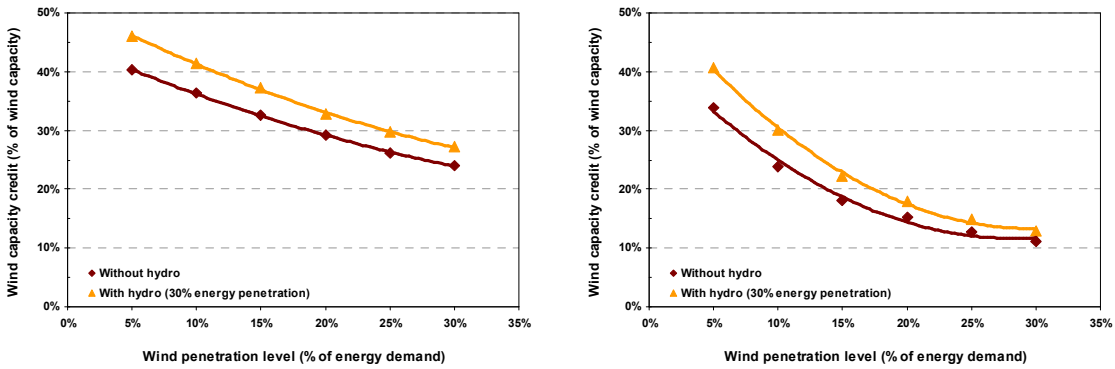
**Figure 2-15: Effect of reliability level on capacity contribution of wind generation**

It can be noted in Figure 2-15a that higher levels of LOLE result in higher risk of loss of supply, the capacity contribution of wind is increased. For example, at 20% wind penetration level increasing LOLE from 4 hours/year to 12 hours/year would result in an additional 300MW displacement of the conventional capacity or an additional 9% capacity credit for wind generation. The calculated capacity credit attributed for various levels of wind generation are shown in Figure 2-15b.

### 2.9.2 Effect of wind resource diversity

In order to study the effect of wind resource diversity on the capacity credit of wind generation two different wind profiles for various penetration levels of wind in the system were prepared. For the diverse wind profile, data is used from wind sites spread across both islands of NZ while for the non-diverse case data from only one island is used that is linearly scaled to represent various levels of wind penetration. In both cases 30% of hydro energy penetration is considered.

The capacity credit of wind determined for the diverse case at various penetration levels of wind is presented in Figure 2-16a while the results for the non-diverse wind are displayed in Figure 2-16b. Clearly diverse wind resource contributes significantly more than the non-diverse case to save thermal capacity.




**(a) Diverse wind resource** **(b) Non-diverse wind resource**

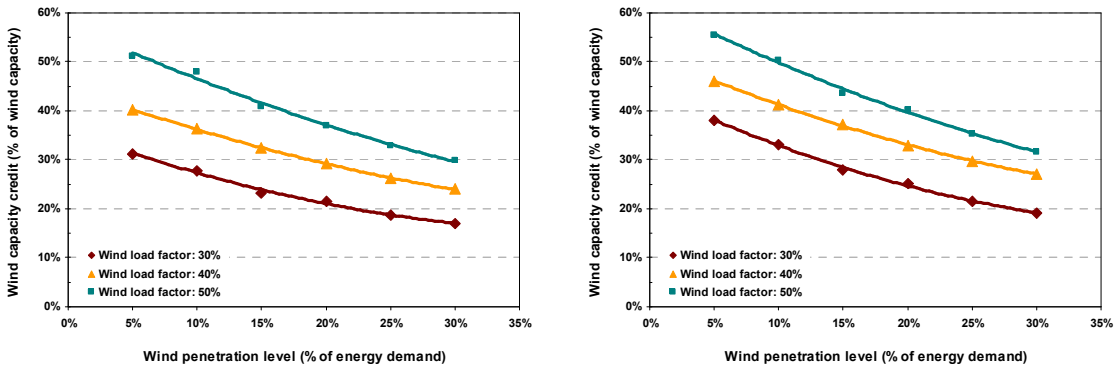
**Figure 2-16: Effect of wind resource diversity on capacity credit of wind generation**

In all subsequent sensitivity studies, wind output profiles representative of a diverse wind resource were used, which is considered a better representation of the generation system under investigation.

### 2.9.3 Effect of load factor of wind generation

The load factor of wind generation represents the average output of all wind farms. In order to analyse the impact of various achievable load factors of wind generation on the capacity credit of wind, studies were performed considering the 30% to 50% range of wind load factor. Half-hourly wind output profiles representing these load factors for different levels of wind penetration in the system are prepared according to the mathematical formulation developed by Shakoor (Shakoor, 2005).

Figure 2-17 presents the capacity credit of wind obtained for different wind load factors and for various levels of wind penetration in the wind-thermal system.




**(a) Wind-thermal system** **(b) Wind-hydro-thermal system**

**Figure 2-17: Effect of wind load factor on capacity credit of wind generation**

Figure 2-17a shows that at lower levels of wind penetration the capacity credit of wind generation equals the corresponding load factor. However, as the level of wind penetration rises, the capacity credit begins to decline and this trend exists for all for the entire load factor range. It was noted that the capacity credit reduces to about half for an increase of wind penetration from 5% to 30% in the wind-thermal system.

The same wind load factor range (30% to 50%) is tested for wind capacity credit evaluation in the wind-hydro-thermal system. It can be seen in Figure 2-17b that at lower wind penetration levels the wind capacity credit is increased by 2 to 6 percentage points for all wind load factors considered. This clearly indicates the effectiveness of the role of hydro generation in enhancing capacity contribution of wind power even in those systems where achievable load factor of wind generation are relatively low. However, at higher levels of wind penetration the presence of hydro generation in the system does not significantly influence the capacity credit for any level of wind load factor.

### 2.9.4 Effect of the amount of hydro generation in the system

In order to analyse the impact of the relative size of hydro and wind generation in the system on capacity credit of wind, different levels of hydro generation in the system are also investigated. For 5% to 30% wind penetration levels, a range of 10% to 30% hydro penetration in the system is examined. Figure 2-18 shows the effect of magnitude of hydro generation in the system on capacity credit of wind generation.

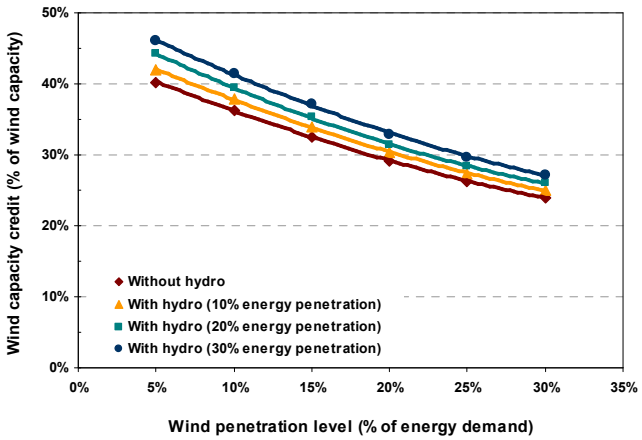



**Figure 2-18: Effect of the magnitude of hydro generation in the system on the capacity credit of wind generation**

Figure 2-18 reveals that at lower levels of wind penetration i.e., up to 20%, changing the amount of hydro generation in the system significantly affects the capacity credit of wind generation. However, as the amount of wind in the system increases the level of hydro presence in the system becomes less effective. Increasing hydro penetration from 10% to 30% at 30% penetration of wind will increase in the capacity credit of wind by 6%. In general, the presence of greater amount of hydro generation in the system results in a larger additional capacity credit benefit for wind generation.

### 2.9.5 Effect of different (dry, average, wet) hydro conditions

The variation of hydro conditions can have a profound effect on the availability of the annual hydro energy in the system. Therefore, sensitivity studies are conducted in order to quantify the effect of dry, average and wet hydro conditions on capacity credit of wind generation and on the capacity credit benefit due to the presence of hydro generation in the system. The capacity credit of wind generation for the different hydro conditions is depicted in Figure 2-19.

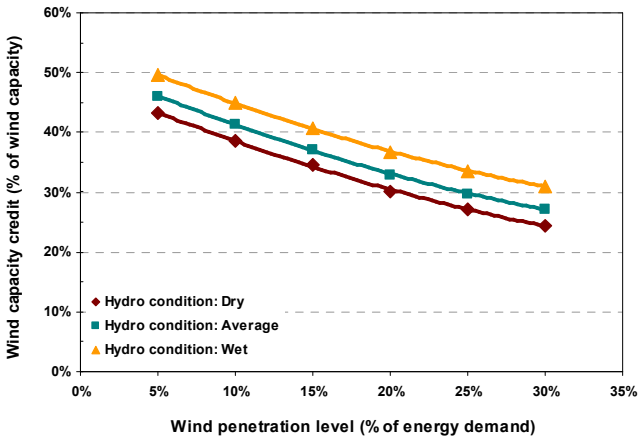



**Figure 2-19: Effect of different (dry, average, wet) hydro conditions on the capacity credit of wind generation**

The effect of the hydro conditions on the additional wind capacity credit due to the presence of hydro generation in presented in Figure 2-20 for 20% wind penetration level.

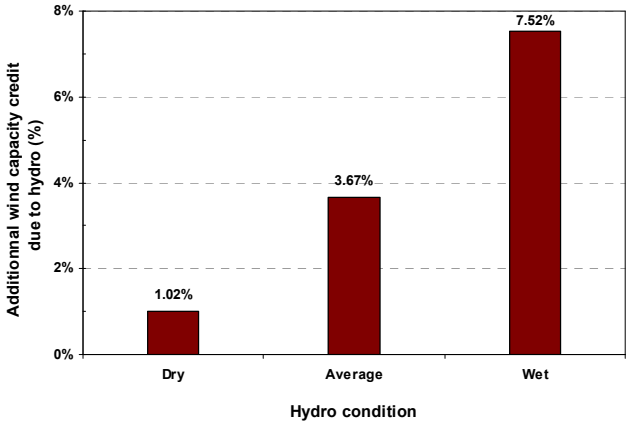



**Figure 2-20: Effect of different (dry, average, wet) hydro conditions on the additional (benefit) capacity credit of wind generation due to hydro generation**

For the case under analysis, the capacity credit gain during the presence of hydro power is more significant at higher levels of availability of the hydro energy.

### 2.9.6 Effect of hydro storage capacity

Another factor influencing the capacity credit of wind generation is the reservoir capacity of the aggregated hydro plant (in energy terms). The effect of the reservoir capacity on the capacity credit benefit due to the presence of hydro generation in the

system was assessed by varying the reservoir capacity from 0% to 10% of the annual hydro energy in the system for a wind penetration level of 20%. This analysis is shown in Figure 2-21 below.

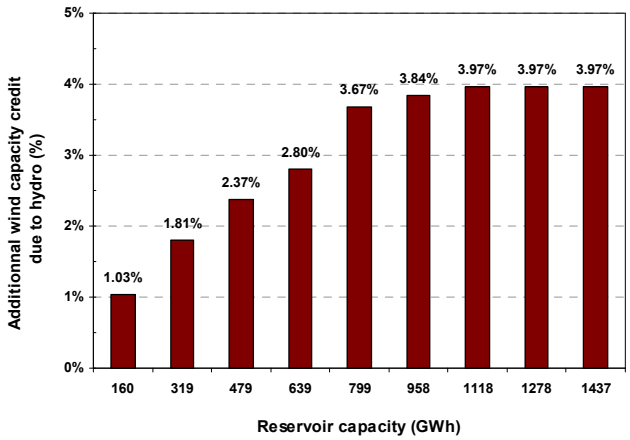



**Figure 2-21: Effect of the reservoir capacity on the additional (benefit) capacity credit of wind generation due to hydro generation**

Figure 2-21 shows that the additional (benefit) capacity credit of wind generation due to the support of hydro is enhanced with the rise of the reservoir capacity. However, the marginal contribution of hydro generation to the capacity credit of wind declines, and saturates, with the rise in the reservoir capacity.

The increase of the reservoir capacity improves the ability of allocating hydro energy during peak demand periods and therefore reduces the amount of thermal plant required in the system. Such behaviour enhances the capacity credit of wind generation translating in an increase of the additional (benefit) capacity credit of wind due to the presence of hydro.

## 2.10 Discussion and conclusions

This chapter presented a new method to compute overall generation capacity adequacy and the capacity credit of wind in wind-hydro-thermal generation systems. The model evaluates the level of the adequate generation capacity in the system based on a reliability criterion of LOLE $\leq$ 8 hours/year. The robustness of the methodology is tested through a set of studies applied on New Zealand equivalent generation system.

The capacity credit of wind generation in the wind-hydro-thermal system is found to range between 46% and 27% for wind penetration of 5% and 30% respectively for a wind load factor of 40%. Relatively high load factor of NZ wind also contributes to higher capacity and energy contribution for a given level of wind penetration. The results demonstrate that the presence of hydro generation in the system considerably enhances the capacity value of wind generation compared to its capacity value in only thermal based systems. The additional (benefit) capacity credit of wind generation due to the support of hydro generation can reach about 6% for low wind penetration. The marginal contribution of hydro generation to the capacity credit of wind declines with increasing penetration of wind in the system.

It is also found that the capacity value of wind is affected by its large variations in a relatively small period of time. This needs increased amounts of capacity reserves and thus reduces its capacity credit at higher penetration. On the other hand the presence of large hydro storage capacity in NZ helps to avoid wind curtailment during periods of high wind output coinciding with low demand and/or high run-of-river hydro yield periods.

Due to relatively high capacity credit of wind generation considered in the studies the disproportion between the amount of capacity and energy displaced by wind power is relatively small. Therefore, the additional capacity costs attributed to wind generation are lower than the thermal based systems. Additional capacity costs attributed to wind generation are found to range between 1.2 £/MWh to 5.5 £/MWh corresponding to 5% and 30% wind penetration respectively.

The application of the developed methodology is further extended to analyse the impact of key factors on the capacity contribution of wind generation. Diversity of wind resource is observed to be a key factor influencing the capacity credit of this source; a rise in diversity level is found to significantly enhance the capacity credit of wind generation compared to a non-diverse wind resource. Also the load factor of wind generation directly influences the capacity credit of this source. Such as; for wind-hydro-thermal system at lower wind penetration levels the wind capacity credit increases by 2 to 6 percentage points for all wind load factors considered.

Hydro power characteristics also impact the overall system adequacy and the capacity credit of wind generation in wind-hydro-thermal systems. The hydro penetration level is perceived to be a factor influencing the capacity value of wind. Thus, increasing hydro penetration level from 10% to 30% at 30% penetration of wind will increase the capacity credit of wind by 2%. In general, presence of greater amount of hydro generation in the system results in larger additional capacity credit benefit for wind generation. Different hydro conditions (dry, average, and wet), that influence the availability of annual hydro energy leading to affect the capacity credit of wind generation. In general, the presence of a greater amount of available hydro energy (during wet hydro conditions compared to dry hydro conditions) in the system results in a larger capacity credit of wind generation (on average, 6% growth) at all levels of wind penetration considered. This also results in larger additional capacity credit benefits for wind generation. Another factor found to affect the capacity credit of wind generation in wind-hydro-thermal systems is hydro storage capacity. The analysis demonstrates that the additional (benefit) capacity credit of wind generation due to the support of hydro is enhanced with the rise of the reservoir capacity. However, the marginal contribution of hydro generation to the capacity credit of wind declines, leading to saturate, with the rise in the reservoir capacity.

This chapter has evaluated the generation capacity adequacy of a system and capacity value of wind generation considering single busbar model. However, the same methodology is further enhanced in the next chapter for application on interconnected wind-hydro-thermal systems. The adequacy of generating capacity in a power system is normally improved by interconnecting the system to another power system. This demands more elaborated methods to analyse the generation capacity adequacy of interconnected wind-hydro-thermal systems, as well as the impact of the interconnector on the capacity adequacy. The next chapter applies a detailed analytical method to compute the overall and regional generation capacity adequacy of interconnected wind-hydro-thermal systems.

# Chapter 3

# Capacity adequacy and capacity credit of wind generation in interconnected systems with hydro generation

## 3.1 Introduction

In interconnected systems, interconnectors play a vital role in maintaining the supply and demand balance. The presence of interconnectors between systems allows the participating systems to be able to receive additional generation from others with available reserve capacities should its own generation be unable to meet the load demand. Mutual support will be available because of the diversity of loads and unit failures, and as a consequence, the reliability of systems with interconnectors to other systems will be higher than without such interconnections. In future systems with substantial amount of wind, the presence of interconnectors could play a major role in mitigating the increased risk of security of supply due to wind power. This necessitates investigating the potential role of interconnectors in maintaining the risk of supply at an appropriate level in systems with a large wind penetration. Such an investigation would be able to answer how the interconnectors can help to improve the reliability performance of the overall system.

This chapter takes on this challenge by first developing a methodology to quantify the overall system's capacity adequacy and capacity credit of wind generation in interconnected wind-hydro-thermal systems.

Although a considerable amount of work has been done on the adequacy and reliability assessment of interconnected systems, these existing techniques are directed towards systems dominated by conventional generation technologies (Billinton and Harrighton 1978; Silva, 1991; Malik, 2004). However, the inherent characteristics of wind power generation coupled with hydro power demand new approaches in evaluating the future system's reliability and the role of the interconnectors on the reliability performance of the overall system.

Probabilistic behaviour of wind and hydro generation have been considered by Matos et al. (Matos et al., 2008) on the evaluation of the reserve requirements (both capacity analysis and operating reserves) of two interconnected generation systems to ensure an adequate supply. This work assesses the behaviour of the reliability indices (conventional and well-being) when a major portion of the energy sources is renewable, mainly hydro and wind. Nonetheless this work does not provide evidence on the role of the interconnector in improving the reliability performance of the interconnected system.

The developed methodology is applied on the New Zealand equivalent system and evaluates the ability of the generation system to meet demand with a desired level of system security under various levels of the power transfer capability of the interconnectors between its two Islands. Sensitivity of the risk indices (e.g. LOLE) to various interconnector parameters and different levels of system reliability at increased levels of wind penetration is determined. Impact of various characteristics of wind power such as the penetration level and resource diversity on risk of supply is evaluated. Furthermore, the influence of the different hydro conditions (dry, average, wet) on the magnitude of the overall capacity requirement in the power system is analysed.

## 3.2 Capacity adequacy of interconnected thermal systems

The following sections present the developed methodology to quantify the overall system's capacity adequacy and capacity credit of wind generation in interconnected wind-hydro-thermal systems. The methodology to assess the adequacy of generation capacity was developed in three distinct phases. Initially the methodology is described for an entirely thermal based interconnected generation system. Hydro generation was then introduced to the thermal system and finally wind generation was added to achieve a combined interconnected wind-hydro-thermal system.

The reliability criterion applied in this analysis is the Loss of Load Expectation (LOLE) which is defined as the number of hours per year when load is expected to exceed the available generation. The developed capacity adequacy model is also able to evaluate Expected Energy Not Supplied (EENS) as a reliability index; however, the more widely applied LOLE criterion is used in the studies.

### 3.2.1 Capacity model

The generation system model is based upon Markov model and assumes statistically independent, stationary and exponential distribution of the failure and repair time of the generating units. The capacity model was created using the recursive algorithm presented by Billinton and Allan (Billinton and Allan, 1984) and computes the probability or long-term availability of various capacity states of the system. The collection of all possible capacity states of the system expressed in the form of capacity outage states, and the associated probabilities are termed as the capacity outage probability table (COPT). Details of this model, including the mathematical formulation, were presented in Chapter 2, section 2.4.1.

### 3.2.2 Load system representation

The load model constitutes a time series of half-hourly peak loads '$L_t$' over a one year time horizon '$T$'. The load system used is based upon the half-hourly electricity demand profile of New Zealand's North and South Islands. The details of this model were presented in Chapter 2, section 2.4.2.

### 3.2.3 Reserve capacity model

System reserve capacity states are computed for each time period '$t$', by describing the conditions of generating capacity in excess of, or lower than the load by convolution of the above mentioned capacity and load models. All generation capacity states are combined with the load statistics to compute the probability of the occurrence of various system reserve capacity conditions designated as reserve margin states during each time period '$t$'. A negative margin represents a state in which the system load exceeds the available capacity and depicts a system failure situation.

### 3.2.4 Reserve capacity model of interconnected thermal systems

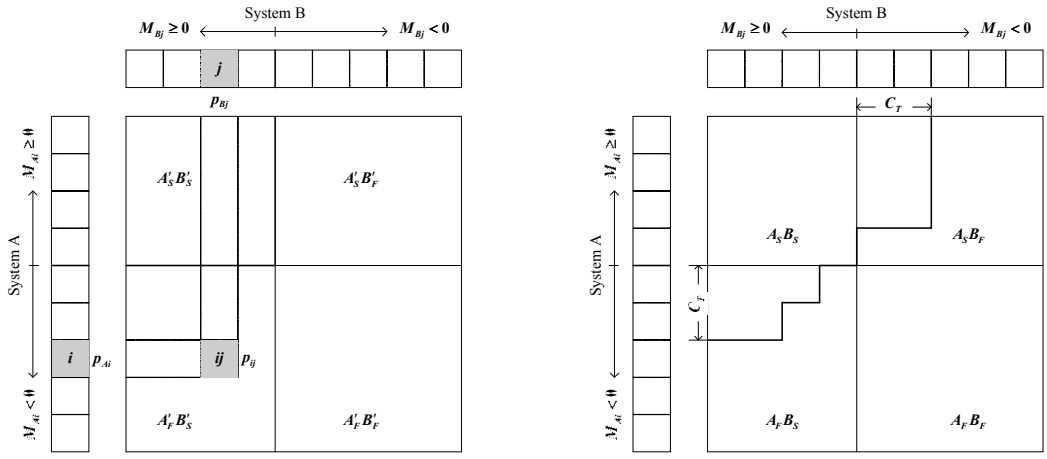
Two interconnected systems, A and B, are considered with the assumption that the load and capacity models in each system are statistically independent. In addition, the following assumptions are made in the model.

– The load models in each system are statistically independent of each other.

– Each system is willing to deplete its own available reserve capacity to assist the other.

– Type of agreement: losses of load are not shared by the systems. In other words, each system will assist the other only as long as it can afford it, and will reduce or halt the assistance if its own needs require such action.

The reserve capacity model of each of the interconnected systems can be combined to represent a two-dimensional probability matrix covering all the possible combinations of reserve capacities in the two systems. The combined reserve capacity states and respective probabilities of the both interconnected systems can be grouped in the form of a table denominated as the 'interconnected system capacity probability table' (ISCPT). This representation can be modified by including the transmission line constraints (line capacity and its FOR). The possible states of the two systems, when there is no interconnection between the systems, and for the case where the systems are interconnected by a transmission line of capacity $C_T$, are illustrated in Figure 3-1 with the help of a combined-state diagram. In the combined-state diagram four areas are discernible, denoted by $A'_S B'_S$, $A'_S B'_F$, $A'_F B'_S$ and $A'_F B'_F$. The primes indicate that in the given case there is no interconnection between the two systems, otherwise the notations are self-explanatory.




**(a) No transmission line** **(b) Transmission line capacity limited to $C_T$**

**Figure 3-1: Combined states of systems A and B (S – success, F – failure)**

If the probability of the *i*th margin state for system A, with a margin $M_{Ai}$, is $p_{Ai}$, and that of the *j*th margin state for system B, with a margin of $M_{Bj}$, is $p_{Bj}$, the probability $p_{ij}$ of the corresponding combined state *ij* is given by the product of $p_{Ai}$ and $p_{Bj}$. This reflects the assumption that both the generation and load models for both systems are independent. The probability of any combined event (e.g. domain $A_S B_S$) equals to the sum of the state probabilities, $p_{ij}$, for the states in the appropriate domain.

To present the effect of the interconnection on system A consider a generic single state *ij* with probability $p_{ij}$; the generating reserve margin for system A in the state, $M_{Aij}$, when a transmission line of finite capacity is in operation, can be computed as the sum of the *i*th margin state for system A and the maximal assistance available from system B, $h_{Bi}$. The maximal assistance available from system B, $h_{Bi}$, is provided by:

$$h_{Bj} = \begin{cases} C_T & if \quad M_{Bi} > C_T \\ M_{Bi} & if \quad 0 \le M_{Bi} \le C_T \\ 0 & if \quad M_{Bi} < 0 \end{cases} \tag{3.1}$$

Equation (3.1) is valid, of course, if the two systems are interconnected. Without transmission line, $h_{Bj} = 0$ and $M_{Aij} = M_{Ai}$. Note that $h_{Bj}$ is never negative whereas both $M_{Ai}$ and $M_{Aij}$ can be. A similar procedure can be followed for system B.

### 3.2.5 Interconnector representation

Systems may be interconnected by several transmission lines, each of which is characterised by a specific rating capacity and an availability less than unit. The capacity model of the transmission network is built applying the COPT methodology (Chapter 2, section 2.4.1). Each possible combination of lines in either fully up or down state defines a capacity state of the transmission system. The resulting states are characterised by their available capacity and associated probabilities.

For the considered electricity system (equivalent to New Zealand system), the inter-Island power transfer capability is limited by a maximum level of flow in either direction. Thus the North-South flow and the South-North flow can be expressed as percentage of the total inter-Island power transfer capability.

### 3.2.6 Computation of risk indices

**Loss of load expectation (LOLE)**

A loss of load in a single node system occurs when the available capacity cannot meet the load demand. In the case of interconnected systems, the capacity deficiency in one system may be compensated by the available support for other systems. This support depends on the available reserve capacity in the other system, the interconnection limitations and the type of agreement between the two systems.

A loss of load situation is considered to arise in one system when the available support through the interconnector cannot offset the capacity deficiency arising due to the capacity outages and/or load conditions in that system. The loss of load situations in each system are determined from the simultaneous capacity outage conditions in combination with the respective systems peak loads (corresponding to the negative reserve margin states) and the support available through the interconnector.

For each half hour time slot '*t*' three loss of load probability (LOLP) values can be computed, one for each of the two separate systems and one for the interconnected system as a whole. The computation of LOLP takes into account not only the limited capacity of the transmission line, but also the probability of failure of the transmission line. Let the availability of the transmission line be $p_t$, and its unavailability $\overline{p}_t$. Using the two-dimensional probability matrix and the conditional probability rule, the risk indices are expressed as follows:

$$LOLP_{System\ A} = p_T \left( \sum_{A_F B_S} p_{ij} + \sum_{A_F B_F} p_{ij} \right) + \overline{p}_T \left( \sum_{A'_F B'_S} p_{ij} + \sum_{A'_F B'_F} p_{ij} \right) \tag{3.2}$$

$$LOLP_{System\ B} = p_T \left( \sum_{A_S B_F} p_{ij} + \sum_{A_F B_F} p_{ij} \right) + \overline{p}_T \left( \sum_{A'_S B'_F} p_{ij} + \sum_{A'_F B'_F} p_{ij} \right) \tag{3.3}$$

$$LOLP_{System} = LOLP_{System\ A} + LOLP_{System\ B} - \sum_{A_F B_F} p_{ij} \tag{3.4}$$

The annual loss of load expectation (LOLE in hours/year) is then determined by summing the LOLP values of each half hour period of the year in each system '*i*' as given by equation (3.5).

$$LOLE_i = \frac{1}{2}\sum_{t=1}^{T} LOLP_{i_t} \tag{3.5}$$

The regional and overall system capacity adequacy of interconnected systems is determined through computation of the annual LOLE.

#### Expected energy not supplied (EENS)

A loss of load situation is associated with load curtailment due to deficiencies in the generation system. In the interconnected system capacity probability table, load curtailment occurs in every negative reserve capacity margin state of the system '*k*', $M_{kij}$. The system's '*k*' load curtailed is then defined as the cumulative sum of all negative reserve capacity margin states $M_{kij}$. The expected load curtailed (ELC) expressed in MW can be computed as follows:

$$ELC_{System\ A} = p_T\left(\sum_{A_F B_S} M_{Aij}\cdot p_{ij} + \sum_{A_F B_F} M_{Aij}\cdot p_{ij}\right) + \overline{p}_T\left(\sum_{A'_F B'_S} M_{Aij}\cdot p_{ij} + \sum_{A'_F B'_F} M_{Aij}\cdot p_{ij}\right) \tag{3.6}$$

$$ELC_{System\ B} = p_T\left(\sum_{A_S B_F} M_{Bij}\cdot p_{ij} + \sum_{A_F B_F} M_{Bij}\cdot p_{ij}\right) + \overline{p}_T\left(\sum_{A'_S B'_F} M_{Bij}\cdot p_{ij} + \sum_{A'_F B'_F} M_{Bij}\cdot p_{ij}\right) \tag{3.7}$$

$$ELC_{System} = ELC_{System\ A} + ELC_{System\ B} \tag{3.8}$$

The annual expected energy not supplied (EENS in MWh) is then determined by summing up the expected load curtailed (ELC) values of each half hour period of the year for each system '*k*', as given by equation (3.9).

$$EENS_k = \frac{1}{2}\sum_{t=1}^{T} ELC_{k_t} \tag{3.9}$$

## 3.3 Capacity adequacy of interconnected wind-hydro-thermal systems

The methodology described in section 3.2 for evaluating the capacity adequacy of interconnected thermal systems is extended for interconnected systems having wind, hydro and thermal generation.

The linear programming based optimisation model for generation dispatch developed (Chapter 2, section 2.5.1) is enhanced to include the presence of the interconnector. It optimally dispatches the wind, hydro and thermal generation, in both regions, during each time period of the simulation horizon such that the requirements of thermal capacity in the system are minimised. The optimisation includes several constraints including the production of wind, hydro and thermal power plants and interconnector.

The interconnected system capacity probability table (ISCPT) is determined in the same way as explained earlier for the interconnected thermal system alone. The optimal thermal generation dispatch and reserve hydro capacity obtained from the dispatch model for the two regions are then combined with the ISCPT to evaluate the system's reliability (LOLE) as described in section 3.2.6.

The adequacy of the overall system capacity is finally assessed by comparing computed LOLE with the LOLE standard. The thermal capacity is iteratively added (or removed) followed by recalculation of the LOLE until the required reliability level is attained.

A schematic representation of the capacity adequacy assessment model for interconnected wind-hydro-thermal systems is elaborated in Figure 3-2.

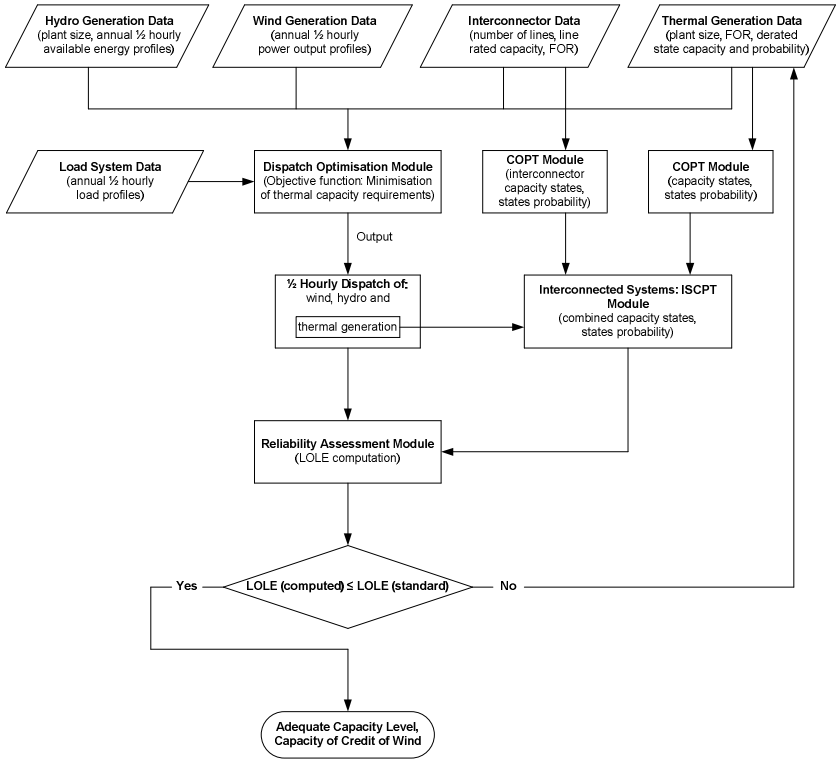



**Figure 3-2: Capacity adequacy model in interconnected wind-hydro-thermal systems**

### 3.3.1 Optimisation model: generation dispatch of interconnected systems

For two interconnected systems having wind, hydro and thermal generation the linear programming based optimisation model for generation dispatch (Chapter 2, section 2.5.1) is extended to include the presence of the interconnector. Two new constraints are added to the problem. These, represent the power flow across the interconnector and the limits on this flow through the interconnector.

#### Interconnector

In order to determine the power flow across the interconnector, the power output from all generators in each time period '$t$' for one of the regions '$k$' is subtracted from the demand in the same time period for the same region, as represented by equation (3.10).

$$\left[\sum_{i=1}^{I} P_{i,k}^{th}(t)\right]+\left[\sum_{h=1}^{H} P_{h,k}^{hd}(t)\right]+\left[\sum_{w=1}^{W} P_{w,k}^{wd}(t)\right]-d_k(t)=F_k(t), \quad \forall k \in K,\ \forall t \in T \qquad (3.10)$$

Where '$F_k(t)$' is the power flow across the interconnector from region '$k$' in time period '$t$', and '$d_k(t)$' is the load demand in region '$k$' during time period '$t$'.

The level of the power flow across the interconnector is constrained in each time period '$t$' by the maximum allowed power flow (interconnectors' rated capacity) from region '$j$' to region '$i$' '$F_{ji}^{max}$', and by the maximum allowed power flow from region '$i$' to region '$j$' '$F_{ij}^{max}$' according to equation (3.11).

$$-F_{ji}^{max} \le F_k(t) \le F_{ij}^{max}, \quad \forall k \in K, \ \forall t \in T \tag{3.11}$$

### 3.3.2 Thermal capacity requirements in interconnected wind-hydro-thermal systems

First, the thermal capacity requirement to meet a given demand considering only a thermal based system using its ISCPT and annual LOLE requirements is determined by applying the approach described in section 3.2.

Subsequently, given quantities of wind and hydro power are added to the same system and thermal power output in each time period is assessed by applying the LP dispatch model explained in the previous sub-section. The half-hourly thermal power output obtained from the model for the two interconnected systems is then combined with the interconnected system capacity probability table of the thermal capacity considered in the interconnected systems and the annual value of LOLE is computed. This generally results in a significantly low level of LOLE. Therefore, thermal capacity is gradually reduced from the region with the lowest LOLE, new reserve capacity model of the two interconnected systems is prepared and LOLE is computed again. This process is repeated until the amount of thermal capacity in the system, in combination with given wind and hydro capacities, provides the required level of LOLE.

## 3.4 Case study: capacity adequacy of interconnected systems

The developed methodology is applied to a system equivalent to New Zealand's electricity system. The NZ electricity system is divided into two Islands i.e., North and South Islands, connected trough a HVDC link. Figure 3-3 depicts a schematic

representation of the two interconnected Islands and the location of the future wind farms.




**Figure 3-3: Map of New Zealand with locations of wind farms representative of the future wind generation scenarios**

### 3.4.1 System description and modelling assumptions

This section outlines the different generation and demand scenarios that are investigated in this work. The scenarios were selected to represent a broad range of the potential energy contribution from wind generation to meet demand for electricity over several time frames: namely the 2010, 2020, and 2030 July-June years. These generation scenarios correspond to the projected demand of the year 2010, 2020 and 2030 as summarised in Table 3-1.

There are two main bases for classification of these scenarios. The first deals with the spatial distribution of wind across New Zealand which is followed by different penetration levels of wind in three future time frames (2010, 2020, and 2030). The spatial distribution based classification is termed as ‘Reference’ and ‘Southland’ scenarios while their sub classification is named according to the respective year in the future.

**Table 3-1: Summary of generation development scenarios**

| Scenario/Year | Scenario Variants | North Island | | South Island | | New Zealand | |
|---|---|---|---|---|---|---|---|
| | | MW | TWh | MW | TWh | MW | TWh |
| 2010 | Demand | 4842 | 29 | 2455 | 17.1 | 7297 | 46.1 |
| | Wind | 423 | 1.7 | 202 | 0.6 | 634 | 2.1 |
| | Wind load factor (%) | - | 43.8% | - | 35.9% | - | 41.3% |
| | Wind (energy) penetration (%) | - | 5.9% | - | 3.5% | - | 4.5% |
| | Hydro (dry conditions) | 1873 | 6.9 | 3557 | 17.9 | 5430 | 24.8 |
| | Thermal generation | 3650 | - | 37 | - | 3687 | - |
| 2020 | Demand | 5600 | 33.7 | 2850 | 19.9 | 8450 | 53.6 |
| | Wind | 1434 | 4.9 | 631 | 1.8 | 2065 | 6.7 |
| | Wind load factor (%) | - | 39.2% | - | 33.1% | - | 37.3% |
| | Wind (energy) penetration (%) | - | 15.5% | - | 9% | - | 12.5% |
| | Hydro (dry conditions) | 1873 | 6.9 | 3557 | 17.9 | 5430 | 24.8 |
| | Thermal generation | 3850 | - | 37 | - | 3887 | - |
| 2030 | Demand | 6273 | 38 | 3197 | 22.4 | 9470 | 60.5 |
| | Wind | 2225 | 7.4 | 1196 | 3.3 | 3421 | 10.7 |
| | Wind load factor (%) | - | 38.5% | - | 32.2% | - | 36.3% |
| | Wind (energy) penetration (%) | - | 19.5% | - | 14.7% | - | 17.7% |
| | Hydro (dry conditions) | 1873 | 6.9 | 3557 | 17.9 | 5430 | 24.8 |
| | Thermal generation | 4150 | - | 37 | - | 4187 | - |

It can be observed from Table 3-1 that the bulk of the existing hydro resource in New Zealand is located in the South Island while the majority of the demand is in the North Island. Thus the South Island has more generation capacity connected to transmission than demand, so transmission power flows are south-north (to demand centres in the North Island). The integration of wind generation capacity into the system will impact the transmission network and in particular the interconnector. The challenge is to understand these impacts of wind on the main interconnector, and then to use this understanding of the physical system to determine the adequacy of these two interconnected systems.

The three main wind scenarios, termed as the Reference scenarios, are analysed for determination of the adequate generation capacity in the system. The capacity value and associated capacity costs attributed to wind generation are then evaluated in each of these scenarios.

### Demand

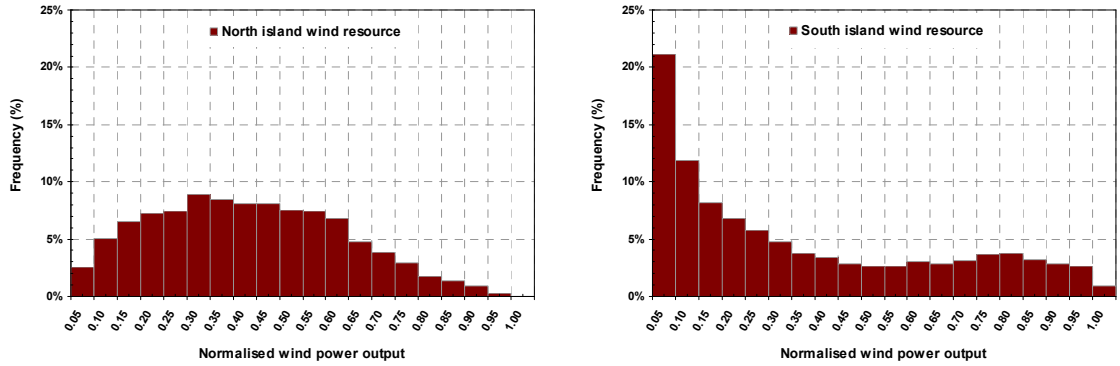
The system demand is modelled as a half-hourly annual load profile based on historical demand data of the North and South Islands. (Chapter 2, section 2.4.2)

### Thermal power plants

Thermal generation is modelled as identical thermal units of generic capacity of 200MW in the North Island and 100MW in the South Island. Each of the generic thermal units has a forced outage rate (FOR) of 15%. A standard two state operation mode (fully up and fully down) of these units is applied. All generating units are assumed to operate independently. For example, it is assumed that an outage of one generator would not directly affect the risk of failure of the other units in the system.

### Wind power plants

The reliability of the wind generators is assumed to be 100% i.e. these are available all the time. Half-hourly aggregated wind power output profiles representative of the levels of wind penetration for each Reference scenario are prepared from historical wind data. The frequency distribution of such wind profiles for the scenario 2030 are presented in Figure 3-4.




**(a) North Island** **(b) South Island**

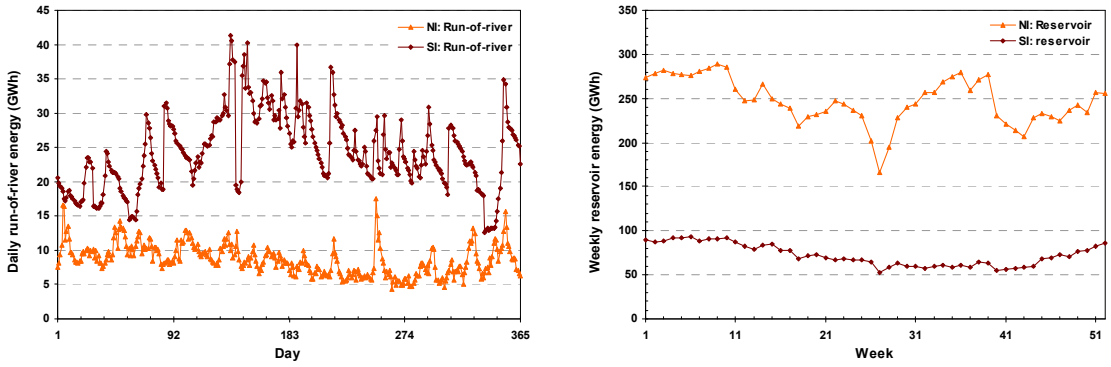
**Figure 3-4: Frequency distribution of the normalised wind output**

Figure 3-4a reflects the uneven geographic dispersal of the wind resource whereas Figure 3-4b represents the clustering of the wind resource in a single location. The wind farms in the North Island are spread across a wide geographical area producing a diversity effect more significant ('diverse' wind). There will be less correlation between outputs from generators in the portfolio under consideration, and less chance of low (or zero) output. Wind farms in close proximity, as seen in the South Island case, will have

a higher correlation in output profiles and will be characterised by low-diversity profiles ('non-diverse' wind).

### Hydro power plants

Hydro generators are considered to be fully reliable i.e. these are assumed to be available all the time and constrained only by their rated capacities and available hydro energy. The hydro inflow energy available is obtained from historical data for the different (dry, average, wet) hydro conditions in NZ. Figure 3-5 illustrates the available hydro energy for dry hydro conditions in the North and South Islands.




**(a) Daily run-of-river energy** **(b) Weekly reservoir energy**

**Figure 3-5: Available hydro energy (dry hydro conditions)**

The run-of-river (*ror*) hydro energy inflows are adopted from historical data on a daily basis for all three (dry/average/wet) hydro conditions. The daily available energy is equally divided in each half-hourly time slot of the day. Like wind energy, all available *ror* energy during each time period is modelled to be fully used unless constrained by the load or the other generator's conditions. The weekly available reservoir energy is also based on historical data for different hydro conditions. This weekly available hydro reservoir energy is dispatched optimally in combination with the available *ror* and wind output during each half-hour in order to achieve minimisation of the overall thermal capacity requirements. It is also assumed that the reservoir inflows in each week arrive equally at the start of each half hour in the week.

#### Interconnector

The interconnector between the two Islands is assumed to be 99% reliable and operating in two states only i.e., available with full transfer capability with a probability of 0.99, and unavailable with no flow possible with a probability of 0.01.

#### System reliability level

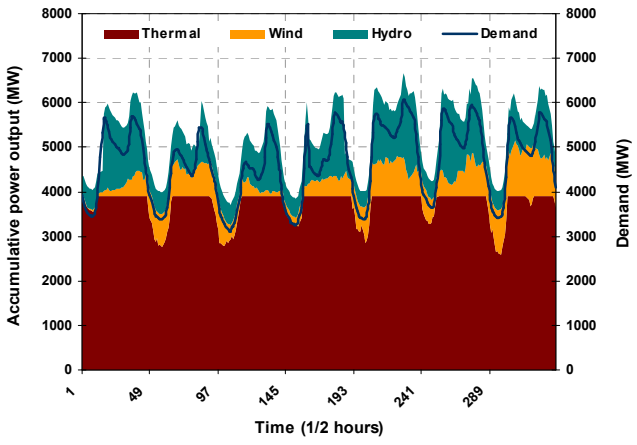
The adequacy of the generation capacity is evaluated by applying a reliability standard of Loss of Load Expectation (LOLE) to be less than 8 hours/year in the system.

#### Capacity credit of wind generation

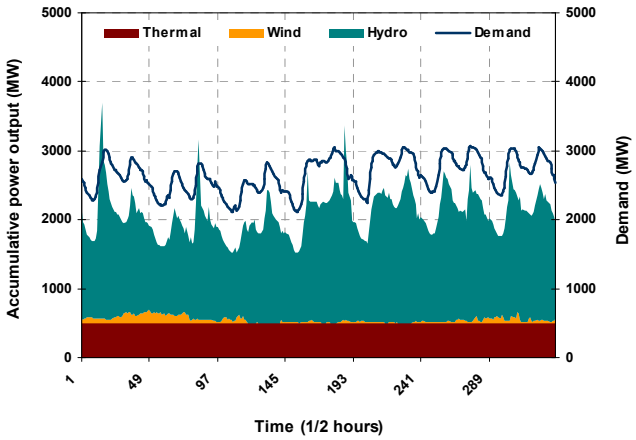
The capacity benefit due to hydro-wind coordination in the system has been attributed to wind generation. This assumes that the hydro generation displaces the same amount of thermal capacity in hydro-thermal and in wind-hydro-thermal systems.

### 3.4.2 Interconnected wind-hydro-thermal system

The developed capacity assessment model is applied which maximises the use of zero marginal hydro and wind energy and minimises the thermal capacity requirements while meeting demand with the required reliability level. For illustration a one week dispatch for both Islands, resulting from one year capacity optimisation process is depicted in Figure 3-6.




**(a) One week dispatch: North Island**




**(b) One week dispatch: South Island**

**Figure 3-6: Illustrative one week dispatch – year 2030**

It can be clearly observed, from Figure 3-6a and Figure 3-6b, that the hydro generation tends to fill the demand peaks resulting in flattening the output of thermal generation. This dispatch approach leads to the minimisation of the thermal capacity requirements.

Figure 3-6 shows that demand in the South Island is met by the hydro generation in the North Island across the interconnector. Therefore the presence of the interconnector helps to reduce the thermal capacity requirements in the South Island through the use of the hydro reserve available in the North Island.

### 3.4.3 Adequate generation capacity requirements

Adequate capacity requirement for each future wind scenario is shown in Figure 3-7. These are based on an existing interconnector level of 520MW between the North and the South Islands and dry hydro conditions. System reliability and resultant capacity adequacy assessments are conventionally carried out to cover the conceivable extremities in the operating conditions. Due to the dominance of hydro power in New Zealand, the capacity adequacy evaluations presented here are carried out while applying the dry hydro conditions. This is considered necessary for long-term reliability assessments including intra year availability of hydro energy in the system.

The sensitivity of generation adequacy to the power transfer capability of the interconnector and other hydro conditions are elaborated in later subsections. It can be observed that with the increase in wind penetration (4.5% in 2010 to 18% in 2030) the

magnitude of overall capacity that is required above the peak demand increases significantly. This is due to a relatively limited contribution of wind generation to system reliability.

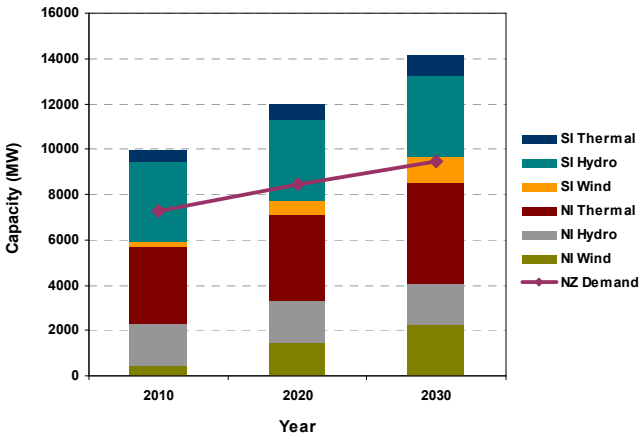



**Figure 3-7: Adequate capacity requirements (Interconnector 520MW)**

### 3.4.4 Impact of the interconnector on system reliability

Various studies are performed to analyse the impact of the power transfer capability of the interconnector between the Islands on adequate generation capacity requirements. First, the impact of interconnector level on the risk of supply is evaluated both in terms of LOLE and EENS in the system. An example of 2030 scenario is depicted in Figure 3-8 below.

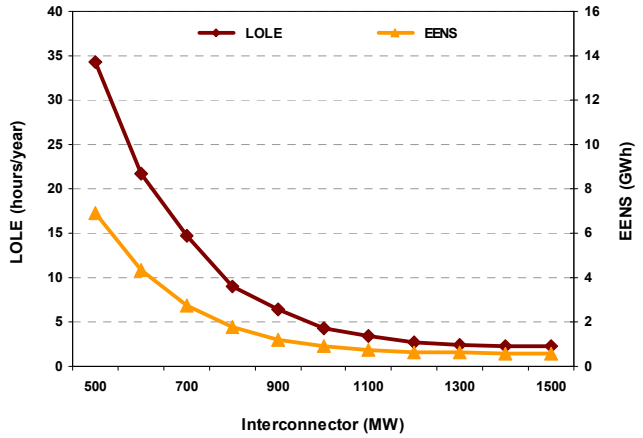



**Figure 3-8: Impact of interconnector on system reliability**

The increase in the power transfer capability of the interconnector clearly reduces the system risk. This is mainly due to the enhanced sharing of the capacity reserve between the two islands through the interconnector. The marginal reduction in the risk gradually decreases till it saturates at a certain threshold (about 1100MW in this case, Figure 3-8). This is because for a fixed generation capacity in the system, both Islands can only share the reserve capacity equal to their individually available reserve. Therefore, when both exhaust sharing of their individually available reserve, no further gain of interconnector growth is observed.

### 3.4.5 Impact of Interconnector ratings on generation capacity requirements

Each future wind development scenario is analysed for three different levels of the power transfer capabilities of the interconnector i.e., 520MW, 1000MW and 1500MW. The North-South flow in each case is limited to a maximum of 2/3rd of the total power transfer capability of the interconnector, while for South-North flow no flow constraints are applied. The adequate capacity requirements in each Island corresponding to the three analysed levels of the interconnector are presented in Figure 3-9, where all the cases meet the reliability standard of LOLE $\leq$ 8 hours/year.

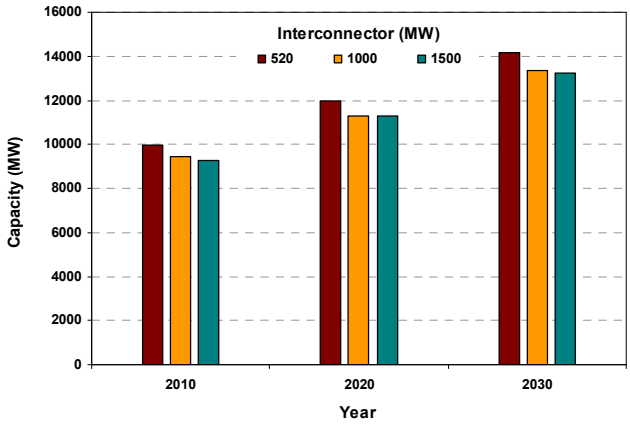



**Figure 3-9: Impact of interconnector on generation capacity requirements**

As mentioned earlier, the increase in the power transfer capability of the interconnector reduces the system risk, which is directly related to the available generation capacity margin in the system. Therefore, at increased interconnector levels generation capacity can be reduced to bring the LOLE to desired levels.

Table 3-2 provides the regional allocation of the different capacity types in the two islands for all the analysed interconnector levels. It can also be seen that both Islands benefit from thermal capacity savings with the increase in the power transfer capability of the interconnector. The incremental capacity savings tend to reduce with the increase in the interconnector level.

**Table 3-2: Impact of interconnector on adequate capacity requirements (MW)**

| Scenario/Year | | 2010 | | | 2020 | | | 2030 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Interconnector (MW) | | 520 | 1000 | 1500 | 520 | 1000 | 1500 | 520 | 1000 | 1500 |
| North Island | Wind | 432 | 432 | 432 | 1434 | 1434 | 1434 | 2215 | 2215 | 2215 |
| | Hydro | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 |
| | Thermal | 3400 | 3200 | 3200 | 3800 | 3400 | 3400 | 4400 | 3800 | 4000 |
| | Total Capacity | 5705 | 5505 | 5505 | 7107 | 6707 | 6707 | 8488 | 7888 | 8088 |
| South Island | Wind | 202 | 202 | 202 | 631 | 631 | 631 | 1196 | 1196 | 1196 |
| | Hydro | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 |
| | Thermal | 500 | 200 | 0 | 700 | 400 | 400 | 900 | 700 | 400 |
| | Total Capacity | 4259 | 3959 | 3759 | 4888 | 4588 | 4588 | 5653 | 5453 | 5153 |
| New Zealand | Wind | 634 | 634 | 634 | 2065 | 2065 | 2065 | 2065 | 3411 | 2065 |
| | Hydro | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 |
| | Thermal | 3900 | 3400 | 3200 | 4500 | 3800 | 3800 | 5300 | 4500 | 4400 |
| | Total Capacity | 9964 | 9464 | 9264 | 11995 | 11295 | 11295 | 14141 | 13341 | 13241 |
| Capacity Margin (%) | | 36.6 | 29.7 | 27 | 41.7 | 33.4 | 33.4 | 49.2 | 40.8 | 39.7 |

A consistent trend of overall capacity saving is found with growth in the power transfer capability of the interconnector between the two Islands. However, major impact is observed in the high wind scenario (18% wind in 2030), where the overall system benefits by 800MW (equivalent to 8% capacity margin saving) by a simple increase of 500MW in the interconnector level. This is strongly linked to the enhanced sharing of capacity reserve, mainly hydro in the south complementing large wind in the North Island.

### 3.4.6 Capacity credit of wind generation

In order to determine the capacity value of wind in a wind-hydro-thermal system, first the adequate levels of overall generation capacity for the future demand projections in each scenario are determined. These generation capacity requirements are determined for two cases i.e., with wind (wind-hydro-thermal) and without wind (hydro-thermal) in each scenario. The difference in the thermal capacity between the two cases, expressed as a percentage of the wind capacity, provides the capacity credit of wind as given in Figure 3-10, mentioned as the ‘capacity credit with hydro’.

In order to see the role of hydro power in firming up wind output, the capacity credit of wind is also assessed without presence of hydro in the system. For each scenario again two cases i.e., with wind (wind-thermal) and without wind (only thermal) are analysed. The adequate overall capacities in both cases are computed. The difference in the thermal capacity provides the capacity credit of wind in wind-thermal system as shown in Figure 3-10, mentioned as the 'capacity credit without hydro'.

Keeping demand the same, the difference in the capacity credit of wind between with and without hydro systems provides the contribution of hydro to increase the capacity value of wind in wind-hydro-thermal systems.

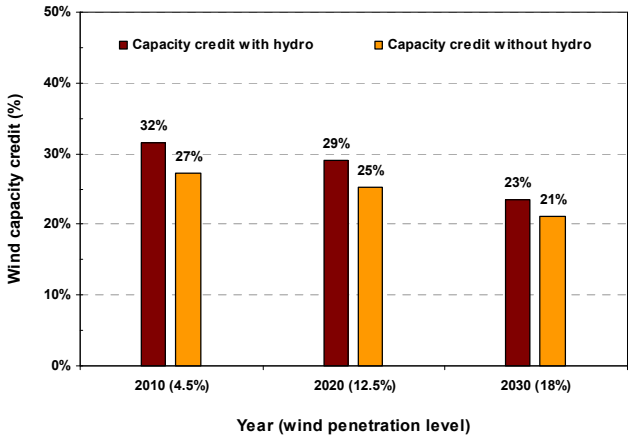



**Figure 3-10: Capacity credit of wind generation**

The results demonstrate that hydro generation in the NZ system will considerably enhance the capacity value of wind. However, the marginal contribution of hydro generation to the capacity credit of wind declines with increasing penetration of wind in the system. This is because for a given level of hydro plant in the system it will be able to mitigate the wind variability up to a certain extent. If wind variability exceeds the mitigation limits of the hydro reserve available in the system then thermal plant will be required to provide capacity reserve to maintain system reliability.

### 3.4.7 Additional capacity costs attributed to wind power

The methodology used to quantify the additional system capacity costs attributed to wind power was developed by (Strbac and Shakoor, 2006). The details of this model were presented in Chapter 2, section 2.7.

System capacity costs attributed to wind generation are computed for each wind development scenario, as given in Figure 3-11. These costs are expressed in comparison to a thermal plant that will substitute the same amount of energy as wind while operating as a base load plant. For each penetration level of wind the additional costs are expressed as a range. The lower limit of the range corresponds to the investment cost of 100 $/kW/yr, while the upper value corresponds to the higher investment cost of 150 $/kW/yr for the base load thermal plant.

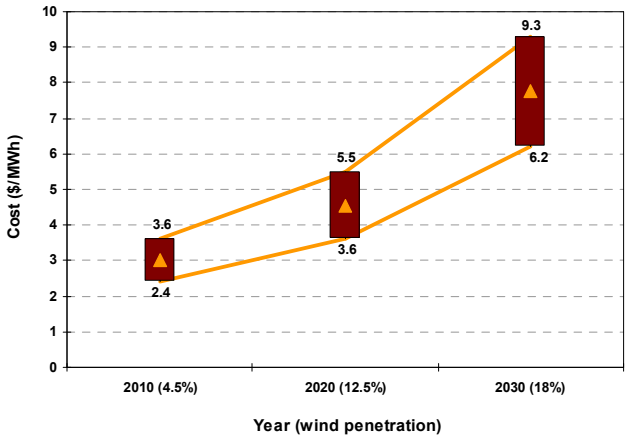



**Figure 3-11: Ranges of additional capacity cost of wind generation**

It is noted that at a wind penetration of 4.5% to 12.5%, the additional capacity costs attributed to wind are small which increase significantly with a further increase in wind penetration to 18%. This is mainly due to a significant drop in the capacity credit of wind at high penetrations.

## 3.5 Effect of key factors on capacity adequacy and capacity credit of wind generation

### 3.5.1 Effect of the spatial distribution of the wind resource

In order to study the effect of different regional distributions of wind generation on capacity adequacy and the capacity credit of wind generation another scenario named here as the Southland scenario is also investigated. A key feature of this scenario is a relatively more balanced distribution of wind capacity between the two Islands. However, in South Island wind capacity is more concentrated in the southland region in this scenario. A summary of this scenario is given in Table 3-3.

**Table 3-3: Summary of Southland wind scenario**

| Scenario/Year | Scenario Variants | North Island | | South Island | | New Zealand | |
|---|---|---|---|---|---|---|---|
| | | MW | TWh | MW | TWh | MW | TWh |
| 2010 | Wind generation | 425 | 1.7 | 463 | 1.4 | 888 | 3.1 |
| | Wind (energy) penetration (%) | - | 5.9% | - | 8.2% | - | 6.7% |
| 2020 | Wind generation | 875 | 3.1 | 1165 | 3.1 | 2040 | 6.2 |
| | Wind (energy) penetration (%) | - | 9.2% | - | 15.6% | - | 11.6% |
| 2030 | Wind generation | 1695 | 5.9 | 1706 | 5.2 | 3401 | 11.1% |
| | Wind (energy) penetration (%) | - | 15.5% | - | 23.2% | - | 18.4% |

All variants except wind generation in the Southland scenario are assumed to be the same as given in the earlier scenario, referred here as the Reference scenario (summarised earlier in Table 3-1).

Applying the system adequacy assessment model with same reliability targets of LOLE ≤ 8 hours/year, the required generation capacity to satisfy demand corresponding to the three time horizons is evaluated as given in Table 3-4. It should be noted that this capacity adequacy assessment is also based on dry hydro conditions.

**Table 3-4: Capacity (MW) requirements in the Southland wind scenario**

| Scenario/Year | | 2010 | | | 2020 | | | 2030 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Interconnector | | 520 | 1000 | 1500 | 520 | 1000 | 1500 | 520 | 1000 | 1500 |
| North Island | Demand | 4840 | 4840 | 4840 | 5600 | 5600 | 5600 | 6275 | 6275 | 6275 |
| | Wind | 425 | 425 | 425 | 875 | 875 | 875 | 1695 | 1695 | 1695 |
| | Hydro | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 | 1873 |
| | Thermal | 3200 | 3200 | 3200 | 4000 | 3600 | 3800 | 4600 | 4000 | 4200 |
| | Total | 5498 | 5498 | 5498 | 6748 | 6348 | 6548 | 8168 | 7568 | 7768 |
| North Island | Demand | 2455 | 2455 | 2455 | 2865 | 2865 | 2865 | 3200 | 3200 | 3200 |
| | Wind | 463 | 463 | 463 | 1165 | 1165 | 1165 | 1706 | 1706 | 1706 |
| | Hydro | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 |
| | Thermal | 400 | 100 | 0 | 600 | 400 | 100 | 800 | 500 | 200 |
| | Total | 4420 | 4120 | 4020 | 5322 | 5122 | 4822 | 6063 | 5763 | 5463 |
| New Zealand | Demand | 7295 | 7295 | 7295 | 8465 | 8465 | 8465 | 9475 | 9475 | 9475 |
| | Wind | 888 | 888 | 888 | 2040 | 2040 | 2040 | 3401 | 3401 | 3401 |
| | Hydro | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 | 5430 |
| | Thermal | 3600 | 3300 | 3200 | 4600 | 4000 | 3900 | 5400 | 4500 | 4400 |
| | Total | 9918 | 9618 | 9518 | 12070 | 11470 | 11370 | 14231 | 13331 | 13231 |
| Capacity Margin (%) | | 36.0 | 31.8 | 30.5 | 42.6 | 35.5 | 34.3 | 50.2 | 40.7 | 39.6 |

These results indicate that the overall capacity requirements in the Southland scenario are relatively higher than the corresponding Reference scenario. This is primarily due to a low average load factor of the wind farms in this scenario compared to the Reference scenario.

It is interesting to note that the role of the interconnector remains the same so far as for the Reference scenario, with predominant impact in the high wind penetration (2030)

scenario. Interconnector growth to 1000 MW above the existing level of 520MW in the 2030 scenario saves about 9% capacity margin.

The requirement of adequate generation capacity under the three hydro conditions is also investigated for the Southland scenario. The required capacity margins relevant to each are given in Table 3-5.

**Table 3-5: Impact of hydro conditions on adequate capacity requirement – Southland scenario**

| | Interconnector (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 520 | | | 1000 | | | 1500 | | |
| Hydro Condition | Dry | Avg. | Wet | Dry | Avg. | Wet | Dry | Avg. | Wet |
| Year (wind penetration) | Capacity Margin (%) | | | | | | | | |
| 2010 (7%) | 36 | 31.8 | 30.5 | 31.8 | 30.5 | 30.5 | 30.5 | 30.5 | 30.5 |
| 2020 (12%) | 42.6 | 40.2 | 37.9 | 35.5 | 34.3 | 33.1 | 34.3 | 35.5 | 33.1 |
| 2030 (18%) | 50.2 | 48.1 | 46 | 40.7 | 39.6 | 38.6 | 39.6 | 39.6 | 39.6 |

At all wind penetrations, a clearly higher availability of water in the average and wet conditions compared to a dry hydrology, reduces the amount of generation capacity while that would provide the same reliability i.e. LOLE $\leq$ 8 hours/year.

The potential benefit of interconnector growth varies for the three hydro conditions. The capacity margin benefits are higher under the dry conditions, primarily due to larger sharing of thermal capacity reserve of the North Island to the help hydro power dominated South Island. However, the marginal contribution to capacity savings diminishes with the enhancement in the power transfer capability of the interconnector beyond 1000MW.

The capacity credit of wind determined for the Southland scenario at various penetration levels of wind is presented in Figure 3-12. The capacity credit of wind for the 2010 case is higher than the corresponding year in the Reference scenario. This is because more wind is placed in the hydro dominated South Island, where hydro can easily absorb the variability of the relatively small wind penetration in this year.

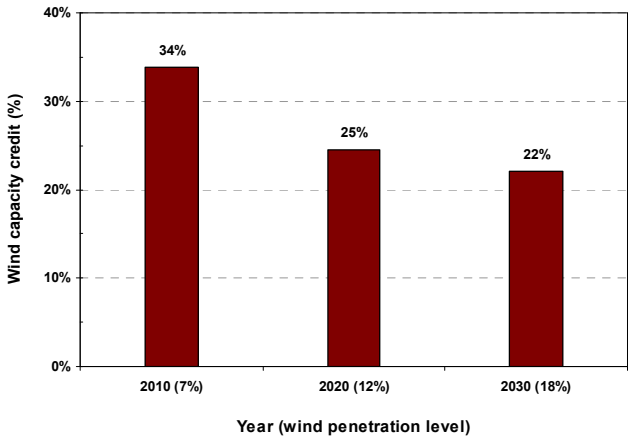



**Figure 3-12: Capacity credit of wind in the Southland scenario**

Also, the concentration of wind farms in the South Island leads to a loss of diversity of the wind resource. This has been attributed to the loss of some capacity value of wind in this scenario for higher penetrations. The capacity credit of wind in 2020 is lower by about four percentage points compared to the Reference scenario, one of the factors here is the relatively low average load factor (about 3%) of wind farms that are included in the South Island.

#### Additional capacity costs attributed to wind power (Southland scenario)

The additional system capacity costs as shown in Figure 3-13 for the Southland scenario are lower for 2010 and 2020 in comparison to the Reference scenario. The lower capacity costs in 2010 are attributed to the high capacity credit of wind in this scenario. Also, in the 2020 scenario the costs are lower although the capacity credit in this case is low in the Southland scenario. This is lead by the low load factor of wind, which has resulted in a smaller disproportion between the displaced capacity and displaced energy by wind. No significant difference between the Southland and Reference scenario is found for the year 2030.

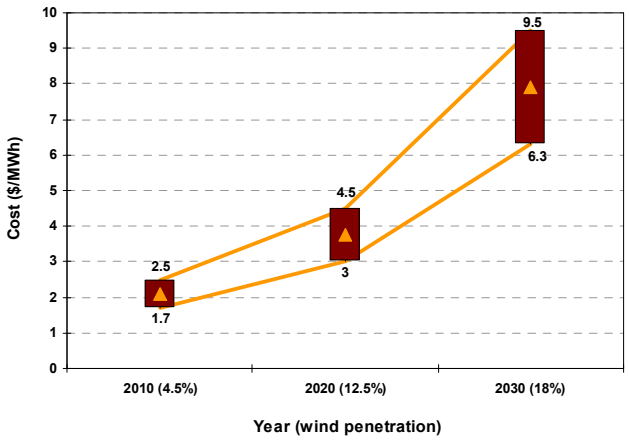



**Figure 3-13: Additional capacity cost due to wind – Southland scenario**

### 3.5.2 Effect of wind forecasting errors

Conventionally, capacity adequacy evaluation methodologies tend to ignore the wind forecasting errors in wind output. However, in systems with the presence of large amounts of energy limited hydro generation, it is considered necessary to take into account the impact of wind forecasting errors on the capacity value of wind.

Capacity credit, including the effect of wind forecasting errors in this work is based on a conservative approach. Capacity reserve in the system is maintained at levels that would accommodate 99% of the wind forecasting errors across a four hour time horizon. During each time-slot (1/2-hour) of simulation, ten discrete levels of wind forecasting errors are considered around the concurrent wind output level (available from data). These error levels range between plus (rise) and minus (drop) three standard deviations of wind forecasting errors in 4 hours. The corresponding probability of each level of error is determined from the statistical behaviour of wind output. The results are shown in Figure 3-14.

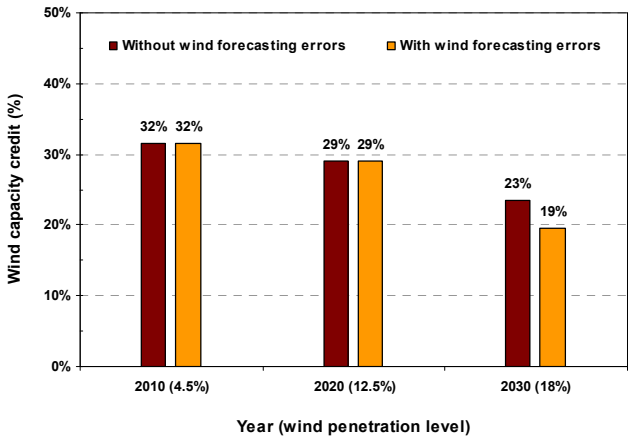



**Figure 3-14: Capacity credit of wind - with and without wind forecasting errors**

It can be observed that up to medium levels of wind penetration (i.e., 12% by 2020) impact of wind forecasting errors on its capacity value are negligible. However, at high penetration (i.e., 18% by 2030) the capacity credit of wind drops by 4 percentage points due to the large forecasting errors involved.

The above mentioned decrease in the capacity credit of wind due to wind forecasting errors is attributed to the additional capacity reserve requirement. This will be required during windy days due to large expected variations in wind output. It is interesting to note that this is contrary to the thermal based systems, where wind drives higher capacity margins (resulting in low capacity credit) mainly to manage no/low wind days during peak demand periods.

### 3.5.3 Effect of different hydro (dry, average, wet) conditions

The variation of hydro conditions can have a profound effect on the availability of annual hydro energy in the system. The historical data indicates that different hydro conditions can lead to about ±25% variation in available annual hydro energy. Therefore, several sensitivity studies are conducted in order to quantify the effect of dry, average and wet hydro conditions on generation capacity adequacy. Additionally these sensitivity studies have been conducted for different power transfer capability of the NI-SI interconnector in each scenario. The required capacity margins necessary to maintain the system reliability are shown in Table 3-6.

**Table 3-6: Required capacity margins under different hydro conditions and interconnector levels**

| | Interconnector (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 520 | | | 1000 | | | 1500 | | |
| Hydro Condition | Dry | Avg. | Wet | Dry | Avg. | Wet | Dry | Avg. | Wet |
| Scenario/Year | Capacity Margin (%) | | | | | | | | |
| 2010 | 36.6 | 31.1 | 29.7 | 29.7 | 27 | 24.2 | 27 | 27 | 24.2 |
| 2020 | 41.7 | 39.3 | 37 | 33.4 | 33.4 | 28.7 | 33.4 | 33.4 | 26.3 |
| 2030 | 49.2 | 47.1 | 45 | 40.8 | 40.8 | 37.6 | 39.7 | 39.7 | 37.6 |

For any given level of the interconnector, it is found that the required capacity margins, necessary to maintain system reliability, decrease with the increase in availability of hydro energy. On the other hand, for each hydro condition the increase in the interconnector level saves the capacity margin.

The benefit of the increase in the available hydro energy gradually reduces with the rise in wind penetration in the system. For example, in the 2010 scenario (4.5% wind) and 1000MW interconnector case the capacity margin reduction due to wet hydro condition compared to dry condition is: 29.7% – 24.2% = 5.5%, however, the same for the 2030 scenario (18% wind) is: 40.8% – 37.6% = 3.2% percentage points. As the installed hydro capacity in these scenarios is almost the same, therefore, its potential to mitigate the larger variability of wind at its higher wind penetrations will be limited.

## 3.6 Discussion and conclusions

A new model for analysing the capacity adequacy in wind-hydro-thermal systems is applied. The model evaluates the level of adequate generation capacity in the system based on a reliability criterion of LOLE ≤ 8 hours/year.

The model is applied to an electricity system equivalent to New Zealand. Three main wind development scenarios termed here as Reference scenarios that correspond to 2010, 2020, and 2030 demand projections are investigated. Wind penetration results in higher capacity margins to maintain system reliability which rise significantly with the increase in wind penetration. For an existing level of interconnector between the two Islands (i.e. 520 MW), the required capacity margins range from 37% in 2010 to about 49% in 2030 which correspond to 5% and 18% wind penetrations respectively.

The power transfer capability of the interconnector is found to directly influence the system reliability. Significant overall generation capacity savings in both interconnected

regions are observed due to the possible expansion of the interconnector. In general, the generation capacity benefits due to interconnector growth are higher at high wind penetration. For example, in the high wind scenario (18% wind penetration in 2030), the system benefits by 800 MW thermal capacity saving (equivalent to 8% capacity margin gain) due to an increase in the interconnector level from 500MW to 1000MW. This is mainly linked to the enhanced sharing of capacity reserve, mainly hydro in the South Island, complementing large wind in the North Island.

Sensitivity studies over a range of hydro conditions (dry, average, wet) that influence the availability of annual hydro energy are also conducted. For any given level of the interconnector, it is found that the required capacity margins, necessary to maintain system reliability, decrease with the increase in the availability of hydro energy. The benefit of the increase in the available hydro energy gradually reduces with the rise in wind penetration in the system. For example, in 2010 (4.5% wind) scenario and 1000 MW interconnector case, the capacity margin reduction due to wet hydro conditions compared to dry condition is: 29.7% – 24.2% = 5.5%, however, the same for the 2030 (18% wind) scenario is: 40.8% – 37.6% = 3.2%.

The capacity credit of wind in the investigated wind-hydro-thermal system is found to range between 32% and 19% for a wind penetration of 5% and 18% respectively. The results demonstrate that hydro generation considerably enhance the capacity value of wind. The additional gain in capacity credit of wind due to hydro are observed to be up to 5 percentage points. However, the marginal contribution of hydro generation to the capacity credit of wind declines with increasing penetration of wind in the system.

High load factor of the investigated wind profiles also contributes to higher capacity and energy contribution for a given level of wind penetration. The presence of large hydro storage capacity helps to avoid wind curtailment during periods of high wind output coinciding with low demand and/or high run-of-river hydro yield periods.

For relatively higher capacity credits of wind generation, the disproportion between the amount of capacity and energy displaced by wind power is relatively small. Therefore, the additional capacity costs attributed to wind generation are found to be lower. Additional capacity costs attributed to wind generation for the analysed scenarios range between 2.4 $/MWh and 9.3 $/MWh of wind energy produced. The higher costs in the

2030 scenario are primarily driven by small capacity credit of wind at its high penetration.

A different set of wind development scenarios in terms of spatial distribution of wind capacity is also analysed. In these scenario capacity margins requirements are found to be relatively higher compared to the Reference scenarios. It is interesting to note that the role of interconnector remains the same in the Southland scenario as for the Reference scenario with a predominant impact at high wind penetration. Interconnector growth to 1000 MW above an existing level of 520 MW in 2030 saves about a 9% capacity margin.

In the Southland scenario at low wind penetration of 7% in 2010, the capacity credit of wind is higher than the corresponding Reference scenario, while at high penetration the capacity credits are relatively low. Therefore, capacity costs attributed to wind in the Southland scenario are lower in the low penetration case while at other penetrations (12% and 18%) the costs are nearly the same as in the Reference scenario.

Having investigated the role of interconnectors in generation adequacy and capacity credit of wind generation, the following chapter assesses the sufficiency of transmission network capacity to accommodate wind generation and to manage security of supply. A transmission planning methodology is developed to evaluate the optimum transmission network capacity levels between the interconnected systems as well as the adequacy of transmission network capacity in systems with wind generation.

# Chapter 4

# Transmission network investment in systems with wind generation

## 4.1 Introduction

Optimising transmission investment is a complex task. A number of factors need to be considered, including forecasts of growth in demand and generation with their temporal and spatial distributions together with the technical and cost characteristics of generation. These forecasts must then be combined into a forecast of future energy market conditions in order to answer the key questions as to 'how much', 'where', 'when' and 'what' transmission reinforcements are justified. Evaluating possible schemes involves comprehensive reliability (i.e. to ensure that transmission network does not unduly restrict generation plant from meeting peak demand) and economic efficiency (i.e. to balance the generation operating cost against the investment cost of the network) assessments. In practice, network investment planners tend to use deterministic planning guides (also called network planning standards) that present a proxy of the comprehensive reliability and economic assessments to make decisions about the adequate amount of transmission network capacity to build against a background of demand and generation (NG 2004, ESB NG 1998).

In many countries, the current technical, commercial and regulatory frameworks that support the transmission network design, investment and operation were created for a power system dominated by large-scale, conventional, centralised generation plant. However, moving towards a more sustainable, low-carbon future power system, the presence of significant share of intermittent wind generation that has considerably different operating characteristics, namely low capacity value, intermittent nature and limited controllability of its output, will drive dissimilar impact on the network operation and investment decisions to that of the incumbent generators.

This will open the question of how much transmission network capacity should be built in order to transport large volumes of wind power from generation sources in remote areas to the centres of demand. This question is an important one as overinvestment in

transmission is likely to lead to higher than necessary costs to electricity customers. Moreover, it might lead to delays to full access to the electricity market by wind generation owners while planning permission for network reinforcement is obtained and construction is undertaken. Conversely, underinvestment in transmission might result in failure to utilise the full potential of wind farms to reduce carbon emissions, or in constraint the operation of wind power generation with the consequence of increased balancing service costs or that the power system might be left in an unsecured condition, resulting in costumers facing an increased risk of loss of supply.

The materiality of the network investment question comes into focus as the applications for the connection of large-scale wind power generation to transmission increases worldwide. As a result, the challenges associated with the accommodation of this generation at transmission levels are receiving considerable attention in many countries (Morrow et al., 2007; Barroso et al., 2007; Dios et al., 2007; Mukhopadhyay, 2007). In the particular case of Great Britain, utilisation of wind power is a fundamental component of the government's energy policy; with more than 12GW of wind generation applications for connection to the onshore transmission and distribution network in Scotland and 8GW offshore, wind generation is likely to make a considerable and material impact on the transmission system. Further impact is also felt because these generators are all connecting in the Northern where generation dominates demand, and a dearth of generation near demand centres in the Southern means an increase of the North-South net flow on an already congested transmission network.

This chapter aims to address the core aspects of this challenge, first by exploring the traditional approach of using reliability standards to drive an investment strategy for network expansion. It then lays out how reliability standards can drive transmission network investment, and highlights how transmission contributes to system risk. The risk that the system will not be able to meet peak demand is computed using a LOLP based analytical technique for reliability evaluation of interconnected systems.

The chapter then explores the characteristics of wind power with relation to generation capacity credit and details the development of a methodology for derivation of the inter-area transmission system transfer capability requirements driven by reliability standards for systems including significant penetration of wind power generation. The approach considers the impact of intermittent wind generation on the transmission network over

the long term investment horizon and it determines the requirement for additional capacity driven by wind power generation. Sensitivity of the key network impacts to wind power characteristics such as; penetration level, resource diversity, load factor, diversity and correlation between distinct regions are quantified. Furthermore, network impacts to conventional generating units' characteristics such as; average unit availability and unit size are also quantified.

## 4.2 Methodology to evaluate the inter-area transmission system transfer capability in systems with wind generation

### 4.2.1 Capacity model

The generation system model is based upon Markov model and assumes statistically independent, stationary and exponential distribution of the failure and repair time of the generating units. The capacity model was created using the recursive algorithm presented by Billinton and Allan, (Billinton and Allan, 1984), and computes the probability or long-term availability of various capacity states of the system. The collection of all possible capacity states of the system expressed in the form of capacity outage states and the associated probabilities is termed as the capacity outage probability table (COPT). Details of this model, including the mathematical formulation, were presented in Chapter 2, section 2.4.1.

### 4.2.2 Modelling and representation of wind generation

#### Wind generation data

Wind generation data used in another project (ILEX Energy and Strbac, Oct. 2002) was also available for this work. In total data was gathered from 39 wind projects across GB with an averaging period of half-hour over a consistent one year period. It was observed from the wind data set that there was as much variation in output within region as there was across regions. To build profiles of high wind penetration, representative of the

diversity of the large scale wind generation, diversity was created by 'time-slipping[2]' proportions of aggregate half hourly wind profiles (Shakoor, 2005).

The degree of diversity introduced was an arbitrary assumption, with a target level of diversity being a middle point between the observed diversity exhibited by the 39 wind projects for which data was available and a theoretical maximum diversity if output across a much larger number of projects was totally uncorrelated.

The frequency distribution of such a developed diverse wind profile is shown in Figure 4-1. It can be observed that the most likely output level of wind power is between 10% - 30% of the installed wind capacity. Also it can be noted that in a diverse wind profile the probability is relatively small for achieving very high power output levels that approach the total installed wind capacity in the system.

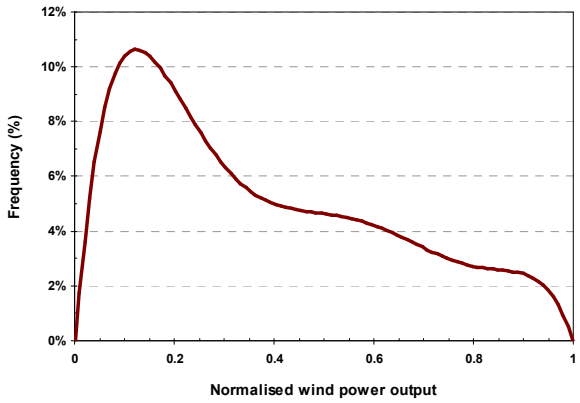



**Figure 4-1: Frequency distribution of the normalised annual wind output**

### Wind power output modelling

Wind generation is dependent upon wind speed, which is a continuous physical phenomenon that evolves randomly in time and space. A stochastic process is considered to be a model of a system which develops randomly in time according to probability laws. Thus wind speed (generation) is a stochastic process with a continuous

[2] Time-Slipping involves scaling-up the observed generation data by overlaying annual half-hourly aggregate generation profiles for the 39 projects, but slipping each tranche of data by half-an-hour more than the last tranche. For example, to create the output equivalent of 117 projects the first profile would represent the aggregate output of 39 projects commencing 00:00 on 1st January, the second commencing at 00:30 and the third at 01:00, thereby artificially increasing the observed diversity in the generation data. The sum of these profiles becomes representative of substantially large wind systems.

state space (time) (Sayas and Allan, 1996) and is modelled in this work by 'Markov chain model'.

The application of Markov Model produces a two dimensional matrix of the frequency of encountering a given wind output level and of the transition frequencies among adjacent states. The state transition rates and probability of occurrence of a state are obtained during the modelling process by extracting the information on the residence time of each state.

The total wind capacity considered is divided into a suitable number of states which do not necessarily have to be equally spaced. However, in this analysis, the size of wind output states for any level of wind capacity was determined to make the difference between two successive output levels equal to 500MW (the size of generic conventional unit). This leads to limiting the state space of the generating capacity as well as of the reserve capacity states resulting in a considerable saving in the computation time.

#### Representation of wind generation

Wind generation in the system is represented as a multi-state unit. This multi-state unit is characterised by the availability and the transition rates of each output level. For a given level of wind penetration annual profile of diverse wind resource is prepared as aforementioned. The total wind capacity is divided into certain number of output levels and the required parameters of each output level are determined by the application Markov Chain model. These output levels represent the various states of the multi-state wind unit. An example of a 5GW wind capacity is shown in Table 4-1. Each level of wind power output is characterised by the probability of residing on a power output level and the upwards and downwards transitions rates which depicts the expected transitions to a higher or lower output level of wind generation respectively, from an existing output level.

**Table 4-1: Matrix of transitions (occurrences/year) among various levels of wind power output (wind capacity = 5GW) (Shakoor, 2006)**

| Outage capacity (MW) | Probability | Upwards transition rate (occ/day) | Downwards transition rate (occ/day) |
|---|---|---|---|
| 0 | 0.001 | 0.000 | 3.773 |
| 500 | 0.056 | 0.879 | 2.199 |
| 1000 | 0.051 | 2.441 | 3.797 |
| 1500 | 0.080 | 2.405 | 3.642 |
| 2000 | 0.087 | 3.349 | 3.602 |
| 2500 | 0.089 | 3.494 | 3.862 |
| 3000 | 0.116 | 2.981 | 3.217 |
| 3500 | 0.131 | 2.852 | 2.705 |
| 4000 | 0.198 | 1.782 | 1.630 |
| 5000 | 0.180 | 1.799 | 0.000 |

For relatively simple analytical techniques like COPT only the probability of each wind power output level is required. Detailed techniques like Frequency and Duration Method require additional information such as state transition rates beside the probability of occurrence of a state, which are obtained during the modelling process by extracting the information on transition frequencies and the residence time of each state.

### 4.2.3 Load system representation

For the purpose of long-term planning the load system can be adequately represented by daily peak load conditions (Ringlee and Wood, 1969). This load model is also amenable for analytical treatment. Nahman states that the two-level load approximation offers a very good estimation of the relative values of all main reliability indices of prospective generation systems (Nahman and Grovac, 1992). The same model, for demand representation, has also been presented in the literature by Billinton and Allan (Billinton and Allan, 1984).

For building this load model the daily peak load levels of the entire year are divided into a suitable number of classes. The frequency of occurrence of a peak load falling in a class determines the probability of that load class (level). The sequence of daily peak loads is assumed to be a stationary, random process in this model. The peak load durations follow an exponential trend that last for some part of the day, represented by an average value, called the exposure factor. During the rest of the day the load is supposed to be equal to another load level called the daily minimum load.

An example of a two-level load system, based upon annual half-hourly electricity demand profile of the GB, is presented. The available annual load profile was scaled up to represent the demand levels (70GW peak demand) and energy requirements (400TWh) expected for the year 2020. The daily peak loads of the new profile are divided into required number of load classes. The frequency of loads in each class is given in Table 4-2.

**Table 4-2: Peak load levels and their frequency of occurrence per year**

| Load level no | Load level (MW) | Frequency (days/year) |
|---|---|---|
| 1 | 70,000 | 5 |
| 2 | 68,000 | 20 |
| 3 | 66,000 | 40 |
| 4 | 63,000 | 65 |
| 5 | 61,000 | 90 |
| 6 | 59,000 | 55 |
| 7 | 57,000 | 45 |
| 8 | 54,000 | 25 |
| 9 | 52,000 | 15 |
| 10 | 50,000 | 5 |

These peak loads are assumed to last on the average for one-third part of each day i.e. 8 hours/day. A minimum load level of 38,000MW is assumed to exist for the rest of the day represented by an average period of 16 hours/day.

Traditionally, transmission planners conforming to reliability standards use conditions of peak demand to drive the design of the network capacity at major transmission boundaries. Thus the two-level load system model is simplified, in this study, to represent a single load level.

The load model constitutes a single load level representative of the annual peak load '$L$'. The annual peak load used in this study is based upon the half-hourly electricity demand profile of Great Britain. The probability '$p_L$' of occurrence of the annual peak load is 1.

### 4.2.4 Reserve capacity model

System reserve capacity states are computed by describing the conditions of generating capacity in excess of, or lower than the load by convolution of the above-mentioned

capacity and load models. The detailed description of this model was presented in Chapter 3, section 3.2.3.

### 4.2.5 Reserve capacity model of interconnected systems

The combined reserve capacity states and respective probabilities of the two interconnected systems can be grouped in a form of table denominated as the 'interconnected system capacity probability table' (ISCPT). The construction of this table was exposed in Chapter 3, section 3.2.4.

### 4.2.6 Interconnector representation

The capacity model of the transmission network is built applying the COPT methodology. This model was presented in Chapter 3, section 3.2.5.

### 4.2.7 Computation of risk indices

A loss of load situation is considered to arise in a system when the available support through the interconnectors cannot offset the capacity deficiency arising due to capacity outages and load demands in that system. The loss of load situations in each system are determined from the simultaneous capacity outages conditions, in conjunction with the respective systems peak load (corresponding to the negative reserve margin states) and the support available over the transmission lines.

For the developed model, the computation of different reliability criteria requires different load models. Loss of load probability (LOLP), defined as the cumulative sum of the loss of load probabilities, requires a load model based only in the annual peak load. Whereas loss of load expectation (LOLE), defined as the cumulative sum of the loss of load probabilities for a given period, requires a load model based on the annual two-day peak load level. LOLE represents the number of hours or days in a year during which a loss of load is expected.

The reliability criterion applied in this analysis is the loss of load probability (LOLP). Three loss of load probabilities (LOLP) will exist, one for each of the two separate systems and one for the interconnected system as a whole. The computation of LOLP

takes into account not only the limited capacity of the transmission line, but also the fact that the transmission line can fail. The mathematical formulation was carefully described in Chapter 3, section 3.2.6.

### 4.2.8 Computation of the inter-area transmission system transfer capability in systems with wind generation

This section presents a methodology for evaluation of the inter-area transmission system transfer capability driven by reliability standards for the future power systems with a large share of intermittent wind generation. The methodology developed is largely based on the presented analytical technique for reliability assessment of interconnected systems.

In most instances, planners conforming to reliability standards use conditions of peak demand to drive the design of network capacity at major transmission boundaries. The total transmission boundary capability required between two major system areas is composed of two components: (i) the capacity required to carry peak flows characterised by expected (average) generation dispatch during peak demand conditions (planned transfer); and (ii) the additional capacity that enables generation in one of the areas to support the load in the other area after failures of generators in the other area. This approach ensures that network capacity is sufficient to allow generation to meet peak demand under most circumstances. Transfer capability across the boundary must be sufficient to allow delivery of support to the area with a temporary deficit in generation capacity.

In many countries, the reliability standard is defined in terms of the statistical probability that consumers of electricity may be faced with the loss of their supplies due to insufficient generation. This is measured by the loss of load probability index (LOLP) representing the probability of the annual peak load exceeding the available generation. The model developed applies this reliability criterion for transmission network planning driven by reliability standards under peak demand conditions.

Nonetheless, the presence of finite transmission network capacity and their associated reliability will also increase the risk of interruptions, imposing additional risk to supply reliability. Assuming the transmission network is designed in accordance to the

traditional approach of using reliability standards conceptualised for large conventional generation, the minimum transfer capability across a boundary can be computed for the peak demand condition. Based upon this transfer capability, the risk of loss of supply can be assessed. Based on the knowledge of this risk, the additional risk (in relative terms) that the system will not be able to meet peak demand that is imposed by transmission system ($Risk_{Tx}$) can be calculated as follows:

$$Risk_{Tx} = \frac{LOLP_{FiniteTx} - LOLP_{InfiniteTx}}{LOLP_{InfiniteTx}} \tag{4.1}$$

'$LOLP_{FiniteTx}$' and '$LOLP_{InfiniteTx}$' are the loss of load probabilities in the systems when interconnected by finite and infinite transfer capability respectively.

This additional acceptable risk can be used as a benchmark for determining the transfer capability requirements in the case of other technologies, such as wind power. The guiding principle adopted is that the change in generation mix in the system from a system dominated by conventional generation to a system with significant penetration of wind generation should not deteriorate the level of system security. Therefore the same level of additional risk pertinent to the transmission system will be applied for systems with different generation mixes. Particularly, in a system with intermittent wind generation, the transfer capability is designed such that the additional risk pertinent to transmission does not exceed $Risk_{Tx}$ determined by the traditional approach based on reliability standards. The target risk level that system ought to meet is termed as $LOLP_{Reference}$.

$$LOLP_{Reference} = \left(1 + Risk_{Tx}\right) \cdot LOLP_{InfiniteTx} \tag{4.2}$$

The schematic representation of the developed model used for evaluating the inter-area transmission system transfer capability in systems with significant penetration of wind generation is represented in Figure 4-2.

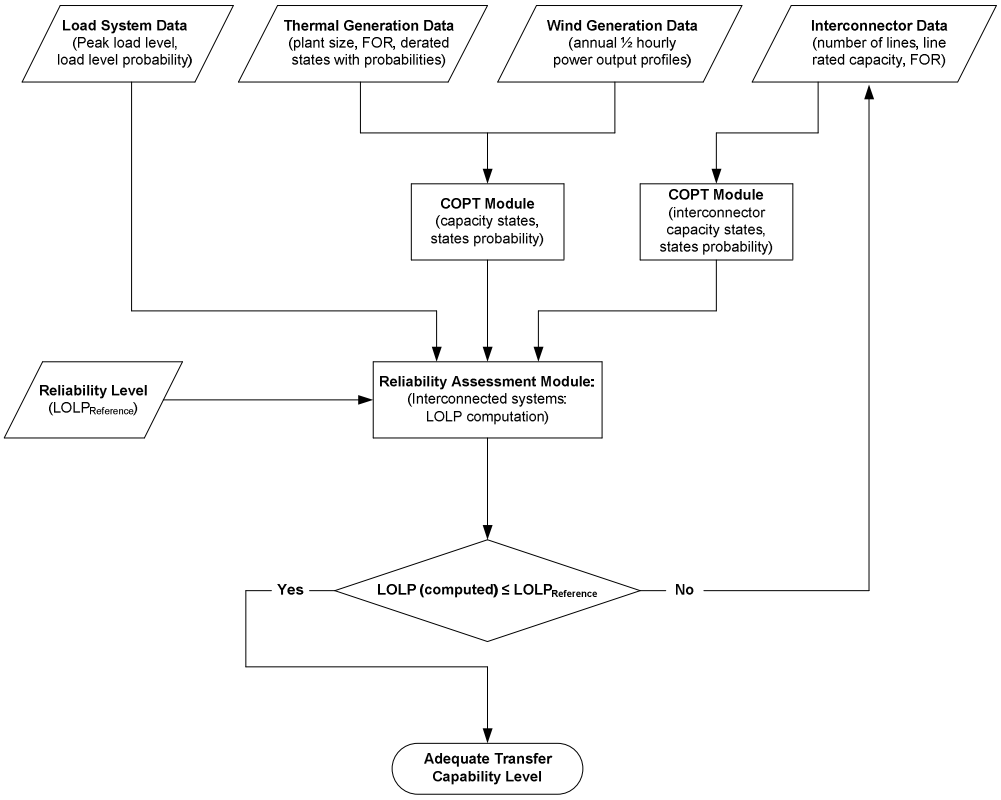



**Figure 4-2: Schematic representation of the model used for quantification of the inter-area transmission system transfer capability in systems with wind generation**

## 4.3 Impact of wind generation on transfer capability requirements

This section exposes the details of the methodology for derivation of transfer capability requirements driven by reliability standards for systems including wind generation. Subsequently, it demonstrates how reliability standards can drive transfer capability, explores characteristics of wind with relation to generation capacity credit, and highlights how transmission contributes to system risk.

The methodology is illustrated on a major transmission boundary characterised by generation/demand background representative of the size of Great Britain electricity system (e.g. Scotland-England transmission interconnector) with different levels of wind penetration. This study is taken since Scotland has more generation capacity connected to transmission than demand, so transmission power flows are north-south (to demand centres in the midlands and south east). Furthermore, the transmission network is already congested both in Scotland and along the main transmission lines that run into England. Applications for the connection of large-scale wind power generation to

transmission network in Scotland are likely to make a considerable and material impact on the transmission system.

### 4.3.1 Security driven capacity evaluation

The most widely used reliability criterion to assess the overall system adequacy is the loss of load probability index (LOLP). This index can be interpreted as the probability of annual peak demand exceeding the available generation (risk of supply deficits).

Prior to deregulation of the power industry, the former Central Electricity Generating Board (CEGB) in the UK, while planning the generation system, proposed that the risk of peak demand exceeding the available supply should not occur more than nine winters in one hundred years. Based on the probabilities of the plant failures (only about 85% of the installed capacity would be available during the winter peak periods) and uncertainty in peak demand the standard would require a capacity margin of about 24% to deal with such eventualities. Capacity margin is defined as the percentage difference between the total system generation capacity and peak system demand with respect to the former.

The security standard employed in the UK is taken for the purposes of this work as indicative of the degree of confidence required to maintain the system's supply risk at acceptable levels.

The generic conventional generation system constituted by identical thermal units of capacity 500MW each is considered here. A standard two-state reliability model is applied to simulate the behaviour of the generating units. The forced outage rate (FOR) of each unit is 15% (average availability of 85%). For a system with a peak demand of 50GW, the minimum installed conventional capacity, necessary to ensure that the risk of loss of supply is at most 0.09, is 62GW. This figure translates in the probability of losing of load as 7.28%.

To observe the effect of the installed capacity on the system's reliability, the COPT method was first applied on a conventional system. Considering a peak demand of 50GW LOLP was computed for various levels of capacity margins as shown in Figure 4-3, where it can be observed that a decrease in the capacity margin from 24% to 12% increases the risk of loss of load from 9% to 90%.

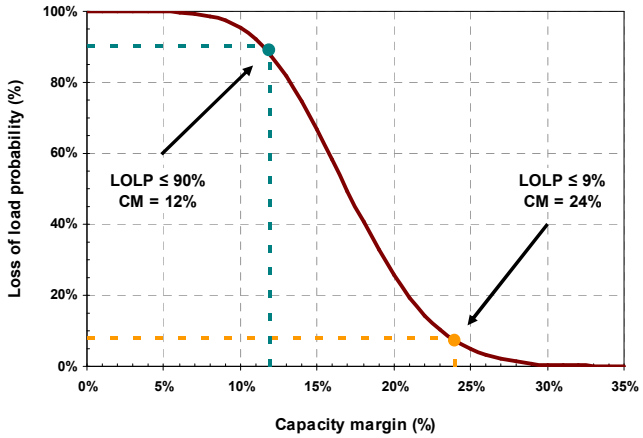



**Figure 4-3: Effect of capacity margin on the risk of loss of load**

### 4.3.2 Quantification of system risk pertinent to the transmission system

The fundamental principle behind the transmission planning standards is that the transmission network should be of sufficient capacity so that it does not unduly restrict generators to contribute to security of supply. In this context it is important to appreciate the link between generation security standards (section 4.3.1) and transmission security standards.

Besides the inherent uncertainties present in the generation system owing to random generator failures and demand uncertainty, additional risks are imposed on the overall system security by the transmission system. These are due to the transmission constraints resulting from finite transfer capabilities and their associated reliabilities. In principle the development of the transmission system should aim at avoidance of those conditions in which a generator is unable to contribute towards the security of the entire system. The requirement that the "transmission network should not unduly restrict generators to contributing to security of supply at the time of winter peak demand" is fundamental to the transmission planning standards and it is maintained in the model developed.

The presence of the finite transmission network capacity and associated FOR will increase the risk of interruptions, imposing an additional risk to supply reliability. Understanding this risk is key to reliability driven network planning, which is exposed below.

To examine this additional risk, the system presented in section 4.3.1 is considered. The system is now divided equally into two contiguous parts, area A and B, as illustrated in Figure 4-4a. Both areas are characterised by the same conventional installed capacity (31GW), the same peak demand (25GW) and are connected by a fully reliable transmission line of finite transfer capability.

If generation outputs are scaled to meet peak demand, net generation will be 25GW from both A and B and average peak flow between the two areas is zero. However, it would be beneficial to have some transmission boundary capability to enable sharing of reserve in both areas and increase the overall system reliability. The amount of reserve that can be shared and the benefits that this has for system reliability will depend on the capacity of the transmission line.

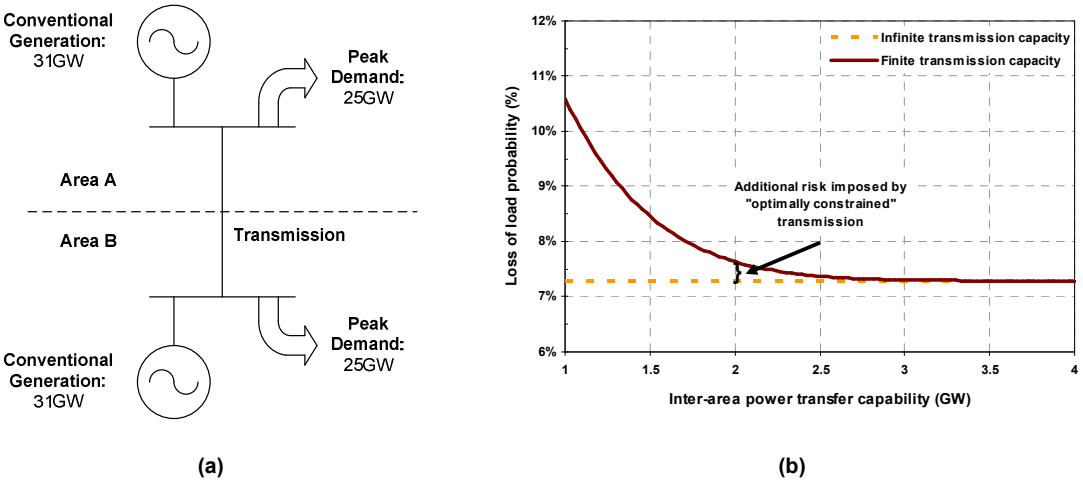



**Figure 4-4: Example of two-busbar system and quantification of system risk pertinent to transmission network**

Figure 4-4b shows the rapid reduction in the risk of interruptions with the increase in transfer capability between the two areas. This trend continues with rapidly diminishing benefits as capacity is added. For transfer capability larger than 3GW, the risk converges to a value that represents the minimum risk that such an interconnected transmission system can have under these conditions.

Historically, appropriate allocation of interconnection capacity has been derived from heuristic rules (MMC, 1987) based on balancing the benefits of lower system LOLP with the cost of installing new capacity. Using this approach, it would suggest a transfer capability of around 2GW for the example in Figure 4-4. With this finite transfer capability of 2GW, the risk (LOLP) of loss of supply is 7.64%, for an infinitely strong

transmission network the risk is marginally lower at 7.28%. This risk level is taken since reducing one generating unit will increase the risk above the standard (9% LOLP). The application of equation (4.1) quantifies the additional risk imposed by transmission system, when planned in accordance with the reliability standards (and dealing with conventional generation technologies only), which is found to be about 5%. This implies that considering the risk induced by the combined effect of limited generation and transfer capability, the total system LOLP should not exceed about 9.5%.

A number of sensitivity studies were carried out on the additional risk introduced by the transmission system due to different proportions of generation and demand in either side of the transmission boundary. Figure 4-5 presents the additional system risk due to the transmission system for the different amounts of generation and demand in the two areas.

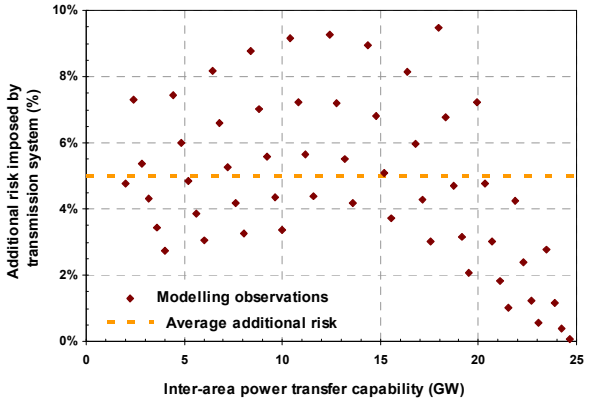



**Figure 4-5: Increased risk due to finite transfer capability**

It can be observed in Figure 4-5 that the increased risk induced by transmission in a system with conventional generation is modest. It only varies between 1-10% of the risk accepted by reliability generation standards (9% LOLP). The value of 5% is representative and stable and it is taken as an initial benchmark. Note that increasing the transfer capability of the link above 2GW will reduce the risk very little.

This additional acceptable risk can be used as a benchmark for determining the transmission investment requirements in the case of other technologies, such as wind power. This additional risk (5%) is used in the next sections to access the impact of wind generation on transfer capability. Note that different additional risk can be adopted without changes in the methodology.

### 4.3.3 Security driven transmission in systems with wind generation

Although wind generation will displace energy produced by conventional plant its ability to displace capacity of conventional generation will be limited. This is because the contribution of wind towards securing peak demand will be limited as wind is much less 'reliable' than conventional plant. The ability of wind generation to displace capacity of conventional plant is the key to answering the question as to how much transmission should be built for it (from the security of supply perspective). In order to illustrate the direct link between the ability of plant to contribute to security of supply (capacity value or capacity credit) and the amount of transmission that it drives, a study was developed and is presented in the following sub-section.

#### Contribution of generation plant to security of supply on the demand for transmission

The amount of transmission to be made available to allow remote generators to secure peak demand will depend on the ability of such generators to contribute to security of supply. To demonstrate this concept, the sample system exposed in section 4.3.1 is divided into areas A and B (see Figure 4-6a). The system's peak demand is 50GW with all load demand located in area B. The total installed capacity of remote generators in area A is 10GW and the total level of installed generating capacity in area B is such that provides a level of LOLP of 9% at most. It is further assumed that generators in area B are identical with an average availability of 85% (as in generation security standards) while the generators in area A are characterised by an increasing availability factor varying from 0 to 85%.

In Figure 4-6b the *x*-axis represents the 'capacity credit' of generators in area A expressed as the ratio between the generating capacity in area B that can be displaced by generators in Area A and the total installed capacity of generators in Area A. The *y*-axis represents the 'scaling factor' expressed as the ratio between the transfer capability required to allow remote generators in area A to contribute to the security of supply in area B and the installed generation capacity in area A, i.e. 10GW.

To simulate different capacity credit of generators in area A, the (peak demand) availability factor of all generating units in area A is varied from 0 to 85%, while

keeping the (peak demand) availability factor for all generating units in area B at 85%. For instance, generators in area A with zero availability are not able to displace any of the generators located in area B. Therefore the capacity credit of generators in area A is zero. Conversely, if the availability factor of generators in area A is 85%, it can displace 10GW of generating capacity in area B and consequently the capacity credit of generators in area A is 100%.

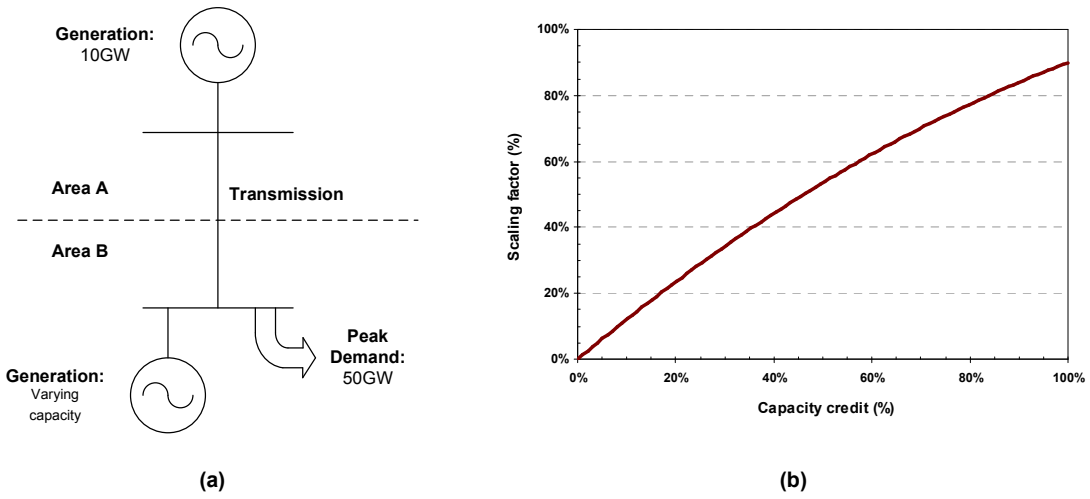



**Figure 4-6: Effect of different generation capacity credits on transmission requirement**

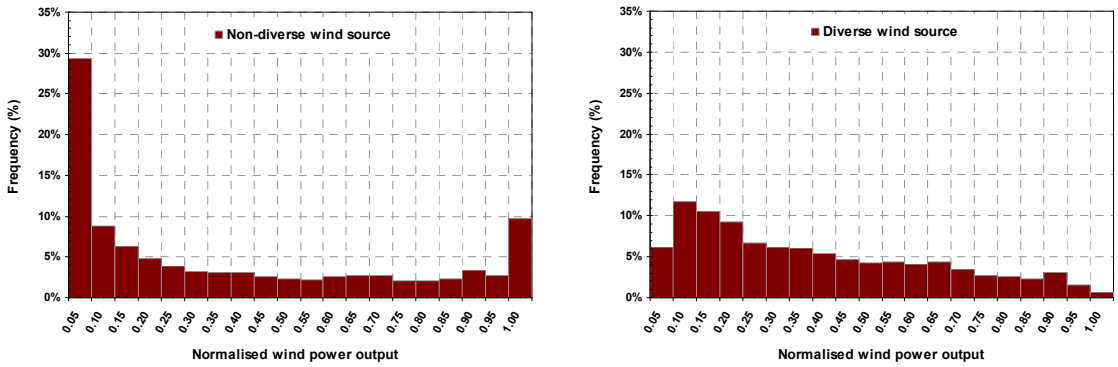
Figure 4-6b shows that in the presence of generators (area A) with zero capacity value, it is not required to make transmission available to allow these generators to secure peak demand (area B). Generators with zero or very low capacity value do not contribute to system's security of supply. Remote generators in area A with relatively high capacity credit, e.g. 100%, drive about 9GW of transmission to support peak demand in area B and reduce system risk. This level of transfer capability (9GW) will accommodate the average peak flows in 'planned transfer' (85% of the installed capacity) and will provide additional capacity to deal with uncertainties in demand and generation.

Note that, if the capacity value of remote generation is 30% (this value can be representative of wind generation plant type), the scaling factor for quantification of the adequate level of transfer capability is about 35%.

### Wind power characteristics

Two extreme wind generation output profiles, diversified and non-diversified, are used to conduct the assessments of the need for transfer capability driven by wind power (as characterised in (ILEX Energy and Strbac, Oct. 2002)). For wind farms spread across a very wide geographical area (e.g. all GB), the diversity effects will be significant ('diverse' wind), whereas wind farms in close proximity will be characterised by low-diversity wind profiles ('non-diverse' wind). This study used a long-term average wind load factor of 35%. Previous work developed (Dale et all, 2004) has been based on similar assumptions.

The variability of wind was statistically assessed from the frequency distribution of wind generation, considering an annual time series. The frequency distribution of the half-hourly wind power output for diversified and non-diversified wind generation profiles are shown in Figure 4-7.



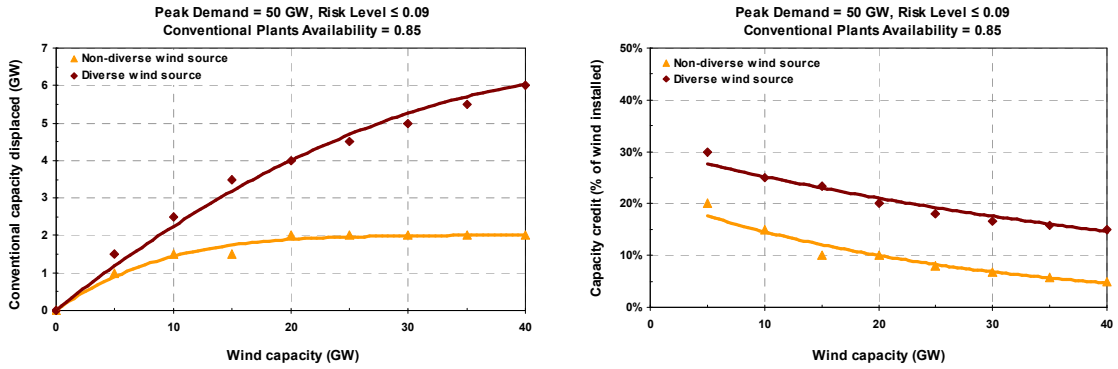

**(a) Non-diverse wind source** **(b) Diverse wind source**

**Figure 4-7: Frequency distribution of the normalised wind output for diverse and non-diverse wind sources**

Figure 4-7 illustrates the smother distribution of the diverse wind source, illustrating that diverse wind output can provide a more consistent resource with an improved load factor to the non-diverse portfolio (higher frequencies of extremely high and low outputs). (Holttinnen, 2004) provides further discussion of the impact of diversity on wind generation output. This analysis is echoed in the estimation of capacity values for diverse and non-diverse sources.

### Contribution of wind generation to adequacy of generation supply

The contribution of wind to system reliability is determined by its ability to displace conventional generation capacity. To explore this, the behaviour of conventional units and wind generation was statistically combined, enabling the risk of peak demand exceeding available generation (LOLP) to be assessed. This analysis was used to calculate the amount of conventional generation that wind generation can displace, while ensuring that the risk of loss of supply is not greater than the designated standard (this analysis applies a LOLP of 9%). Using the normalised outputs in Figure 4-7, Figure 4-8 represents the contribution of wind generation to capacity for various levels of installed wind capacity and illustrates the two different diversity characteristics. The capacity credit of wind generation ($W_{cc}$), Figure 4-8b, is obtained as the ratio between the conventional capacity displaced by wind power and the corresponding wind generation capacity installed (in other words $W_{cc}$ can be calculated by dividing values on the $y$-axis with the corresponding values on the $x$-axis in Figure 4-8a)




**(a) Capacity of conventional plant that can be displaced by wind generation**

**(b) Capacity credit of wind generation**

**Figure 4-8: Capacity value and capacity credit of wind generation**

Figure 4-8a shows that at low levels of wind penetration the capacity value of wind is relatively significant. However, as the capacity of wind generation increases the curve heads towards saturation resulting in a decrease of the marginal contribution: 40GW of wind capacity displaces only about 6GW of conventional generation. Clearly, in order to maintain the same level of reliability, a significant capacity of conventional plant will still be required. Previous work developed, (Milborrow, 2004), has yielded similar results to those shown in Figure 4-8. In the case of wind farms characterised by a non-diversified profile, the capacity value of wind reduces further. Figure 4-8a shows that

the capacity displacement tails off after the 20GW wind penetration level. The reason is that the probability of wind output at low levels is much higher than in the case of diversified profile as shown in Figure 4-7. The correlation effect as seen for the output of diversified resources is lost in non-diversified output.

This illustrates that wind (particularly from non-diverse sources) makes an increasingly limited contribution to maintaining the generation capacity margin. The knock-on impact of this is that load secured by connection of wind generation will not be equal to the capacity of wind generation added into the system. Only a (small) proportion of capacity can be relied upon as a resource to secure load during peak conditions when making calculations regarding system reliability. Because wind (and other technologies with a low capacity value) can only make a small contribution to system reliability, this generation technology is unlikely to require significant network capacity in systems built for reliability. This is illustrated in the following sub-sections.

### 4.3.4 Wind and transfer capability

The presented concepts of the generation capacity credit of wind were expanded to permit the computation of the adequate transfer capability in a system with significant penetration of wind generation. Transfer capability is designed such that the additional risk pertinent to transmission does not exceed 5% (as discussed in section 4.3.2). The target LOLP that the system, constituted by a generation mix of conventional and wind plants, ought to meet is termed $LOLP_{Reference}$ and is given by equation (4.2). Using the exposed concepts, the network capability required to secure demand in a system that includes wind generation can now be quantified.

### 4.3.5 Impact of wind generation on transfer capability requirements

A two-busbar system can be used to illustrate the impact of wind generation on driving capacity reinforcements in systems designed for reliability, Figure 4-9. The system under analysis is now characterised by 5GW of peak demand in area A and 45GW of peak demand in area B. Area A is also characterised by the presence of wind power with an increasing penetration level varying from 0 to 20GW. The conventional generating units have the characteristics presented in section 4.3.1.

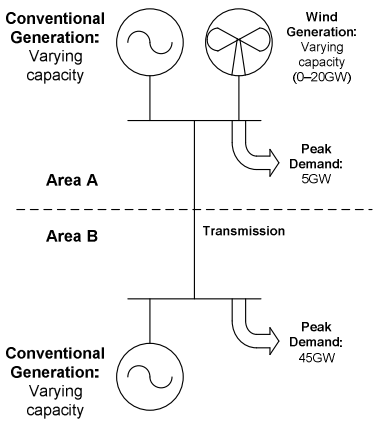



**Figure 4-9: Example of two-busbar system with combined conventional and wind generation system**

Figure 4-10 and Figure 4-11 present the transfer capability required to connect the two areas for different levels of conventional generation and wind generation capacities in area A. Figure 4-10 presents the case for a non-diverse wind profile, Figure 4-11 for a diverse profile. In all cases, the amount of transfer capability maintains the $LOLP_{Reference}$ based on the 5% additional risk imposed by finite transfer capability.

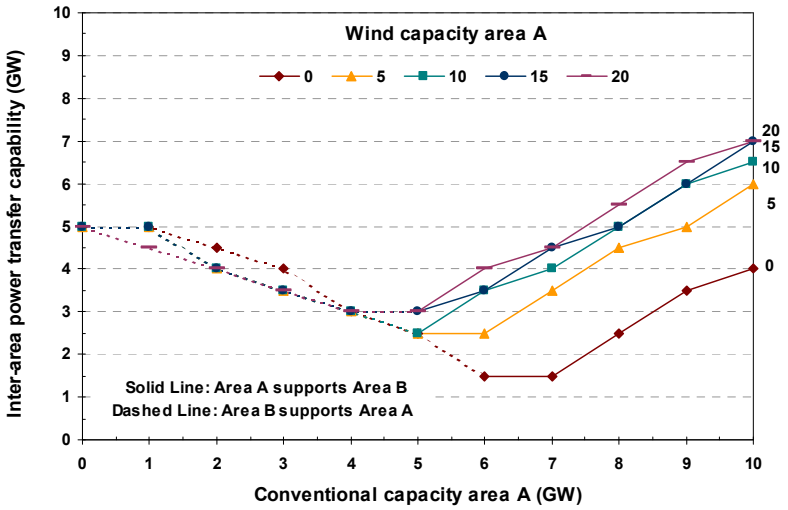



**Figure 4-10: Transfer capability requirements for the system with non-diverse wind source**

Figure 4-10 and Figure 4-11 show that when area A is an importing area, the presence of wind generation in the system leads to a relatively modest reduction of transfer capability requirements compared to the transfer capability required by the equivalent system without wind. The transfer capability remains practically at the same level for increased levels of installed wind capacity. Such behaviour suggests that wind has a modest transfer capability value to provide reliability in the importing area. It is

important to note that an area is considered to be an importing area if additional generation in that area reduces transfer capability requirements, although the total installed generation capacity may already exceed the peak load in that area.

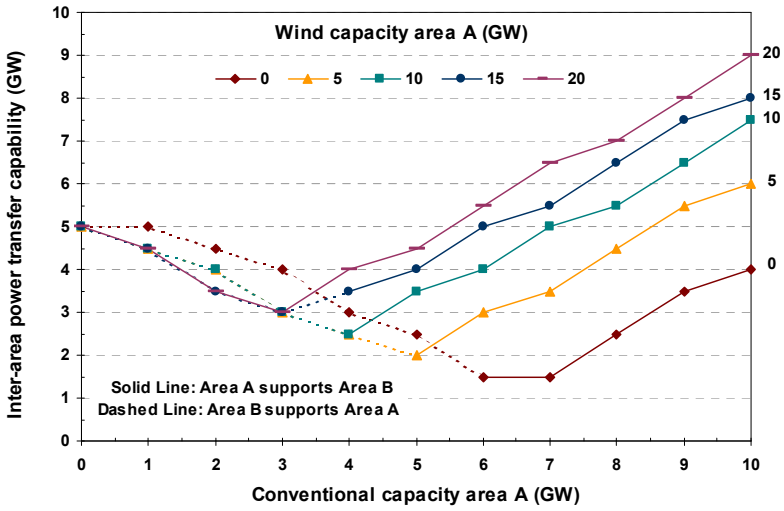



**Figure 4-11: Transfer capability requirements for the system with diverse wind source**

When area A is an exporting area, although the presence of wind generation increases the need for transmission, this increase is relatively small compared with the wind capacity installed. As expected, it can also be observed that diverse wind generation would require more transmission than non-diverse wind. For example, in the instance where 8GW of conventional generation is present in system A, the transfer capability will increase from 2.5GW for no wind to 5.5GW for 10GW of diverse wind installed. In the case of 10GW of non-diverse wind, the required transfer capability will be 5GW. In this case, transmission is built to allow conventional and wind generation in area A to contribute to the reliability of supply in area B. However, the increase in transfer capability required for this purpose becomes smaller with increased levels of installed wind capacity. This indicates that the transfer capability credit of wind generation (percentage of the conventional capacity that wind can displace) decreases when wind penetration level increases.

In summary, it will not be appropriate to treat wind power as conventional generation, under reliability considerations, as wind drives relatively little additional capacity. This is because it has limited capacity credit and cannot be relied upon to secure load at times of peak demand.

## 4.4 Effect of key factors on transmission network capacity in systems with wind generation

Among the various factors that can influence the optimum level of transmission network capacity, two groups of factors are investigated here and their impact on capacity credit of wind and on inter-area transmission system transfer capability is quantified. The groups of factors studied include wind power characteristics (wind penetration level, wind resource diversity and wind load factor) and conventional generating units' characteristics (average unity availability and unit size).

The two-area system introduced in section 4.3.5 is used for this analysis. Area A is characterised by a fixed level of 8GW of installed conventional capacity and the presence of wind power with an increasing penetration level varying from 0 to 40GW. Throughout this analysis, it should be stressed that area A is an exporting area while area B is an importing area.

### 4.4.1 Effect of penetration level of wind generation

In order to study the effect of penetration level of wind generation on transmission network capacity wind power is also connected in area B with increasing penetration level varying from 0 to 20GW. This study uses a diversified wind profile with a long-term average load factor of 35%.

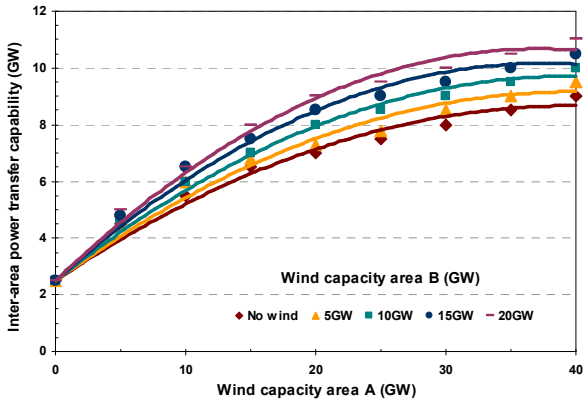



**Figure 4-12: Effect of wind penetration level on transfer capability**

Figure 4-12 shows that when wind power is not connected in area B, increasing levels of wind power in area A require increasing levels of transmission network capacity. Transmission is built to allow conventional and wind generation in area A to contribute to the reliability of supply in area B.

Assuming a specific level of wind power connected in the exporting area A, the presence of increasing levels of wind power in the importing area B require higher levels of transmission network capacity. For the case where 10GW of wind is present in area A, the transfer capability will increase from 5.5GW for no wind in area B to 6.5GW for 20GW of installed wind capacity in area B. Wind has relatively modest capacity value, however, its presence in the system offsets conventional generation plant in Area B. As such, conventional generation plant (high availability) is substituted by less reliable plant (wind power) in the importing area B, leading to an increase in transfer capability in order to maintain risk of loss of supply at acceptable levels. In the former case, when 10GW of wind power and 8GW of conventional plant are connected in area A, the required conventional capacity in area B decreases from 51.5GW for no wind in area B to 47GW for 20GW of wind installed capacity in area B.

### 4.4.2 Effect of wind resource diversity

To study the effect of wind resource diversity on the need for transmission network capacity two extreme wind generation output profiles, diversified and non-diversified, are used for various penetration levels of wind in area A. For instance, the diversity of the wind generation output profile in Great Britain is likely to be somewhere between the diverse and non-diverse profiles, as generation is usually geographically dispersed, but there can be limited locational variation in weather patterns. In both cases there is no wind generation connected in area B.

It can be observed in Figure 4-13 that the diverse wind resource requires 20% to 40% more transfer capability to the interconnector compared to the non-diverse wind resource under the same system risk ($LOLP_{Reference}$).

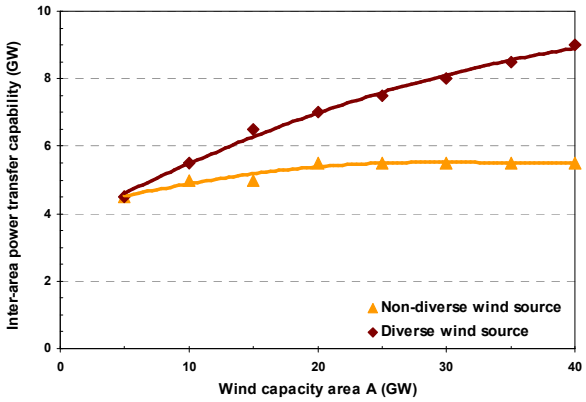


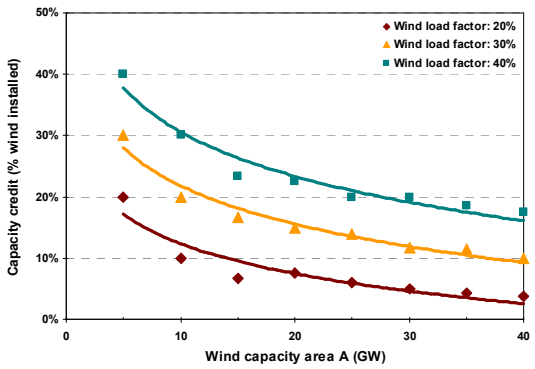

**Figure 4-13: Effect of wind resource diversity on transfer capability**

However, it can be seen in Figure 4-13 that for both cases, i.e. diverse and non-diverse wind resource, the marginal increase in transfer capability requirements declines with increasing penetration of wind generation in the system. In particular, for the non-diverse case, the transfer capability required tends to tail off after the initial penetrations of up to 20GW of installed wind capacity. This behaviour clearly demonstrates that the capacity value of wind generation (Figure 4-8, identical behaviour) is a major contributor to the network capacity that it can drive.

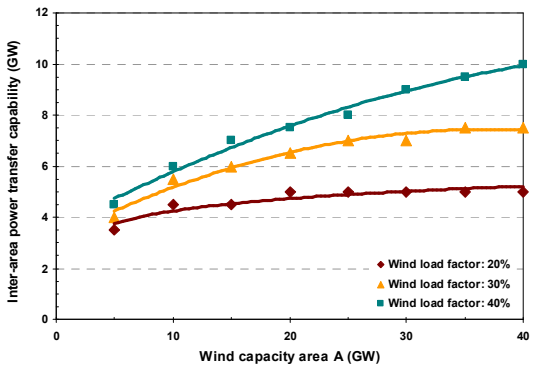
### 4.4.3 Effect of load factor of wind generation

The load factor of wind generation represents the average output of all wind farms. In Europe load factors for wind generators normally vary between 20% and 40% (DTI, 2001). Great Britain, having one of the best wind resources in Europe, is believed to possess the higher values of these load factors. In order to analyse the impact of various achievable load factors of wind generation on transfer capability requirements, studies were performed considering 20% to 40% range of wind load factor for GB wind.

Figure 4-14 presents the impact of wind load factor on its capacity credit as well as the transmission network capacity requirements for different wind load factors and for various levels of wind penetration in area A. This assessment uses a diversified wind profile.




(a) Capacity credit of wind at various load factors of wind




(b) Transfer capability requirements at various load factors of wind

**Figure 4-14: Effect of wind load factor on transfer capability**

Figure 4-14a shows that at lower levels of wind penetration the capacity credit of wind generation is found to be about the same as the average load factor of wind. However, as the level of wind penetration rises, the capacity credit begins to decline even at higher load factors. In summary, higher wind load factors have the ability to displace more capacity from conventional plant.

It can be observed in Figure 4-14b that for a specific level of installed wind capacity in area A, e.g. 10GW, the transfer capability will increase from 4.5GW for 20% wind load factor to 6GW for 40% wind load factor. The increase of wind capacity value from 1GW for 20% wind load factor to 3GW for 40% wind load factor translates in higher ability of wind and conventional generation in area A to contribute to reliability of supply in area B and therefore higher transfer capability is required to be built.

### 4.4.4 Effect of wind diversity and correlation

This subsection explores the impact of the degree to which output patterns from wind farms located in different areas of the interconnected transmission system are correlated. Correlation of the output of wind farms is defined as the measure of how well the output patterns from wind farms located in area A follow the output patterns from wind farms located in area B.

To assess the impact of correlation of wind power output on transfer capability requirements two extreme cases of correlation, non-correlated (i.e. statistically independent) and correlated (i.e. totally correlated), are considered for various

penetration levels of wind generation in area A and for 5GW of installed wind capacity in area B. This assessment uses a diversified wind profile with long-term average load factor of 35%.

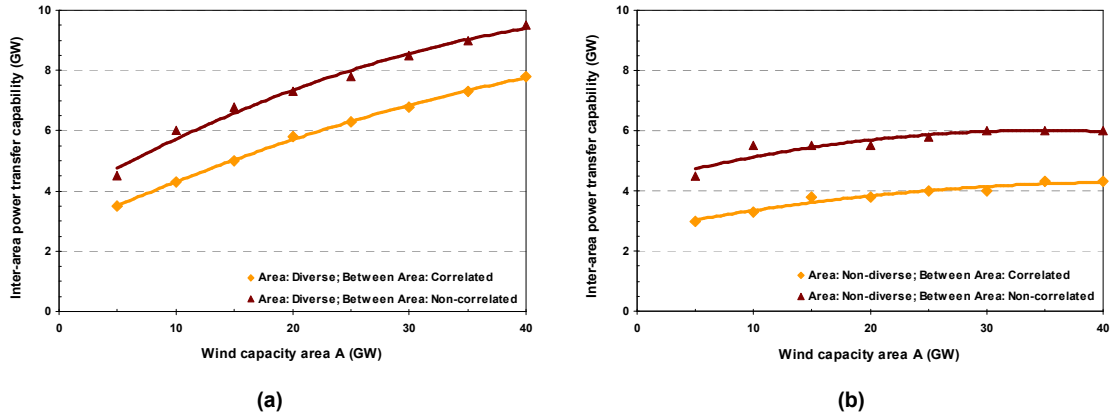



**Figure 4-15: Effect of diversity of wind resource and correlation on transfer capability**

Figure 4-15 shows that wind farms located in different sites, characterised by non-correlated output at times of day, increase the need for network capacity of about 1.5GW at all penetration levels of wind, when compared to correlated wind farms output. Positive effects in capacity value of wind are seen if there is low or no correlation in the output between wind farms located in different areas (i.e. the wind falls in one area at a time when it is blowing in another). In exporting areas, the higher capacity value of wind, due to the combined effect of low correlation of wind farms output, improves the ability of wind and conventional generation to support demand in area B and therefore more transfer capability is required to be built.

### 4.4.5 Effect of conventional plant availability

To examine the impact of average conventional plant availability on transmission network capacity requirements, studies were performed considering a 70% to 95% range of average availability of the units in both areas for various levels of wind power in area A. The results of these studies are presented in Figure 4-16.

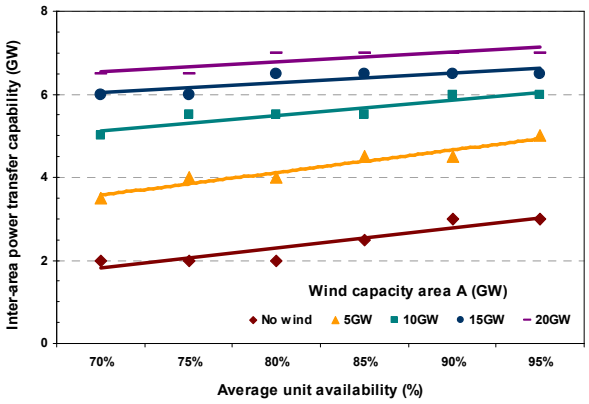



**Figure 4-16: Effect of plant availability on transfer capability**

Figure 4-16 shows that when 10GW of wind power are connected in area A, improving the average availability of the units from 70% to 90% results in conventional capacity savings in area B of about 33% along with an increase in transfer capability of about 1GW, without compromising the system reliability. In other words, the savings in conventional capacity in area B, due to the presence of more reliable generators, is replaced by transmission network capacity in order to maintain the same reliability level ($LOLP_{Reference}$).

### 4.4.6 Effect of conventional unit size

Another factor influencing the optimum level of transmission network capacity under the same reliability level ($LOLP_{Reference}$) is the composition of the system. The effect of the size of the generic conventional unit on the required level of transfer capability was assessed by varying it from 200MW to 800MW with the same average availability (85%) for an increasing penetration level of wind power varying from 0 to 20GW. This analysis is shown in Figure 4-17 below.

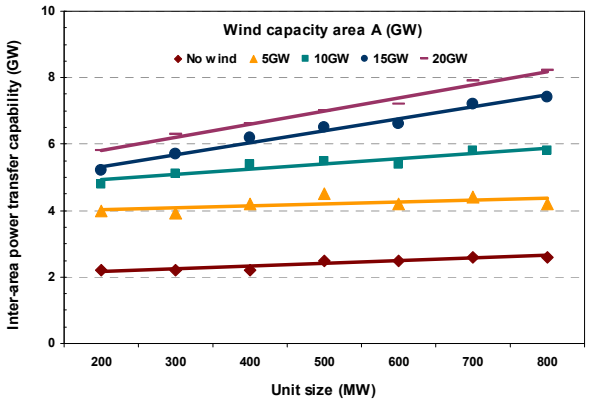



**Figure 4-17: Effect of unit size on transfer capability**

It is observed in Figure 4-17 that for 10GW of installed wind capacity in area A, the transfer capability increases from 4.8GW for a system composed of smaller sized units of 200MW, to 5.8GW for units sized at 800MW. This is because the effect of the failure of a large unit on the system reliability is significantly more than that of the failure of a smaller sized unit. Hence, more transfer capability is required to be built to maintain the reliability of supply at an adequate level. It is clear that systems with larger numbers of smaller units can reduce the needs for transfer capability.

## 4.5 Case study

To demonstrate the application of the proposed methodology and to discuss the impact of wind power on transmission investment, three generation scenarios are explored in this section using a simplified Great Britain (GB) transmission system. The system divides GB into a number of areas that are interconnected through the GB main interconnected transmission system (Figure 4-18).

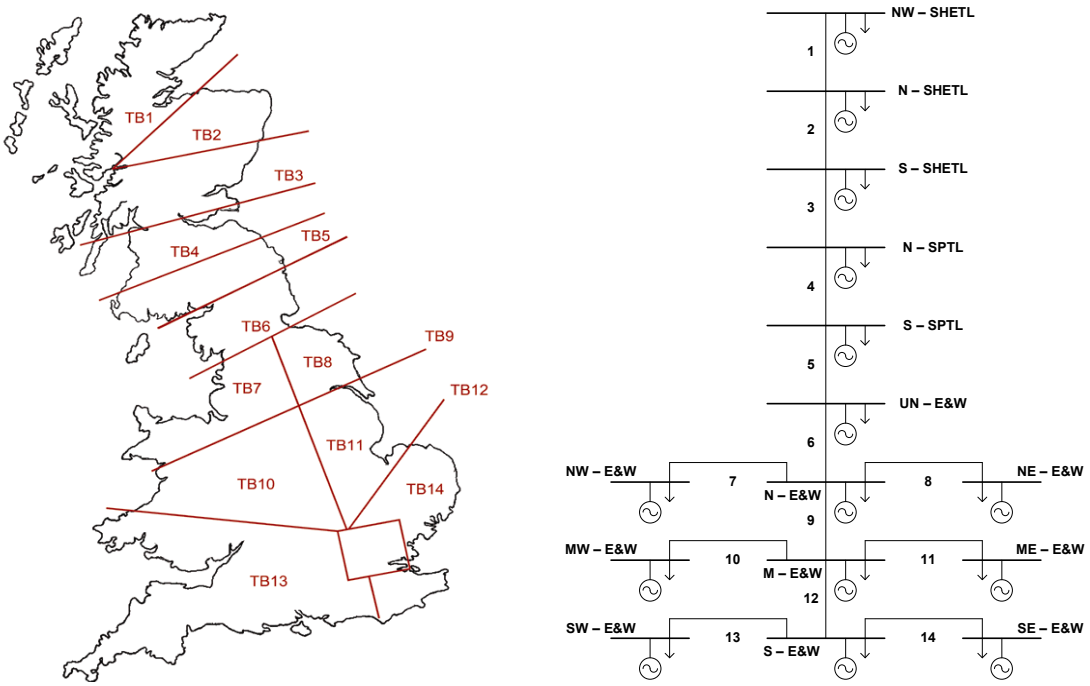



**Figure 4-18: Simplified Great Britain (GB) transmission system**

As a base case, the capacity of the GB transmission system was determined by excluding wind generation. The second and third cases consider 10GW and 15GW of wind power in Scotland and 3GW connected in the South East of England respectively. Given the concentration of wind power in relatively limited geographical areas (Scotland), the analysis uses non-diversified wind profiles. This is in line with the recent analysis carried out by (Grubb, 1988; Oswald, 2006) that demonstrated that the correlation between peak demand and wind output was weak and correlation between wind output and cold temperatures is also uncertain (Oswald, 2006).

### 4.5.1 Input data

The simplified GB transmission system consists of 15 buses representative of 14 GB major transmission boundaries. Table 4-3 presents the GB main interconnected transmission system identifying the areas they are connecting. The generation capacity and the forecast peak for each busbar were extracted from the National Grid Electricity Transmission (NGET) 2007 GB Seven Year Statement (SYS) (SYS, 2007). This data is presented in Table 4-3.

**Table 4-3: Main interconnected transmission system**

| Boundary | From area | To area | Length (Km) |
|---|---|---|---|
| TB 1 | NW-SHETL | N-SHETL | 53 |
| TB 2 | N-SHETL | S-SHETL | 42 |
| TB 3 | S-SHETL | N-SPTL | 120 |
| TB 4 | N-SPTL | S-SPTL | 35 |
| TB 5 | S-SPTL | UN-E&W | 72 |
| TB 6 | UN-E&W | N-E&W | 130 |
| TB 7 | NW-E&W | N-E&W | 67 |
| TB 8 | NE-E&W | N-E&W | 30 |
| TB 9 | N-E&W | M-E&W | 93 |
| TB 10 | MW-E&W | M-E&W | 75 |
| TB 11 | ME-E&W | M-E&W | 45 |
| TB 12 | M-E&W | S-E&W | 155 |
| TB 13 | SW-E&W | S-E&W | 195 |
| TB 14 | SE-E&W | S-E&W | 60 |

**Table 4-4: Generation capacity and peak demand forecast for the case study with 10GW and 15GW of wind in Scotland**

| Location | Area | Wind capacity (MW) | Conventional capacity (MW) | Peak demand (MW) |
|---|---|---|---|---|
| Scotland | NW-SHETL | 3572 / 5358 | 1000 | 614 |
| | N-SHETL | 1843 / 2764 | 1500 | 586 |
| | S-SHETL | 1144 / 1716 | 500 | 716 |
| | N-SPTL | 0 | 2500 | 1239 |
| | S-SPTL | 3441 / 5162 | 4000 | 3318 |
| | **Total Scotland** | **10000 / 15000** | **9500** | **6473** |
| England & Wales (E&W) | UN-E&W | 0 | 4500 | 3561 |
| | NW-E&W | 0 | 10000 | 8383 |
| | NE-E&W | 0 | 13500 | 6638 |
| | N-E&W | 0 | 0 | 0 |
| | MW-E&W | 0 | 4000 | 8798 |
| | ME-E&W | 0 | 7000 | 820 |
| | M-E&W | 0 | 0 | 0 |
| | SW-E&W | 0 | 15000 | 13373 |
| | SE-E&W | 3000 | 14000 | 8639 |
| | S-E&W | 0 | 5000 | 11005 |
| | **Total E&W** | **3000** | **73000** | **61217** |
| **Total** | | **13000 / 18000** | **82500** | **67690** |

From the reliability point of view, and without loss of generality, the generation system model assumes that all conventional generating units have a generic capacity of 500MW. A standard two-state operation mode is applied to simulate the behaviour of the generating unit. The unit is fully available with probability 0.85 and the unit is completely unavailable with probability 0.15 (FOR equal to 15%). It is also assumed

that there is no correlation between the availabilities of individual conventional units – failure of one does not increase the risk of failure of others.

### 4.5.2 Transfer capability for reliability

Transfer capability requirements, calculated from the developed planning methodology, i.e. reliability driven network capacity, are presented in Figure 4-19 for the generation scenarios considered.

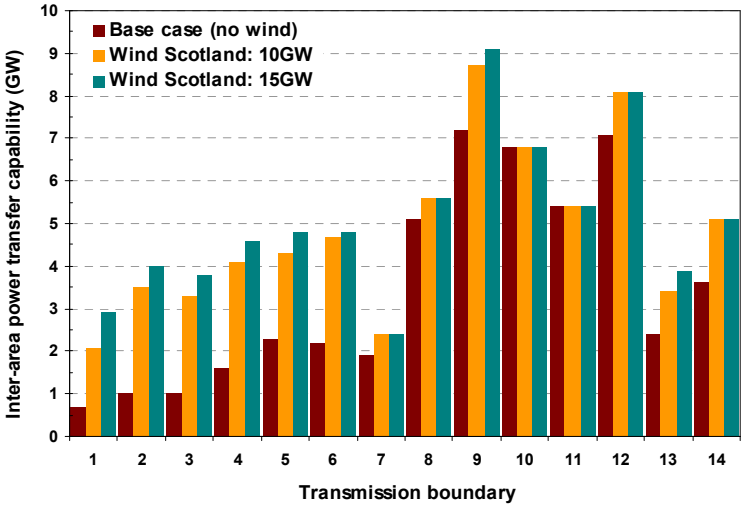



**Figure 4-19: Capacity of the major GB transmission boundaries with different wind penetration levels**

When 10GW and 15GW of wind are added in Scotland, investment is required to reinforce the network, assuming that no conventional plant is decommissioned in Scotland (the worst case scenario). This assumption will tend to increase the need for transmission between Scotland and England.

It is observed that the network capacity across the boundary between Scotland and England (TB5), driven by reliability, increases to 4.3GW for 10GW of wind and to 4.8GW for 15GW of wind. Note that increasing wind capacity from 10GW to 15GW changes the transfer capability very little as the capacity value of non-diverse wind is limited (see Figure 4-8). To ensure system reliability, the transmission network must be of sufficient capacity to enable generation to contribute to the supply of load at peak times. Thus, it is not appropriate to build significant amount of transfer capability for a power source that is not sufficiently reliable (limited capacity value). The results also

show that for security reasons, 3GW of wind installed in the South East of England will not reduce the transfer capability needed.

In summary, these findings confirm that wind generation drives less transfer capability than conventional generation. This is because wind has limited capacity value and cannot be relied upon to secure load at times of peak demand.

### 4.5.3 Transfer capability for economic efficiency

Historically, reliability driven design of the transmission network to meet peak demand requirements has also delivered capacity that has not compromised the economic efficiency of the system (i.e. ensuring demand can access to low cost generation). However, in the emerging system with a high penetration of wind, this approach of designing networks to maintain system reliability may no longer be the only and key driving factor for the specification of transmission network design.

High penetration of low capacity value generation such as wind requires existing conventional generation to remain on the system to ensure that sufficient capacity is available during demand peaks. Thus, the emerging system will feature an increasingly large generation capacity margin which exceeds demand by a significant amount[3]. Under these conditions, it is clearly not economically efficient to invest in sufficient network capacity to accommodate simultaneous peaks from all generators, as there would never be sufficient demand to absorb this generation. Therefore, the network design for systems with significant share of intermittent wind generation must also consider economic efficiency as a fundamental factor in network investment decisions.

This section illustrates how economic efficiency can drive transmission network investment in systems with significant penetration of wind generation, and highlights how the balance between reliability and economic driven investment changes.

[3] Consider the following example: in a system dominated by conventional generation, 60GW peak demand is supplied with 72GW of generation; this is equivalent to a 20% capacity margin. If another 26GW of wind is added to this mix this will displace, say 5GW of conventional capacity (using an optimistic assumption that wind has a capacity value of 20%); in this system there is now a total installed capacity of 93 GW to supply 60GW of peak, more than 50% capacity margin.

### Economic efficiency driven transmission in systems with wind generation

Optimisation of network capacity according to the most economically efficient solution will allow demand customers to take advantage of low marginal cost generators, such as wind. By conducting a cost-benefit analysis, decisions taken to reinforce transmission can be justified if the savings in the marginal reduction in generation costs (marginal cost of constraints) caused by penetration of new wind generation are greater than the marginal transmission network investment cost.

A study from the SEDG Centre (Strbac et al., 2007) developed an investment optimisation methodology (based on a Drain Current Optimal Power Flow formulation and using a simplified GB transmission model, Figure 4-18) that, through simulation and optimisation of the system operation across an annual time horizon, balances the annual generation costs and amortised investment costs in order to analyse the need for transmission system reinforcements. Under this methodology, the cost of transmission infrastructure and the cost of constraints will be the key drivers for decisions associated with network reinforcement[4].

It is out of the scope of this thesis to attempt a detailed description of the transmission planning methodology based on cost-benefit analysis. Such analysis is developed and presented in (Strbac et al., 2007).

### Transfer capability requirements for wind in systems designed for economic efficiency

To illustrate the outcome of a Cost Benefit Analysis (CBA) for transmission requirements in the case of connection of wind in Scotland, 10GW of wind was connected in locations in Scotland in the GB model outlined above. The analysis assumes that no conventional plant will be decommissioned in Scotland (worst case scenario) and that constraint costs are cost reflective. The total installed capacity of generation (conventional plus wind) in Scotland is fixed at 19.5GW, and local load is set at 6.5GW (Table 4-4). The results for economically optimal transfer capability at

[4] Although it is in principle appropriate that a cost-benefit analysis is applied for determining network capacity and investment, this approach also relies on a range of assumptions that may be contentious. This includes future generation technology distributions, fuel costs, projection of future constraint costs and their variations in time and space, network reinforcement cost.

each of the 14 boundaries are presented in Table 4-5 alongside the results for a reliability optimised design.

**Table 4-5: Comparison of transfer capabilities associated with key system boundaries derived using the approaches for reliability and economic efficiency**

| Boundary | From area | To area | Transfer capability (MW) | |
|---|---|---|---|---|
| | | | Reliability | Economics |
| **TB 1** | **NW-SHETL** | **N-SHETL** | **2100** | **2437** |
| **TB 2** | **N-SHETL** | **S-SHETL** | **3500** | **3571** |
| **TB 3** | **S-SHETL** | **N-SPTL** | **3300** | **4110** |
| **TB 4** | **N-SPTL** | **S-SPTL** | **4100** | **3564** |
| **TB 5** | **S-SPTL** | **UN-E&W** | **4300** | **5357** |
| **TB 6** | **UN-E&W** | **N-E&W** | **4700** | **4935** |
| TB 7 | NW-E&W | N-E&W | 2400 | 1942 |
| TB 8 | NE-E&W | N-E&W | 5600 | 2218 |
| **TB 9** | **N-E&W** | **M-E&W** | **8700** | **7870** |
| TB 10 | MW-E&W | M-E&W | 6800 | 4798 |
| TB 11 | ME-E&W | M-E&W | 5400 | 4459 |
| **TB 12** | **M-E&W** | **S-E&W** | **8100** | **8434** |
| TB 13 | SW-E&W | S-E&W | 3400 | 2781 |
| TB 14 | SE-E&W | S-E&W | 5100 | 1438 |

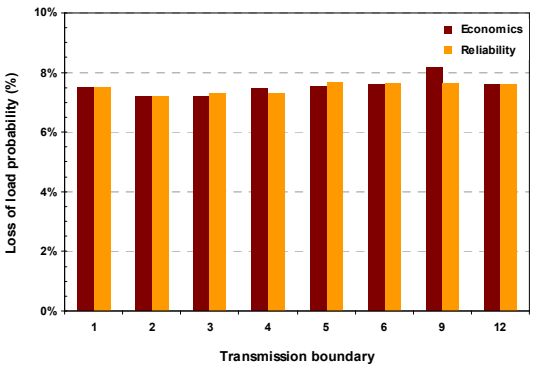
When building a transmission network for economic efficiency, the key impact of wind generation is that it is no longer optimal to build a network to support the simultaneous output from all generators; instead generators can share network capacity. This is illustrated in the capacity requirements indicated for the Cheviot Boundary (boundary number 5 between Scotland and England). To accommodate peak output would indicate the construction of more than 10GW of capacity in this location (the total generation capacity in Scotland less the local demand). However, from Table 4-5 it can be observed that the economically optimal network capacity across boundary 5 should be set at 5.4GW. This result provides clear evidence that it is not economically efficient to invest in transmission to accommodate simultaneous peak outputs from both wind and conventional generation, and it demonstrates that transfer capability should be shared between conventional and wind generation. On windy days the capacity of transmission corridor between Scotland (S-SPTL) and England (UN-E&W) is primarily used to transport wind power, while on non-windy days, this capacity would be used to export energy from conventional plant. Hence, the network design for systems with a significant penetration of wind should create an optimally constrained network that facilitates the economically efficiency sharing of network capacity between wind and conventional generators.

In summary, the cost-benefit approach illustrates that economically efficient transmission investment is made when the opportunities for sharing of transmission between different generating resources are recognised.

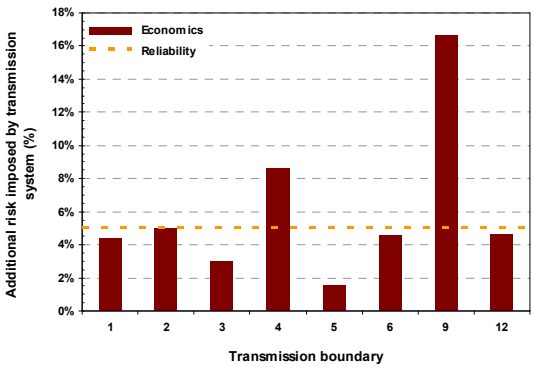
### 4.5.4 Shift in the nature of the transmission network investment

It was demonstrated in the previous section that in the presence of a significant share of intermittent wind generation in future systems, the design of the transmission network is not only and mainly driven by reliability considerations, but also by economic efficiency. As wind generation has limited capacity value (ability to displace conventional generation) and cannot be relied upon to secure load at times of peak demand, it requires building relatively small transfer capability to accommodate it. However, the requirement for economic efficiency (ensuring demand can access to low cost generation) should create an optimally constrained network that facilitates efficient sharing of network capacity between wind and conventional generators. Thus, the requirement for economic efficiency is likely to drive larger transmissions capacities than reliability considerations. These findings can be observed in Table 4-5 for the highlighted transmission boundaries (specifically selected to resemble the GB main interconnected transmission system present in GB SYS). It should also be stressed that the transfer capability associated with transmission boundary 4 and 9 is mainly driven by reliability rather than economic efficiency.

Based on the economically optimal transfer capabilities, the risk that the system will not be able to meet the demand as well as the additional risk to supply reliability induced by the presence of finite transfer capability are quantified and presented in Figure 4-20a and Figure 4-20b respectively.




(a) System risk imposed by transmission system




(b) Additional system risk imposed by transmission system

**Figure 4-20: System risk in economically efficient transmission network**

It is observed in Figure 4-20a that in the transmission boundaries where higher transfer capability is delivered by economic assessment (boundaries 1, 2, 3, 5, 6 and 12), the reliability of the network is slightly higher than that in the system designed for reliability, as additional capacity over and above that required by reliability is justified on the ground of economic efficiency. As a result, for these same boundaries, the additional risk introduced by the transmission system is slightly lower than the 5% additional risk driven by reliability assessment. For example in the case of Scotland-England transmission interconnector (boundary 5), the system risk decreases from 7.68% for the reliability approach to 7.53% for the economic efficiency approach along with a decrease in the additional risk from 5% for reliability to 1.54% for economic efficiency. In the transmission boundaries 4 and 9 the methodology for designing networks for reliability delivers more transfer capability than the economic efficiency approach. This highlights the importance of considering both reliability and economic efficiency approaches for specification of transmission network design.

## 4.6 Discussion and conclusions

The impact assessment undertaken in this chapter allowed to understand how reliability standards drive transmission network investment, and highlighted how the (constrained) transmission network contributes to system risk. The contributions of the network to compromising overall system reliability through preventing generation from accessing demand under peak conditions are limited. The presence of an optimally constrained transmission network only increases the Loss of Load Probability (LOLP) from 9 to

9.5% (increasing the chance of system failure from 9 to 9.5 times in 100 years). This means that historically, generation has had almost full access to load; the network has been built on the basis of reliability which has created a transmission system with a degree of network redundancy that does not compromise the economic efficiency driver for transmission (more than adequate capacity is built to satisfy the transmission requirements that allow load to access cheap generation).

Unlike the design of the transmission network in conventional systems, where all the operational network constraints are kept to a minimum, the introduction of wind power to the network changes this picture. As the impact assessment has identified, wind power can displace energy produced by conventional plant (i.e. reduce the fuel burnt), but its ability to displace capacity of conventional generation is limited. As the capacity credit of wind power is limited, network reinforcement driven by wind generation will be limited in systems designed for reliability. Wind generation is essentially a fuel saver, rather than a contributor to generation capacity, so building transmission to support it on this basis appears not to be optimal.

This chapter has highlighted that wind power generation has a low marginal cost and thus it is not justified to subject it to significant constraints. In this context, transmission network design for systems with significant penetration of wind should create an optimally constrained network that facilitates the economically efficient sharing of network capacity between wind and conventional generators. Broadly, expensive and fossil fuelled generation should be constrained off the system when the wind is blowing coincident with system peaks.

This suggests a shift in the nature of transmission network investment. While reliability is still a driver for specification of transmission network design; in the future sustainable power system with significant share of intermittent wind generation, the optimal networks are likely to be constructed with economic efficiency as a dominant driving factor for network investment decisions. Under these circumstances, the requirement to design a relatively unconstrained network to ensure reliability will be reduced (i.e. not all connected generators will contribute to this aspect of system planning), and in areas where network capacity is constructed for economic efficiency the relevance of the constraints is likely to increase.

Networks exist to transport energy securely and efficiently from generation to demand; and the design and investment of the network will be driven by the characteristics and requirements of both these network users. The impact assessment has identified and quantified the sensitivity of the key network impacts to different generation conditions. The import/export nature of the local network will impact on the transmission requirements of wind generators. In exporting areas the addition of wind generation plant type often drives less transfer capability than conventional generation. In importing areas, addition of wind generation may not displace significant amounts of network interconnection capacity and therefore interconnection capacity is still required to allow the load to be secured from other areas. Also, the capacity credit of a generation technology is a major contributor to the network capacity that it can drive. Wind power generation has low capacity credit and cannot be relied on to secure a significant amount of load at peak time and will correspondingly drive less transfer capability to support this limited activity. The diversity of the wind resource, as well as its load factor directly influence the capacity credit of this source and therefore the amount of network capacity that it can drive. Diversity relates to geographic dispersal of the wind resource. Wind farms that are spread across a wide geographical area will be subject to different wind regimes producing a diversity effect more significant. There will be less correlation between the output from generators and less chance of low/no output.

This chapter has identified and quantified the main impacts that the connection of wind generation has on the transmission network design and investment. The current technical and regulatory frameworks that support the transmission network design, investment and operation were created for a power system dominated by conventional plant and do not recognise the characteristics and impact of this new wind generation. The next chapter takes up this discussion to develop transmission security standards that recognise and take into account the different characteristics and impact of wind power generation.

# Chapter 5

# Development of transmission security standards to include wind generation

## 5.1 Introduction

Electric power systems are undergoing a period of material change around the world. The rapid rise of interest in the connection of wind power generation to both transmission and distribution systems present new challenges for network investment planners and stakeholders in the electricity supply industry. In the United Kingdom, the government has set targets of 10% and 20% of electrical energy from renewable sources by the year 2010 and 2020 respectively (BERR, 2007). These targets and the accompanying renewable energy incentive schemes have initiated a vast increase in applications for connections to the national transmission and distribution systems (Bayfield et al., 2006).

If the significant on and offshore wind resources in the UK are exploited for generation, its efficient integration in the transmission network operation and development is critically important. The design and investment of the transmission infrastructure is driven by the Great Britain Security and Quality Supply Standards (NG, 2004) that have been conceptualised for conventional, large-scale, centralised generation plant and do not consider the distinct characteristics of wind power. The limited contribution that wind generation can make to the security of the system and their low utilisation factors challenges the underlying assumptions of the security standards. As wind power and conventional generation have such different operating characteristics, applying the same rules and assumptions across the different generation technologies is likely to lead to suboptimal over- or under- investment and might result in a significant increase in the risk of loss of supply. There is therefore a need to establish how wind generation should be treated in the context of transmission network planning and to identify which appropriate modifications to the standard should be made.

There have been a number of studies investigating the transmission network reinforcement requirements arising from the increased penetration of wind generation.

The initial work undertaken by the three Great Britain transmission licensees as part of the Renewable Energy Transmission Study, (DTI, 2003), assumed that wind and conventional generation drive the same amount of transmission investment (i.e. 83% of the installed wind capacity). Subsequent work (NG, 2008) by the transmission licensees acknowledges that building transmission to transport 72% of the aggregated installed capacity of wind power will be adequate in most instances. This implies that most of the power output from wind and conventional generation can be accommodated during peak demand conditions. Other work undertaken by Sinclair Knight Merz, (SKM, 2005), highlights that the expected wind power output during peak demand is only about 20% of the installed wind capacity. Thus it argues that transmission should only be built for that capacity, with conventional plant constrained during peak wind conditions. Independent analysis (Allan et al., 2004) carried out to assess the security contributions of generators on distribution networks demonstrated that the contribution of wind to secure peak demand is about 25-30% of the installed wind capacity.

This chapter presents the development of a new transmission planning criterion which provides a rational and clear basis for investment in transmission. The minimum inter-area power transfer capability is defined by means of contribution factors of the different generation technologies and demand, both location specific, to the required level of transfer capability. This new method, described as the 'contribution factors method', is presented as the basis to update the design criteria of the GB main interconnected transmission system as stated in the GB SQSS.

This chapter goes over the principles and concepts on which the deterministic transmission planning guidelines were developed and the assumptions underpinning existing application procedures in order to identify and examine their strengths and weaknesses. It first outlines the background upon which the planning criteria of the GB MITS have been conceptualised and developed for conventional generation plant. It then lays out how wind generation is treated in the context of transmission investment planning. Alongside, it identifies and discusses points of friction where the penetration of wind generation is most likely to cause investment challenges.

The chapter then exposes the new methodology, the 'contribution factors method', to determine an adequate level of the inter-area transmission system transfer capability based on the characterisation of simple functions. The 'contribution factors method'

devises practical rules for the application in transmission planning procedures by transmission planners. In addition it explores the effect of various sensitivity factors, i.e. wind power characteristics and generation units' characteristics, on the contribution factors of the different generation technologies and demand to the inter-area transmission system transfer capability.

The review exercise is not a wholesale revision of the existing standard or assessment of the philosophy and principles behind it, but an update exercise to incorporate consideration of requirements driven by inclusion of wind into the UK generation mix.

## 5.2 Design criteria of the Great Britain main interconnected transmission systems

The main interconnected transmission systems (MITS) design criteria in the present Great Britain 'Security and Quality of Supply Standard' (GB SQSS) is composed of two parts: (i) 'security', i.e. a minimum secure inter-area transfer capability at time of system peak demand; and (ii) 'economic optimality', i.e. minimum transfer capability under conditions in the course of a year's operation.

In the context of 'security' criteria, one of the key features of the transmission planning guidelines used by CEGB, prior to decentralisation of the electricity industry in Great Britain in 1990, was a rule for determining the minimum secure capability of the system to transfer power between one region and another. This same rule is still in force today, and to comply with their operating licences, the three GB transmission licensees – National Grid (NG), Scottish Power Transmission (SPT) and Scottish Hydro-Electric Transmission Limited (SHETL) – must invest to provide an adequate level of transmission capacity consistent with the rule and other criteria written in the Great Britain Security and Quality of Supply Standard (GB SQSS) (NG, 2004). Broadly, the purpose of this rule is to enable a secure level of access to generation remote from demand when there is a deficit of available generation in relation to local demand, i.e. 'the transmission network should be of sufficient capacity so that it does not unduly restrict generators in contributing to security of supply'.

The minimum inter-area transmission system transfer capability is defined in (NG, 2004) for the time of system peak demand by means of two components: (i) 'planned

transfer'; (ii) 'interconnection allowance'. The transmission system transfer capability is expressed as follows:

$$TC = PT + IA \tag{5.1}$$

Where '*TC*' is the transmission capability, '*PT*' is the planned transfer and '*IA*' is the interconnection allowance.

The planned transfer is the median level of transfer of power across the boundary at the time of system peak demand. The interconnection allowance represents an estimate of the maximum additional power transfer above the planned transfer as a consequence of generation deficits and uncertainty in load demand.

### 5.2.1 Planned transfer

The 'planned transfer' is defined as the inter-area transfer (average transfer of power) at the time of peak demand and is determined by the average local plant/demand balances known as the 'planned transfer condition'. The overall process for modelling the planned transfer may be regarded as being made up of two techniques; (i) the ranking order technique (to be applied when capacity margin exceeds 20%), and (ii) the straight scaling technique (to be applied when capacity margin is 20% or less).

#### Ranking order technique

To maintain adequate security of supply, the total installed generation capacity must be larger than the system maximum demand in order to account for generation breakdowns and variations in demand. The magnitude of generation plant above the peak demand is called the capacity margin. The former generation security standard, used by CEGB ahead of industry's decentralisation, required a 24% capacity margin to ensure a risk of loss of supply of 9% at most (CEGB, 1985). Since decentralisation, the observed capacity margin in England and Wales has consistently been around 20% (Bell, 2006) and providing there is not a generation security standard that requires a particular capacity margin, the 20% figure is written into the GB SQSS in the context of the transmission planning criteria.

Presuming a system characterised by a capacity margin greater than 20%, the ranking order technique must be applied until a capacity margin of 20% or just below is achieved. To do so, all generating units are arranged in order of likelihood of operation at time of system peak demand. Generating units with a high load factor over the winter period are ranked as having a high likelihood of operation at time of system peak demand and therefore they are placed at the top of the list. These units are treated as 'contributory' generation, i.e. equally likely to be utilised for meeting demand. The lower ranking plants in the ranking order are then progressively removed and treated as 'non-contributory' until a capacity margin of 20% or just below is attained. GB SQSS defines capacity margin as follows:

$$CM = \frac{\sum_{T_j}\left(B_T \times \sum_i G_{T_i}\right) - \left(\sum_j D_j - \sum_k P_{I_k}\right)}{\sum_j D_j - \sum_k P_{I_k}} \tag{5.2}$$

Where '$CM$' is the capacity margin, '$B_T$' is the winter peak availability of generation of type '$T$' at the time of system peak demand, '$G_{Ti}$' is the generation capacity of unit '$i$', '$D_j$' is the demand in area '$j$' at the time of system peak demand and '$P_{Ik}$' is the import capacity from the '$k$' external system.

To illustrate the ranking order technique, consider a simple system composed of identical conventional units, with a generic capacity of 500MW each and a peak demand of 50GW. The ranking order is presented in Table 5-1. '$\text{Unit}_1$' is the most likely to run and therefore is placed at the top of the table. '$\text{Unit}_1$' to '$\text{Unit}_{k-2}$' are termed as 'contributory' generation, constituting the generation background for the purposes of planned transfer condition. The remaining units are treated as 'non-contributory' generation ('$\text{Unit}_{k-1}$' and '$\text{Unit}_k$') as they are not used in the generation background for transmission planning. To supply a peak demand of 50GW with a capacity margin of 20% the system requires 60GW of installed generation capacity.

**Table 5-1: Ranking order of conventional generation technologies**

| Generating unit | Registered capacity (MW) | Cumulative capacity (MW) | Capacity margin (%) |
|---|---|---|---|
| $Unit_1$ | 500 | 500 | 0 |
| $Unit_2$ | 500 | 1000 | 0 |
| … | … | … | … |
| **$Unit_{k-2}$** | **500** | **60000** | **20** |
| $Unit_{k-1}$ | 500 | 60500 | 21 |
| $Unit_k$ | 500 | 61000 | 22 |

In establishing which plant in the ranking order is to be regarded as contributory and non-contributory, the cumulative system generation capacity to be compared with demand in the calculation of capacity margin has been taken as 100% of the capacity of each conventional generator ('$B_T$' for conventional generation is represented by '$B_C$') (NG, 2007).

### Straight scaling technique

Straight scaling technique is applied, when the capacity margin is 20% or less, to balance generation and demand. The generation output of all contributory plant is scaled down uniformly across the system by applying '$A_T$' and '$S$' scaling factors to their capacities, to exactly meet the forecast peak demand. Generation is scaled in proportion to its availability at the time of system peak demand as follows:

$$P_{T_i} = S \times A_T \times R_{T_i} \tag{5.3}$$

Where '$P_{Ti}$' is the power output of generating unit '$i$' of type '$T$', '$S$' is a scaling factor to match generation and demand and represents the utilisation factor of generation of type '$T$' at the time of system peak demand, '$A_T$' is the availability of generation of type '$T$' at the time of system peak demand and '$R_{Ti}$' is the registered capacity of unit '$i$' of type '$T$'. Under the system balance condition, the total output of all generating units equals the total demand. The following expression describes the planned transfer condition:

$$S \times \sum_T \left( A_T \times \sum_i R_{T_i} \right) = P_{loss} + \sum_j D_j - \sum_k P_{I_k} \tag{5.4}$$

Where '$P_{loss}$' is the active power losses on the transmission system.

Note that import capacity from external systems is not subject to scaling. This is based on the assumption that generation capacity from external sources will always be available, up to the capacity level of the interconnector, during times of peak demand.

#### Planned transfer calculation

The planned transfer can be determined for any interconnected transmission system as the power flow across the interconnector under the planned transfer condition (balance system), that is, the difference between scaled generation and demand on any side of the interconnector. The arithmetic sign of the difference indicates the direction of the flow. The planned transfer '*PT*' is expressed by equation (5.5):

$$PT = S \times \sum_{T_j} \left( A_T \times \sum_i R_{T_i} \right) - \sum_j D_j \tag{5.5}$$

The system under analysis is now divided into two contiguous parts, area A and B interconnected by a transmission line of finite transmission capacity. The total installed generation capacity of all contributory generation and the peak demand of the two resultant areas are representative of the size of the Scotland-England transmission interconnector and are illustrated in Figure 5-1.

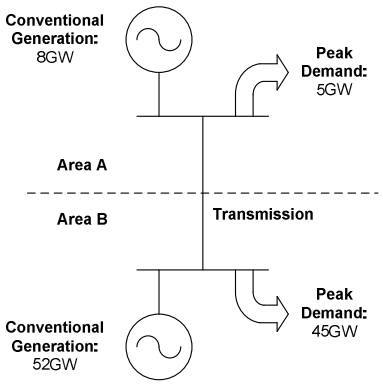



**Figure 5-1: Example of two-busbar system based on conventional generation technologies**

The scaling factor '*S*' is calculated by solving equation (5.4) with respect to variable '*S*'. The availability factor '$A_T$' for conventional generation is represented by '$A_C$' and the

registered capacity '$R_{Ti}$' for conventional generation is represented by '$R_{Ci}$'. Traditionally, network investment planners have taken an availability factor of 100% for conventional generation. '$P_{loss}$' and '$P_{ik}$' are assumed to be zero. In this respect, the scaling factor '$S$' is calculated as follows:

$$S = \frac{P_{loss} + \sum_{j} D_j - \sum_{k} P_{I_k}}{\sum_{T} \left( A_T \times \sum_{i} R_{T_i} \right)} \tag{5.6}$$

The application of an availability factor of 100% for conventional generation leads to a contributory output for conventional generation of 83% in the planned transfer condition. This reflects the high utilisation factor of these plants during peak demand conditions. In systems dominated by conventional generation, the resulting network design has limited constraints to ensure that simultaneous output from all generators is possible to meet the system peak demand.

The planned transfer is calculated for both sides of the interconnector applying equation (5.5) as follows:

$$PT = S \times A_C \times \sum_{i} R_{Ci_A} - D_A = 0.83 \times 1 \times 8 - 5 = 1.67\text{GW} \tag{5.7}$$

$$PT = S \times A_C \times \sum_{i} R_{Ci_B} - D_B = 0.83 \times 1 \times 52 - 45 = -1.67\text{GW} \tag{5.8}$$

Under the planned transfer condition, there is an excess of generation in area A while there is a deficit of generation of the same magnitude in area B. The planned transfer across the interconnector is therefore 1.67GW from area A to area B. As mentioned earlier, this is the expected power flow across the boundary under peak demand conditions

#### Discussion on planned transfer

The planned transfer may be interpreted as to represent the median of the transfer across a boundary at a time of system peak demand, thus, there is a 50% chance that transmission network capacity will restrict generation in meeting demand. Furthermore,

there is no bias regarding the market's 'preference' for utilisation of some generators over others, of the same technology type, due to differing reliability or economics. That is, the concept of 'planned transfer' ignores the fact that the unplanned availability, the location and economics of the generation that the merit order uses can limit the inter-area transfer capability and lead to high constrain costs.

### 5.2.2 Interconnection allowance (the 'circle diagram' (MMC, 1987))

In reality, the system is unlikely to present an 'average' behaviour at all boundaries across the whole system, due to deficits of available generation and uncertainties of demand. The result is that the expected transfers will have a distribution surrounding the average or planned transfer value. This deviation from the average is allowed for by adding a margin to the planned transfer. This margin is known as the interconnection allowance and is calculated empirically from the size of two parts by inspection of the circle diagram (stylised form suitable for deterministic application, Figure 5-2). The purpose of the interconnection allowance is to ensure that transmission does not unduly restrict generation from contributing to demand security. Note, however, that the interconnection allowance does not seek to provide a constraint-free transmission system.

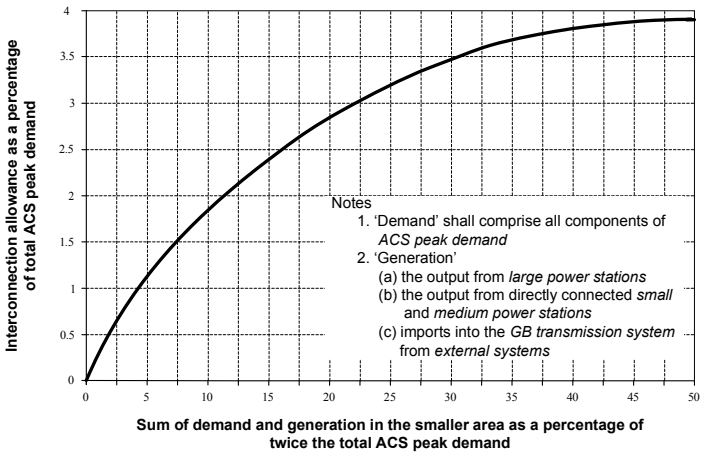



**Figure 5-2: Interconnection allowance as a function of area size (the 'circle diagram')**

The circle diagram was derived by analysing actual inter-area flows over a period of time (1943-1949) and constructing a relationship between the likely maximum required transfer and the generation and demand in the smaller of the two areas under

consideration (MMC, 1987). The interconnection allowance shall apply to any transmission boundary, providing that the smaller part has more than 1500MW of peak demand at the time of system peak demand.

The interconnection allowance is read off the *y*-axis of the circle diagram (as a percentage of the system peak demand) for a corresponding *x*-axis value. The *x*-axis value is calculated as the sum of the demand and total generation capacity under the planned transfer condition within the smaller area as percentage of twice the system peak demand. The relationship characterising the *x*-axis of the circle diagram is as follows:

$$x_j = \frac{S \times \sum_{T_j} \left( A_T \times \sum_i R_{T_i} \right) + D_j}{2 \times \sum_j D_j} \tag{5.9}$$

Where '$x_j$' is the *x*-axis of the circle diagram.

The interconnection allowance is determined from the *y*-axis of the circle diagram as follows:

$$IA = y_j \times \sum_j D_j \tag{5.10}$$

Where '*IA*' is the interconnection allowance and '$y_j$' is the *y*-axis of the circle diagram.

It can be concluded from Figure 5-2 and from the equations (5.9) and (5.10) that '*IA*' is greater for relatively large areas and smaller for smaller areas. The nearer the two areas are to being equal in 'size', the larger the '*IA*'.

For the example developed along this section, the smaller area is determined by comparing the sum of the peak demand in area A and total generation capacity under planned transfer condition in area A with that in area B, that is, 11.67GW compared with 88.33GW respectively. Clearly, area A is the smaller area. The *x*-axis of the circle diagram is determined as follows:

$$x_A = \frac{S \times \sum_{C_A} \left( A_C \times \sum_i R_{Ci_A} \right) + D_A}{2 \times \left( D_A + D_B \right)} = \frac{0.83 \times 1 \times 8 + 5}{2 \times \left( 5 + 45 \right)} = 11.67\% \quad (5.11)$$

By inspection of the circle diagram, Figure 5-2, to an abscissa value of 11.67% corresponds an ordinate value of 2.07%. This equates to an interconnection allowance of 1.04GW ($0.0207 \times 50 = 1.04$). The interconnection allowance is a function of the number of the circuit outages being considered. Thus, the GB SQSS requires a full interconnection allowance, 1.04GW, when considering any single circuit out of service, and half of the interconnection allowance, 0.52GW, in case of two circuits out of service.

#### Discussion on interconnection allowance

The circle diagram is based on power flows observed in the 1940s. At that time, the system was operated in discrete areas, each with sufficient generation (small number of large-scale generating units) to meet its own local demand and with limited interconnection only to facilitate support during generation maintenance or at off-peak times. On this system the actual power flows over the limited interconnection at the time of peak demand indicated the extent of imbalance between areas. The maximum imbalances observed in that limited period would not serve as good estimates of the maximum long-term imbalances that might be observed under common underlying conditions, but rather would represent some quite high percentile of the long-term distribution of imbalances. Thus the use of the 'circle diagram' is not fully consistent with its derivation, since it is applied to an unbalanced system and not to a balanced system of the type which existed in the 1940s.

### 5.2.3 Minimum inter-area transmission system transfer capability

The requirement of the GB SQSS is that the transmission system must be capable of securing, for each relevant boundary at time of peak demand and against a loss of a single circuit, a level of inter-area transfer equal to the planned transfer of the boundary plus its interconnection allowance, equation (5.12). Thus, within the statistical limits of

the interconnection allowance function, a single circuit fault outage should only very rarely be a cause of insufficiency of import capability to serve demand in a large area.

$$TC_{(N-1)} = PT + IA \tag{5.12}$$

Where '*TC*' is the transmission capability, '*PT*' is the planned transfer and '*IA*' is the interconnection allowance.

There is a 'N-D' or 'N-2' required transfer capability, i.e. that secure to the fault outage of a double circuit. The transmission system must be capable of securing, for each relevant boundary at time of peak demand, a level of inter-area transfer equal to the planned transfer of the boundary plus half of its interconnection allowance, equation (5.13).

$$TC_{(N-2)} = PT + \frac{IA}{2} \tag{5.13}$$

The existence of two levels of secure transfer capability reflects the notion that 'N-2' circumstances during peak demand conditions are less likely to arise, and therefore the 'N-2' level of secure transfer capability does not need to encompass as wide range of possible transfer requirements as for 'N-1'. When these security tests reveal any overloading investment in system reinforcement must be made.

The required transmission system transfer capability is calculated using equation (5.12) and (5.13) for the credible contingencies:

$$TC_{(N-1)} = PT + IA = 1.67 + 1.04 = 2.71\text{GW} \tag{5.14}$$

$$TC_{(N-2)} = PT + \frac{IA}{2} = 1.67 + 0.52 = 2.19\text{GW} \tag{5.15}$$

The network must be able to carry 2.71GW with any single circuit out of service and 2.19GW with any two circuits out of service.

Figure 5-3 illustrates the concept of the planned transfer as well as the impact of applying the interconnection allowance to the inter-area transfer capabilities by the means of the probability distribution of the inter-area power flow.

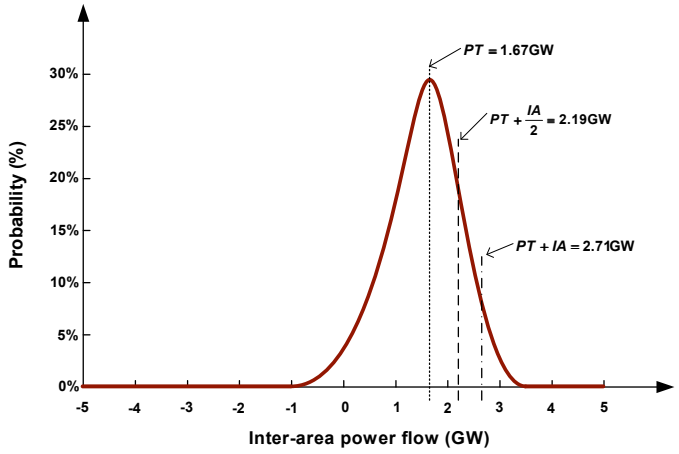



**Figure 5-3: Probability distribution of the inter-area power flow over the winter peak period**

Figure 5-3 demonstrates that there is a 50% chance that the actual flows across the boundary, during the time of peak demand, could exceed the planned transfer. It is observed that by adding the interconnection allowance to the planned transfer, the likelihood of the actual inter-area transfers exceeding the required transfer capability is reduced. 'N-2' (*PT+IA/2*) circumstances at time of peak demand are less likely to arise, and therefore 'N-2' level of secure transfer capability need not to encompass as wide a range of the possible transfer requirements as 'N-1' (*PT+IA*). In summary, the interconnection allowance reduces the likelihood of inter-area flows exceeding the boundary's transfer capability.

### 5.2.4 Performance of the current design criterion of the MITS

The performance of the transmission infrastructure design criteria of the present GB SQSS is compared with the reliability based approach developed in Chapter 4. A two-area system (similar to the example presented in Figure 5-1) is used to illustrate the transmission network capacity requirements driven by the two approaches. The system under analysis is characterised by 5GW of peak demand in area A and 45GW of peak demand in area B. Area A is now characterised by increasing levels of installed conventional capacity varying from 0 to 10GW.

Figure 5-4 presents the transfer capability required to connect the two areas for different levels of installed conventional capacity in area A.

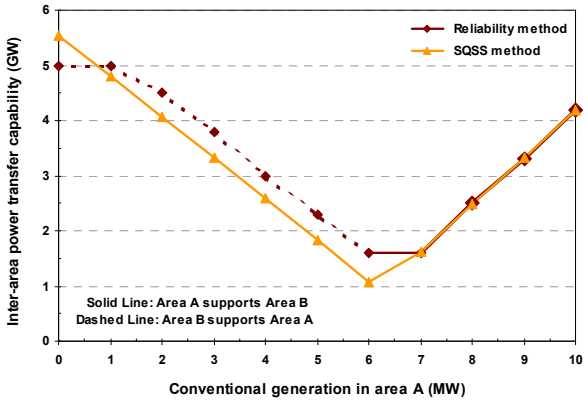



**Figure 5-4: Comparison of required transfer capability derived using the methods for reliability and current SQSS in a system with conventional generation technologies**

In importing areas GB SQSS slightly underestimates (about 500MW less of transfer capability) the transfer capability requirements when compared to the reliability based approach. Nonetheless, in purely demand dominated areas characterised by the inexistence of conventional plant, GB SQSS overestimates (about 500MW excess) the transfer capability requirements. It builds transmission networks to be able to carry an inter-area transfer of power of 5GW enhanced by 500MW of interconnection allowance to supply the local peak demand. In this case, an interconnection allowance is not required to maintain the same level of security of loss of supply delivered by the reliability approach.

For exporting areas the levels of transfer capability suggested by GB SQSS maintain the risk of loss of supply in the system at adequate levels (not greater than benchmark risk, $LOLP_{Reference}$). The levels of transfer capability are similar to those delivered by reliability approach. This analysis demonstrates that the present transmission security standards deliver sufficient transmission system transfer capability in systems with conventional generation technologies.

## 5.3 The design criterion of the Great Britain MITS with the presence of intermittent wind power generation

The design of the MITS has been conceptualised for large conventional generating units. These units have a high utilisation factor during peak demand conditions (typically 83% given a capacity margin of 20%). The limited contribution that wind generation can make to the security of the system and their low utilisation factors challenges the underlying assumptions of the security standards.

In the present transmission security standards the fundamental method of calculating both the 'planned transfer' and 'interconnection allowance' recognises different scaling factors according to generator type, based on typical availabilities at times of peak demand; this is particularly relevant when considering contributions from wind generation. However, it does not provide any indicative values for the scaling factors of different generator types. The improper set of the scaling factors might result in failure to utilise the full potential of wind farms to reduce emissions, they might result in higher risks of loss of supply and in excessive system constraint costs.

This section reviews the philosophy and assesses the performance of the design criteria of the MITS in the context of the intermittent wind generation. It identifies and examines strengths and weaknesses of the transmission security standards and discusses the implications of wind power generation in the transmission investment strategy.

### 5.3.1 Wind generation in the 'ranking order'

In the present GB SQSS, the contribution of a generating plant of type '$T$' in the ranking order is expressed by the winter peak availability factor '$B_T$' that figures in the calculation of the capacity margin, equation (5.2). The quantification of '$B_W$' is based on converting the installed wind capacity into an equivalent conventional plant that has the same average availability at the time of system peak demand. The observed load factor, over the winter peak period, is in the region of 36% for wind generation and 90% for conventional generation (NG, 2008). The equivalent conventional capacity of wind generation expressed as a percentage of its installed capacity is calculated as the ratio between winter wind load factor and the conventional plant availability factor (0.36/0.9 = 0.4). This suggests that a 100MW wind farm, for example, would be treated as a 40MW thermal unit (with an availability of 90%) in the ranking order.

To illustrate the ranking order technique, consider the system presented in section 5.2.1 (subsection 'ranking order technique'), now with the presence of 10GW of wind power generation. The ranking order is presented in Table 5-2 where wind generation is ranked as having high likelihood of operation during the winter peak period and therefore placed near the top of list.

**Table 5-2: Ranking order of conventional and wind generation technologies**

| Generating unit | Registered capacity (MW) | Capacity Margin Contribution (MW) | Cumulative capacity (MW) | Capacity margin (%) |
|---|---|---|---|---|
| $Unit_1$ | 500 | 500 | 500 | 0 |
| $Windfarm_1$ | 400 | 0.4×400=160 | 660 | 0 |
| $Windfarm_2$ | 200 | 0.4×200=80 | 740 | 0 |
| … | … | … | … | … |
| **$Unit_{k-1}$** | **500** | **500** | **60000** | **20** |
| $Unit_k$ | 500 | 500 | 60500 | 21 |

It can be observed in Table 5-2 that the contributory output of wind generation is 40% of the installed wind capacity. This relatively low value translates the limited capacity contribution of wind generation in securing demand.

In a system level based analysis, 10GW of wind generation capacity corresponds to 4GW of equivalent conventional capacity. Treating the 10GW of wind generation capacity as contributory generation, 4GW of conventional generation near the bottom of the raking order list will become non-contributory generation.

Note that in establishing which plant, in the ranking order, is to be regarded as contributory and which is non-contributory, wind power generation is constantly treated as contributory generation.

To supply a peak demand of 50GW, in a generation system mix composed of 10GW of wind power generation and conventional plant, the installed conventional capacity required to ensure a system capacity margin of 20% is 56GW.

It must be stressed that the '$B_W$' factor of 40% is only used for the purposes of the ranking order technique.

**Discussion on 'the appropriateness of using winter wind load factor and its availability to compute the capacity credit of wind power generation'**

A recent GB based study (Oswald, 2006) identifies that wind power output is frequently below 20% of the total installed wind capacity during low temperatures, which can be interpreted as low wind output during time of peak demand. This result suggests that assuming a winter wind load factor of 36% for GB is somewhat optimistic.

'$B_W$' on equation (5.2) expresses the contribution of wind towards securing system peak demand. Specifically, it represents the ability of wind to displace capacity of conventional plant, i.e. the capacity credit wind, '$W_{CC}$'. In this context, it can be concluded that $W_{CC}$ is defined as the ratio between the winter wind load factor and the conventional plant availability factor (0.36/0.9 = 0.4). Using alternative approaches (Giebel, 2006) and (Milligan, 2005) to determine $W_{CC}$, lower figures are obtained. Results from other studies on the capacity credit of wind (Sinden, 2007), (UKERC, 2006), and (Mott MacDonald, 2003), also demonstrate that the capacity credit of wind power generation in GB is relatively low and varies according to its characteristics (i.e. penetration level, diversity, load factor, correlation between wind and peak demand, etc.). From reference, (Sinden, 2007) shows that at 10% penetration of wind energy the capacity credit of wind is about 20% and (Mott MacDonald, 2003) shows similar results with a value for $W_{CC}$ of 20%-30%.

The use in the GB SQSS of 40% as the capacity credit of wind generation, compared to the referenced lower values, results in an increase of the contribution of wind generation to security of supply (i.e. higher capacity margin in the ranking order technique). The outcome of this process is the growth of the inter-area transfer capability driven by wind power leading to transmission over-investment. On the contrary, the application of a capacity credit of wind lower than 40%, in the GB SQSS, leads to a lower capacity margin required for system security, driving less transmission capability.

### 5.3.2 Wind generation in the 'planned transfer'

The fundamental method of calculating planned transfer, equation (5.5), recognises different scaling factors, '$A_T$', according to generator type '$T$', based on typical availabilities at times of peak demand. However, the GB SQSS does not provide any

indicative values for the scaling factors of different generator types. Traditionally, network investment planners have taken an availability factor of 100% for conventional generation, leading to a contributory output for conventional generation of 83% in the planned transfer condition ('$A_T$' for conventional generation is expressed as '$A_C$'). The GB transmission licensees have specified an availability factor of 72% for wind generation to be used for the calculation of planned transfer in the GB SQSS (NG, 2007), ('$A_T$' for wind power is expressed as '$A_W$'). This availability factor translates to a contributory output for wind generation of 60% in the planned transfer condition.

For an interconnected transmission system containing significant volumes of wind power generation located in the areas on either side of the boundary, the use of a single availability factor for wind power across the network is no longer appropriate. At a contributory output of 60% in the planned transfer condition, the support from wind generation in the importing area would be over-estimated. To account for an imbalance in the wind generation output between the two areas, a low availability factor should be used for wind generation in the importing area. The GB SO proposed that the availability factor for wind generation located in importing areas is 5%, while that for wind generation located in exporting areas is 72% (these factors translate to contributory output for wind generation of 4% and 60% in the planned transfer respectively) (NG, 2008). A side-effect of this approach is that a single planned transfer has to be defined for each boundary that has wind on either side. Nevertheless, because most of the applications for connection of wind power generation are in Scotland (which is predominantly exporting area) only the 72% factor has been used across the entire system.

To illustrate how wind generation might impact the required inter-area transfer capability, consider the system under analysis (section 5.3.1) divided into two contiguous parts, area A and B, interconnected by a transmission line of finite transmission capacity. The total installed generation capacity of all contributory generation and the peak demand of the two resultant areas are illustrated in Figure 5-5. The generation/demand background is representative of the size of the Scotland-England transmission interconnector.

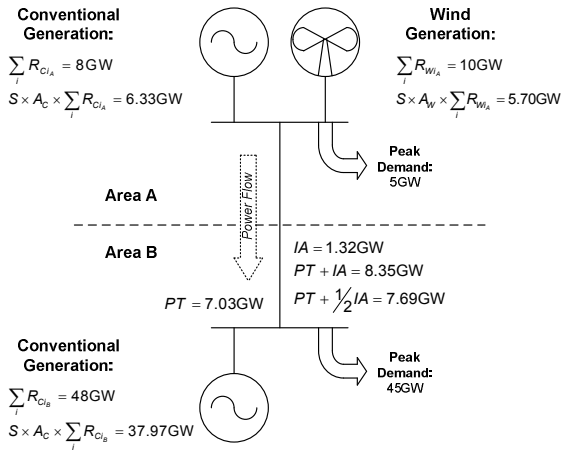



**Figure 5-5: Example of two-busbar system based on conventional and wind generation technologies**

The scaling factor '$S$' is calculated by solving equation (5.4) with respect to the variable '$S$'. The registered capacity '$R_{Ti}$' for wind generation is represented by '$R_{Wi}$'. On condition that '$P_{loss}$' and '$P_{ik}$' are zero, '$S$' is calculated as follows:

$$S = \frac{D_A + D_B}{A_C \times \left( \sum_i R_{Ci_A} + \sum_i R_{Ci_B} \right) + A_W \times \sum_i R_{Wi_A}} = \frac{50}{1 \times (8 + 48) + 0.72 \times 10} = 0.7911 \qquad (5.16)$$

The application of an '$S$' factor of 79% across the system leads to a contributory output factor of 79% for conventional generation and 57% for wind generation. Conventional plants is characterised by a high utilisation factor whilst wind is characterised by a smaller contributory factor, translating its limited contribution to transmission capacity.

The planned transfer is expressed by equation (5.5) and can be calculated based in the smaller area A. The planned transfer is as follows:

$$PT = S \times \left( A_C \times \sum_i R_{Ci_A} + A_W \times \sum_i R_{Wi_A} \right) - D_A = 0.79 \times (1 \times 8 + 0.72 \times 10) - 5 = 7.03\text{GW} \qquad (5.17)$$

The median level of transfer of power across the interconnector at time of peak demand is 7.03GW.

**Discussion on 'the appropriateness of using an availability factor for wind power, in the planned transfer, of 72% in exporting areas and 5% in importing areas'**

'$A_W$' represents the availability factor of wind power generation to be applied in the calculation of planned transfer, equation (5.5), in the GB SQSS. In essence, it can be seen as the contribution of wind power generation to the inter-area transmission system transfer capability, i.e. how much transfer capability wind generation drives from a security of supply perspective.

Earlier findings (Chapter 4, section 4.3.5) revealed that in exporting areas, the presence of wind generation increases the need for transmission reinforcement. However this increase is relatively small due to the limited wind power generation contribution to security of supply. In this respect, the allocation of a high availability factor for wind generation in the GBSQSS, 72%, is likely to lead to transmission over-investment in exporting areas.

It was earlier demonstrated (Chapter 4, section 4.3.5) that wind generation has a modest transmission capacity credit to provide reliability in importing areas; therefore it is not necessary to build transmission capability to accommodate it. The use of a low availability factor for wind power in the GB SQSS, 5%, might be appropriate to deliver secure transfer capability in importing areas.

Under the current deterministic arrangements, the scaling factors applied to generation have a considerable impact upon network investment requirements.

### 5.3.3 Wind generation in the 'interconnection allowance'

The method of calculating the interconnection allowance applies differential scaling factors according to generator type, based on typical availabilities at the time of peak demand. The availability factor for wind generation located in importing areas is 5% while that for wind generation located in exporting areas is 72%. The *x*-axis of the circle diagram is computed using equation (5.9):

$$x_A = \frac{S \times \left( A_C \times \sum_i R_{Ci_A} + A_W \times \sum_i R_{Wi_A} \right) + D_A}{2 \times \left( D_A + D_B \right)} = \frac{0.79 \times \left( 1 \times 8 + 0.72 \times 10 \right) + 5}{2 \times \left( 5 + 45 \right)} = 17.03\% \qquad (5.18)$$

This *x*-axis value gives a *y*-axis value of 2.64% which equates to an interconnection allowance of 1.32GW ( $0.0264 \times 50 = 1.32$ ).

**Discussion on 'interconnection allowance'**

Wind power generation has very different operating characteristics when compared to the conventional plant. Correspondingly, its impact on network design and operation is also different to that of the incumbent generators. While the method of calculating interconnection allowance (in particular, the *x*-axis of circle diagram, equation (5.9)) applies differential scaling factors according to generator type, the circle diagram has not been revised to account for the different characteristics of wind power generation.

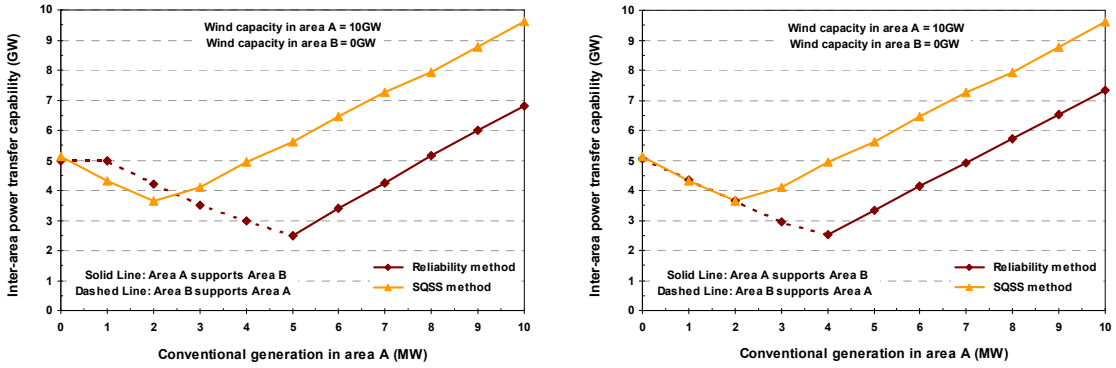
### 5.3.4 Wind generation in the 'transmission system transfer capability'

The minimum inter-area transmission system transfer capability, given by equation (5.12) and equation (5.13), is 8.34GW for any single circuit out of service and 7.68GW for any two circuits out of service.

### 5.3.5 Performance of the current design criterion of the MITS in systems with wind generation

The performance of the MITS design criterion of the present GB SQSS is compared with the reliability based approach developed in Chapter 4 in systems with wind generation. GB SQSS applies a scaling factor for wind equal to 72% in exporting areas and 5% in importing areas for the calculation of the planned transfer.

A two-area system (similar to the example presented in Figure 4-9) is used to illustrate the transmission network capacity requirements driven by the two aforementioned approaches. The system under analysis is characterised by 5GW of peak demand in area A and 45GW of peak demand in area B. Area A is now characterised by increasing levels of installed conventional capacity varying from 0 to 10GW and by an installed wind capacity of 10GW. Figure 5-6a and Figure 5-6b present the transmission capacity required for non-diverse and diverse wind source respectively.




**(a) Non-diverse wind source** **(b) Diverse wind source**

**Figure 5-6: Comparison of required transfer capability derived using the methods for reliability and current SQSS in a system with conventional and wind generation technologies**

Figure 5-6 shows that applying scaling factors '$A_{WE}$ = 72%' and '$A_{WI}$ = 5%' for wind power in the GB SQSS leads to significant over-investment in exporting areas. Nevertheless, in importing areas, the scaling factor '$A_{WI}$ = 5%' translates the low contribution of wind to security of supply leading to transmission capacity requirements similar to those delivered by the reliability based approach.

For higher levels of penetration of wind generation, these effects are significantly more prominent, resulting in significant transmission over-investment in the case of area A being an exporting area.

Clearly, applying unrealistically large scaling factors to wind generation, as used in the present GB SQSS, can lead to under-investment in transmission for importing areas and over-investment in transmission for exporting areas.

## 5.4 Approach to update the Great Britain transmission security standards

This section presents the development of a new transmission planning criterion which provides a rational and clear basis for investment in transmission. In the view of the requirement that any new MITS planning rule should not deliver less reliability of supply than presently delivered, a suitable basis for a new MITS planning rule might be that the required transmission capability should be that determined for the adequate meeting of peak demand for electricity.

The overall aim of the approach is to produce a practical and easy to apply new MITS planning criterion. The development of the new MITS planning criterion adopted three guiding principles in the definition of its scope:

i) to provide a simple, accurate and reliable means of identifying the required secure power transfer capability across boundaries of the GB main interconnected transmission system;

ii) to depend on the input of no more data than the equivalent MITS capability method in the present GB SQSS requires;

iii) the approach should be robust against feasible changes to the generation and demand background in the future years so minimising the likelihood of a further review of the MITS planning criterion being required in that period.

The inter-area power transfer capability is a stochastic quantity, influenced by uncertainty in demand and the availability of generation. A transmission planner might perform a detailed probabilistic assessment (as detailed in Chapter 4) of the required boundary capability for any given background of peak demand and generation capacity. However, noting the objectives above, the underlying relationships between the stochastic variables are characterised by a relatively simple function that the transmission planner might apply. In essence, the approach developed devises practical rules, similar to the present transmission security standards, for the application in transmission planning procedures.

### 5.4.1 Contribution factors method

The contribution factors method seeks to provide a relatively simple function to characterise the required transmission system transfer capability for any given background of peak demand and generation capacity. The minimum inter-area power transfer capability is defined for the time of system peak demand by means of the capacity contribution of the different generation technologies and demand, both location specific, to the required level of transfer capability. The inter-area transmission system transfer capability is expressed as follows:

$$TC = \sum_{t=1}^{T} \left( C_{T_k} \cdot G_{T_k} \right) + C_{D_k} \cdot D_{peak_k} \tag{5.19}$$

Where '$T$' is the number of the different generation technology types, '$C_{Tk}$' is the contribution factor of generation technology of type '$T$' in the area '$k$', '$G_{Tk}$' is the generation capacity of the generation technology of type '$T$' in the area '$k$'. '$C_{Dk}$' is the contribution factor of peak demand in the area '$k$' and '$D_{peakk}$' is the peak demand in the area '$k$'.

**Evaluation of the contribution factors**

The method to evaluate the capacity contribution of the different generation technologies and peak demand to the required transfer capability employs the methodology developed to quantify the optimum level of inter-area transmission system transfer capability in systems with wind power generation (Chapter 4, Section 4.2.8). The starting point is to determine the amount of conventional generation capacity that is adequate to supply a given peak demand with a desirable level of LOLP ($LOLP_{InfiniteTx}$). Peak demand and conventional generation only at either side of the boundary are now assumed to be interconnected by a transmission line of finite capacity, designed in accordance with the present MITS planning criterion. Based upon this transfer capability, the risk of loss of supply (LOLP as $LOLP_{FiniteTx}$) is quantified. Based on the knowledge of the previous risks, the additional risk that the system will not be able to meet peak demand that is imposed by transmission system ($Risk_{Tx}$) is calculated as in equation (4.1). Wind generation is then added to the system and the additional acceptable risk is used as a benchmark for determining the optimum level of required transfer capability in case of wind generation technologies, equation (4.2).

The capacity model (Chapter 4, Section 4.2.1) in each of the interconnected systems, A and B, can be represented by a combined-state diagram covering all the possible combinations of generation capacities states and peak demand in the two systems, Figure 5-7. For each combination of generation capacity states and peak demand, '$ij$' (Figure 5-7), scaling factors for generation technologies and demand are computed.

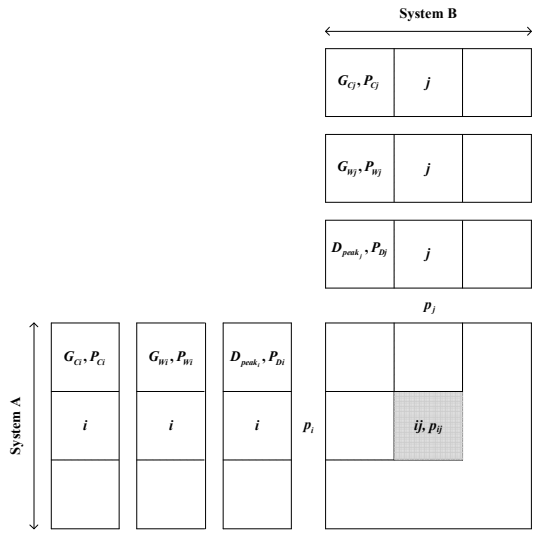



**Figure 5-7: Combined-state diagram of conventional and wind generation technologies and peak demand**

The scaling factors for generation balance the generation and demand in each state '*ij*'. Hence, the scaling factors for conventional generation '$SF_{Gij}$', are expressed as follows:

$$SF_{G_{ij}} = \begin{cases} \dfrac{D_{peak} - G_W}{G_C} & if \quad G \geq D_{peak} \\ 1 & if \quad G < D_{peak} \end{cases} \tag{5.20}$$

'$D_{peak}$' is the system's peak demand ($D_{peak}$=$D_{peaki}$+$D_{peakj}$), '$G_C$' is the system's conventional generation capacity in the state '*ij*' ($G_C$=$G_{Ci}$+$G_{Cj}$) and '$G_W$' is the system's wind generation capacity in the state '*ij*' ($G_W$=$G_{Wi}$+$G_{Wj}$).

Wind power is considered inflexible generation, that is, all wind generation capacity available is used towards meeting demand, therefore the scaling factor for generation in the state '*ij*' is equal to 1 ($SF_{Wij}$=1).

In order to balance generation and demand in states '*ij*' characterised by higher level of demand than generation, demand is curtailed. Hence, the scaling factors for demand '$SF_{Dij}$', are expressed by equation (5.21).

$$SF_{D_{ij}} = \begin{cases} 1 & if \quad G \geq D_{peak} \\ \dfrac{G_C + G_W}{D_{peak}} & if \quad G < D_{peak} \end{cases} \tag{5.21}$$

The scaling factors for generation technologies and demand are now used to compute the inter-area flow in each state '*ij*'. In generation dominated states, the generation capacity levels composing the state '*ij*' are scaled down uniformly across the system, by applying '$SF_{Gij}$' scaling factor, to exactly meet system peak demand. In demand dominated states the system's peak demand is scaled down, by applying '$SF_{Dij}$' scaling factor, to exactly match generation. The flow is each state '*ij*' is determined by the following equation:

$$F_{AB_{ij}} = SF_{G_{ij}} \cdot G_{C_{A_i}} + SF_{W_{ij}} \cdot G_{W_{A_i}} - SF_{D_{ij}} \cdot D_{peak_{A_i}} \tag{5.22}$$

'$F_{ABij}$' is the flow from system 'A' to system 'B' in the state '*ij*'. Note the flow '$F_{BAij}$' has the same magnitude but opposite direction, therefore $F_{ABij}$=-$F_{BAij}$.

Having the knowledge about the peak demand and generation capacity background at either side of the boundary, the optimum level of inter-area transmission system transfer capability, the scaling factors for the different generation technologies and demand, the probability of each '*ij*' state ('$p_{ij}$') and the magnitude and direction of the flow from one area to another, the capacity contribution factors of generation technologies and demand to inter-area power transfer capability can be quantified. In the computation of the contribution factors, only the flows '$F_{ABij}$' that drive the optimum level of transfer capability are taken into account. These are all states '*ij*' characterised by '$F_{ABij}$' equal to '*TC*'.

The capacity contribution, in MW, of the different generation technologies to the required inter-area power transfer capability is expressed by equation (5.23).

$$CC_{G_{T_k}} = \sum_{m=1}^{n} \left[ \left( c_G \cdot d_{flow_m} \cdot SF_{G_{T_m}} \cdot G_{T_m} \cdot G_{coef} \right) \cdot \frac{p_m}{\sum_{m=1}^{n} [p_m]} \right] \tag{5.23}$$

'$CC_{GTk}$' is the capacity contribution of the generation technology of type '*T*' in the area '*k*'. '*m*' represents all '*ij*' states which the inter-area flow is equal to the required transfer capability, '*n*' is the total number of states. '$c_G$' is a constraint factor for generation equal to -1 or 1 when area '*k*' is a importing area (demand dominated) or

exporting area (generation dominated) respectively. '$d_{flowm}$' is a factor that represents the direction of the flow (equal to -1 or 1). '$G_{coef}$' is a generation factor applied to achieve the appropriate spilt between generation and demand capacity contribution factor and is equal to 0.5. '$p_m$' is the probability of the state '$m$'.

The capacity contribution, in MW, of peak demand to the required inter-area power transfer capability is expressed by equation (5.24).

$$CC_{D_k} = \sum_{m=1}^{n} \left[ \left( c_D \cdot d_{flow_m} \cdot SF_{D_m} \cdot D_{peak_m} \cdot D_{coef} \right) \cdot \frac{p_m}{\sum_{m=1}^{n} [p_m]} \right] \tag{5.24}$$

'$CC_{Dk}$' is the capacity contribution of peak demand in the area '$k$'. '$c_D$' is a constraint factor for demand equal to -1 when area '$k$' is a generation dominated area or 1 when area '$k$' is demand dominated area. '$D_{coef}$' is a generation factor applied to achieve the appropriate spilt between generation and demand capacity contribution factor and is equal to 0.5.

In order to obtain the different generation technologies and demand factors that figure in equation (5.19), the capacity contributions factors must be normalised according to equation (5.25) and equation (5.26) respectively.

$$C_{G_{T_k}} = \frac{CC_{G_{T_k}}}{G_{T_k}} \tag{5.25}$$

$$C_{D_k} = \frac{CC_{D_k}}{D_{peak_k}} \tag{5.26}$$

Where '$C_{GTk}$' is the contribution of the generation technology of type '$T$' in the area '$k$' and '$C_{Dk}$' is the contribution factor of peak demand in the area '$k$'.

The schematic representation of the developed model used for evaluation of the contribution factors of different generation technologies and demand to transmission system transfer capability is represented in Figure 5-8.

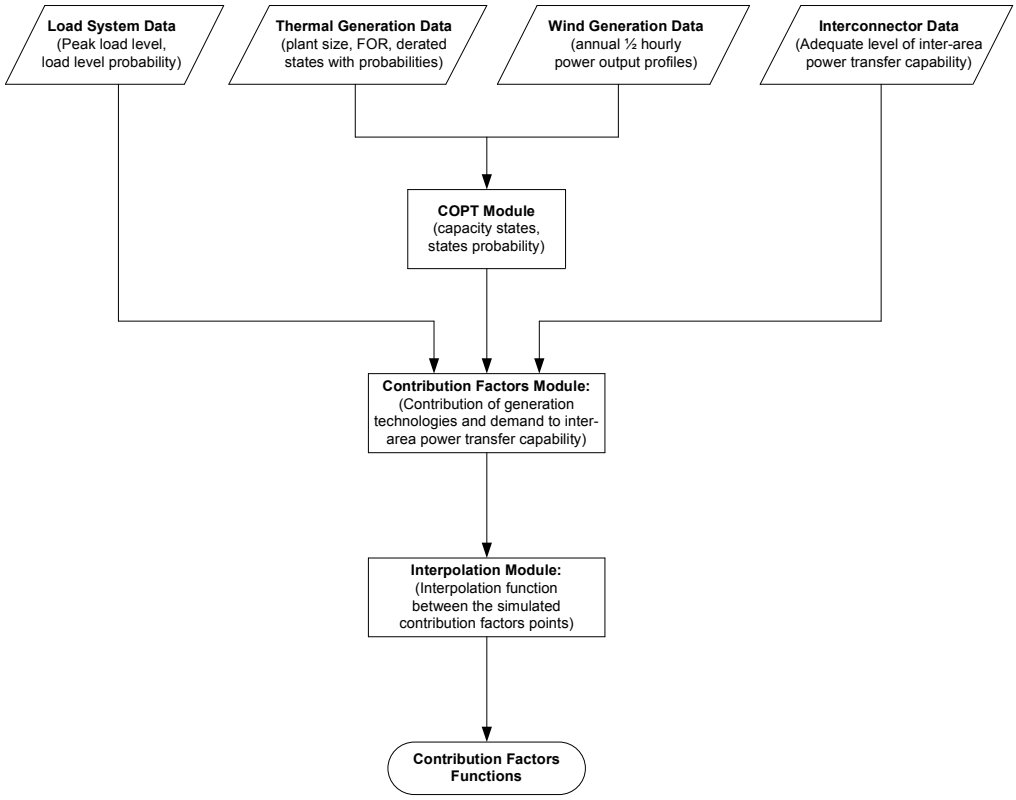



**Figure 5-8: Schematic representation of the model used for quantification of the contribution factors of the different generation technologies and demand to the inter-area transmission system transfer capability**

### 5.4.2 Characterisation of the contribution factors

This section seeks a suitably robust characterisation of the required transmission network capabilities by the means of a simple function representing the contribution factors of the different generation technologies and demand to inter-area transmission system transfer capability. A simple function based on a few inputs inevitably lacks some information that determines the system's 'real' position. However, suitable assumptions might be made for this information representing the system's 'typical' behaviour. These include (i) the average size of the conventional generating unit that would be subject to the most frequently occurring periods of forced outage, (ii) the average winter period availability of conventional generation (iii) the wind power characteristics, such as the wind resource diversity, the load factor of wind and the penetration level of wind generation.

With suitable assumptions for the above, studies are carried out to quantify the contribution factors of the different generation technologies and demand to the inter-area transmission system transfer capability. The studies are set up to cover the entire

feasible range of the inputs in order to identify the contribution factors that might be used by a transmission planner. The results permit an exploration of the relationships between the values of the inputs and that of the output – the 'N-1' or 'N-2' contribution factors to required transfer capability. These relationships are found to be sufficiently smooth, and given that the number of studies is sufficiently large and well distributed throughout the problem space, it is possible to generalise them. This in turn permits accurate interpolations between simulated points and provides a simple, accurate and reliable means of identifying the contribution factors and ultimately the required secure power transfer capability.

From the studies performed to quantify the contribution factors, it was possible to identify smooth relationships involving the following variables:

- the peak demand in an area at the time of system peak;
- the conventional generation capacity in the area;
- the wind generation capacity in the area;
- the contribution factors for conventional and wind generation and demand in the area.

The studies were developed for both 'N-1' and 'N-2' secure boundary transfer capabilities and revealed a set of curves in a space for which the axes were:

- *x*-axis: the difference between the total generation capacity in the area and the peak demand in the area;
- *y*-axis: the contributions factors of generation technologies and demand to the required boundary transfer capability.

The different curves represent different ratios of wind generation capacity in the area to the system's peak demand.

The assumptions made for the 'base case' enabling the characterisation of the contribution factors have been the following:

- conventional generating units of average size of 200MW represented by a 'two state' model and availability of 85%;

- wind power characteristics: (i) diversified wind resource, (ii) average load factor of 35%, (iii) increasing wind penetration levels varying from 0% to 40%.

- the additional system risk imposed by the transmission system, '$Risk_{Tx}$', on any boundary was 5% for 'N-1' and 45% for 'N-2'.

The 'base case' system is characterised by a peak demand of 50GW. The minimum installed conventional capacity, necessary to ensure that the risk of loss of supply is at most 9%, is 60.8GW. This figure translates in a probability of losing of load of 7.89%. The system is now divided into two areas, A and B. Area A is characterised by the following:

- Peak demand: increasing levels of peak demand varying from 0GW to 25GW in steps of 200MW;

- Conventional generation: increasing levels of installed conventional capacity varying from 0GW to 25GW in steps of 200MW;

- Wind generation: wind generation is connected just in area A with increasing levels of installed wind capacity varying from 0GW to 20GW in steps of 2GW.

It should be noted that the absolutes values of the results for the 'base case' depend on the underlying assumptions regarding the variation of peak demand, available power and wind power characteristics, but also on the chosen benchmark value of risk. (The same methodology can be used for different risk benchmarks as well as demand and generation assumptions)

#### Contribution factors of wind power generation

Figure 5-9 presents the smooth relationships leading to a (relatively) simple function for characterisation of the contribution factors of wind generation to the inter-area transmission system transfer capability. The relationships are shown based on the 'N-1' required transfer capability.

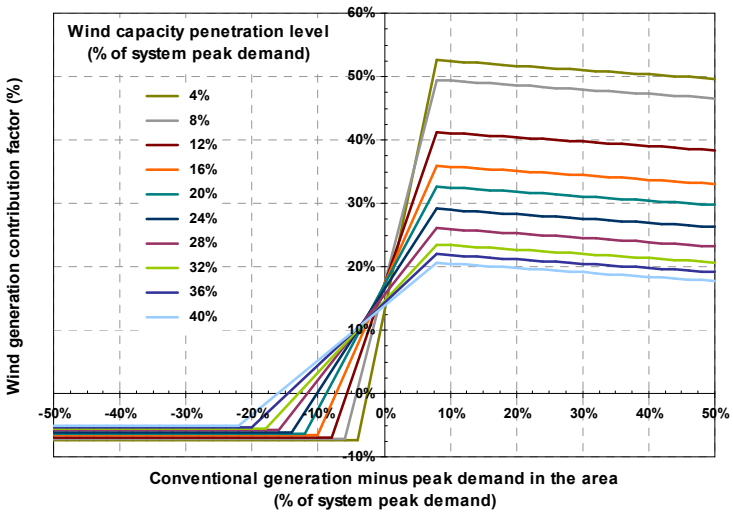



**Figure 5-9: Contribution factors of wind generation to inter-area transmission system transfer capability ('N-1' secure boundary transfer)**

Wind power generation has a limited ability to displace capacity from conventional plant as its contribution towards securing peak demand is also limited. In this sense, the capacity credit of wind presents a gradual reduction with a rise in the penetration level of wind in the system until it reaches saturation. The effect of capacity credit of wind on the boundary export transfer capability is translated in Figure 5-9 by the lower levels of the contribution factors of wind generation attained with the rise of the penetration level of wind.

Figure 5-9 shows that the contribution of wind generation to the boundary import transfer capability is constant. This is because wind generation has a modest transmission capacity value to provide reliability in the importing area. Hence wind does not contribute to the reduction of the required transfer capability translating in a constant contribution to inter-area transmission system transfer capability.

For areas where inter-area transfer capability is driven by the amount of exporting required capacity, the contribution of wind generation to boundary export capability slightly decreases as the amount of conventional generation capacity in the area increases. Higher levels of available conventional capacity in the system require building higher levels of transfer capability to allow this generation to contribute to security of supply. Thus, in the generation system mix of wind and conventional the required transfer capability to accommodate wind generation becomes lower resulting in a smaller contribution of wind generation to the inter-area transmission system transfer

capability. Transmission is being built not to accommodate the simultaneous peak of output from both conventional and wind generation. Instead the required boundary export transfer capability is shared between conventional generation and wind.

Figure 5-9 provides a (relatively) simple function to transmission planners for identification of wind contribution factors to inter-area transmission system transfer capability and ultimately to the identification of the adequate level of transmission network transfer capability.

Similar relationships were developed for characterisation of the contributions factors of wind generation to the inter-area transmission system transfer capability for the 'N-2' security boundary transfer, Figure 5-10.

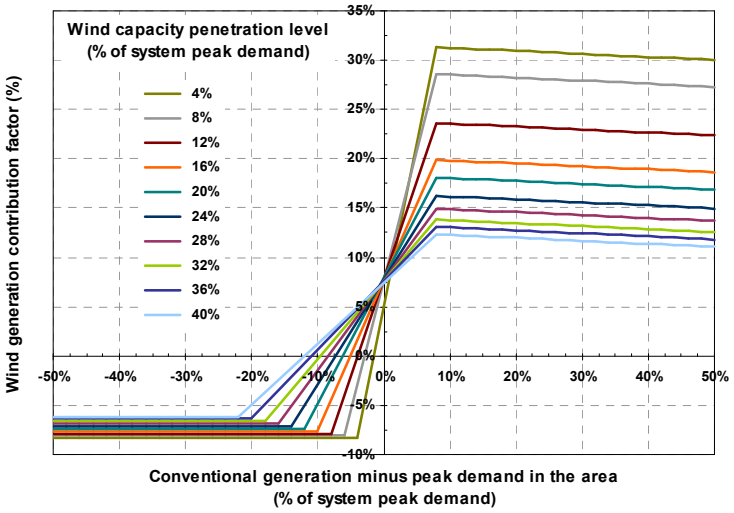



**Figure 5-10: Contribution factors of wind generation to inter-area transmission system transfer capability ('N-2' secure boundary transfer)**

Under 'N-2' security criteria, the required inter-area transmission system transfer capability is lower than that of 'N-1' security criteria. Thus, the additional system risk imposed by the transmission system for 'N-2' is higher than that of 'N-1' constraining generators in remote areas from contributing to security of supply of loads (see Figure 4-4). In this sense, Figure 5-10 clearly demonstrates that the contribution factors of wind generation to the required boundary export capability for 'N-2' are lower than those for 'N-1' secure boundary transfer.

### Contribution factors of conventional generation

The contribution factors of conventional generation to inter-area transmission system transfer capability are shown in Figure 5-11.

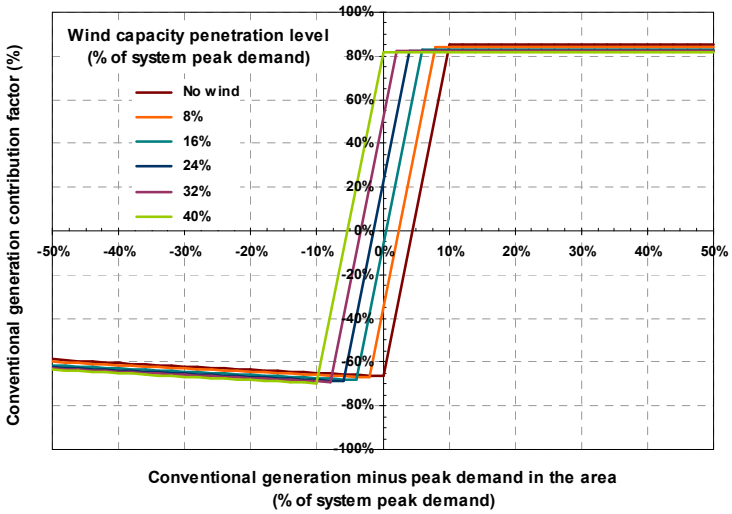



**Figure 5-11: Contribution factors of conventional generation to inter-area transmission system transfer capability ('N-1' secure boundary transfer)**

Figure 5-11 shows that when the amount of importing capacity required in the area drives the inter-area transfer capability, the contribution factors of conventional generation to inter-area power transfer capacity slightly decrease (more negative) with the rise of the available reserve capacity in the area. The increasing presence of conventional generation units in the area improves the system's reliability when compared to that of the system constituted of a smaller number of conventional generation units in the area. Thus a reduction on the transmission network transfer capability, to maintain security of supply at adequate levels, is translated on a decrease (more negative) of the contribution factors of conventional generation to inter-area transmission system transfer capability.

In areas where boundary transfer capability is export driven, the contribution of conventional generation to boundary export transfer capability, for the case of no wind, is about 85% of the installed conventional capacity. This value represents the most likely level of available conventional generation capacity, describing the relation of the average plant availability (assumed 85%) and the total available generation in the system.

**Contribution factors of peak demand**

The contribution factors of peak demand to the inter-area transmission system transfer capability are presented in Figure 5-12.

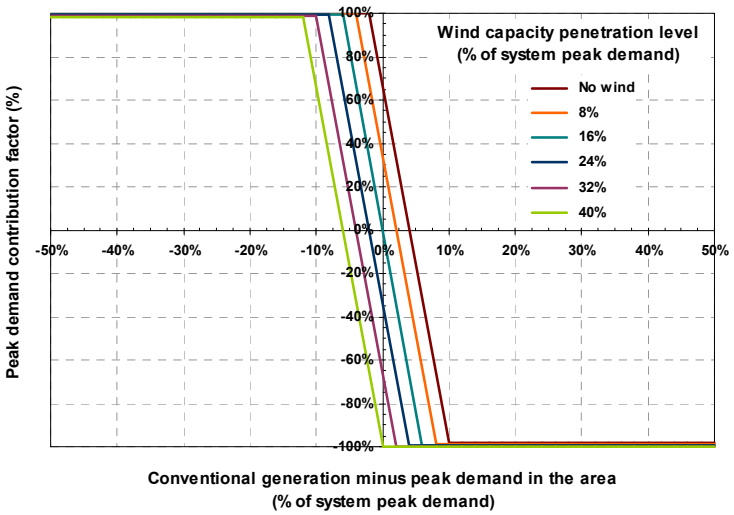



**Figure 5-12: Contribution factors of peak demand to inter-area transmission system transfer capability ('N-1' secure boundary transfer)**

Figure 5-12 shows that the peak demand contribution factor to boundary transfer capability is constant and equal to 100% when the inter-area transfer capability is driven by the amount of importing capacity required in the area and constant and equal to -100% when driven by the amount of export capacity required in the area. This result is in agreement with the modelling assumption of having a unique and firm level of peak demand.

### 5.4.3 Effect of key factors on the contribution of wind generation to transmission system transfer capability

The contribution factors method is applied to quantify the impact of various key factors, influencing the contribution factors of wind generation to the inter-area transmission system transfer capability for 'N-1' security criteria. The factors studied include wind power characteristics (wind penetration level, wind resource diversity and wind load factor) and conventional generating units' characteristics (average unit availability and unit size).

The two-area system presented in Chapter 4 (Section 4.3.5, Figure 4-9) is used in the study. Area A is characterised by a fixed level of 8GW of installed conventional capacity and the presence of wind power with an increasing penetration level varying from 0% to 40%. Note that area A is an exporting area in this study.

Although the studies are performed on a specific system, generic understanding of the effect of the various factors can be derived.

### Effect of penetration level of wind generation

To study the effect of the penetration level of wind generation on the contribution factors of wind generation to boundary transfer capability, wind power is also connected in area B with increasing penetration level varying from 0% to 40%. This study uses a diversified wind profile with a long-term average load factor of 35%.

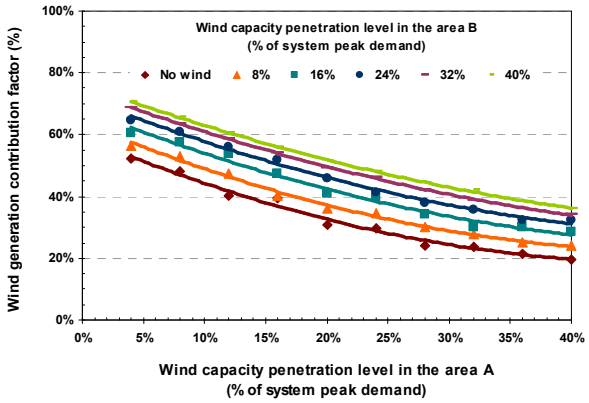



**Figure 5-13: Effect of wind penetration level on the contribution factors of wind generation to inter-area transmission system transfer capability**

Figure 5-13 show that when wind power is not connected in area B, increasing levels of wind power in area A lead to decreasing levels of contribution factors of wind to boundary transfer capability in the area A. As the penetration level of wind generation increases its marginal contribution to security of supply (i.e. wind generation in area A contributes to reliability of supply in area B) decreases and so does its contribution to inter-area power transfer capability.

Assuming a specific penetration level of wind generation connected in the exporting area A, the presence of increasing levels of wind power generation in the importing area

B originates higher wind contribution factors to transmission network transfer capability in the area A. For the case where 20% of wind is present in area A, the wind contribution factors in area A will increase from 31% for no wind in area B to 54% for 40% wind penetration level in area B.

Wind power has limited capacity value, however its presence in the system displaces relatively modest amount of conventional generation plant in the area B. Substituting conventional generation plant (high availability) by less reliable plant (wind power generation) in the importing area results in a increase of the required boundary import capability into the area B and in a increase of the wind contribution factors in the area A in order to maintain the risk of loss of supply at acceptable levels. For instance, 20% of penetration level of wind and 8GW of conventional plant are connected in area A, the installed conventional plant in area B decreases from 50.6GW for no wind in area B to 46.6GW for 40% wind penetration level in the area B.

#### Effect of wind resource diversity

In order to study the impact of wind resource diversity on the contribution factors of wind generation to inter-area power transfer capability two different wind profiles, diversified and non-diversified, are considered for various penetrations levels of wind generation. In both cases there is no wind generation connected in area B.

Figure 5-14 shows that the diverse wind farms are capable of contributing about 10% more to inter-area power transfer capability than the non-diverse wind farms under the same reliability standard ($LOLP_{Reference}$).

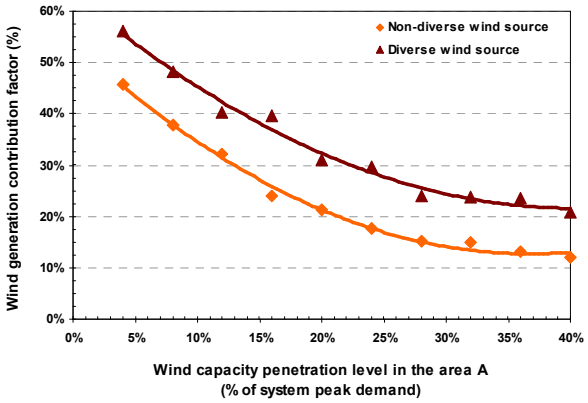



**Figure 5-14: Effect of wind resource diversity on the contribution factors of wind generation to inter-area transmission system transfer capability**

It can be also seen that for both cases, i.e. diverse and non-diverse wind resource, the contribution factors of wind generation to transfer capability tends to tail off sharply after the initial penetrations of up to 25% of installed wind capacity. This behaviour clearly demonstrates that the capacity credit of wind generation (Figure 4-8, identical behaviour) is a major driver to the contribution of wind power generation to boundary transfer capability.

### Effect of load factor of wind generation

For the purpose of this analysis a range of 20% to 40% load factors is explored for wind generation for its contribution factors to transmission network transfer capability. It can be observed in Figure 5-15 that for a specific level of wind penetration in area A, e.g. 24%, the contribution factors of wind generation increase from 16% for a 20% wind load factor to 30% for a 40% wind load factor.

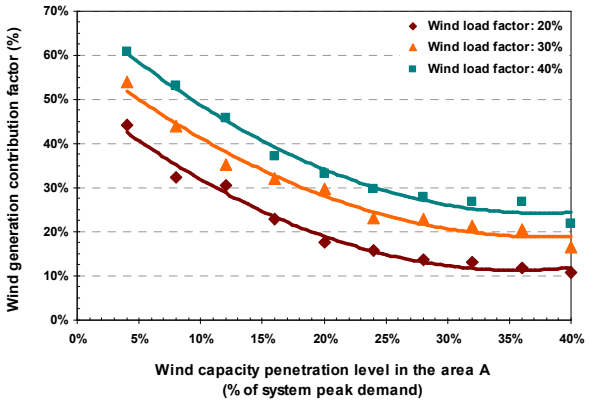



**Figure 5-15: Effect of load factor of wind generation on the contribution factors of wind generation to inter-area transmission system transfer capability**

The increase of wind capacity credit from 8% for 20% wind load factor to 22% for 40% wind load factor translates in a higher ability of wind and conventional generation in area A to contribute to reliability of supply in area B and therefore higher contribution factor of wind generation to transmission network transfer capability.

### Effect of conventional plant availability

To assess the impact of the average conventional plant availability on the contribution factors of wind generation to transmission network capacity requirements, studies were performed considering a 70% to 95% range of average availability of the units in both areas for various levels of wind power in area A. The results of these studies are presented in Figure 5-16.

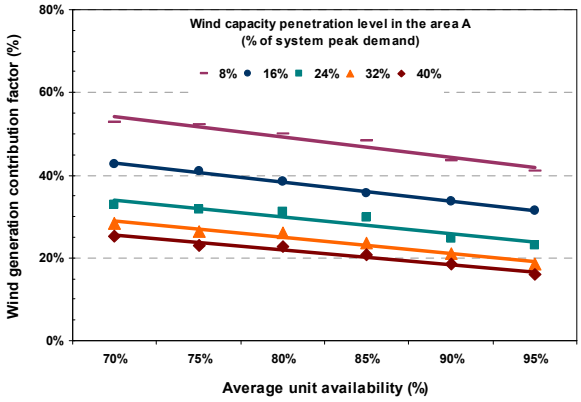



**Figure 5-16: Effect of conventional plant availability on the contribution factors of wind generation to inter-area transmission system transfer capability**

Figure 5-16 shows that for a wind penetration level of 24% in area A, improving the average availability of the units from 70% to 90% results in a decrease of the wind contribution factors in the exporting area A from 33% for 70% average conventional units' availability to 23% for 95% average conventional units' availability, maintaining systems' reliability of supply at adequate levels. In other words, the presence of more reliable generators in the system lead to lower wind contribution factors for required transmission network export capability.

### Effect of conventional unit size

The effect of the size of the generic conventional unit on the contribution factors of wind generation to transmission network capability was assessed by varying it from 100MW to 800MW with same average availability (85%) for an increasing penetration level of wind power in area A varying from 8% to 40%. This analysis is shown in Figure 5-17 below.

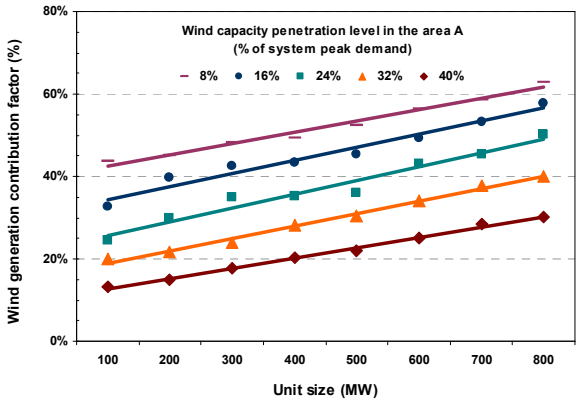



**Figure 5-17: Effect of conventional unit size on the contribution factors of wind generation to inter-area transmission system transfer capability**

It is observed in Figure 5-17 that at 24% of wind penetration level in area A, the wind contribution factors in the exporting area A increase from 24% for a system composed of smaller sized units of 100MW to 50% for 800MW of unit size. This is because the effect of the failure of a large unit on the system reliability is significantly more than that of the failure of a small sized unit. Hence a higher contribution of wind generation to boundary export transfer capability is required to maintain reliability of supply at adequate levels.

### 5.4.4 Effect of key factors on the contribution of conventional generation to transmission system transfer capability

The contribution factors method is applied to quantify the impact of key factors influencing the contribution factors of conventional generation to inter-area transmission system transfer capability for 'N-1' secure boundary transfer. The factors studied include the average unit availability of the conventional generating units, the conventional generating units' size and the number of conventional generating units.

The two-area system presented in Chapter 4 (Section 4.3.5, Figure 4-9) is used in the study. Area A is characterised by a fixed level of 8GW of installed conventional capacity and no wind power generation present in the area. Note that area A is an exporting area in this study.

#### Effect of conventional plant availability

The effect of the average conventional plant availability on the contribution factors of conventional generation to transmission network capability was assessed by varying it from 70% to 95%. The results of the analysis are shown in Figure 5-18 below.

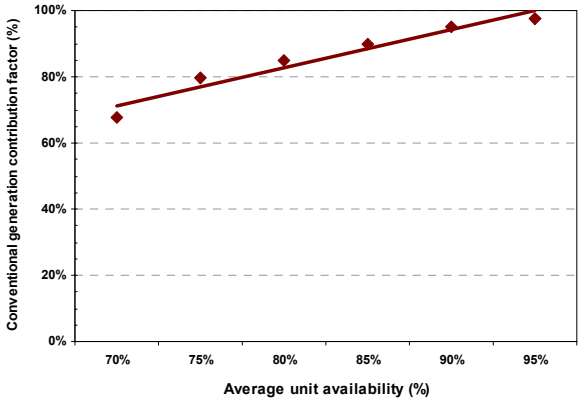



**Figure 5-18: Effect of conventional plant availability on the contribution factors of conventional generation to inter-area transmission system transfer capability**

Figure 5-18 shows that the contribution of conventional generation to boundary transfer capability is about the same as average conventional plant availability. For instance, at 85% average unit availability, the conventional generation contribution to transfer capability is around 85% of the installed conventional capacity. The most likely level of

available conventional generation capacity (85% of the installed conventional capacity) contributes to the inter-area transmission system transfer capability.

### Effect of conventional unit size

To assess the impact of the size of the generic conventional unit on the contribution factors of conventional generation to transmission network capacity requirements, studies were performed considering 100MW to 800MW range of conventional unit size. The results of these studies are presented in Figure 5-19.

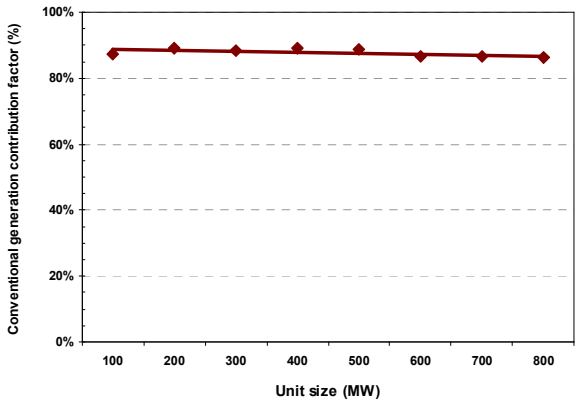



**Figure 5-19: Effect of conventional unit size on the contribution factors of conventional generation to inter-area transmission system transfer capability**

It can be observed in Figure 5-19 that the impact of the size of the conventional units on the conventional generation contribution factors is not significant.

### Effect of the number of conventional generation units

To study the effect of the number of conventional generation units on the contribution factors of conventional generation to boundary transfer capability, the number of conventional units in the area A was varied from 0 to 50. This is equivalent to a change in conventional capacity in the area A from 0GW to 10GW.

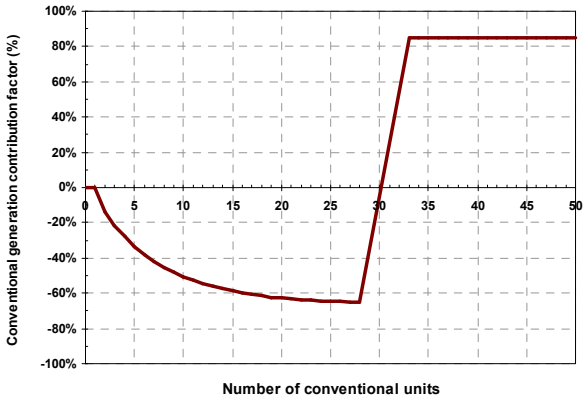



**Figure 5-20: Effect of the number of conventional generation units on the contribution factors of conventional generation to inter-area transmission system transfer capability**

It is observed in Figure 5-20 that when the amount of importing capacity required in the area drives the inter-area transfer capability, the conventional contributions factors in the importing area A decrease from 0% for a system composed of 2 conventional generation units to -65% for 28 conventional generating units. The increasing presence of conventional generation units in the area improves the system's reliability when compared to that of the system constituted of a smaller number of conventional generation units in the area. Thus a reduction on the transmission network transfer capability, to maintain security of supply at adequate levels, is translated on a decrease (more negative) of the contribution factors of conventional generation to inter-area transmission system transfer capability.

When the amount of exporting capacity required in the area drives the inter-area transfer capability, the contribution of conventional generation to boundary export transfer capability is fairly close to the average plant availability (assumed 85%).

## 5.5 Case study

The methodology for determining the optimum level of transmission capability required to integrate wind generation in the GB electricity grid is applied to a typical wind scenario for a base year (2007/8) and two future years (2013/4 and 2020/21) developed by the GB SO for this purpose (NG, 2008). The years 2007/08 and 2013/14 were mainly adopted from the GB SYS (NG, 2007) while the 2020/21 is one possible future outcome. The study zones are given as well as how they are grouped to form SYS study

zones. The SYS boundaries are defined in terms of the SYS zones. Figure 5-21 defines on a GB map the SYS transmission boundaries and SYS study zones for 2007/8.

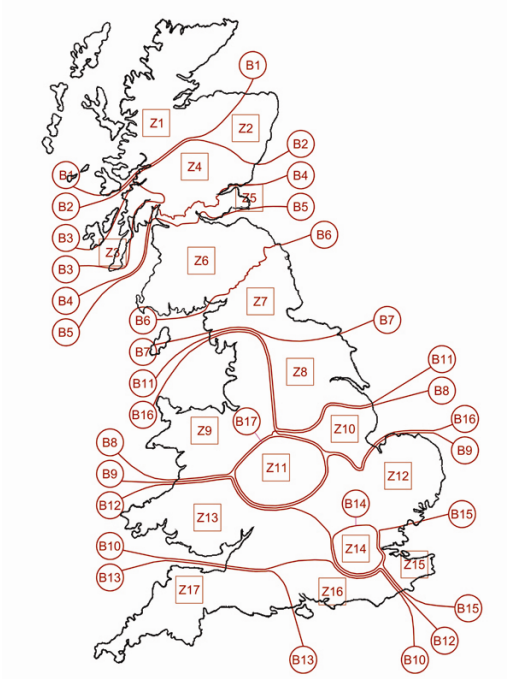



**Figure 5-21: GB SYS transmission boundaries and study zones**

### 5.5.1 Generation and demand background

Study zones, plant names, generation types, generation capacities, plant availabilities, and ranking order list are given for the different study years. Table 5-3 gives a brief summary of the generation capacities for the study years. The scenario has been developed to be consistent with the government renewable targets. The target for renewable energy contribution in 2020 is 20%. In the year 2020, transmission connected wind makes 16% contribution, leaving 4% to be met by other renewable generation including embedded wind generation.

The installed wind capacities are given for the study years rather than the power output from wind generation. In order to determine the zonal wind power outputs over the period of a year, zonal wind speed data are given together with a generic turbine wind speed-power curve. Zonal wind speed data is presented with a half hourly resolution. Table 5-3 presents the installed wind capacity for the different scenarios.

Demand data is given by study zones and is also allocated to nodes on the network. The data presented is the peak demand excluding transmission losses. Table 5-3 presents a summary of the demand data.

**Table 5-3: Summary of generation scenarios**

| Study year | 2007/8 | 2013/4 | 2020/1 |
|---|---|---|---|
| GB installed capacity (MW) | 76500 | 85500 | 94700 |
| GB transmission connected conventional capacity (MW) | 74500 | 75500 | 74700 |
| GB transmission connected wind capacity (MW) | 2000 | 10000 | 20000 |
| Peak demand | 60500 | 63500 | 65200 |
| Capacity margin (%) (wind not scaled down) | 26 | 34 | 45 |
| Loss of load probability (%) | 0.23 | 1.28 | 2.31 |
| Forecast energy consumption (TWh) | 357 | 375 | 385 |
| Transmission wind contribution at 35% load factor (TWh) | 6.1 (1.7%) | 30.6 (8%) | 61.3 (16%) |
| Target renewables contribution (TWh) | - | 49 (13%) | 77 (20%) |

The average availability of the different generation technologies type is shown in Table 5-4. The average availabilities remain constant for the future wind scenarios.

**Table 5-4: Generation availabilities by plant type**

| Generation type | Availability (%) |
|---|---|
| Nuclear | 80 |
| Coal | 88 |
| Oil | 95 |
| Gas | 90 |
| CHP | 88 |
| Waste | 80 |
| Hydro | 80 |
| Pump Storage | 80 |
| Interconnectors | 100 |

### 5.5.2 Generation capacity adequacy pertinent to the GB system

The COPT method (Chapter 2, section 2.4.1) is employed to evaluate the amount of conventional generation capacity that is adequate to supply a given demand (Table 5-3) with a desirable level of LOLP (9 days in 100 years). It can be seen in Table 5-3 that the LOLP, for the different study years, has significant lower level. Therefore, thermal capacity is gradually reduced from the system, in accordance to the ranking order list, until the risk of loss of supply is at most 9%. The adequate capacity requirement for each wind scenario is shown in Table 5-5.

**Table 5-5: Adequate capacity requirements**

| Study year | 2007/8 | 2013/4 | 2020/1 |
|---|---|---|---|
| GB installed capacity (MW) | 73100 | 82700 | 92800 |
| GB installed conventional capacity (MW) | 71100 | 72700 | 72800 |
| GB installed wind capacity (MW) | 2000 | 10000 | 20000 |
| Peak demand | 60500 | 63500 | 65200 |
| Capacity margin (%) (wind not scaled down) | 21 | 30 | 42 |
| Loss of load probability (%) | 9 | 9 | 9 |

This approach is analogous to the capacity margin adjustment technique employed in the GB SQSS except that this is based on maintaining the single bus LOLP rather than a fixed capacity margin. This approach is more appropriate to the introduction of intermittent wind generation, as it takes into account the wind power characteristics.

### 5.5.3 Additional system risk pertinent to the GB transmission system

The evaluation of the additional system risk pertinent to the GB transmission system adopted two guiding principles (i and ii) and one earlier finding (iii):

i) The fundamental premise, upon which the GB SQSS was developed, 'transmission network should not unduly restrict generation from contributing to security of supply at the time of peak demand', should be maintained;

ii) The method developed to update the GB SQSS, to include wind power generation, should deliver no worse reliability of supply than the present approach.

iii) That the SQSS delivers sufficient transmission system transfer capability in systems constituted by conventional generation technologies.

Based on the aforementioned, the quantification of the additional system risk is then carried out separately for 'N-1' and 'N-2' security assuming the SYS boundary capabilities for the 2007/8 scenario without wind power generation. The boundaries for which this was done were the SYS boundaries to which the current 'planned transfer' and 'interconnection allowance' concepts apply, i.e. boundaries 4 to 17.

Figure 5-22 shows the loss of load probability for the 2007/8 scenario with boundary capabilities equal to those required by the present transmission security standard. It can be seen that the risk of loss of supply is quite different from one boundary to the next,

thus making less than obvious what single, GB representative 'benchmark' risk thresholds should be for 'N-1' and 'N-2'.

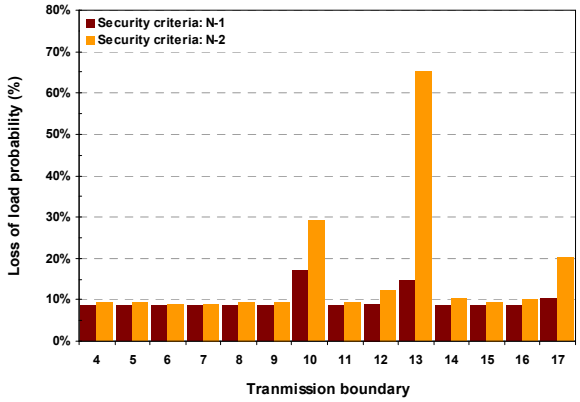



**Figure 5-22: Loss of load probability associated with GB transmission system boundaries**

Suitable benchmark indices are determined by the root mean squared deviation between the LOLP resulting from the transmission network planned in accordance with the present planning standards and that required by an infinitely strong transmission network, summed over all the SYS boundaries B4 – B17 for the 2007/8 scenario. The *RMS* deviation is expressed by equation (5.27).

$$RMS = \sqrt{\frac{1}{n_b}\sum_{i=1}^{n_b}\left(LOLP_i^{SQSSTx} - LOLP_{InfiniteTx}\right)^2} \qquad (5.27)$$

Where '$LOLP_i^{SQSSTx}$' is the system's loss of load probability resulting from the transmission network designed in accordance to the current transmission security standard representative of the '$i^{th}$' system's boundary, '$LOLP_{InfiniteTx}$' is the system's loss of load probability for an infinitely strong transmission network. The difference between these two quantities is defined as '$\Delta LOLP$'. '$n_b$' is the number of boundaries in the GB transmission system.

The 'RMS' deviations were calculated for 'N-1' and 'N-2' and the resultant benchmark values are shown in Table 5-6.

**Table 5-6: Additional system risk pertinent to the GB transmission system**

| Security criteria | $\Delta LOLP$ | Additional risk ($Risk_{Tx}$) |
|---|---|---|
| N-1 | 0.53% | 6% |
| N-2 | 3.71% | 43% |

### 5.5.4 GB transmission system transfer capability

The application of the contribution factors method and the use of the benchmarks proposed in section 5.5.3 above have allowed the required capabilities to be identified for the 2007/8, 2013/4 and 2020/1 scenarios. These are presented and compared in Table 5-7 for 'N-1' security criteria.

**Table 5-7: Required transfer capabilities associated with the GB transmission system boundaries**

| Boundary | Description | Transmission boundary transfer capability N-1 (MW) | | |
|---|---|---|---|---|
| | | 2007/08 | 2013/14 | 2020/21 |
| 1 | SHETL North West | 500 | 1200 | 2700 |
| 2 | SHETL North/South | 1200 | 2100 | 3700 |
| 3 | SHETL Sloy | 100 | 100 | 200 |
| 4 | SHETL – SPTL | 1000 | 2000 | 3800 |
| 5 | SPTL North/South | 2300 | 3100 | 4800 |
| 6 | SPTL – NGET | 2700 | 3100 | 3300 |
| 7 | NGET Uppr Nrth/Nrth | 3000 | 3200 | 2500 |
| 8 | NGET North/Midlands | 10100 | 10000 | 7800 |
| 9 | NGET Midlands/South | 9500 | 8900 | 8600 |
| 10 | NGET SouthCoast | 6300 | 5300 | 5300 |
| 11 | NGET Nest and Yrkshr | 9900 | 10000 | 9200 |
| 12 | NGET Sth and SthWst | 6100 | 4300 | 3700 |
| 13 | NGET South West | 2800 | 2500 | 2300 |
| 14 | NGET London | 8300 | 8900 | 9700 |
| 15 | NGET Thms Estry | 7100 | 6500 | 7300 |
| 16 | NGET NEst/Trnt/Yrkshr | 13200 | 14100 | 14600 |
| 17 | NGET West Midlands | 5200 | 6600 | 6000 |

Table 5-7 provides a comparison of the boundary capabilities for the different scenario years. All boundaries in Scotland except boundary 3 (Sloy) show a significant increase in transfer capability requirement as wind penetration increases. In England and Wales, boundary 16 (NGET Central/South West) and boundary 14 (London) also show a significant increase in transfer capability requirements.

The remaining boundaries do not show significant changes in required transfer capabilities. Although there are a number of factors influencing the transmission requirements, such as demand growth, the location of generating units displaced during the process of adjusting the single bus LOLP (analogous to units dropping off the bottom of the ranking order) and an increase in wind generation in Scotland results in increased power flows towards England and Wales, hence the increases in transfer capability requirements. There are significant wind generation volumes that are connected to the England and Wales system towards 2020, however, which is offset to

some extent due to demand growth. This mitigates the increase in transmission requirements in the England and Wales system due to security requirements.

#### The contribution factors method in the GB transmission system

The contribution factors of the different generation technologies and peak demand to the required transfer capabilities in the exporting areas of each of the 17 boundaries are presented in Table 5-8.

**Table 5-8: Contribution factors to required transfer capabilities associated with the GB transmission system boundaries for the 2013/14 boundary**

| Boundary | Description | Contribution factors to required transfer capability N-1 (%) | | |
|---|---|---|---|---|
| | | Exporting area of the boundary | | |
| | | Wind generation | Conventional generation | Peak demand |
| **1** | **SHETL North West** | **54.27%** | **85.84%** | **-100** |
| **2** | **SHETL North/South** | **51.68%** | **88.95%** | **-100** |
| 3 | SHETL Sloy | 24.00% | 50.00% | -96 |
| **4** | **SHETL – SPTL** | **42.36%** | **86.27%** | **-100** |
| **5** | **SPTL North/South** | **45.08%** | **85.14%** | **-100** |
| **6** | **SPTL – NGET** | **37.60%** | **82.88%** | **-100** |
| 7 | NGET Uppr Nrth/Nrth | 34.13% | 85.52% | -100 |
| 8 | NGET North/Midlands | 29.58% | 86.12% | -100 |
| 9 | NGET Midlands/South | 27.64% | 86.20% | -100 |
| 10 | NGET SouthCoast | 23.78% | 86.37% | -100 |
| 11 | NGET Nest and Yrkshr | 29.80% | 87.82% | -100 |
| 12 | NGET Sth and SthWst | 20.70% | 86.89% | -100 |
| 13 | NGET South West | 25.47% | 85.75% | -100 |
| 14 | NGET London | 22.80% | 85.39% | -100 |
| 15 | NGET Thms Estry | 23.09% | 93.97% | -100 |
| 16 | NGET NEst/Trnt/Yrkshr | 26.29% | 88.14% | -100 |
| 17 | NGET West Midlands | 26.06% | 85.89% | -100 |

Observation of these results shows that the contribution factors of wind generation to inter-area transmission system transfer capability are significantly lower than the contribution factor of conventional generation. This is because wind generation, due to its limited contribution to securing demand, will drive much less transmission capacity than conventional plant.

It can also be observed that the contribution factors of wind generation are higher in all boundaries in Scotland (highlighted in bold) where the bulk of the wind generation has been placed.

The contribution of conventional generation to boundary export transfer capability is on average about 85% of the installed conventional capacity. This value represents the

most likely level of available conventional generation capacity, describing the relation of the average plant availability (assumed 85%) and the total available generation in the system. However, note that boundary 'SHETL Sloy' has a significant lower contribution factor. This is due to the fact of the presence of a single generating unit in the exporting area. Thus an increase on the transmission network transfer capability, to maintain security of supply at adequate levels, is translated on a decrease of the contribution factor of conventional generation to inter-area transmission system transfer capability.

### The contributions factors method and the SQSS

The results for the required transmission transfer capability for the 2013/4 scenario at each of the 17 boundaries are presented in Figure 5-23 for the contribution factors method and the current SQSS method.

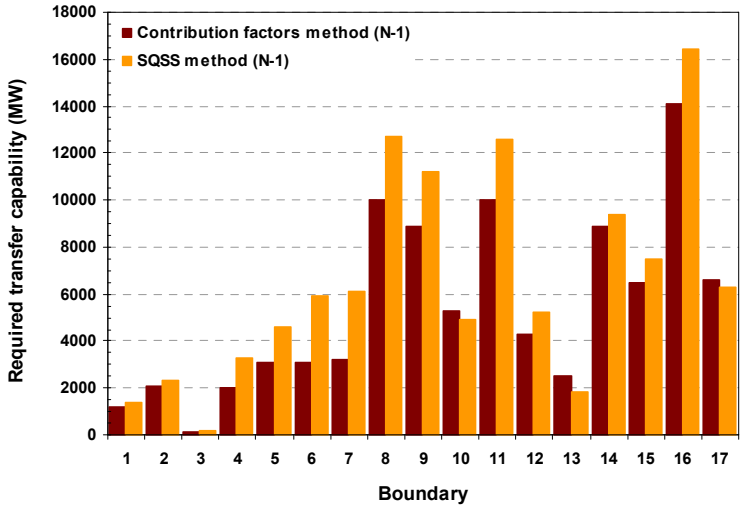



**Figure 5-23: Comparison of transfer capabilities associated with the GB transmission system boundaries for the 2013/14 scenario using the contributory factors method and SQSS method**

Boundaries 1, 2 and 3 in Figure 5-23 correspond to those boundaries for which the demand is less than 1500MW and therefore, under the SQSS method, the interconnection allowance is not applicable. For these boundaries, the results shown are actually planned transfers rather than 'N-1' required transfer capabilities.

It can be seen in Figure 5-23 that, broadly speaking, the SQSS method has the highest required capabilities except for those boundaries that are characterised by one side

having little generation capacity relative to demand in the area, e.g. B10, B13 and B17. In these cases the contribution factors method delivers the highest required capabilities. While both approaches are based on comparable principles, the differences in results are likely to be due to differences in modelling, of conventional generation and, in particular, wind generation.

## 5.6 Discussion and conclusions

**The review of the design criteria of the MITS**

This chapter reviewed the philosophy and assessed the performance of the design criteria of the Main Interconnected Transmission Systems as stated in the Great Britain Security and Quality of Supply Standard. The review went over the principles and concepts on which the deterministic transmission planning guidelines were developed and the assumptions underpinning existing application procedures in order to identify and examine their strengths and weaknesses.

First, the review process analysed the transmission security standards within the context for which they were designed, i.e. for a power system dominated by conventional, large scale, centralised generation plant. It was demonstrated that the concept of 'planned transfer' ignores the fact that the unplanned availability, the location and economics of the generation that the merit order uses can limit the inter-area transmission system transfer capability. The use of the 'circle diagram' is not fully consistent with its derivation since it is applied to an unbalanced system and not to a balanced system of the type which existed in the 1940s. The review performed a comparison between the developed reliability approach for transmission investment (Chapter 4) and the present GB SQSS. The analysis demonstrated that the present transmission security standards deliver sufficient transmission system transfer capability in systems with conventional generation technologies.

The review process investigated then the transmission security standards in the context of intermittent wind generation. The fundamental method of calculating both the 'planned transfer' and 'interconnection allowance' has been updated to recognise different scaling factors according to generator type, based on their typical availabilities. The use in the capacity margin of '$B_W$' factor equal to 40% (as the capacity credit of

wind generation) compared to the referenced lower values, results in an increase of the contribution of wind generation to security of supply (i.e. higher capacity margin in the ranking order technique). The outcome of this process is the growth of the inter-area transfer capability driven by wind power leading to transmission over-investment. Earlier findings (Chapter 4, section 4.3.5 ) revealed that in exporting areas, the presence of wind generation increases the need for transmission reinforcement. However this increase is relatively small due to the limited wind power generation contribution to security of supply. In this respect, the allocation of a high availability factor '$A_W$', for wind generation in the 'planned transfer' condition, 72%, is likely to lead to transmission over-investment in exporting areas. While the method of calculating interconnection allowance (in particular, the *x*-axis of circle diagram) applies differential scaling factors according to generator type, the circle diagram has not been revised to account for the different characteristics of wind power generation.

The review examined the impact of implementing the present GB SQSS approach on networks with significant levels of wind power generation on the security of the system. The MITS criterion of the GB SQSS was compared with the developed reliability approach for transmission investment (Chapter 4). The comparison clearly revealed that applying unrealistically large scaling factors to wind generation, as used in the present GB SQSS, can lead to under-investment in transmission for importing areas and over-investment in transmission for exporting areas.

#### Contributions factors method

This chapter presented the development of a new method, the 'contribution factors method', as the basis to update the design criteria of the GB main interconnected transmission system as stated in the GB SQSS. In the contribution factors method the minimum inter-area power transfer capability is defined by the means of contribution factors of the different generation technologies and demand, both location specific, to the required level of transfer capability. The 'contribution factors method' provides a suitably robust characterisation of the required transmission network capabilities ('N-1' and 'N-2' secure boundary transfer) by the means of a simple function representing the contribution factors of the different generation technologies and demand to inter-area transmission system transfer capability.

#### Contribution factors for wind power generation

In exporting areas, the contribution of wind generation to boundary export capability decreases as the penetration level of wind generation in the area rises. For the 'base case' performed under 'N-1' secure boundary transfer, the contribution factors of wind generation decrease from 52% for a wind penetration level of 2% to 20% for a wind penetration level of 40%. In importing areas, the contribution of wind generation to boundary import capability is constant and about 10%.

#### Contribution factors of conventional generation

In exporting areas, the contribution of conventional generation to boundary export transfer capability was found to be about the same as the average conventional plant availability. In importing areas, the contribution factors of conventional generation to inter-area power transfer capacity slightly decrease with the rise of the available reserve capacity in the area.

#### Contribution factors of peak demand

The peak demand contribution factor to boundary transfer capability is constant and equal to 100% when the inter-area transfer capability is driven by the amount of importing capacity required in the area and constant and equal to -100% when driven by the amount of export capacity required in the area.

#### Effect of key factors on the contribution of wind generation to inter-area transmission system transfer capability

The application of the contribution factors method was further extended to analyse the impact of key factors on the contribution of wind generation to inter-area transmission system transfer capability. The key factors included wind penetration level, diversity of wind resource, wind load factor, conventional plant availability and conventional unit size.

Wind penetration level and diversity of the wind resource are observed to be key factors influencing the wind contribution factors to inter-area transmission system transfer capability. Table 5-9 summarises their impact.

**Table 5-9: Contribution factors of wind generation to inter-area transmission system transfer capability in exporting areas**

| | Low penetration | High penetration |
|---|---|---|
| Low diversity | 35% | 20% |
| High diversity | 45% - 50% *(N/A)*[*] | 30% |

[*]Low wind penetration is unlikely to produce high diverse wind profile

Also the load factor of wind generation affects the wind contribution factors to inter-area transmission system transfer capability. A change in wind load factor from 20% to 40%, for example, would increase the wind contribution factors by about 15 percentage points.

Other factors such as the conventional plant availability and the conventional unit size also impact the wind contribution factors to the inter-area transmission system transfer capability. Improving the average availability of the conventional generating units results in a decrease of the wind contribution factors. It was also shown that the rise of the conventional generating unit size leads to higher wind contribution factors to inter-area transmission system transfer capability.

This work clearly demonstrated that the contribution factors of wind generation to inter-area transmission system transfer capability are significantly smaller than the contribution factors of conventional generation. This implies that wind generation drives less transmission capacity than conventional plant. This will open the debate on how the distinct contributions that individual generation technologies have on transmission network investment costs should be allocated in a cost reflective and non-discriminatory manner to all network users. The following chapter takes up this discussion analysing and evaluating the gaps on the present GB transmission use-of-system charging methodology.

# Chapter 6

# Transmission network pricing in systems with wind generation

## 6.1 Introduction

Electricity is a commodity with a value that varies with location (of generation and consumption) and time of use/generation. Value is attributed to electricity on generation, transmission (transport over national grid infrastructure), distribution (delivery to local demand centres) and supply (metering and service provision). Costs are incurred at each of these points e.g. through losses, network congestion, network operation/maintenance and metering.

In the context of electrical power systems and charging for network access, cost reflectivity of charges is required to send accurate price signals to individual users of the network with respect to the costs they impose on network operation and/or development. This will ensure that in the short term, the system is efficiently operated without cross-subsidy between users and that, in the long term, it follows the path of least cost development (efficient investment).

For network operation and expansion, this requires some form of coordination between generation and network development as the optimisation of the network in isolation from generation would almost certainly not meet the above objective. Historically, vertical integration of conventional utilities seemed necessary for a sufficient level of coordination to be achieved. In the competitive environment, as exists in the UK, the necessary coordination of investing in generation and network assets is to be achieved through efficient network pricing mechanisms. These price signals directed at users of the network should be developed to influence their future decisions with regard to (a) location in the network (b) patterns of network use and (c) the need for (and location of) new network investments, i.e. encourage efficient network investment and discourage overinvestment. Apart from the economic efficiency objective, network prices must also enable Transmission Network Operators (TNOs) to recover allowed revenues.

The present Great Britain's Transmission Network Use of System (TNUoS) charging methodology was developed for a system with conventional generation only and is consistent with the present GB SQSS. It considers a single peak demand condition and the location specific network charges are evaluated on the basis of the impact that individual users have on the need for transmission under this condition. Given the assumption that all generators operate during peak conditions, generators connected in the same area would have the same impact on the transmission network investment and hence will be exposed to the same TNUoS charges. This is clearly inappropriate for systems with mixes of conventional and various forms of distributed and renewable generation technologies, such as wind. What is important in this context is to determine the distinct contributions that individual generation technologies have on transmission network investment costs. Generators in the same area could possibly impose very different demands for transmission network investment. In other words, if non-discriminatory access to transmission network is to be established, TNUoS charges would need to discriminate between generation technologies.

Following this approach, while applying different scaling factors for conventional and wind generation, this chapter proposes a simple modification of the present TNUoS charging mechanism in order to recognise the different contributions of individual generation technologies to transmission network costs and therefore to achieve cost reflectivity.

This chapter first sets the primary objectives of network pricing in a competitive environment, including a discussion on the meaning and importance of each of the objectives as well as their interaction. It then reviews the basic network pricing methods and practices with their ability to achieve the ideal pricing objectives for transmission networks.

The chapter then reviews and evaluates the current GB charging framework to determine whether it offers a fair and optimal framework for a power system characterised by significant penetration of wind generation. The critical analysis of the current arrangements identifies a number of inefficiencies in the current arrangements that are favouring conventional generation at the expense of providing efficient, non-discriminatory and cost reflective charges for wind generation. The chapter builds upon these outcomes by proposing a simple modification of the present TNUoS charging

mechanism in order to recognise the diverse contributions of individual generation technologies to transmission network costs and hence achieving cost reflectivity.

## 6.2 Fundamental objectives of network pricing

Network pricing should aim to achieve the following primary objectives:

*Economic efficiency (cost reflectivity)*: in the context of electrical power transmission systems, economic efficiency is concerned with sending price signals to users of the network with respect to the costs the users impose on network operation and/or development. Efficient pricing distinguishes between different user locations and between different times of use thus avoiding cross subsidies.

There are essentially two types of costs namely (i) *network operational costs* (ii) *network development costs*. Network development costs involve investment into expansion of the network and its capacity. Network pricing based on network development costs is the primary focus of this chapter.

In a competitive environment, economic efficiency is achieved by sending cost reflective price signals to users of the network so as to influence their decisions with regard to (i) location in the network and (ii) patterns of network use. This is the fundamental reason why economically efficient network use of system charges should be location and time-of-use specific. It is also worthy noting that, because the focus of economic efficiency in pricing is to influence future behaviour, the investment costs that are relevant in the determination of efficient network use of system charges are the *future network expansion costs*[5] rather than present or past network costs.

*Future investment signalling*: this should (i) send clear cost messages regarding the location of new generation facilities and loads (ii) show the need for and location of new transmission network investments, i.e., encourage efficient network investment and discourage over-investment.

[5] The time horizon and assumptions on the locations of users, their future development and usage patterns would need to be defined for the future costs to be quantified.

*Deliver on revenue requirements*: efficient prices based on network operating and/or development costs may not deliver the required revenue. These efficient prices would hence need to be modified to yield sufficient amount of revenue to allow efficient operation and development of transmission networks. This requirement may distort the objective of economic efficiency.

*Provide stable and predictable prices*: Price stability and predictability is important for users' investment decisions. The right balance must however be struck between price stability and flexibility, allowing prices to respond to changing situations.

*Determination of prices must be transparent, auditable and consistent*; allowing users and other interested parties to easily understand the structure and derivation of network tariffs.

*The prices must be practical to implement*: any proposed network pricing method should balance the economic efficiency of tariffs and their complexity as well as social objectives. Furthermore, from a practical standpoint the pricing method should be easy to understand and implement.

One of the major challenges in setting tariffs is establishing the trade off between various objectives of tariff setting. These include, as listed above, the ability to accurately reflect cost streams, efficiency in responding to changing demand and supply conditions, effectiveness in delivering appropriate revenue requirements, stability and predictability of revenue and tariffs which may be difficult to satisfy simultaneously.

## 6.3 Methods for pricing network services

A brief review of the methods traditionally used for pricing the use of the transmission networks is presented below. Although this review is by no means exhaustive, it covers the main methods used to price network services that are in common use around the world. The transmission pricing methods exposed are cost based. The goal of these pricing schemes is to allocate and/or assign all or part of the existing and the new cost of transmission system to wheeling customers (Shirmohammadi et al., 1991a). The methods can be classified broadly into two categories. In the first category are methods in which pricing is driven by transmission investment cost. These methods are

sometimes referred to as *embedded cost methods*. The second category encompasses all methods in which pricing is driven by generation costs. A popular name for methods in this category is *short-run marginal cost (SRMC)* or *nodal pricing*. Embedded cost methods are mainly criticised for lacking a firm foundation in economic theory. In the case of nodal or SRMC pricing, the disregard of actual network investments in determining transmission prices, and reliance mainly on generation prices as the basis for pricing network use, is a cause for some disquiet about this type of network pricing.

In order to overcome the limitations and criticisms of both embedded cost and nodal pricing methods described above Farmer et al. (Farmer et al., 2005) developed an alternative framework for optimal pricing of transmission and distribution network services based on the concept of a reference network. This pricing method takes both generation costs and transmission investment into account when determining the optimal network on which allowable network revenue and prices are based.

A brief critical review of the basic methods under the two categories is first given in the following subsections.

### 6.3.1 Pricing driven by transmission investment

#### Contract path method

The contract path method for pricing network services dates back to the early days of the electricity industry when systems where interconnected by few tie lines (Cassaza, J. A. et al., 1989). In this approach an electrically continuous path is specified from a generator to a point of delivery. The chosen path must have sufficient spare capacity to transport the amount of power to be wheeled. The wheeling charge is determined so as to recover the necessary rate of return of the transmission assets assigned for the wheeling and any other costs incurred by the utility arising from the wheeling transaction.

In contrast to the contract path method, the *postage stamp method* considers system wide average costs rather than specifically selected facilities (Shirmohammadi, D. et al., 1991b). This method derives its name from the fact that calculated wheeling charges are the same irrespective of distance or location.

These methods have been criticised for a lack of a credible foundation in economic theory and for ignoring the immutable laws that govern power flows in electric networks.

Because of their simplicity and easy practical implementation, these methods have been used extensively, mainly in the US.

#### Methods based on usage (MW-mile)

These methods are founded on the philosophy that all users of network services must bear a proportionate share of the embedded costs of the network. The methods therefore focus on two key measurements: the amount of capacity used and the per-unit cost of transmission capacity. Embedded cost based evaluation and pricing has the disadvantage that it cannot differentiate between justifiable and unjustifiable investments. Network pricing based on usage has been applied, again mainly in the US, in the calculation of wheeling charges.

#### Long run marginal cost (LRMC) based methods

(Hunt et al., 1993) Long-run marginal costs (LRMC) are estimated on the assumption that the capacity of the plant, and not just the degree of utilisation, is assumed to adjust in order to meet the incremental demand. LRMC therefore incorporates both capital and operating costs. In essence, LRMC provides a tariff today based on the predicted cost of future system operation and investment. Network pricing based on LRMC methods requires long term assessment of future generation costs, capacities and sites, together with demand profiles and corresponding geographical data.

#### Investment cost related network pricing (ICRP)

This type of network pricing was developed by National Grid (NG 1992) and it is currently the basis of the Great Britain use of system charging methodology. NG is the sole transmission company in England and Wales and the Great Britain system operator. In this pricing approach, the optimal capacity of the network is determined from a transmission network model in which predetermined generation output, corresponding

to the maximum demand is assumed. The maximum demand is the planned peak demand, which is met by generators in proportion to their installed capacity (e.g. 83% in the case of a 20% generation margin). This method takes into account security in an approximate way through a security factor. The prices are calculated on the basis of the impact of incremental utilisation on planned critical flows in various circuits. This impact is in effect the sensitivity of planned critical flows to network injections. The sensitivity factors are combined with the circuit prices to compute the nodal transmission use of system prices. These prices, which are location specific, are then grouped into various zones for generation and demand. Finally, the prices are adjusted to raise the allowed network revenue in such a way that generators and demand face positive and negative charges depending on their locations. Price differentials between zones are maintained.

Because of the absence of generator costs in the model, the trade off between transmission capacity investments and transmission driven out-of-merit generation costs in the process of network capacity optimisation is lost. As a consequence, the resultant transmission prices, although locational in character, do not convey the desired cost messages accurately.

### 6.3.2 Pricing driven by generation system costs

Marginal cost pricing is the most widely accepted way of achieving economic efficiency in pricing network services as the prices are generally cost reflective and avoid both temporal and spatial cross-subsidies between customers. By definition, the marginal cost of a good or service is the increase in the total cost of providing the good or service as a result of a relatively small increase in the rate of output of the good or service. If the required increase in output can be met solely from an increase in the degree of utilisation of the existing plant, the associated increase in cost is referred to as short-run marginal cost (SRMC). In the context of electric power systems the SRMC of operation at any point in time is the marginal cost of supplying an additional unit of demand holding the capital stock constant. Pricing of network services using the SRMC methods was first proposed by Caramanis et al. (Caramanis et al., 1982) and further developed in subsequent work, (Caramanis et al., 1986; Schweppe et al., 1985; Schweppe et al., 1988; Hunt et al., 1993; Tabors, 1994). According to basic principles of economic

theory (Boiteux, 1960), optimal economic efficiency in the short-run is attained when conditions for perfect competition exist and both customers and suppliers pay or are paid spot prices (i.e. SRMC prices) for energy consumed or produced respectively. Prices based on SRMC will ensure the most efficient use of resources, resulting in maximum benefit to society as a whole in the short run.

The spot price '$sp_k(t)$' at a given location '$k$' and instant in time '$t$' is defined as the short run marginal costs of electricity production with respect to demand at this node and instant in time '$t$'. Therefore SRMC (or nodal pricing) as a basis for pricing network services relies fundamentally on generation costs. Assuming the network service provider is regulated so that it receives the surplus of the transaction, the revenue would be:

$$\text{Network Revenue} = \sum_{\text{all lines}} \left( sp_j(t) - sp_i(t) \right) \cdot F_{ij} \tag{6.1}$$

Where '$F_{ij}$' is the power flow between nodes '$i$' and '$j$'.

The main argument in support of SRMC is that prices should reflect prevailing costs and not the costs that would prevail on average during an indefinite period in the future. Prevailing costs depend on the relationship between the current level of output and the current capacity of the system. Thus if there is excess capacity, prices should be reduced to encourage consumption and if there is a constraint on capacity, prices should be raised to the level necessary to restrict demand to the available capacity. Under conditions of equilibrium, when the amount of capacity available is just sufficient to produce the desired level of output, long- and short-run marginal costs coincide. Outside equilibrium, prices should reflect short-run marginal costs, which (as suggested above) can be defined as the price that brings demand and supply into balance.

The concept of Contract networks proposed by Hogan (Hogan, 1992) provides a set of financial instruments for hedging against spatial variation and volatility of spot prices when transmission pricing is based on nodal (spot) prices. Under the notion of contract networks long-term capacity right holders between any two nodes in the system are indifferent as to the delivery of power or the receipt of congestion rent. Capacity rights are assigned on the basis of some agreed mechanism, for example through auctions.

Because transmission prices that are derived from nodal prices depend mainly on generation costs, ignoring actual transmission investment, a supplementary charge is invariably required to recover transmission investment costs. As a consequence, nodal pricing based transmission pricing usually takes the form of a two-part tariff. The first part of the tariff is the SRMC based price and the second is an access charge intended to recover transmission investment. The access charge is often determined using any one of the methods described in section 6.3.1.

However, application of SRMC based pricing for pricing network use has two fundamental problems. The first one is that the pricing regime rewards the network utility when network performance deteriorates: the larger the losses, congestion and unavailability of the network facilities the larger the revenue. This creates perverse incentives for the network utility regarding network maintenance practices and network development. The second problem is that real systems are seldom optimal due to the existence of important effects such as economies of scale, reliability constraints and other deviations from ideal conditions; this means that the network revenue falls significantly short of that which is necessary to recover the total costs of the network. This leads to excessive revenue reconciliation to enable full cost recovery, which has the potential of distorting the desired price signals to users of the network services.

It is important to emphasise that as the network business is dominated by capital investment and revenue from network operation is highly uncertain under SRMC (due to high volatility of spot prices), economic optimality in the short run may not necessarily result in economic optimality in the long run.

### 6.3.3 Pricing based on the concept of a reference network

For various reasons, the methods described in section 6.3.1 and 6.3.2 fail to address the requirements for the ideal transmission pricing strategy. Farmer et al. (Farmer et al., 2005) using principles formulated by Boiteux (Boiteux, 1949) and Crew (Crew, 1968), developed an alternative framework for optimal pricing of transmission and distribution network services based on the concept of the reference network (also known as the ‘economically adapted network’). The framework developed by Farmer et al. takes both transmission investment and generator operating costs into consideration in determining the secure optimal network capacity. The optimal network capacity sets the level of

allowable capital investment and hence revenue. Optimal transmission prices are then determined by allocating the optimal investment costs to users of the network using marginal cost pricing principles. The resultant prices are discriminated in time and space.

Although the level of detail and hence the complexity involved in determining the "global economic optimality" of a transmission network may vary considerably, the reference network, in its simplest form, would be topologically identical to the existing network, with the same generation and load layouts. It would operate at the same voltage levels as the real one, but the individual transmission circuits would have optimal capacities. These optimal capacities are determined in an exercise that balances operating cost and investment cost of networks, while satisfying security constraints. Clearly, fewer and smaller duration constraints result from higher circuit capacities. This implies higher network investment costs but lower operating costs of the system. If it is now assumed that the network capacity can take any size (with, say, a constant marginal investment cost), the resulting reference network would have exactly the optimal amount of constraints to which the optimal amount of investment cost would be associated, such that the total investment and operating costs are minimised.

The reference network pricing framework addresses many of the concerns raised regarding determination of transmission prices using either transmission cost driven methods (embedded cost) or generation driven cost methods (nodal or SRMC pricing).

## 6.4 Pricing of transmission network capacity in Great Britain

The Transmission Network of Use of System charges (TNUoS) reflect the cost of installation and maintenance of the transmission system. These activities are undertaken to the standards prescribed by the transmission licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security. The underlying rationale behind TNUoS charges (NG, 2006a) is that efficient economic signals are provided to 'users' when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that 'users' of the transmission system at different locations would have on the Transmission Owner's (TO) costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs

in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

The GB SO is required to plan, develop and operate the GB transmission system according to specified standards (NG, 2004). These requirements mean that the system must conform to a particular security standard and capital investment requirements are largely driven by the need to conform to this standard. It is this obligation that provides the underlying rationale for the TNUoS charges methodology, i.e. for any changes in generation and demand on the system, the GB SO must ensure that it satisfies the requirements of the security standard.

The security standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' Transmission Entry Capacity (TEC) accommodated. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system at the time of peak demand. The charging methodology (NG, 2006a) therefore recognises this peak element in its rationale.

### 6.4.1 Overview of the Transmission Network Use of System charges

The current TNUoS tariff encompasses two elements. The first is the locational element, derived from the ICRP (Investment Cost Related Pricing) transport model. The ICRP is an incremental pricing strategy that calculates the marginal cost of investment in the transmission system, which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission based on a study of peak condition on the transmission system. The second is the non-locational element related to the provision of security and residual revenue recovery. The latter charge is applied uniformly to all transmission network users. In essence, part of the TNUoS charges is specific to users who caused the network increment, and the other part of the charges is share among all network users.

**The elements of the TNUoS**

The locational element is designed to reflect the costs of capital investment and maintenance of the GB transmission system to provide bulk transport of power to and from different locations. The methodology for derivation of the locational element of the TNUoS tariff uses the Investment Cost Related Pricing (DCLF ICRP) transport model. This model uses a DCLF algorithm to calculate the marginal costs of investment in the transmission system required as a result of an increase in demand or generation at each node on the transmission system. This is based on a study of peak conditions with generation scaled to match demand. In order to reflect the difference in cost between overhead line routes at different voltages and cable routes, circuit '*expansion factors*' are calculated and employed. The resultant marginal kilometres from the DCLF model are grouped into zonal marginal km and are subsequently converted into costs ('initial locational transport tariffs') by the application of an '*expansion constant*', '*expansion factors*' and a '*locational security factor*'.

The '*expansion constant*' is based on expected future costs and represents the annualised value of the transmission infrastructure capital investment required to transport 1MW over 1km including an allowance for operating costs.

The '*expansion factors*' represent the cost of other types of lines and cables relative to the cost of a 400kV line.

The '*locational security factor*' represents the incremental investment in capacity required to provide security for transmission outages on a locational basis.

Once the initial locational transport tariff has been calculated, a correction factor is applied to achieve the appropriate split between generation and demand charges. GB SO applies a split between generation and demand of 27% and 73% respectively (NG, 2006a). Once this split has been reached through the application of a correction factor (producing the corrected transport tariffs), a flat residual tariff non-locational element is added to reach the target (total) revenue for TNUoS charges.

#### The final TNUoS charge

The final TNUoS charge is the sum of the locational and non-locational TNUoS elements. The relevant generation nodes making up a zone will be within £1/kW and geographically and electrically proximate. Generation TNUoS charges in positive tariff zones are calculated by multiplying a generator's TEC by the relevant £/kW zonal tariff to produce an annual charge. Generation TNUoS charges in negative tariff zones are calculated by multiplying a generator's 'Chargeable Capacity' by the relevant £/kW zonal tariff. The 'Chargeable Capacity' is calculated from the power station's average of the three highest metered volumes between November and February, separated by 10 clear days and each capped by its TEC, for the relevant financial year.

### 6.4.2 TNUoS charging methodology and wind power generation

The TNUoS methodology has been criticised by many observers for its treatment of renewable generation. In particular, wind generation is treated in exactly the same way as a conventional generation plant. The transmission charges are based on the analysis of (winter) peak demand conditions. While it may be assumed that the probability of all conventional plants generating at the system peak demand is more or less the same, wind power plants are intermittent and the probability of their generation at the peak demand is roughly proportional to their capacity factor. Hence wind generation should drive transmission investment to a lesser extent than thermal generation (Strbac et al., 2007). In other words, if non-discriminatory access to transmission network is to be established, TNUoS charges would need to discriminate between generation technologies.

### 6.4.3 Application of the GB TNUoS charging methodology

This sub-section presents the application of the GB TNUoS charging methodology to a three area system constituted of two major boundaries representative of the size of Great Britain's electricity system. The required inter-area transmission system transfer capabilities for the two boundaries were obtained from the application of the GB SQSS approach described in Chapter 5. The generation/demand background for each area can be found in Figure 6-1.

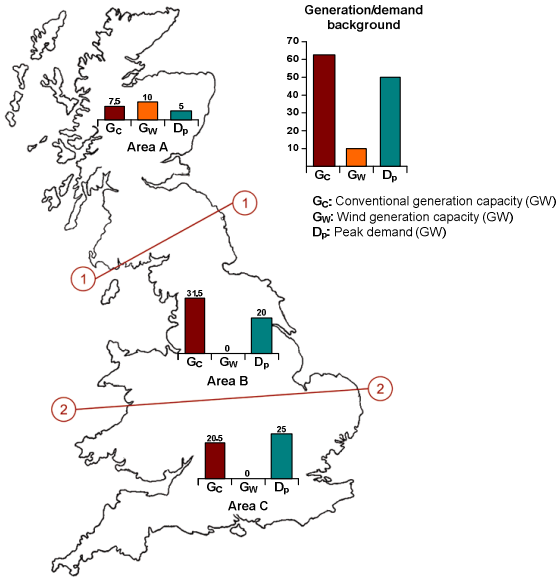



**Figure 6-1: Generation/demand background for the two boundary system**

Table 6-1 presents the transmission network prices for the different generation technologies present in the system and for demand customers.

**Table 6-1: Transmission network charges (£/KW/Year)**

| ICRP model | | | |
|---|---|---|---|
| Area | Wind generation | Conventional generation | Peak demand |
| A | 3.43 | 3.43 | -3.43 |
| B | 0 | 1.27 | -1.27 |
| C | 0 | -3.38 | 3.38 |

It can be inferred from Table 6-1 that the GB TNUoS charging methodology does not discriminate from different generation technologies, as wind generation pays the same transmission prices as conventional generation.

## 6.5 Pricing methodology for transmission network capacity driven by reliability

The proposed methodology for transmission network pricing provides a method to apportion the cost of the transmission network to generators and demand that use it. The underlying rationale is that efficient economic signals are provided to 'users' when services are priced to reflect the marginal costs of supplying them. Therefore, charges

should reflect the impact that 'users' of the transmission system at different locations would have on the network costs.

Transmission security standards use conditions of peak demand to identify transmission network investment. The derivation of the marginal investment costs at different points on the system is therefore determined against the requirements of the system at the time of peak demand. This introduces the concept of 'time-of-use pricing'.

Following this approach, while applying different contribution factors for conventional and wind generation, this method proposes a simple modification of the present TNUoS charging mechanism in order to recognise the different contributions of individual generation technologies to transmission network costs and hence to achieve cost reflectivity.

### 6.5.1 Linkage between network pricing and investment drivers and planning

Given that one of the principal objectives of network pricing is to send signals to users of the network regarding the costs they impose on network development, it is necessary to first establish network investment costs. Network investments and the associated costs are driven by the network design (planning) process. There is therefore a close link between network pricing and network design. Network design, in a simplified form, is in fact a key input to network pricing. In the context of the GB transmission, network design is driven by:

- the need to satisfy network design standards (security standards, i.e. GB SQSS);
- a set of incentive mechanism within the regulatory framework that may influence further investment (quality of supply, losses and incentives to connect renewable energies).

In principle, all the drivers of future network costs should be included in the determination of network prices, although in practice the choice of which investment drivers will be included in the process is likely to be based on the materiality of the individual cost driver and the objectives of the pricing exercise.

In order to demonstrate the basic principles of the proposed network pricing methodology, network design (planning) is assumed to be primarily driven by network security standards, i.e. the network costs are driven by network security considerations. Thus, the transmission planning methodology (the contribution factors method) developed in Chapter 5 for investment in transmission is employed as the driver for network design.

### 6.5.2 Network pricing method

The minimum inter-area power transfer capability is defined for the time of system peak demand by means of the capacity contribution of the different generation technologies and demand, both location specific, to the required level of transfer capability. The inter-area transmission system transfer capability is expressed as follows:

$$TC = \sum_{t=1}^{T} \left( C_{T_k} \cdot G_{T_k} \right) + C_{D_k} \cdot D_{peak_k} \tag{6.2}$$

Where '$T$' is the number of the different generation technology types, '$C_{Tk}$' is the contribution factor of generation technology of type '$T$' in the area '$k$', '$G_{Tk}$' is the generation capacity of the generation technology of type '$T$' in the area '$k$'. '$C_{Dk}$' is the contribution factor of peak demand in the area '$k$' and '$D_{peakk}$' is the peak demand in the area '$k$'.

To quantify the transmission network investment cost '$tc_{Tx}$' (£/year), the annuatised transmission network price '$tp_u^{Tx}$' expressed in '£/kW/km/year' has to be allocated to the transmission network, and its length '$l$' in 'km' considered. The transmission network investment cost is defined by equation (6.3).

$$tc_{Tx} = TC \cdot l \cdot tp_u^{Tx} \tag{6.3}$$

In order to apply the pricing policy described above, transmission network costs must be converted into area transmission prices through monitoring the network users' contributions to inter-area transmission system transfer capability.

It is important to remember that circuit prices are only applied during the period when optimal transmission network flows are binding. The peak period is the one when flows are binding. Allocation of prices exclusively to peak periods introduces the concept of 'time-of-use pricing'. By allocating circuit prices to areas, a second concept is introduced namely 'location-specific pricing'. Therefore once transmission network prices are allocated to areas the resultant 'use of system charges' are both location and time of use specific.

In order to reflect transmission network prices to areas, it is necessary to evaluate the incremental change that each network user causes on the network prices. Since generators and demand have opposite effects on the transmission network loading during the period of critical loading of the network, both positive and negative charges will be present. In the case of area 'k' being an exporting area, generators pay, while demand gets paid for reducing network capacity requirement. Similarly, if area 'k' is an importing area, generators get paid, while demand pays for increasing network capacity requirement. On the other hand, charges outside of the period of maximum plant loading are zero, since the incremental change in the loading of the transmission network does not require reinforcement and hence does not impose any capacity related cost.

For example, area A in Figure 6-2 is an exporting area, therefore an incremental change in injection at area A will result in an increase of the transmission network flow from area A to area B. It is evident that the derivative of optimal transfer capability connecting areas A to B with respect to area injection '$P_{CA}$' or '$P_{WA}$' at area A is positive. This derivative is called the sensitivity of the optimal transfer capability to the injection at area A.

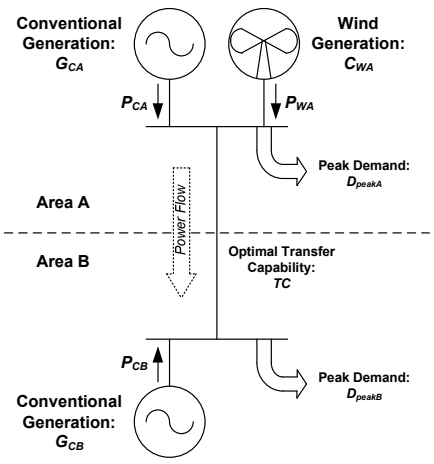



**Figure 6-2: Layout of the two-busbar example and power flows**

The sensitivity of the optimal transfer capability with respect to demand and generation customers in the area '*k*' are given by equation (6.4) and (6.5) respectively.

Sensitivity for demand costumers in the area 'k':

$$S_k^{D_{peak}} = \frac{\partial TC}{\partial D_{peak_k}} = C_{D_k} \tag{6.4}$$

Sensitivity for generation costumers of technology type '*T*' in the area '*k*':

$$S_k^{G_T} = \frac{\partial TC}{\partial G_{T_k}} = C_{T_k} \tag{6.5}$$

The transmission network investment marginal price '*tnp*' for both demand and generation costumers connected to area '*k*' are expressed in '£/kW/year' by equation (6.6) and (6.7) respectively.

$$tnp_k^{D_{peak}} = S_k^{D_{peak}} \cdot \lambda_k \tag{6.6}$$

$$tnp_k^{G_T} = S_k^{G_T} \cdot \lambda_k \tag{6.7}$$

'$tnp_k^{Dpeak}$' is the transmission network price for demand costumers in the area '*k*', '$tnp_k^{GT}$' is the transmission network price for generation costumers of technology type '*T*' in the area '*k*', '$\lambda_k$' is the nodal reference price in the area '*k*'.

The transmission network investment charges '$Q$' for demand and generation costumers connected to area '$k$' are expressed in '£/year' by equation (6.8) and (6.9) respectively.

$$Q_k^{D_{peak}} = ntp_k^{D_{peak}} \cdot D_{peak_k} \tag{6.8}$$

$$Q_k^{G_T} = ntp_k^{G_T} \cdot G_{T_k} \tag{6.9}$$

'$Q_k^D$' is the transmission network charges for demand costumers in the area '$k$' and '$Q_k^{GT}$' is the transmission network charges for generation costumers of technology type '$T$' in the area '$k$'.

The total area based transmission network revenue obtained from all users of the network across the entire system has to recover the total cost of the transmission network (equation (6.3)). Such relationship is defined in equation (6.10).

$$tp_{TC} = \sum_{k=1}^{K}\left[\sum_{t=1}^{T}\left(Q_k^{G_T}\right) + Q_k^D\right] \tag{6.10}$$

Where '$K$' is the total number of areas in the system and '$T$' is the number of the different generation technology types.

For a radial system, areas are chosen so that all lines are considered between neighbouring nodes. The amount of generation and load in areas formed in this way will be equal to the total generation and load that is electrically connected to each of the nodes of the pair of busbar under consideration.

In the UK, the overall contribution to the transmission costs is currently 73% from demand customers and 27% from generation (NG, 2006a), in this case the following holds:

$$\sum_{k=1}^{K}\left[\sum_{t=1}^{T} Q_k^{G_T}\right] = \left(\frac{0.27}{0.73}\right)\sum_{k=1}^{K} Q_k^D \tag{6.11}$$

The linear equation (6.10) and (6.11) can be solved to obtain the value of '$\lambda_k$' all areas. Once these values are obtained, transmission network charges for the network users in all the areas can be calculated using equation (6.8) and (6.9).

Figure 6-3 shows the overall process for deriving network use of system charges

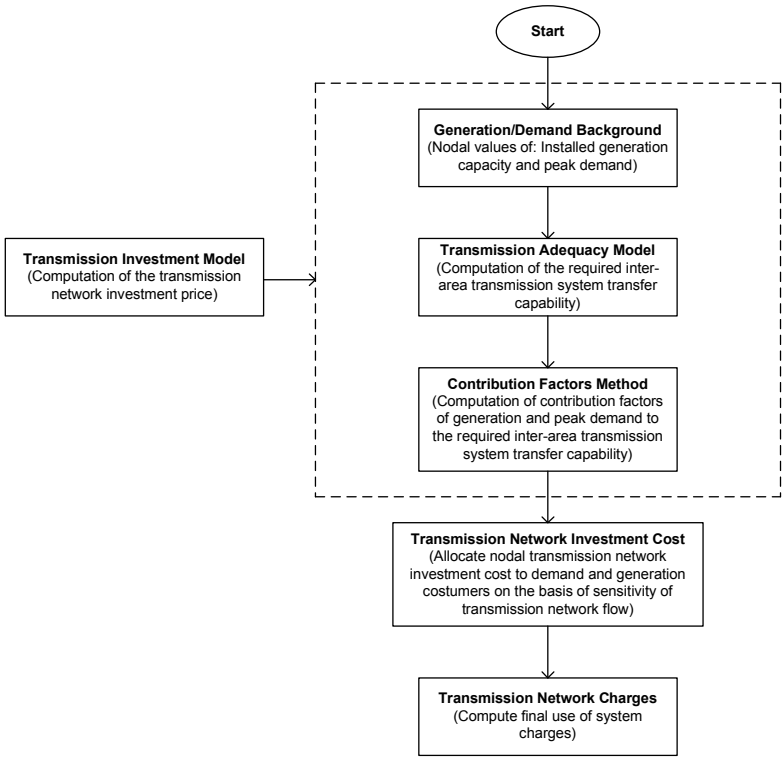



**Figure 6-3: Transmission network use of system charge model**

## 6.6 Illustration of the principles of the proposed network pricing method

The aim of this section is to present the core features of the pricing methodology and illustrate them through the application of an example. The three area system is constituted of two major boundaries characterised by the generation/demand background representative of the size of the Great Britain electricity system. The required inter-area transmission system transfer capabilities for the two boundaries were obtained from the planning methodology described in Chapter 4. The generation/demand background and required boundary transfer capabilities for each area can be found in Figure 6-4.

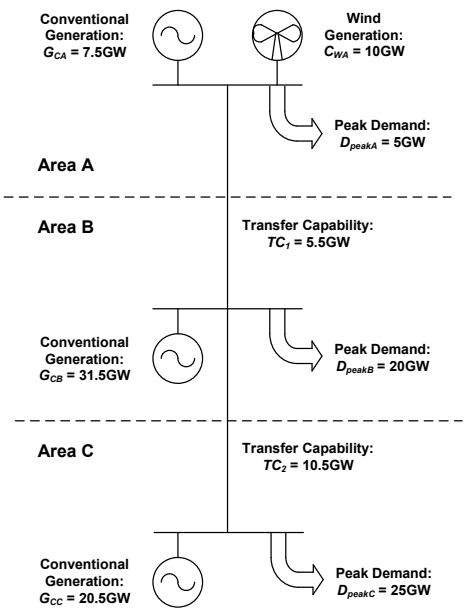



**Figure 6-4: Example of three-busbar system with combined conventional and wind generation system**

For the radial system, the areas are chosen so that all lines are considered between neighbouring nodes. The amount of generation and peak demand in areas formed in this way will be equal to the total generation and load that is electrically connected to each of the nodes of the pair of busbars under consideration. In a sequence of this process, the generation/demand background and the required inter-area transmission system transfer capability for each boundary are presented in Table 6-2.

**Table 6-2: Generation/demand background**

| | North Area | | | South Area | | |
|---|---|---|---|---|---|---|
| Boundary | $G_C$ (GW) | $G_W$ (GW) | $D_{peak}$ (GW) | $G_C$ (GW) | $G_W$ (GW) | $D_{peak}$ (GW) |
| 1 | 7.5 | 10 | 5 | 52 | 0 | 45 |
| 2 | 39 | 10 | 25 | 20.5 | 0 | 25 |

### 6.6.1 Transmission network investment cost

The transmission network investment cost is calculated from the knowledge of the required boundary transfer capability, the length of the transmission corridor and from making a suitable assumption regarding the annuatised marginal price of transmission network, 30 £/MW/km/year. The transmission network investment costs are obtained from the application of equation (6.3) and are presented in Table 6-3.

**Table 6-3: Transmission network investment cost**

| Boundary | Length (km) | Transfer capability (GW) | Annuatised investment price (£/kW) | Investment cost (M£/year) |
|---|---|---|---|---|
| 1 | 72 | 5.5 | 2.16 | 11.88 |
| 2 | 155 | 10.5 | 4.65 | 48.83 |

### 6.6.2 Contributions factors of generation and demand to inter-area transmission system transfer capability

The contribution factors method (Chapter 5, section 5.4.1) is employed to evaluate the contribution of the different generation technologies and peak demand to the required boundary transfer capability. The contribution factors relative to each boundary are presented in Table 6-4.

**Table 6-4: Contributions factors of generation and demand**

| | North Area | | | South Area | | |
|---|---|---|---|---|---|---|
| Boundary | $C_{GC}$ (%) | $C_{GW}$ (%) | $C_{Dpeak}$ (%) | $C_{GC}$ (%) | $C_{GW}$ (%) | $C_{Dpeak}$ (%) |
| 1 | 86 | 40 | -100 | -76 | 0 | 100 |
| 2 | 81 | 38 | -100 | -70 | 0 | 100 |

### 6.6.3 Nodal reference prices

The magnitude of the nodal reference price in the area '$k$', '$\lambda_k$', can be obtained by the solving the system of two linear equations, equation (6.10) and (6.11). The nodal reference prices in the areas at either side of the boundaries are presented in Table 6-5.

**Table 6-5: Nodal reference prices**

| | North Area | South Area |
|---|---|---|
| Boundary | $\lambda$ (£/kW) | $\lambda$ (£/kW) |
| 1 | 1.77 | 0.39 |
| 2 | 1.61 | 3.04 |

### 6.6.4 Transmission network prices and charges

The prices and charges of the transmission network are quantified and allocated to the different users of the network, using equation (6.6)-(6.9). The transmission network prices and charges for the north and south area of each boundary are presented in Table 6-6 and Table 6-7 respectively.

**Table 6-6: Transmission network prices (per boundary)**

| | North area prices (£/kW/year) | | | South area prices (£/kW/year) | | |
|---|---|---|---|---|---|---|
| Boundary | $ntp_{GC}$ | $ntp_{GW}$ | $ntp_{Dpeak}$ | $ntp_{GC}$ | $ntp_{GW}$ | $ntp_{Dpeak}$ |
| 1 | 1.53 | 0.71 | -1.77 | -0.30 | 0 | 0.39 |
| 2 | 1.31 | 0.60 | -1.61 | -2.14 | 0 | 3.03 |

**Table 6-7: Transmission network charges (per boundary)**

| | North area charges (M£/year) | | | South area charges (M£/year) | | |
|---|---|---|---|---|---|---|
| Boundary | $Q_{GC}$ | $Q_{GW}$ | $Q_{Dpeak}$ | $Q_{GC}$ | $Q_{GW}$ | $Q_{Dpeak}$ |
| 1 | 11.45 | 7.14 | -8.85 | -15.38 | 0 | 17.52 |
| 2 | 51 | 6.05 | -40.14 | -43.87 | 0 | 75.79 |

Transmission network prices and charges obtained for the north and south area of each boundary can now be rearranged, allowing the allocation of calculation of the nodal transmission network prices and charges to each user of the network. The nodal transmission network prices and charges are presented in Table 6-8 and Table 6-9 respectively.

**Table 6-8: Transmission network prices (per area)**

| | Transmission network prices (£/kW/year) | | |
|---|---|---|---|
| Area | $ntp_{GC}$ | $ntp_{GW}$ | $ntp_{Dpeak}$ |
| A | 2.83 | 1.32 | -3.38 |
| B | 1.01 | 0.60 | -1.22 |
| C | -2.44 | 0 | 3.42 |

**Table 6-9: Transmission network charges (per area)**

| | Transmission network charges (M£/year) | | |
|---|---|---|---|
| Area | $Q_{GC}$ | $Q_{GW}$ | $Q_{Dpeak}$ |
| A | 21.25 | 13.19 | -16.88 |
| B | 31.88 | 0 | -24.33 |
| C | -49.93 | 0 | 85.52 |

Results in Table 6-8 demonstrate that in the exporting areas, A and B, wind generation prices are smaller than the conventional generation prices. This reflects the fact that wind generation, drives less boundary export transfer capability than conventional generation as previously concluded. For instance, in the exporting area A, generation prices are positive given the transmission is built to allow access of generation A to B while demand customers in area A should get rewarded since they contribute to the reduction of the required boundary transfer capability.

The transmission network investment cost can be obtained by summating the transmission network charges imposed on individual users of the network, as shown in

Table 6-9. The total transmission revenue is equal to the transmission network investment price (60.71 M£/year), obtained in Table 6-3.

## 6.7 Case study

The application of the proposed transmission network pricing mechanism that is applicable to both conventional and variable generation is demonstrated on the simplified GB transmission network introduced in Chapter 4, section 4.5. The results are presented in Table 6-10 for the generation scenario of 10GW of wind generation in Scotland and 3GW of wind generation in England. The detailed input data for the generation scenario under analysis can be found in Chapter 4, section 4.5. Table 6-10 also presents a comparison between proposed transmission network pricing mechanism and the present transmission network use of system charging framework (ICRP model).

The proposed transmission network pricing mechanism is broadly consistent with the present TNUoS framework and is based on the impact that generation has on security driven network capacity. It should be noted that the pricing based on security considerations consider conditions of peak demand. When determining the impact that individual generation technologies have on network investment, different scaling factors for conventional and wind are applied as appropriate.

**Table 6-10: Transmission network charges (£/kW/year)**

| | Proposed pricing mechanism | | | ICRP model | | |
|---|---|---|---|---|---|---|
| Node | Wind generation | Conventional generation | Peak demand | Wind generation | Conventional generation | Peak demand |
| NW-SHETL | 3.39 | 15.44 | -15.92 | 16.30 | 16.30 | -16.30 |
| N-SHETL | 2.65 | 13.86 | -14.33 | 14.71 | 14.71 | -14.71 |
| S-SHETL | 2.17 | 12.62 | -13.07 | 13.45 | 13.45 | -13.45 |
| N-SPTL | 1.03 | 9.07 | -9.47 | 9.85 | 9.85 | -9.85 |
| S-SPTL | 0.77 | 8.04 | -8.42 | 8.80 | 8.80 | -8.80 |
| UN-E&W | 0 | 5.94 | -6.26 | 0 | 6.64 | -6.64 |
| NW-E&W | 0 | 0.98 | -0.35 | 0 | 0.73 | -0.73 |
| NE-E&W | 0 | 3.03 | -3.26 | 0 | 3.64 | -3.64 |
| MW-E&W | 0 | -1.23 | 2.68 | 0 | -2.30 | 2.30 |
| ME-E&W | 0 | 1.12 | -0.92 | 0 | 1.30 | -1.30 |
| SW-E&W | 0 | -5.92 | 8.08 | 0 | -10.55 | 10.55 |
| SE-E&W | 0.15 | -2.99 | 4.48 | -2.90 | -2.90 | 2.90 |
| S-E&W | 0 | -4.67 | 6.28 | 0 | -4.70 | 4.70 |

The results in Table 6-10 demonstrate that the cost reflective charges for wind, when the transmission investment is driven by reliability considerations rather than ICRP model, are always less than the charges for conventional generators in the exporting area

(Scotland and North of England). The ratio of transmission charges between wind and conventional plant is similar to the generation capacity credit of wind. In importing areas, as wind generation does not practically contribute to maintaining system security, wind generation cannot displace transmission capacity, and therefore will not get rewarded. In this example, wind generation in the South East of England will still need to pay transmission charges while conventional generation at the same location gets paid.

The results from the proposed pricing mechanism show that in most cases wind generation should pay less than conventional generation. However, in the case where transmission is built because of high wind penetration level and there is not adequate conventional generation which can fully use that transmission, wind can be charged higher than conventional generation. It is also important to note that based on the same arguments, different types of conventional generation can also have different transmission prices depending on their contribution on the critical flows. The results also show that in the South, wind generation gets paid higher prices than the conventional peak plant due to a higher contribution of wind energy compared with the peak plant during peak load.

The ICRP model treats wind generation similar as conventional generation and therefore pays the same transmission prices. This is inappropriate because wind generation drives less transmission capacity.

## 6.8 Discussion and conclusions

The work developed in this chapter built up on a previous study on transmission network investment in system with wind power generation (Chapter 4). The previous study developed a new methodology to determine the inter-area transmission system transfer capability requirements in systems designed to ensure reliability of the interconnected transmission system development. The application of this methodology to systems including wind generation illustrated that wind generation drives less transfer capacity than conventional generation and that wind and conventional generation should share transmission network capacity. The present methodology for the evaluation of transmission network use of system charges (TNUoS charges) is not consistent with the network investment planning process, i.e. all generation is charged the same amount

irrespective of the need it imposes on the network investment. In other words, the present TNUoS is not cost reflective and necessary modifications have yet to be made to achieve the consistency between network investment and network pricing.

This chapter have therefore examined a possible cost reflective investment, within the present TNUoS framework, that is based transmission pricing methodologies which recognise the distinct contribution of individual generators to network costs. The results demonstrate that when transmission investment is driven by reliability, in exporting areas the cost reflective charges for wind are always less than the charges for conventional generators. In importing areas, where wind generation does not practically contribute to maintaining system security (i.e. wind generation cannot displace transmission capacity), it does not get rewarded while conventional generation at the same location is likely to get paid.

The results from this work also illustrated that reflection of the differences in inter-area power transfer capability requirements for wind and conventional generation will result in cost reflective pricing that treats wind generation differently. This approach also highlights that the cost reflective approach (for investment and pricing) comes from recognition of the location of generation and the time at which transmission pricing is required.

# Chapter 7

# Conclusions and future work

## 7.1 Introduction

The global decline in environmental quality and the accompanying effects of climate change impacts is compelling the world community to find low carbon energy solutions. In order to meet their commitments for reduction in Green House Gas (GHG) emissions under regional as well as international agreements like the Kyoto Protocol, some countries plan to supply significant share of their future energy requirements through renewable sources. The UK, which is currently responsible for about 3% of the Global GHG emissions, has set a targets of by 2015 generating 15% of its electricity needs from renewable sources. A major contribution towards meeting these targets is likely to come from onshore and offshore wind generation. The principle challenges are then to ensure the cost effective integration of this power generation source in the operation and development of the power systems without compromising the security of supply.

## 7.2 Conclusions

### 7.2.1 Response to research question

The aim of this thesis was to evaluate the ability of generation to meet demand (generation adequacy) and the ability of transmission system to carry power from the generation plants to the consumption areas (transmission adequacy) in the future sustainable power system featuring significant penetration of wind generation. This challenge was addressed in two parts: (i) through the development of new methods of system planning which encapsulate wind generation's characteristics and promote an understanding on how wind generation affects the generation and transmission system development, and (ii) through the development of standards and regulatory arrangements associated with the transmission system to facilitate the cost effective integration of wind generation technologies.

To this end, five research questions were identified to scope the research objectives and build a structure for this thesis. These initial research questions and the key conclusions on each are elaborated below. Following this are the overarching conclusions from this thesis.

**RQ1. What is the impact of the presence of a flexible generation source such as hydro power on the capacity value of wind generation?**

A rigorous methodology was developed to compute generation capacity adequacy and capacity credit of wind generation in wind-hydro-thermal systems. The developed methodology is applied to a system equivalent to New Zealand's electricity system, which depicts a good combination of thermal and hydro generation with an expected rapid deployment of wind power in the near future. Based on the application of the developed methodology it was found that the presence of flexible generation source in the generation system, such as hydro power (with reservoir/storage capability), considerably enhances the capacity value of wind generation. However, the marginal contribution of hydro generation to the capacity credit of wind declines with the increasing penetration of wind generation in the system.

The methodology was further enhanced to allow the quantification of the additional capacity costs attributed to wind power when this technology penetrates into the hydro-thermal system. Due to relatively high capacity credit of wind generation in NZ the disproportion between the amount of capacity and energy displaced by wind power is relatively small. Therefore, the additional capacity costs attributed to wind generation in NZ are lower than the thermal based systems. Additional capacity costs attributed to wind generation are found to range between 1.2 £/MWh to 5.5 £/MWh corresponding to 5% and 30% wind penetration respectively. Cost estimates for other countries (e.g. Great Britain) reveal similar cost levels (UKERC, 2006).

The method is also applied to evaluate and comprehend the influence of various characteristics of wind and hydro generation on the capacity value of wind generation. Sensitivity studies indicated that wind resource diversity and the load factor of wind generation significantly affect its capacity value. For example highly diverse wind farms in the NZ raise the capacity credit of wind generation by about 12 percentage points compared to a wind resource with low diversity. At 5% penetration level of wind the

capacity credit of wind generation increases 6 percentage points for all wind load factors considered. This clearly indicates the effectiveness of the role of hydro generation in enhancing capacity contribution of wind power.

The quantitative analysis also revealed that hydro power characteristics considerably impact overall system adequacy and the capacity credit of wind generation in wind-hydro-thermal systems. The presence of a greater amount of hydro generation capacity in the system results in larger additional capacity credit benefit for wind generation. Different hydro conditions (dry, average, and wet), which lead to a higher availability of the annual hydro energy, increases the capacity credit of wind generation at all levels of wind penetration considered. Another factor found to affect the capacity credit of wind generation in wind-hydro-thermal systems is the hydro storage capacity. The analysis demonstrates that the additional (benefit) capacity credit of wind generation due to the support of hydro is enhanced with the rise of the reservoir capacity. However, the marginal contribution of hydro generation to the capacity credit of wind declines, heading towards saturation, with the rise in the reservoir capacity.

**RQ2. What is the impact of interconnectors on capacity adequacy and capacity value of wind generations in systems with hydro generation?**

A methodology is developed to evaluate the generation capacity adequacy and capacity credit of wind power in interconnected wind-hydro-thermal systems for various levels and locations of wind generation. The developed methodology is applied to a system equivalent to New Zealand's electricity system. Based on the developed method, the impact of the interconnectors on the overall system's capacity adequacy is assessed. It was found that the power transfer capability of the interconnector directly influences the system reliability. Therefore, significant overall generation capacity savings in both Islands are observed due to possible expansion of the interconnector. In general, the generation capacity benefits due to interconnector growth are higher at high wind penetration. This is strongly linked to the enhanced sharing of capacity reserve, mainly hydro in the South complementing large amounts of wind in the North Island.

Sensitivity studies over a range of hydro conditions (dry, average, wet) that influence the availability of annual hydro energy are conducted. For any given level of the interconnector it is found that the required capacity margins, necessary to maintain

system reliability, decrease with the increase in the availability of hydro energy. The benefit of the increase in the available hydro energy gradually reduces with the rise in wind penetration in the system.

The capacity contribution of wind generation in the form of capacity credit of wind was assessed. It was found that hydro generation in the NZ system will considerably enhance the capacity value of wind. However, the marginal contribution of hydro generation to the capacity credit of wind declines with increasing penetration of wind in the system. These capacity credits of wind are higher compared to thermal generation based systems.

High load factor of NZ wind also contributes to higher capacity and energy contribution for a given level of wind penetration. It is also found that the capacity value of wind is affected by the possibility of relatively sudden, large variations in power generated which need increased amounts of capacity reserves and thus reduce its capacity credit at higher penetration. On the other hand the presence of large hydro storage capacity in NZ helps to avoid wind curtailment during periods of high wind output coinciding with low demand and/or high run-of-river hydro yield periods.

The additional capacity costs attributed to wind generation in NZ are lower than the thermal based systems due to the relatively small disproportion between the amount of capacity and energy displaced by wind power. Such small disproportion is caused by the relatively high capacity credit of wind generation in NZ. Additional capacity costs attributed to wind generation for the analysed scenarios range between 2.4 $/MWh and 9.3 $/MWh of wind energy produced. The higher costs in the 2030 scenario are driven by larger capacity reserve requirements to accommodate larger wind forecasting errors.

**RQ3. What is the impact of wind generation on the need for transmission network capacity and on systems' security of supply?**

To quantify and assess the impact of wind generation on the need for transmission network capacity and on system's security of supply a new transmission planning methodology based on reliability evaluation of interconnected systems was developed.

Analysis of the contribution of wind generation to system's security of supply revealed that, although wind generation will displace energy produced by conventional plant, its

ability to displace capacity of conventional generation will be limited. This is because the contribution of wind towards securing peak demand will be limited as wind is much less 'reliable' than conventional plant. The ability of wind generation to displace capacity of conventional plant is the key to answering the question as to how much transmission should be built for it (from the security of supply perspective). Clearly, wind generation, due to its limited contribution to securing demand will drive much less network capacity than conventional plant.

The impact assessment has identified and quantified the sensitivity of the transmission network capacity to different generation conditions. The import/export nature of the local network will affect on the transmission requirements of wind generators. In exporting areas, the addition of wind generation plant type often drives less transmission network capacity than conventional generation. In importing areas, addition of wind generation may not displace significant amounts of network interconnection capacity and therefore interconnection capacity is still required to allow the load to be secured from other areas. Also the capacity credit of a generation technology is a major contributor to the network capacity that it can drive. Wind power generation has low capacity credit and cannot be relied on to secure a significant amount of load at peak time and will correspondingly drive less transmission network capacity to support this limited activity. The diversity of the wind resource as well as its load factor directly influence the capacity credit of this source and therefore the amount of network capacity that it can drive. Thus, diverse wind farms require 20% to 40% more transfer capability from the inerconnector compared to the non-diverse wind farms, whereas a change in the load factor of wind from 20% to 40% increases the inter-area power transfer capability about 30% at 10GW of wind in the system.

**RQ4. What are the main challenges facing the continued use of the present transmission security standards in systems with wind generation? What should be the main features of transmission security standards when applied to systems wind generation and how should the technical framework be implemented?**

A rigorous analysis was developed to assess whether the current Great Britain transmission security standards are suitable for application in future systems with growing levels of wind generation, in the context of the long term development of transmission network. The assessment analysis went over the principles and concepts on

which the current transmission planning guidelines were developed and the assumptions underpinning existing application procedures in order to identify and examine their strengths and weaknesses.

The design of the Main Interconnected Transmission Systems is driven by the Great Britain Security and Quality Supply Standards. These standards were conceptualised for large, conventional generation and do not consider the distinct characteristics of wind power. Generation technologies are differentiated by the use of dissimilar scaling factors based on their typical availabilities at times of peak demand. Thus, wind generation is treated as any other generation technology except that a lower availability factor is applied. The GB transmission licensees have determined an availability factor for wind generation of 5% for importing areas and of 72% for exporting areas, to be used in the calculation of 'planned transfer' in the GB SQSS. While the method of calculating 'interconnection allowance' (in particular, the x-axis of circle diagram) also applies the different scaling factors according to generator type, the 'circle diagram' has not been revised to account for the different characteristics of wind power generation.

The review process completed included a comparison between the developed reliability approach for transmission investment (Chapter 4) and the present GB SQSS in systems with significant levels of wind generation. The comparison clearly revealed that applying the proposed scaling factors to wind generation, without considering the inherent characteristics of this generation technology, is likely to lead to under-investment in transmission for importing areas and over-investment in transmission for exporting areas.

A new method, described as 'contribution factors method', is then developed as the basis to update the design criteria of the GB main interconnected transmission system, as stated in the GB SQSS, in order to incorporate the effects of wind power generation. In the contribution factors method the minimum inter-area power transfer capability is defined by the means of contribution factors of the different generation technologies and demand, both location specific, to the required level of transfer capability. The 'contribution factors method' provides a suitably robust characterisation of the required transmission network capabilities by the means of a relatively simple function that the transmission planner might apply. In essence, the approach developed devises practical

rules, similar to the present transmission security standards, for application in transmission planning procedures.

In exporting areas, the contribution of wind generation to boundary export capability decreases as the penetration level of wind generation in the area rises. On the other hand, in importing areas, the contribution of wind generation to boundary import capability is constant at about 10%. This reflects the earlier finding that in exporting areas the addition of wind generation plant type often drives less transmission network capacity than conventional generation and in importing areas, due to its limited capacity credit, it is not necessary to build transmission network capacity to accommodate it.

It was found that contribution factors for wind power are affected by many parameters; in particular: diversity of output of wind sources and penetration levels. However, the range of figures that would appropriate to use (in exporting areas) was found to be relatively small, between 20% and 35%, depending on the penetration level and the diversity of wind power output. Also the load factor of wind generation affects the wind contribution factors to inter-area transmission system transfer capability. For example, a change in wind load factor from 20% to 40% would increase the wind contribution factors by about 15 percentage points.

**RQ5. How should the network costs be allocated in a cost reflective manner to all network users in future low-carbon power systems with large scale penetration of wind generation?**

At the transmission level the current pricing arrangements are not cost reflective when applied to non-conventional generation because they fail to recognise the impacts outlined previously. They do not recognise differences in generation technologies that drive the different impacts on the network according to location and time of use of the system. As such the future system with significant penetration of wind generation has different requirements from the network in terms of long term capacity needs.

Earlier findings illustrated that wind generation drives less transfer capacity than conventional generation and that wind and conventional generation should share transmission network capacity. Thus, recognition of the differences in inter-area power

transfer capability requirements for wind and conventional will result in cost reflective pricing that treats wind generation differently.

When transmission investment is driven by reliability, in exporting areas the cost reflective charges for wind are always less than the charges for conventional generators. In importing areas, where wind generation does not practically contribute to maintaining system security (i.e. wind generation cannot displace transmission network capacity), it does not get rewarded while conventional generation at the same location is likely to get paid.

### 7.2.2 Final conclusions

Overall, four broad conclusions can be drawn from this work; each conclusion is stated and discusses in brief below. Following this are suggestions for further work in the area.

**C1. The contribution of hydro power to compensate the effects of variability of wind power, in particular during peak demand periods, considerably augments the capacity value of wind generation.**

Evaluation of the capacity credit of wind generation is necessary for wind farm developers, utility planners, system operators as well as other decision makers in order to plan future power systems that are economically efficient and meet the desired reliability standards. Capacity credit of wind generation varies across different regions due to the difference in the characteristics of the wind output as well as due to the different compositions of the incumbent generation systems. The presence of other flexible generation sources in the system such as hydro power (with reservoir/storage capability) can mitigate the variability of wind generation. This will lead to retain reduced thermal capacity in the system to maintain system security and thus enhances the capacity value of wind generation. However, the marginal contribution of hydro generation to the capacity credit of wind declines with the increasing penetration of wind generation in the system.

**C2. Wind generation drives less transmission network capacity than conventional generation.**

Wind power can displace energy produced by conventional plant (i.e. reduce the fuel burnt), but its ability to displace capacity of conventional generation is limited. As the capacity credit of wind power is limited, network reinforcement driven by wind generation will be limited in systems designed for reliability. Wind generation is essentially a fuel saver, rather than a contributor to generation capacity, so building transmission to support it on this basis is not optimal. Hence, wind generation, due to its limited contribution to securing peak demand will drive much less transmission network capacity than conventional plant.

**C3. Wind and conventional generation should share the same transmission network capacity.**

Wind power generation has a low marginal cost and thus it is not justified to subject it to significant constraints. In this context, transmission network design for systems with significant penetration of wind should create an optimally constrained network that facilitates the economically efficient sharing of network capacity between wind and conventional generators. Broadly, expensive and fossil fuelled generation should be constrained off the system when there is coincidence between the wind blowing and system peaks. This suggests a shift in the nature of the transmission network investment. While reliability is still a driver for the specification of transmission network design; in the future sustainable power system with significant share of intermittent wind generation, the optimal networks are likely to be constructed with economic efficiency as a dominant driving factor for network investment decisions.

**C4. When transmission investment is driven by reliability, in exporting areas the cost reflective charges for wind are always less than the charges for conventional generators.**

The current technical, commercial and regulatory arrangements associated with the transmission system are fit for the purpose for which they were designed. The pricing of the transmission network was designed to support a power system dominated by conventional, large-scale, centralised generation plant. However, the movement towards a more sustainable, low carbon power system will bring with it a broader mix of

generation technologies of varying size, generation profile and controllability. Location and time of use factors play a key role in the impact of these technologies and this is not aligned with the traditional methodologies for transmission network pricing in the system. Thus, discrimination between generation types to reflect these differences in operation characteristics and output is essential if cost-reflective pricing regimes are to be devised.

Wind generation, due to its limited contribution to securing peak demand will drive much less transmission network capacity than conventional plant. Thus, recognition of the differences in inter-area power transfer capability requirements for wind and conventional will result in cost reflective pricing that treats wind generation differently. In exporting areas the cost reflective charges for wind are always less than the charges for conventional generators (i.e. wind generation drives much less transmission network capacity than conventional plant) and in importing areas, where wind generation does not practically contribute to maintaining system security (i.e. wind generation cannot displace transmission network capacity), it does not get rewarded while conventional generation at the same location is likely to get paid.

## 7.3 Recommendations for further work

The investigation of the impacts of integration of different levels of intermittent wind generation to power generation system has opened up new areas for further research. Those identified as potential areas are outlined below.

### 7.3.1 Development of alternative techniques for capacity adequacy evaluation

It is realised that analytical techniques to evaluate system security with intermittent generation sources have limited flexibility in accommodating all the factors necessary to model the behaviour of an intermittent source of generation. For example, it is extremely difficult to model the chronology of system generation and its correlation with demand. Secondly, analytical techniques only provide average values of various measures relevant to quantifying the system security such as; average probability, average frequency, and duration of a particular level of shortage is obtained. However for system design point of view it is important to know the distribution or the spread of

these indices. Simulation techniques are more flexible in incorporating a wide range of factors while modelling the behaviour of both intermittent and conventional generators and can more closely simulate the operation of generation systems. These alternative techniques will also help to validate results through comparison with earlier developed techniques.

### 7.3.2 Analysis of system operation in systems with significant penetration of wind power

The emerging low-carbon power system is likely to have a high penetration of unpredictable wind generation and inflexible nuclear generation. The combination of these two generation technologies will prompt a fundamental change in system operation away from the traditional mode of operation seen in system dominated by conventional thermal generation. In particular, an increased penetration of variable and unpredictable wind power will place an additional duty on the remaining generating plant with respect to balancing supply and demand and will increase the need for flexibility required from conventional plant. In order to manage the balance between demand and supply the system will need to hold increased amounts of response and reserve services, generally provided by a combination of synchronised plant, demand and standing reserve.

Quantification of the reserve requirements and the economic impact of these additional services is a key area for research currently facing the power sector. Therefore, there is a need to evaluate and quantify the extent and costs of the additional balancing requirements, assess key cost drivers such as plant flexibility characteristics, determine the value of different technologies competing to provide balancing services, including demand side management, and explore appropriate market arrangements to stimulate optimal investment in response and reserve services.

### 7.3.3 Role of energy storage, demand side management and grid interconnections

Storage and/or demand side management plant may provide some part of the system reserves and enhance the ability of the system to absorb increased levels of wind generation at low costs. Therefore, enhancement in existing analytical techniques to

incorporate the role of the storage facilities and DSM with renewables will provide an extended framework to analyse their role in future systems. The key aim of such an analysis would be quantifying the value of reserves being provided by competing technologies i.e. storage, demand side management and transmission interconnectors including combinations of these, considering present market arrangements.

### 7.3.4 Role of wind forecasting

To integrate large penetration of wind energy successfully into electricity system operation, it will be important to predict wind energy production as accurately as possible. A number of wind forecasting systems have been developed, looking over time horizons from one hour to one day ahead of real time operation. These are potentially very valuable for reducing the amount of various types of reserves necessary to balance demand and supply. It is recommended that an analysis should be carried out to examine the role of wind forecasting in reducing the cost of system operation and enhancing the commercial value of wind energy.

### 7.3.5 Access to transmission networks in systems with significant penetration of wind power

The current technical, commercial and regulatory framework associated with transmission access is fit for the purpose for which they were designed, namely, the operation, investment and pricing of the transmission network to support a power system dominated by conventional, large-scale, centralised generation plant. However, the UK generation mix is now materially changing. More than 16GW of wind generation have applied for connection to the onshore distribution and transmission network in Scotland along with about 8GW of offshore wind in England. The variability of wind generation output means that a) its requirement for transmission access is not correlated to peak network conditions and b) it displaces the energy produced by incumbent generation, but not an equivalent amount of generation capacity (required to maintain system reliability). On this basis, the analysis produced in this thesis has demonstrated that transmission networks to support non-conventional generation will be different from the incumbent system in two fundamental ways, i) wind and conventional generation should share transmission network capacity, and ii) network should be

reinforced beyond the requirements for reliability. To continue using the traditional approach to transmission investment, access and pricing fails to take account of these differences in characterisation and use of the network. This omission leads to inefficiencies in the development and operation of the transmission network resulting in discrimination against new renewables, unnecessary delay in connection and ultimately in higher prices for consumers.

In this context, there is a need to i) review the current transmission access arrangements in light of the challenges of integration of large amounts of wind generation in Scotland and present the evidence in support of a radical change in access arrangements, ii) set out the high level requirements for enduring transmission access arrangements, and iii) develop a framework for enduring transmission access that would deliver efficient transmission infrastructure investment for a system with significant contribution of wind power.

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