Integration of Variable Renewable Generation into Electricity Systems

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Submitted in accordance with the requirements for the degree of
Doctor of Philosophy

University of Leeds
Low Carbon Technologies Doctoral Training Centre
School of Chemical and Process Engineering

August, 2015

The candidate confirms that the work submitted is his own, except where work which has formed part of jointly-authored publications has been included. The contribution of the candidate and the other authors to this work has been explicitly indicated below. The candidate confirms that appropriate credit has been given within the thesis where reference has been made to the work of others.

The following jointly authored publications are part of the thesis:

1. EDMUNDS, R. K., COCKERILL, T. T., FOXON, T. J., INGHAM, D. B. & POURKASHANIAN, M. (2014). Technical benefits of energy storage and electricity interconnections in future British power systems. *Energy*, 70, 577-587.

2. EDMUNDS, R., DAVIES, L., DEANE, P. & POURKASHANIAN, M. (2014). Thermal power plant operating regimes in future British power systems with increasing renewable penetration. *Energy Exemplar Research Publication*

3. EDMUNDS, R., DAVIES, L., DEANE, P. & FOXON, T. (2015). Using a capacity expansion model to understand the requirements for capacity provisions in electricity systems with increasing renewable penetration. *To be submitted to Energy Policy*

Details of the contributions from the candidate and co-authors are listed below:

1. Edmunds wrote the article and developed the models. Foxon, Ingham and Pourkashanian provided guidance and proof reading. Cockerill contributed with further details, comments, guidance and proof reading.

2. Edmunds wrote the article and developed the models, with guidance from Deane. Davies and Deane contributed with further details, data, comments, guidance and proof reading. Pourkashanian provided further guidance.

3. Edmunds wrote the article and developed the models, with guidance from Deane. Foxon, Davies and Deane contributed with further details, data, comments, guidance and proof reading.

Acknowledgements

The opportunity to study towards a PhD was made possible through the funding provided by the Engineering and Physical Sciences Research Council, for which I am very grateful to have received. I must thank Professor Paul Williams for providing me with the incredible opportunity to pursue my research interests and support my professional development. Also, I must thank my supervisors for their guidance and support throughout the course of my studies.

Special thanks to Dr Paul Deane and Lloyd Davies for their advice and feedback when undertaking the research in Chapters 6 and 7. Further, I would like to thank Energy Exemplar for providing the software to complete the research in these chapters. Also, I thank Professor Peter Taylor for his invaluable insights and comments on the research completed in Chapter 6.

I am very grateful to Peter Børre Eriksen, for providing the opportunity to work with Energinet.dk in Denmark, and to the British Council, for the chance to complete the RENKEI programme in Japan. These were incredible experiences that not only shaped my thinking, but allowed me to develop many far reaching collaborations and friendships.

I must thank all of my friends and colleagues that I have met throughout my time in Leeds. I feel very privileged to have been part of such a stimulating and friendly working environment. Finally, and most importantly, I would like to thank my friends and family who have loved, supported and inspired me throughout the years – I am forever grateful and could not have wished for better.

Abstract

Achieving the emission reductions that scientists recommend will require the deployment of technologies, such as wind turbines and solar photovoltaics, which have fundamentally different characteristics to the fossil fuel generators that have contributed to the growth and prosperity enjoyed throughout the industrialised world. This research has centred on developing a greater understanding of the technical and economic challenges of increasing variable renewable penetration in electricity systems.

Following a review of the literature, three important topics for research are identified and analysed. Initially, the EnergyPLAN tool is used to quantify the benefits of increasing energy storage and interconnection capacity in future British power systems. The findings conclude that increasing the interconnection and storage capacity allows for an increase in the maximum technically feasible wind penetration, this permitting a reduction in system emission intensity.

Subsequently, the operational requirements for thermal plants in future power systems are investigated using the PLEXOS Integrated Energy Model. In the scenarios considered, the utilisation of gas plants is relatively low but remains fundamental to security of supply. The findings have important implications for energy policy as government intervention may be required to prevent early decommissioning of gas capacity, should the prevailing market conditions not guarantee revenue adequacy.

Finally, using the PLEXOS Integrated Energy Model, a capacity expansion model is developed to understand the long term price implications in systems constrained by emission reduction and system security targets. As the long run costs increase at a greater rate than the short run costs, revenues from the energy market are increasingly insufficient for firm generation capacity to recover costs. The insights highlight the importance of designing power markets that provide incentives to satisfy both emission reduction targets and security constraints, in systems with increasing variable renewable generation.

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1 Introduction

A secure energy supply is fundamental to the success of any modern economy. Governments around the world have long been aware of both the benefits of developing a secure energy supply and the social, political and economic consequences of unsuccessful energy polices. Traditionally government energy policies have been centred on achieving two primary objectives, namely; security of supply and affordability. However, with the growing scientific consensus that global warming is exacerbated by human activities, environmental objectives are increasingly included within energy policies around the world (Oreskes, 2004).

While scientists have been developing theories on the implications of human activity on the climate for over 100 years, the first international agreement to reduce emissions did not enter force until 2005 (United Nations, 2014, King, 2005). Although a second international binding agreement is yet to be reached, the number of countries with renewable energy policies has continued to increase and over 144 countries now have renewable energy targets (REN21, 2014). The technological advancements and cost reductions of lower carbon technologies and renewables has led to governments and industry realising that these options may play a crucial role in achieving objectives beyond decarbonisation, namely; security of supply and affordability. Further, while not always an explicit primary objective of energy policies, the accelerated roll out of these technologies may have the added value of industry and job creation.

The challenge of a global shift away from fossil fuels will require a strong social and political will to transform the way in which energy is used. Traditionally, population growth, energy consumption and economic growth have been linked. However, to achieve the reduction in greenhouse gas emissions to levels that climate scientists recommend, nations will have to decouple emission production and economic growth. Achieving this will require the commercialisation of technologies with fundamentally different characteristics to conventional generation. Thus, major research and development breakthroughs and an understanding of the macro-economic impacts of the roll out of these technologies on the wider economy will be required.

An accelerated roll out of low carbon technologies into electricity systems will be significantly challenging. Variable renewable technologies, notably wind and solar, differ from conventional thermal generators by six fundamentally different properties (International Energy Agency, 2014b). Output from renewable generation is *uncertain*, in that it is difficult to predict accurately ahead of time, and *variable*, in that output varies significantly over time. These technologies can be described as *modular*, with unit outputs that are typically much lower than conventional thermal generators. As the availability of variable renewable generators is dictated by the resource, these technologies are described as *location constrained*. Variable renewable generators are typically connected to the grid via power electronics and thus are lacking the *grid stabilisation capabilities* of conventional units. Finally, due to the low fuel costs, variable renewable generators have *low short-run marginal costs* compared to conventional thermal generation.

The aim of this research is to contribute to the understanding of the implications of a greater penetration of variable renewable technologies on power systems and markets. Considering the characteristics of variable renewable generation and the suitability of different modelling approaches, the aim is to progress the field by considering, (a) the benefits of technologies that can enable a greater penetration of variable renewable generation; (b) the requirements for energy policies that consider not only the deployment of variable renewable generation, but also the implications for incumbent generators; and (c) the benefits of long term modelling to enable a greater understanding of the long term implications of increasing variable renewable generation on price formation and electricity market design. The analysis focusses on the electricity system in Great Britain, but the findings would be applicable to systems in other countries with similar characteristics.

1.1 Aims and Objectives

The overriding aim of this thesis is to examine the implications of the six properties, described previously, for the integration of variable renewables into power systems, in the context of a transition to a low carbon energy system. Further, the aim is to contribute to the knowledge and understanding within the research field of renewable integration analysis. After completing a critical review of the existing literature, a number of research gaps that warrant further research are identified, and these research gaps are analysed. Based on the research gaps identified, the following research questions have been formulated;

1) *What are the technical benefits of energy storage and electricity interconnectors in electricity systems with increasing renewable penetration?*
2) *How will the operation and utilisation of coal and gas power stations change in electricity systems with increasing renewable penetration?*
3) *What are the longer term implications of the properties of variable renewable generation on price formulation and electricity market design?*

The justification for each research topic and the required modelling approach are discussed fully in Chapter 4, but they are also briefly summarised here. The first research topic considers the benefits of increased energy storage and electricity interconnections in future British power systems with increasing variable renewable generation. The second research topic considers some of the further work recommendations from the analysis of the first research topic. The topic aims to develop a greater understanding of the expected operation regimes of thermal power plants in future power systems with increasing renewable penetration. The third research topic considers the longer term implications of increased variable renewable generation on the power system. The research discusses the implications of failing to account for some of the characteristics of variable renewable generation in renewable integration analysis.

1.2 Outline of Thesis

This thesis has been written in such a way that the reader can review the major research chapters independently. The chapters are laid out as follows: Chapter 2 provides an overview of the characteristics of variable renewable generation. The chapter discusses six key properties that differentiate variable generation from conventional thermal power generation. The characteristics, as outlined by International Energy Agency (2014b), include; low short-run marginal costs, variability, uncertainty, modularity, non-synchronous and location constrained. The chapter discusses the costs and impacts associated with each of these properties when the capacity of variable renewable generation is increased. Further, a number of important system and market properties that will influence the ability of energy systems to handle high level of variable generation are discussed.

Chapter 3 provides an overview of the models used for energy system and power system analysis. The overriding objective of the chapter is to explain to the reader the justifications for the models, tools and methods used in Chapters 5, 6 and 7. The chapter includes a brief introduction to the history of energy system modelling and a broad comparison of the different types of energy system models. An overview of some of the most commonly used energy models for aiding decision makers is included. The chapter then discusses some modelling challenges that are associated with the characteristics of variable renewable generation, as outlined in Chapter 2. The chapter concludes by discussing the processes and criteria for selecting the models used in Chapters 5, 6 and 7.

Chapter 4 identifies three main research topics for this study. Research gaps identified within the literature search for Chapters 2 and 3 are discussed and placed in context with the wider subject area. The first research topic considers the technical benefits on increasing energy storage and interconnections in future power systems with increasing renewable penetration. Research topic two considers the operating requirements for thermal power plants in a range of discrete future power system scenarios. Research topic three considers the requirements for capacity provisions in future power systems with increasing renewable penetration. The methodology required to examine each research topic is described and can be summarised as follows. Chapter 5 uses the technical optimisation capabilities of the EnergyPLAN tool to analyse a range of discrete scenarios to offer insights on the technical benefits of energy storage and electricity interconnectors. Chapter 6 uses the optimisation and production cost modelling capabilities of PLEXOS to understand the operation of thermal plants in future power systems with increasing renewable penetration. Chapter 7 uses the optimisation and capacity expansion modelling capabilities of PLEXOS to evaluate the long term implications of variable renewable generation for price formation and electricity market design.

Chapter 5 provides an analysis of the technical benefits of increasing energy storage and electricity interconnections in power systems with increased variable generation. This chapter uses the EnergyPLAN advanced systems analysis computer tool to analyse a range of plausible future scenarios for the years 2020 and 2030. The chapter includes an introduction, describing and placing the research in the context of the existing literature and the novelty of the work. The modelling approach, describing the model set-up and scenarios are included within the methodology section. The results focus on the maximum technically feasible wind penetration that can be achieved in each of the scenarios. A number of model parameters are analysed including; variable generation capacity, interconnection capacity and energy storage capacity, to understand the effect on maximum technically feasible wind penetration. Further results focus on the critical excess electricity production and system emission intensity. The discussion of the results outlines the policy implications of the research, the requirements for a whole system approach and topics for further research.

Chapter 6 addresses some of the further work recommendations outlined within Chapter 5. The chapter focusses on the operation regimes of thermal power plants in future British power systems with increasing renewable penetration. As with Chapter 5, a scenario analysis is used and the results from four discrete scenarios compared to the results obtained from a validated 2012 model of the British power system. The introduction describes the key characteristics of variable renewable generation that will influence the operation of thermal power plants in future power systems, along with the important modelling challenges, notably the requirement for sub-hourly modelling to capture the intra-hour variability of renewable generation and the technical constraints, such as ramping constraints, of thermal plants. Within the methodology section, a description of the PLEXOS Integrated Energy Model is included. In this application, the models solves the unit commitment and economic dispatch problem, subject to a number of technical, environmental and policy constraints. The results section focusses initially on the broad system level results, including total system costs, system emissions and contribution to demand by fuel type. The operating regimes of thermal power plants are then analysed. Again, the discussion focuses on the policy implications of the research.

Chapter 7 considers the longer term policy implications of increasing variable renewable generation. As such, the modelling approach used here considers the expansion of the electricity system over several decades. This is different to Chapters 5 and 6, where the models consider the detailed operation of a number of plausible power systems for the years 2020 and 2030. In this study, the model optimises the timings of the investments throughout a user defined planning horizon. The introduction focusses on placing the research in context, highlighting the challenge of power market design in future power systems with increasing variable renewable penetration. The methodology describes the long term capacity expansion problem and the set-up of a long term model using the PLEXOS Integrated Energy Model. The results section focusses on the development of the generation mix through time and investment required. Also, the model outputs allow for an understanding of the costs associated with different emission reduction targets. A number of key model outputs, including; capacity shadow price, long run marginal costs, short run marginal costs and plant capacity factors are analysed. The conclusions and discussions of this chapter focus on the policy implications and changing dynamics of energy markets in regions with increasing variable renewable penetration.

Chapter 8 provides a final discussion and a number of recommendations for further work. The Chapter draws the results together, emphasising the importance of whole systems analysis and applying the relevant analytical approaches. Recommendations for further work that contribute to the fields of renewable integration analysis, power system modelling techniques and energy policy analysis are included.

Finally, Chapter 9 summarises how the research questions have been answered, and provides the concluding remarks.

2 Characteristics of Variable Renewable Generation

2.1 Introduction

This chapter provides an introduction to the challenges associated with integrating variable renewable generation into power systems. In the first section, the expansive growth of variable renewable capacity and penetration in recent years is illustrated and discussed. The second section discusses six specific characteristics of variable renewable generation, as outlined by the International Energy Agency (IEA). The power system and market impacts of these specific characteristics are discussed, drawing on recent literature. The chapter serves as an introduction to the field of renewable integration. It should be noted that the energy system models for analysing the impacts of variable renewable generation on power systems are discussed in Chapter 3 and specific areas for research are discussed in Chapter 4.

2.2 Variable Renewable Energy: The Global Context

2.2.1 Global Growth in Installed Capacity

Global variable renewable generation capacity has grown rapidly over the past two decades. This section contains information about the global and regional growth of wind and solar power, along with short term market forecasts.[1] Statistics for the global cumulative capacity, global annual installed capacity and regional installed capacity are included. The market forecasts are provided by the Global Wind Energy Council (GWEC) and the European Photovoltaic Industry Association (EPIA) (Global Wind Energy Council, 2015a, European Photovoltaic Industry Association, 2014).

[1] The figures in this section are based on statistics taken from reports written in 2014, for the year 2013. Due to the strong growth in solar and wind capacity, particular in Asia, the figures in 2014 and beyond could be significantly different.

2.2.2 Global and Regional Wind Capacity Growth

Global installed wind capacity has increased from around 7GW in 1997 to over 318GW in 2013, as shown in Figure 2.1 (Global Wind Energy Council, 2014). Much of this growth has occurred over the past 5 years, with almost 200GW installed between 2009 and 2014. This growth can be attributed to the increased commitment to renewable energy by governments around the world. In 2014, over 140 countries had implemented renewable energy targets, up from 48 in 2004 (REN21, 2014).

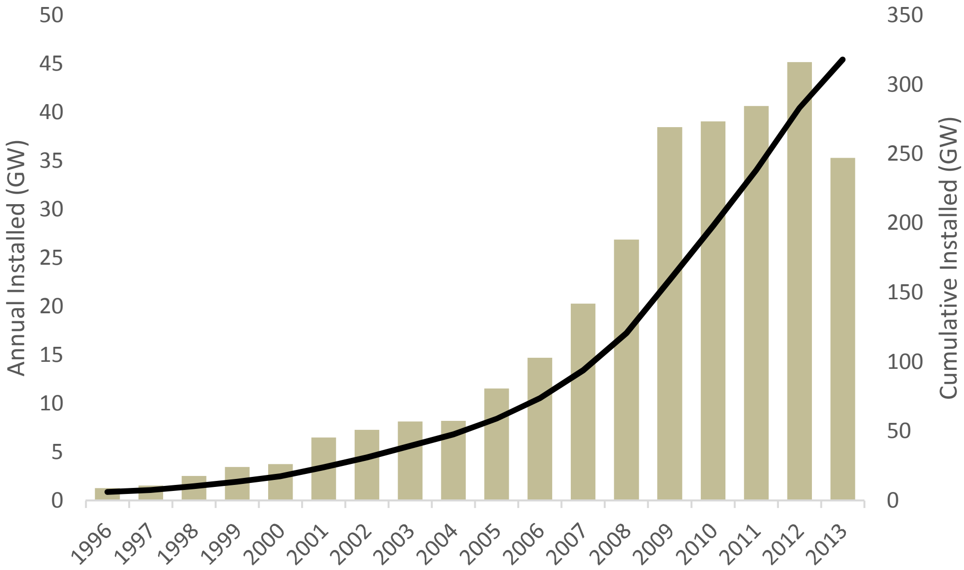

Figure 2.1 – Global annual installed wind capacity and global cumulative wind capacity (GW).[2]

Figure 2.2 shows the annual installed capacity for wind over the period 2006-2013. It is clear that the vast majority of growth has taken place in Asia, North America and Europe. Analysing the statistics can provide some further insights. In 2013, China (91.4GW) and India (20.1GW) accounted for 96% of the installed wind capacity in Asia. In North America, the United States (61.1GW), Canada (7.8GW) and Mexico (1.9GW) made up the capacity. In Europe, many countries have achieved a relatively high

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[2] Figure 2.1 and Figure 2.2 have been compiled by statistics taken from the GWEC Global Wind Report: Annual Market Updates, for the years 2006-2013.

capacity, with Germany (34.3GW), Spain (23GW), UK (10.5GW), Italy (8.6GW), France (8.3GW) and Denmark (4.7GW) accounting for over 70% of the installed capacity. While turbines are installed in many countries around the world, over 80% of the worlds installed capacity is located within nine countries, namely; China, United States, Germany, Spain, India, UK, Italy, France and Canada.

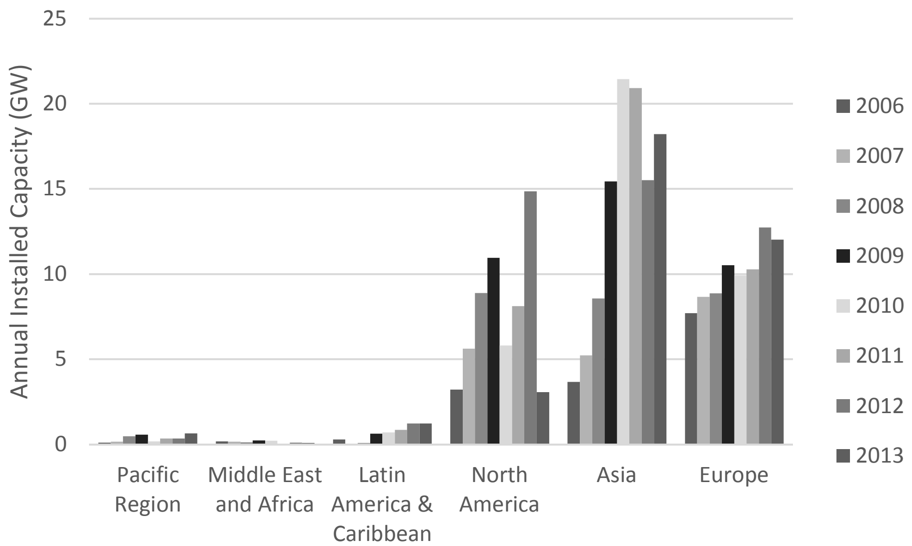

Figure 2.2 – Regional annual installed wind capacity (GW).

While cumulative installed wind capacity growth remains strong, Figure 2.1 shows a sharp decline in installations in 2013. As Figure 2.2 shows, the sharp decrease from 2012 to 2013 is primarily due to the reduced construction in the North American region. In 2012, just under 15GW was installed in this region, while in 2013, this dropped by over 10GW to below 4GW. The decline in installations was due to the uncertainty in the future of the PTC (Production Tax Credit) in the US (U.S. Department of Energy, 2015). While the PTC was extended in January 2013, developments only had to be under construction by the end of 2013 to qualify for the credit, thus offering little incentive to become operational in 2013. However, in December 2013, a record 12GW of wind was under development, thus ensuring that both 2014 and 2015 promise to be strong years for growth in the US (American Wind Energy Association, 2014).

The market outlook for wind installations between 2014 and 2018 shows that strong growth is expected to continue. The Global Wind Energy Council (GWEC) global wind report 2013 only contains an outlook for the period 2014-2018 and forecasts that the global installed capacity will increase from 318GW in 2013 to 596GW in 2018. As in the past decade, growth is largely expected to be centred in Europe, North America and Asia. In Asia, China is likely to continue to dominate with an ambitious 200GW target set for 2020 (International Energy Agency, 2012). European growth is forecasted to be steady, with between 11 and 15GW of annual installations forecasted between 2013 and 2018. North America is described as the most difficult region to forecast as the region is dominated by the US where there is significant uncertainty regarding the PTC. Nevertheless, the outlook is optimistic with a forecasted total capacity of 132GW in 2018. The Middle East and Africa can expect significant growth with installed capacity forecasted to rise from 1GW in 2013 to 14GW in 2018. The capacity in Latin America is also expected to grow significantly, largely due to the ambitious deployment plans in Brazil (Global Wind Energy Council, 2014). Finally, the Pacific region has forecasted growth to increase from 4GW in 2013 to 9GW in 2018. Based on the projections, the regional market share in 2018 is as follows; Asia 39%, Europe 32%, North America 22%, Latin America 3%, Middle East and Africa 2% and Pacific 2%.

2.2.3 Global and Regional Solar Capacity Growth

Solar PV has also experienced a high growth rate, with installed capacity increasing from 5GW in 2005 to over 139GW in 2013.

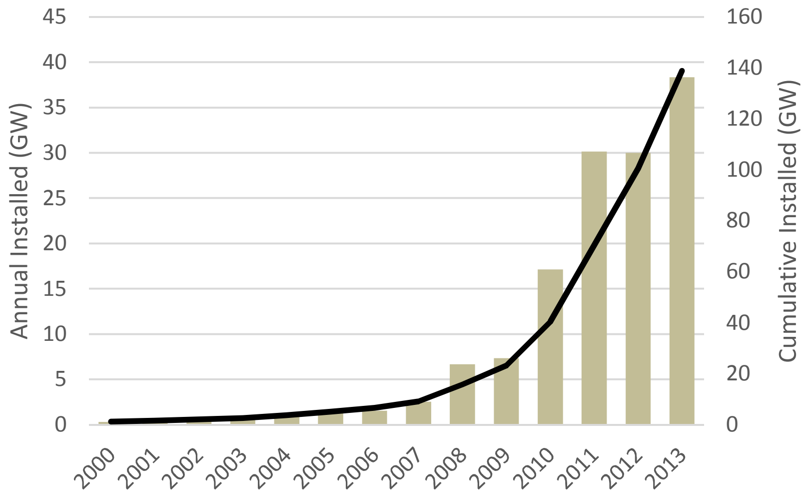

Figure 2.3 - Global annual installed solar capacity and global cumulative solar capacity (GW).[3]

On comparing Figure 2.1 and Figure 2.3 it is clear that the large scale deployment of wind began a number of years before that of solar.

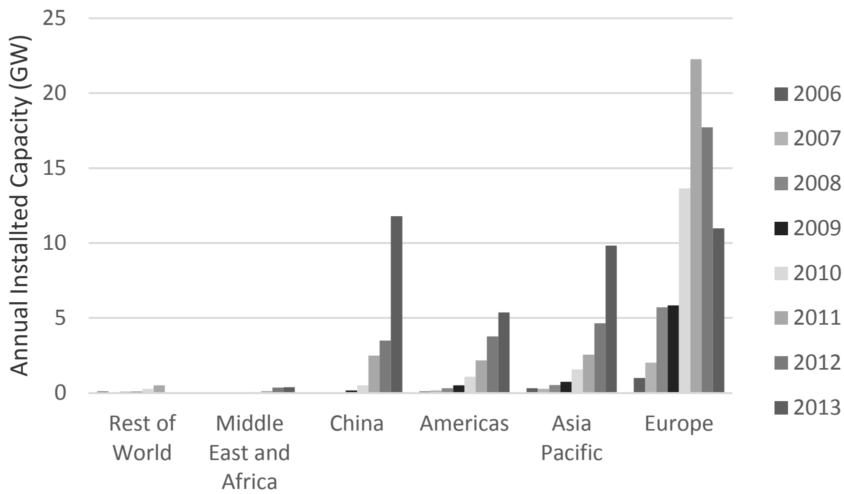

Figure 2.4 - Regional annual installed solar capacity (GW).[4]

Figure 2.4 shows the regional annual installed solar capacity. It is clear that Europe has been a strong leader in terms of installations, accounting for 81GW (or 59%) of the global installed capacity. In 2013, Europe experienced a sharp reduction in installations, due to a significant reduction in

[3] Figure 2.3 and Figure 2.4 have been compiled by statistics taken from the EPIA Global Market Outlook for Photovoltaics 2014 – 2018.

[4] Note that Figure 2.2 and Figure 2.4 have been regionalised differently. This is due to the different data collection techniques at the EPIA and the GWEC.

installations in Germany and Italy, which together account for 65% of the total capacity in Europe. In Europe, over 80% of the capacity is installed in just 5 countries, namely; Germany (36GW), Italy (18GW), Spain (5GW), France (5GW), and the UK (3GW). China has achieved significant growth in recent years, and in 2013 installed 12GW to top the market. Of the 22GW installed in the Asia Pacific region, about 14GW is installed in Japan. Both India (2GW) and Australia (3GW) also contribute significantly to the capacity in the region. In the Americas region, the US with over 12GW, accounts for over 90% of the installed capacity. As with wind, much of the globally installed capacity is concentrated in only a few countries. Together, Germany (36GW), China (19GW), Italy (18GW), United States (12GW), Spain (5GW) and France (5GW) account for 95GW (or 68%) of the global installed solar capacity.

Within the European Photovoltaic Industry Association (EPIA) global market outlook, the three forecasted scenarios suggest that the strong growth in PV installations is set to continue. The low scenario forecasts an annual global market of between 35 and 39GW between 2014 and 2018. Over the same period, the high scenario forecasts annual installations of between 52 and 69GW. Within the report, the medium scenario fall’s centrally between the high and low scenarios. Regarding the national and regional market share, China is set to remain the dominant country, with a market share of between 29 and 32% in 2018. Europe (between 21 and 25%) and the Americas (between 18% and 19%) also retain a significant market share. The outlook forecasts strong growth in the Middle East and Africa, with the market share rising from 1% in 2013 to between 7 and 10% in 2018. Finally, the Asia Pacific region is forecasted to have a market share of between 17 and 22% in 2018. In summary, substantial growth in the solar industry is set to continue, with total installed capacity forecasted to grow from 139GW in 2013, to between 321 and 430GW in 2018.

2.2.4 Market Outlook Uncertainty

It is important to recognise that there are significant uncertainties regarding the market forecasts for both wind and solar capacity. A wide variety of factors can lead to the slow down or acceleration of deployment, not least; price of fossil fuels, price of carbon, investment in research and development, commitment to environmental policy, financial and policy support, regulation, consumer behaviour, energy demand and strength of the economy. Even with all of these uncertain variables, it is difficult to envisage global wind and solar deployment collapsing completely. Also, it should be noted that installations could increase above the forecasted levels and that the growth trends could be greater than expected.

2.3 Variable Generation Penetration Level

While the installed capacity data is useful for highlighting the strong growth in solar PV and wind deployment, it doesn't reflect the contribution to the total electricity supply. Therefore, it is not the key metric for this research. At present energy systems and electricity market designs are planned on either a national or regional level and, as such, system planners and policy analysts are interested in the contribution of different technologies to electricity supply and system security. The contribution of a technology to the total electricity demand or capacity can be termed penetration. This research focusses on the cost effective system and market integration of variable renewable generation and, as such, we are interested in the variable renewable penetration.

As Holttinen et al. (2011) report, penetration can be described in both capacity (installed capacity as a percentage of peak load capacity) and energy (generation as a percentage of electricity demand) metrics. Throughout this study we use the latter definition, as we are primarily interested in the contribution of variable renewable generation to meeting the total electricity demand and thus the decarbonisation of the power system.[5]

Figure 2.5 shows the wind penetration, as the contribution to total electricity supply, in the 16 countries that have the highest penetration (International Energy Agency Wind, 2014). When we compare Figure 2.5 and Figure 2.2 and the resulting discussion, it is clear that many of the countries and regions that have a large installed capacity do not always have a high wind penetration. Of course, this is due to the relative size of the systems, consider the US, China and India. In 2012, they had electricity systems with a total installed capacity of 1063GW, 1174GW and 255GW, respectively. Denmark, Portugal and Spain have total installed capacities of 14GW, 20GW and 105GW (U.S. Energy Information Administration, 2015). The relatively strong commitment to environmental policy in the EU has led to the high penetration reached in several European Countries (da Graça Carvalho, 2012). It is important to note that Denmark has had a long standing commitment to wind energy deployment and has long been a leader in research and development, especially in terms of wind turbine development and integration of renewable energy in power systems (Meyer, 2007).

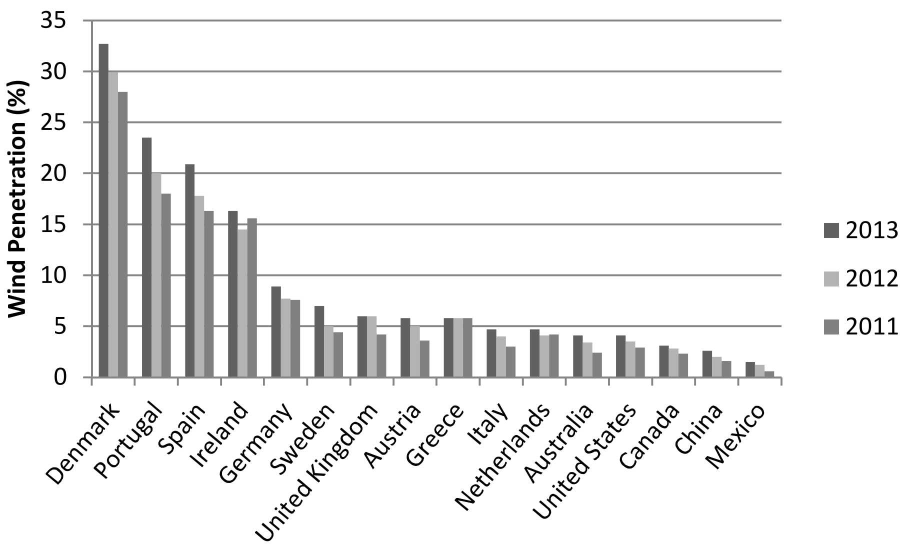

Figure 2.5 – Wind penetration by country.[6]

[5] Many renewable integration studies use the energy definition as they tend to be interested in the contribution of renewable generation to total demand.

It is clear that the leaders, in-terms of wind deployment, are not necessarily the leaders, in-terms of wind penetration. Another point to note from Figure 2.5 is that the top 11 countries are located in Europe, where the power systems can be referred to as stable (International Energy Agency, 2014b).[7] This means that while the growth in installation rates in Europe and North America may slowdown in the coming years, the wind penetration is likely to continue to increase. Therefore, increasing wind capacity is likely to contribute to an increase in the wind penetration.[8] This is not necessarily the case in dynamic power systems, where increased demand could outpace the electricity supply from wind generation, even when wind capacity is increasing. The following sections will explain the important differences and challenges in integrating variable renewable generation into power systems; this section only introduces the concept that penetration, in terms of contribution to electricity demand, is often the key metric in renewable integration studies.

2.4 Power System and Market Impacts of Variable Generation

This section provides an overview of the power system and market impacts of increased variable renewable generation. The International Energy Agency has outlined six specific properties of variable renewable generators that affect their contribution to the operation of the power system and markets. The six properties are; variability, uncertainty, location-constrained, modularity, non-synchronous and low short-run costs (International Energy Agency, 2014b). The following sections provide some detail on each of these properties, drawing from both the IEA's report on *"The Power of*

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[6] Figure 2.5 has been compiled by statistics taken from the IEA WIND 2013 annual report.

[7] Stable systems are those with low load growth and low short term infrastructure requirements, for example, Germany, Ireland and Denmark. Dynamic systems have demand growth and/or infrastructure requirements, for example, China, India and Mexico.

[8] Note that when the installation growth rate is low, the wind resource plays a more significant role in wind penetration for a given year. For example, if a systems wind capacity only increases by 100MW in 2015 in a system that already has over 10,000MW installed, then the wind penetration may decrease in 2015 if the wind resource in the previous year was particularly strong.

Transformation" and a number of key peer-reviewed studies that contribute to the concepts.

As the impacts of variable generation are highly system and market specific, this section discusses some of the important properties that will determine the impacts that variability will have on power system and market operation.

2.4.1 Important Power System Properties

Power system impacts of increased variable penetration are highly system specific and a large range of results are to be expected, depending on the impact and power systems studied. The associated impacts of increased wind penetration are a function of many factors; not least, generation mix, wind resource characteristics, geographical spacing of wind turbines, balancing area size, correlation between demand and variable renewable supply, demand growth and infrastructure requirement, interconnections to neighbouring electricity systems and the integration of the electricity sector with other energy sectors, specifically heat and transport (International Energy Agency, 2014b, Lynch et al., 2012, International Energy Agency, 2011, Sinden, 2007, Holttinen, 2003).

If we compared the costs and impacts of renewable integration in Denmark and Great Britain, we would expect significant differences. In the case of Denmark, a country with a significant wind penetration, the system has a high level of interconnection (Norway (1.04GW), Sweden (2.64GW) and Germany (2.38GW southbound, 2.1GW northbound), large integration of heat and electricity (due to a high level of combined heat and power plants) and a strong wind resource (Energinet.dk, 2012). In the case of GB, there is little integration between electricity and heat. While the GB system has a number of interconnectors (to France 2GW, Ireland 1GW and The Netherlands 1GW), relative to the size of the peak demand this is very small (National Grid, 2013a). In summary, relative to the Danish system, GB has a very rigid energy system.

2.4.2 Important Power Market Properties

Along with the characteristics of the power system, the market structure and dispatch arrangements will influence the impact of increased renewable generation. Important dispatch arrangements include, size of trading blocks, dispatching process for both non-renewable and renewable generators and gate closure time (International Energy Agency, 2014b). Markets that allow trading in small blocks and operate close to real time are more efficient as forecasts have a greater degree of accuracy closer to real time (Foley et al., 2012b). Short term forecasting reduces generation and load uncertainty, leading to a reduction in the requirements for short-term reserves (International Energy Agency, 2014b). Efficient dispatch requires the optimisation of the full generation portfolio. Therefore, a centralised pool without bilateral contracts is regarded as the most effective market design to prevent constraining the dispatch process (International Energy Agency, 2014b). Further, the dispatch incentives for renewable generation can distort the market. Ideally, variable renewable generation should have no incentive to bid below the short-run marginal costs (International Energy Agency, 2014b).[9]

Other important market design characteristics include; the arrangements for reserve provision, representation of the grid in price formulation and trading arrangements for interconnectors (International Energy Agency, 2014b). For effective interconnector management, cross border co-ordination and harmonization of balancing markets would allow for the interconnectors to be used to the maximum potential (Poyry, 2014). Under the third energy package, the EU strongly supports the move to a single market and the harmonization of electricity markets is a core objective (da Graça Carvalho, 2012). However, at present only the day-ahead markets are harmonized and for this reason the flows through the interconnectors are determined many

[9] Some markets prioritise the dispatch of renewable generation. In some markets this is explicit (i.e. the regulator requires that if available, wind generation is dispatched) in others it is implicit (i.e. wind generation is incentivised to bid below it’s true short-run marginal costs through feed-in tariffs or renewable certifications). Depending on the requirement or incentive for priority dispatch of variable renewable generation, market operation can be significantly distorted, as renewable generators may bid into the market at a negative price.

hours in advance. Allowing interconnectors to access balancing markets could provide significantly flexibility to the interconnected regions (Poyry, 2014).

Grid representation refers to the consideration of grid constraints in the market price formulation. At the highest level, prices are formulated on nodes throughout the system (locational marginal pricing) and at the lowest level only one single price is formulated (i.e. no representation of grid constraints). An alternative is zonal pricing, where regions are split into several zones. Locational marginal pricing (LMP), zonal pricing and a single market price all have advantages and disadvantages. For example, LMP allows for a short gate closure and short trading intervals as the transmission system operator (TSO) has a stronger representation of the existing grid constraints, compared to single market pricing where grid constraints are not represented. However, a concern with LMP and zonal pricing is market power abuse, with few companies controlling the supply at a given node or zone.

Historically, in many countries reserve provision was fixed; however with the addition of supply side variability this can lead to the sub-optimal procurement of reserves, as reserves may be over procured. Therefore, it is important that reserve procurement takes into consideration variable renewable generation. Further, it is important that reserve services are traded in a competitive market to ensure that remuneration is sufficient for the different products offered.

2.5 Characteristic 1: Variability

The next six sections discuss six specific characteristics of variable renewable generation and their impacts on power systems and markets. As wind and solar generation is primarily dictated by the changes in weather conditions, the output is subject to significant variability. This is different to the output from conventional thermal plants (including nuclear, gas and coal units), where units can be dispatched and electricity supplied at a predefined level, subject to restrictions from forced and unforced outages. The variability of wind and solar is studied across many timescales, depending on the research topic. For system level renewable integration studies Holttinen et al. (2012) recommend that a minimum resolution of 1 hour is used.

2.5.1 Estimating Wind Variability and Power System Impacts Using Meteorological Data

Prior to large scale wind deployment, studies attempted to better understand the characteristics of the wind resource with a view to assessing the ability of wind energy to reliably contribute energy to power systems. These studies typically use historical weather station data, scaling the wind speeds to the hub height of a wind turbine and correlating the speed to a power output from a turbine power curve.

In Great Britain, Sinden (2007) studied data obtained from 66 weather stations over a 34 year period (1970 – 2003), reporting the inter-annual, monthly and diurnal variability. According to the analysis of the aggregated output from 25GW of wind capacity, significant variability occurs on each of the times scales. The results highlight lower capacity factors are expected in the summer months (May-September) and greater output is expected in the winter months. The diurnal results show significant increases in the capacity factor during daylight hours. A key finding was that the correlation between wind output from different sites decreases with distance. Therefore, a greater geographical diversification of wind farms leads to a reduction in overall variability. Sinden (2007) reports a power output correlation decreasing from 0.75 at approximately 40km to 0.4 at approximately 410km and 0.2 at approximately 750km. These findings agree with an earlier study by Holttinen (2003), where real wind power production data from Nordic Countries was used to analyse the hourly wind power variations and cross-correlation coefficients for the region for the year 2001 are reported. Holttinen (2003) concludes that *“large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero peak output”.* Using data from 45 meteorological stations and scaling the data to turbine hub height using the log law for onshore wind and an empirical equation developed by Hsu et al. (1994) for offshore wind, Reeves and Watson (2011) also reported that the output from a geographically dispersed fleet of wind farms will reduce variability.

Oswald et al. (2008) calculated the aggregated wind power output for each hour in January for the period 1995 – 2006, based on data from eight weather stations and a wind capacity of 25GW. The study then calculates a residual demand curve by subtracting the wind output from the electricity demand. The authors report, that in January 2005, the residual demand could vary between 5.5 and 56GW. Further, a number of periods when the residual demand changes within a short period, for example falling 18GW in 22h before rising by 14GW in 16h, are reported. Oswald et al. (2008) drew two main conclusions. First, large power swings (over 70% of total wind output) could occur within a 12 hour period. Second, that wind output in Britain and nearby European countries can be very low at periods of peak demand. The study suggests that the variability of wind will have implications for the gas network, system security and the utilisation of thermal power plants.

While the Oswald et al. (2008) study offers some insights into the variability of the wind resource, the implications drawn are somewhat contentious. Gross and Heptonstall (2008) responded to a number of the points raised in the study. The comments are broadly categorised into two categories, namely; general comments and system wide issues and impacts on the power system.

Within the first category, Gross and Heptonstall (2008) contend that *“there is consensus amongst power system engineers that the only way to quantify and assess the impact of power swings on a power system is through a time series representation of demand and supply using statistical analysis and/or a power system simulation”.* They also suggest that further analysis is required to consider why the Oswald et al. (2008) study reported results counter to the established view that large geographical distance between wind farms reduces correlations in power output. Another general comment questions the selection of weather stations and the absence of data from South-East England. Oswald et al. (2008) stated that *“South-Eastern*

England is not expected to make a large contribution to wind power in the future". However, the London Array project (630MW) and Kentish Flats projects (90MW), in the South-East region, that Gross and Heptonstall (2008) mention, are both now operational. Further, in 2015, over 2GW is now located in this region (RenewableUK, 2015).

Within the second category, Gross and Heptonstall (2008) contend some of the conclusions regarding the impacts on conventional thermal plants. The Oswald et al. (2008) statement *"swings of 70% within 12h are to be expected in the winter",* offers very little insight into how these variations in wind output will impact on the thermal plant. As Gross and Heptonstall (2008) report, the impact of increased variable renewable generation will be dependent on a number of power system and market properties, not least; plant mix, system size and gate closure time. Understanding the impacts requires a much more detailed and rigorous analysis. Further, understanding the build out and operation of individual plants requires a full power market model. Gross and Heptonstall (2008) conclude that the Oswald et al. (2008) study *"risks repeating mistakes of the past by interpreting data in a selective manner; or singling out alarming sounding findings".* Suggesting that *"…answers can only be sought through a statistical or time series simulation model of the British electricity system that takes into account how the electricity system and market operate and the complexities of assessing its on-going development".*

It should be noted that, while the conclusions of the paper are contentious, the analysis of large quantities of weather station data is useful for understanding the variability of the wind resource. Although, a better practice is to use a greater number of stations data that is more representative of the installed wind capacity.

Coker et al. (2013) assessed the UK wind, solar and tidal current resource, focussing on the Bristol Channel region. The study reports that "v*ariability cannot be considered as a distinct resource property with a single measurable parameter, but is a multi-faceted concept best described by a range of distinct characteristics".* The study describes specific variability characteristics including, statistical distribution, persistence, frequency and correlation, highlighting the important differences between the characteristics for each resource and the consequent implications for distinct power system operational challenges.

While there has been a large focus on interpreting the onshore wind potential, the offshore resource has received less focus. This is due to both the difficulty and challenges faced when analysing the resource and the slower development of the offshore industry. In 2012, only 2% of the global installed capacity was offshore (Global Wind Energy Council, 2015b). Foley et al. (2012a) demonstrated that offshore wind resources could be estimated from pre-existing offshore wind measurements from meteorological buoys. While the study suggests that the methodology is adequate for an estimation of the resource, a more complex model, which takes into consideration the variance of the surface roughness length at different wind speeds and direction, is recommended for a more accurate representation. McQueen and Watson (2006) use a variety of simple methodologies to infer the wind speeds at three locations where offshore wind masts are located. The predicted wind speeds for each of the methodologies are then compared to the observed wind speeds from the masts, and the root mean square error is reported. McQueen and Watson (2006) report that the wind speed is calculated to be within 25%, with the exception of two of the thirteen methodologies.

With large scale deployment of variable renewable generation now realised in many European countries, it is now common practice to use real aggregated wind power output data in energy systems and power market studies, thus misrepresentation of the regional wind output has become more unlikely in renewable integration studies. As Holttinen (2003) report, *“when enough turbines from a large enough area are combined, the smoothing effect reaches saturation and the time series can be up scaled with representative hourly variations”*. Britain now has over 10GW of wind capacity, much of which is connected to the transmission system (RenewableUK, 2015). Half-hourly aggregated output can be obtained from ELEXON for the transmission entry wind capacity and this provides a strong representation of the variability of the GB onshore and near shore resource

(ELEXON, 2014). Further work is likely to be required to understand the potential variability of the offshore resource.

2.5.2 Impacts of Variability

Variability related issues can occur over short and long term time scales and can have both a positive and negative affect on the operation of the power system and markets (International Energy Agency, 2014b). As Coker et al. (2013) suggest, treating variability as a multi-faceted concept is required to capture the impacts on the power system. For example, the impacts of variable renewable generation on system balancing requirements requires an understanding of the persistence of the resource and the output changes within a time scale of minutes to days. Longer term impacts, such as the impact of variable renewable generation on thermal plant capacity factors will require an understanding of the distribution and summary statistics. In this section we focus on the main impacts of variable generation on the operation of power systems and markets.

The short term effects of variability (in minutes to days), is referred to as the "balancing effect" (International Energy Agency, 2014b). As more variable generation is added to the system, the net load[10] is observed to become more volatile (International Energy Agency, 2014b, Poyry, 2009, Oswald et al., 2008). The increase in net load volatility will have consequent implications for the system reserve requirements, cycling of thermal plant and transmission and distribution grid flows. The longer term effect is termed the "utilisation effect", and refers to the displacement of primarily mid-merit generation during times of medium and high variable renewable generation output. As discussed in Sections 2.4.1 and 2.4.2 the impacts will be dependent on a number of power system and market properties. Therefore, the insights and trends are more important than the numerical values reported.

[10] Net load is equal to the total system load minus the generation from renewables.

2.5.2.1 Balancing Impacts

Many integration studies have focussed on the increasing costs and requirements for balancing services in systems with increasing variable generation. Holttinen et al. (2011) provide a summary of the results of an IEA collaboration titled *“Design and Operation of Power Systems with Large Amounts of Wind Power”.* The results summarised focus on the increase in reserve requirements, increase in balancing costs, increase in transmission costs and capacity value of wind power. Only, the increase in reserve requirements and balancing costs will be reported in this section as transmission costs are associated with the location constrained property of variable renewable generation. Results are compiled from a number of high profile integration studies from multiple regions and countries around the world, including, Denmark, Finland, Germany, Ireland, Netherlands, Norway, Portugal, Sweden, UK and several US regions. Holttinen et al. (2011) report a large range, 1-15% of installed wind capacity at 10% penetration and 4-18% of installed wind power capacity at 20% penetration, for the increase in short term operating requirements. A wide range of values are also reported for the increase in balancing costs due to increased wind power. Additional balancing costs of €1-4/MWh were reported for wind penetrations of up to 20% (Holttinen et al., 2011). As discussed in Section 2.4, the costs will be dependent on a number of power system and market properties, such as balancing area size and gate closure time.

The balancing effect will also cause additional cycling of thermal plants in systems with increasing wind penetration. Troy et al. (2010) use the WILMAR planning tool to assess the impact of increased wind penetration on the cycling of base load units in Ireland. As wind penetration increases, the combined cycle gas turbine (CCGT) units experience rapid increases in start-stop cycling and a significant reduction in utilisation. Also, coal units are subject to increased part load operation and ramping. Denny and O’Malley (2009) developed a PLEXOS model of the Irish Single Electricity Market (SEM) to analyse the impact of carbon prices on generation-cycling costs, finding that carbon prices significantly increase the cycling costs. As recommended by Gross and Heptonstall (2008), both of these studies consider a detailed representation of the power system and as such offer valuable insights to the discussion on the increased cost of plant cycling. In the US, National Renewable Energy Laboratory (2013) considered the costs associated with cycling plant, reporting that at 33% combined wind and solar penetration, annual cycling costs increase by $0.47 - 1.28/MWh.

There exist a number of options, for the mitigation of balancing impacts. As mentioned in Section 2.4.2, a market design that facilitates short term trading can allow for a more accurate forecast of both renewable generation and demand. Also, dispatching in short blocks (as low as 5 minutes) allows for the re-scheduling of plant to meet the net load.[11] Further, a larger balancing area can reduce the fluctuations in net load, thus reducing the requirement for balancing (International Energy Agency, 2014b). Greater incentives for demand side response could also reduce the balancing impacts. Also, a more flexible system, where must run capacity is limited, also reduces the balancing effect. As in the IEA report, in the longer term the generation mix should see a structured re-optimisation towards more flexible capacity (International Energy Agency, 2014b). MacCormack et al. (2010) also draw a similar conclusion.

2.5.2.2 Utilisation Impacts

The utilisation effect is a longer term impact of increased variable generation and relates to the reduction in use of incumbent power plant as variable generation penetration increases. This effect is due to both the variability and low-short run cost characteristics of variable renewable generation. This effect can be illustrated through the steepening of a net load duration curve (LDC), as illustrated in Figure 2.6.

[11] The net load can change significantly within the hour and such allowing the plants to re-dispatch can reduce the requirement for reserve services.

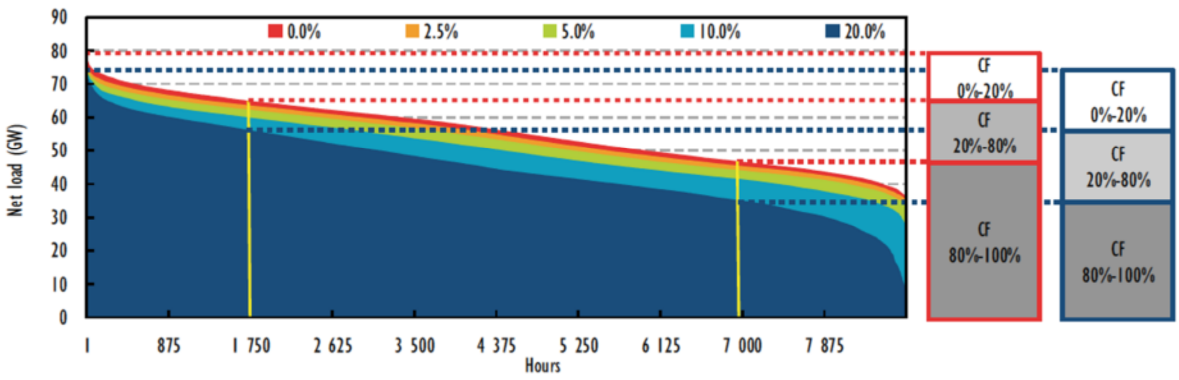

Figure 2.6 – Impact of the utilisation effect on net load curves and optimal power plant mix (International Energy Agency, 2014b).

When wind penetration increases, the net LDC steepens due to periods of scarcity (when wind output is very low and the net load is a very high percentage of the total load); and abundance (when the wind output is high and the net load is a low percentage of the total load) (International Energy Agency, 2014b). While the utilisation effect is categorised by longer term (weekly, monthly, annually) distribution statistics, the effect will increase as the variable renewable penetration increases. In the short term, the utilisation effect is referred to as the transitional utilisation effect and will be mostly limited to stable systems with expanding renewable generation (International Energy Agency, 2014b). In stable systems, with low load growth and short term infrastructure requirement, the short term utilisation effect will cause mid-merit plant to operate at lower capacity factors, see Figure 2.6. This is the case across Europe where many thermal plants (particularly CCGT's) have been prematurely mothballed or decommissioned as a result of the reduced revenue associated with reduced utilisation (International Energy Agency, 2014a). In the long term, the utilisation effect is referred to as the persistent utilisation effect. Systems should adapt with more flexible capacity and reduced baseload capacity (International Energy Agency, 2014b). As such the persistent utilisation effect will require a structural shift to more flexible capacity. The utilisation effect is due to both the variable and low short run marginal characteristics of variable renewable generation and, as such, is discussed in more detail in the following section.

While the utilisation effect is highly dependent on a number of power system and market properties, the correlation between variable renewable generation output and load is very important. In systems, with a good correlation (i.e. high renewable generation at times of high demand), the utilisation effect will be less severe compared to systems with a poor correlation (i.e. high renewable generation at times of low demand).

2.6 Characteristic 2: Low Short Run Marginal Costs

As variable generation has very low short-run marginal costs, it is generally dispatched when it is available (Steggals et al., 2011). For this reason, as variable generation increases, average wholesale prices will be depressed. This is known as the merit order effect and is best illustrated through the use of merit-order curves.

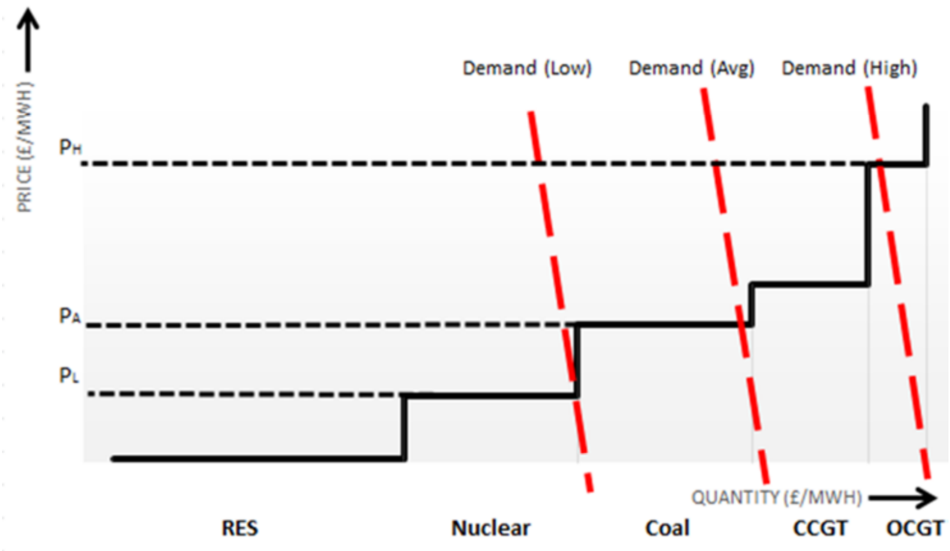

Figure 2.7 - Merit order in system with high renewable output.

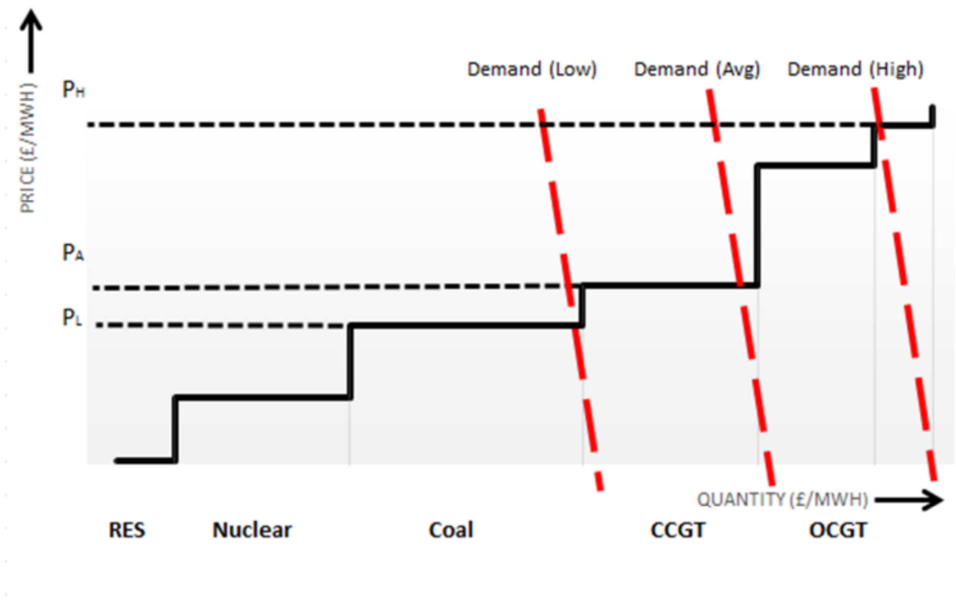

Figure 2.8 - Merit order in system with low renewable output.

Figure 2.7 and Figure 2.8 illustrate two scenarios for an arbitrary system with high variable renewable generation capacity. As shown in Figure 2.7, due to the low short run marginal cost of variable renewable generation, when renewable output is high during times of average demand, mid merit generation is displaced and the price is lowered. However, as shown in Figure 2.8, when renewable output is low, the price is once again set by the mid merit generation, in this case CCGT's.[12] In stable systems, where variable generation is added to a system with sufficient generation adequacy and slow demand growth, average prices will decrease. Also, due to the comparatively low capacity credit of variable generation, to retain security of supply the overall system capacity will have to increase. Therefore, in the absence of an already highly flexible plant mix, the transitional utilisation effect will be apparent.

[12] Of-course the merit order curve will constantly change and prices change according to the supply and demand balance. Further, the balance will be highly dependent on many factors, not least; plant availability, load profile, grid constraints, variable generation output and behaviour of generator and supplier companies.

2.6.1 Impacts of Low Short Run Marginal Costs

Many studies have agreed that the introduction of variable renewable generation tends to lower prices. Woo et al. (2011) consider the implications of wind on electricity prices in Texas. While the methodology and reported values differ, studies in Ireland (Clifford and Clancy, 2011) , Australia (Forrest and MacGill, 2013) Spain (Sáenz de Miera et al., 2008), Germany (Traber and Kemfert, 2011) have agreed that under the current market arrangements, increased variable generation lowers average prices. In a recent study, Clò et al. (2015) considered the empirical evidence of the merit-order effect in the Italian power system, reporting that "*over the period 2005-2013 an increase of 1GWh in the hourly average of daily production from solar and wind sources, has on average, reduced wholesale electricity prices by 2.3euro/MWh and 4.2euro/MWh, respectively".*

MacCormack et al. (2010) developed a system model that included, hourly wind generation, load and residual demand, dispatchable generation availability, a model of an energy-only market with a price cap and a model of generator costs and dispatch behaviour. The study reported the medium term impacts of large scale wind integration on; electricity prices, reliability of supply, generation mix, and average revenues of dispatchable capacity.

Long term impacts, including; removal of peaking generation from the market, reliability of supply and changes in dominant supplier were reported. The results show lower medium term prices. However, MacCormack et al. (2010) report that in the long term *"prices must at least equal the average cost of production or sufficient dispatchable supplies will not be built and the reliability of supply will deteriorate. In the very long term, deterioration in reliability can be addressed by a structural re-optimization of the generation mix".* However, in-order for this re-optimization to take place, price caps should be raised to enable dispatchable capacity to recover the fixed costs. However, the study only considers an energy-only market. As such capacity mechanisms and their effect on the generation mix and wholesale electricity prices are not considered within the modelling approach. The conclusions drawn by MacCormack et al. (2010) are in line with the idea of the persistent utilisation effect discussed by International Energy Agency (2014b). Further, MacCormack et al. (2010) provided some options for ensuring the profitability of flexible plant in an energy-only market, by illustrating the importance of raising the market price cap.

Forrest and MacGill (2013) employ a range of econometric techniques to assess the impact of wind generation on wholesale prices and thermal plant dispatch in the Australian National Electricity Market (NEM), finding that wind output depresses market prices and displaces primarily flexible gas generation and to a lesser extent coal fired generation. Other studies have considered the incentives to invest in thermal units in power systems with increasing renewable penetration. Traber and Kemfert (2011) find that reducing market prices in Germany, due to increasing wind penetration, significantly diminishes the attractiveness of investment in natural gas fired units. Also, Di Cosmo and Malaguzzi Valeri (2014) determine that as wind penetration increases, profits for all baseload plants are reduced. Significantly, profits are reduced more for natural gas plants than less flexible coal plants, meaning that investment may be encouraged in less flexible plants.

The effective market integration of variable renewable generation is attracting increased attention around the world. This study only provides an overview of the common themes and consensus. It is clear, from the literature reviewed, that increased variable renewable generation will depress market prices and reduce the attractiveness of mid merit plant investment, under current market arrangements. The development of markets that provide incentives for both variable renewable generation and sufficient firm and dispatchable capacity will be key to achieving a cost effective transition to lower carbon power systems (International Energy Agency, 2014b).

2.7 Characteristic 3: Uncertainty

The output from variable renewable generation is dependent on the availability of the resources. As such, variable renewable generation is fundamentally different from conventional sources of electricity generation, for example nuclear, gas and coal, where output can be scheduled, subject to outages. As power systems have to be continuously balanced, the uncertainty of the generation from variable renewables can pose challenges to the system operators. The additional uncertainty creates new challenges for; the operation and procurement of reserve services, the optimization of power plant unit commitment and dispatch and grid operation (Deane et al., 2014, International Energy Agency, 2014b, Holttinen et al., 2011).

2.7.1 Impacts of Uncertainty

As supply and demand have to be continuously balanced, system operators (National Grid in GB) are required to procure a number of reserve and response services. The exact specification of reserve products purchased is highly system specific, but normally operators will procure a number of different types. For example, in GB, National Grid procures; fast reserve (available within 2 minutes), BM start-up (available within 89 minutes) short term operating reserve (available within 240 minutes) and demand side response (National Grid, 2014b). The introduction of variable generation into the power system will increase the supply side uncertainty, leading to a requirement to procure additional reserves and increase in renewable integration costs. The costs associated with increased reserve requirements are discussed in Section 2.5.2.1.

As generation from variable renewable energy is typically dispatched early in the merit order, thermal plant operators will also be required to have an understanding of the forecasted variable generation output. Errors in renewable output forecasts can lead to the requirement to increase generation supply or reduce demand within a very short time horizon, leading to increased plant cycling. The accuracy of variable renewable generation forecasts therefore plays a significant role in their system integration and it is for this reason that a great deal of research has focussed on increasing forecast accuracy. Foley et al. (2012b) provide a comprehensive review of the methods and advances in forecasting of wind power generation. Widén et al. (2015) provide a review of the previous research on variability assessment and forecasting of solar, wind, wave and tidal energy. Further, Diagne et al. (2013) and Inman et al. (2013) review the methods for solar forecasting.

2.8 Characteristics 4 and 5: Location Constrained and Modularity

All power stations are location constrained as developers have to gain planning permission prior to construction. Also, the location for gas, coal or nuclear power stations may be heavily constrained by the existing infrastructure. For example, a developer of a nuclear power station may propose the construction of a new project close to, or at the same site, as an existing plant where local residents are familiar with the industry and the electricity transmission grid may require only relatively minor upgrades. However, the term “location constrained” here refers to the resource constraints rather than the development constraints. While the development of coal, nuclear or gas power stations may be constrained, the location will not affect their power generation. The output from variable renewable generation is however largely affected by the location.

In systems where variable generation is offered incentives, developers will likely construct projects where profit can be maximised. Due to the large distances between load centres and the new developments, new transmission or distribution lines may be required to connect the generators and end-users. Therefore, the location constrained characteristic of variable renewable generation has consequent implications for both the cost and operation of the electricity transmission and distribution infrastructure.

The modularity characteristic refers to the relatively small unit size of variable renewable generation compared to conventional thermal plants. Wind farms will typically consist of multiple turbines, with output ratings of between 0.5 and 7MW (RenewableUK, 2015). Solar PV panels have lower powers ratings, often between 0.0001 and 0.0003MW (International Energy Agency, 2014b). Conventional thermal units can have rated capacities from a few MW to over 1000MW. As with the location constrained characteristic, modularity implies a much more decentralised power system.

An increasingly decentralised power system with a high capacity of modular capacity can provide a number of challenges for the operation of the transmission and distribution grids. Historically, the distribution system has been considered to be a passive system that was sized to meet the anticipated demand. However, with increasing penetration of distributed variable renewable generation, the system may have to be upgraded so that it is capable of handling both increasingly modular capacity and bi-directional flows. Also, smarter systems and technologies may also have to be rolled out to ensure that the voltage levels remain within a required range as variable generation increases.

Along with the technical challenges associated with the modularity characteristic of variable renewable generation, this characteristic will provide new operational and planning challenges. Moving from a system with a high level of centralised generation to a system with a high level of both centralised and decentralised generation will require greater collaboration between transmission system operators (TSOs) and distribution system operators (DSOs). In order to correctly allocate line capacity, TSO's will have to have an accurate representation of the available capacity within the distribution system. Also, in the long term, transmission grids and distribution grids may have to be sized according to the needs of the wider system. For example, the transmission grid may have to be upgraded in regions where the distribution system has a high level of decentralised generation.

2.8.1 Impacts of Location Constraints and Modularity

Studies in Europe and the US have attempted to quantify the grid related costs associated with integrating variable renewable generation. In the US, costs of between \$92/kW/year at 6% penetration and \$46/kW/year at 30% penetration have been reported (International Energy Agency, 2011). In Europe, at a wind penetration of 10%, the cost is approximated at \$2.1/kW/year. However, the cost increases significantly at penetrations beyond 10%, with reported costs of $11.8/kW/year at 13% penetration (International Energy Agency, 2011). The PV Parity (2013) project considered the grid costs of integrating 480GW of Solar PV into the European power system by 2030 reported transmission costs of €2.8/MWh and distribution costs €9/MWh. Clearly there is large disparity between the results, as discussed in Section 2.4; the results are highly dependent on the approach used and the system that is being considered. The values reported in these sections are only included to highlight that significant costs are incurred when integrating moderate to high levels of variable renewable generation.

The location constrained characteristic also provides challenges for the long term development of the electricity system. This is especially the case in liberalised markets, where different companies can own the transmission, distribution and generation assets. Ideally, the transmission infrastructure that connects a remote cluster of wind farms would be optimally sized for the planned capacity of the cluster. Or alternatively, the cluster sized according to the availability of the transmission infrastructure. The challenge here is the co-ordination of the transmission, distribution and generation infrastructure, where developers may ultimately have different motivations.

2.9 Characteristic 6: Non-Synchronous

As the grid frequency has to be maintained within a certain tolerance, conventional thermal power stations in a conventional centralised power system are synchronised to ensure that frequency is maintained. When the system frequency increases, for example when demand increases, the on-line generators should rotate at the speed necessary to retain the frequency. However, variable renewable generation is characterised as non-synchronous and is incapable of providing these services to the systems. Variable renewable generation is connected to the grid via power electronics and thus is referred to as non-synchronous generation. As variable renewable generation increases, new means of providing the services to maintain system frequency will be required.

It is for this reason that the non-synchronous penetration is limited in Ireland (McGarrigle et al., 2013). While, at present, variable renewable generation can be described as non-synchronous, technology advances may enable the systems to provide inertia in the future (International Energy Agency, 2014b). The research conducted in Chapters 5, 6 and 7 will set appropriate constraints for the consideration of non-synchronous generation.

2.10 Variable Generation: The UK Energy Policy Context

The research completed in this thesis will be of interest to researchers and policy-makers in many regions with increasing renewable penetration. However, the models developed in Chapters 5, 6 and 7 are based on the power system in Great Britain. Therefore, it is important to include a section on the policy context in the UK. Further, the implications of the research for UK energy policy are discussed in Chapters 5, 6, 7 and 8.

In 2008 the UK government passed the Climate Change Act, legally committing the government to reduce the UK's GHG (greenhouse gas) emissions by 80% on 1990 levels by 2050 (Committee on Climate Change, 2011). With electricity generation accounting for 27% of the GHG emissions in the UK, it is considered that in order to reduce emissions by 80% then the electricity system will have to be almost completely decarbonised (HM Government, 2011, Parliamentary Office of Science and Technology, 2007).

Nations across the European Union are also bound to shorter-term emission reduction targets under European legislation (da Graça Carvalho, 2012). Due to these targets and many other policies, such as the phase out of nuclear power in Germany, generation mixes in a number of countries are experiencing rapid changes. Due to the EU legislation, the UK has set an indicative target for 40% of electricity to be generated by low carbon technologies (renewables and nuclear power) by 2020 (HM Government, 2009). Under EU targets, the UK has committed to produce 15% of its energy from renewable sources by 2020. This implies that at least 30% of electricity will need to be generated by renewables by 2020.

While EU legislation beyond 2020 remains unclear, the UK is required to meet the targets set within the fourth carbon budget, namely a 50% emissions reduction on 1990 levels by 2025 (Committee on Climate Change, 2013a). The Climate Change Committee have stated that 30-40GW's of low carbon capacity needs to be added to the power system through the period 2020 – 2030, in order to meet the fourth carbon budget and to prepare for the 2050 target (Committee on Climate Change, 2010). In 2012, renewables (11.3%) and nuclear (19%) contributed 30.3% of the UK's electricity generation (Department of Energy & Climate Change, 2013c). In order to meet the targets, it is expected that wind power will contribute between 50 and 90TWh of electricity generation in the UK by 2020 (Department of Energy & Climate Change, 2011). Therefore, it is clear that the level of variable renewable generation in the UK is forecasted to increase significantly.

The Industrial Emissions Directive (IED) is also relevant to the development of the power system in GB. The IED, which entered force on 6th January 2011, aims to improve the environment and human health by reducing industrial emissions across the EU (European Commission, 2015). Under the IED, power plants are required to satisfy stringent emissions limits or close by the 31st December 2023 (Gross et al., 2014). Owners have three options: Compliance, Limited Life Derogation (LLD) or participating in a Transitional National Plan (TNP). Full compliance may require retrofitting plants to meet the emission limits. Plants selected for LLD must close after 17,500 hours of operation from 1st December 2016, or close by 31st December 2023. TNP allows the decision over compliance to be delayed until 2020; however, a descending emission production ceiling is placed on plants between 2016 and 2020 (Gross et al., 2014). As plant owners to do not have to confirm their choices until January 2016, there is significant uncertainty around the UK coal capacity in 2020.

It is estimated that investment of up to £110bn by 2020 will be required to ensure security of supply and to support the decarbonisation necessary to meet the carbon budgets (Department of Energy & Climate Change, 2012a). Taking the view that the existing legislation and market frameworks would be insufficient to attract this level of investment, the Secretary of State for

Energy and Climate Change (Rt Hon Edward Davey at the time) confirmed the introduction of the Energy Bill on the 29th November 2012 (HM Government, 2013). The Energy Act received Royal Assent on 18th December 2013 (HM Government, 2013). Of direct relevance to the integration of increased variable renewable generation are the measures set-out within the Act for Electricity Market Reform.

In line with wider UK energy policy, the objectives of EMR are to: ensure security of supply, ensure investment in low-carbon technologies and maximise benefits and minimise costs to consumers and tax payers (Department of Energy & Climate Change, 2012a). EMR includes two key market mechanisms. The Feed-in Tariffs with Contracts for Difference (CfDs) aim to reduce market and regulatory risk and provide certainty to investors in low carbon technologies. Generators with contracts will receive a top-up payment, based on the differential between a reference market price and an agreed strike price. However, if the reference market price is above the strike price, generators will be required to return the difference (Department of Energy & Climate Change, 2012a).

The second market mechanism is the introduction of a Capacity Market to ensure security of supply. Under this mechanism, future peak demands and the total amount of capacity required to ensure security of supply is forecasted (Department of Energy & Climate Change, 2012a). The required capacity, new or existing, is then contracted through a competitive auction 4 years ahead of the delivery year. In return for the agreed capacity price, providers must be available in the delivery year or face penalties. The results of the first Capacity Auction, held in December 2014, are now available from National Grid (2015) and are discussed in more detail in Section 8.4.

EMR also includes two supporting mechanisms: the Carbon Price Floor (CPF) and Emissions Performance Standard (EPS) (Department of Energy & Climate Change, 2012a). The CPF aims to provide the signals required to invest in lower carbon technologies by increasing the price of carbon. Initially, it was proposed that the carbon price floor would increase form £15.70/tCO_2 to £30/tCO_2 in 2020 and £70/tCO_2 in 2030. However, the decision in the 2014 Budget to freeze the level of the carbon price floor at

£18/tCO_2 until 2020 makes such a scenario unlikely in the short and medium term (HM Revenue & Customs, 2014). The EPS limits the emissions intensity of new build generation capacity to 450gCO_2/kWh, except those that are part of the UK's (or EU's) CCS funding programmes (Department of Energy & Climate Change, 2012a). The Government has also stated that the EPS will be grandfathered at 450gCO_2/kWh until 2045, i.e. any plant that receives building consent under this level would not be affected by any subsequent changes to the level. This aims to provide long term certainty to investors in new gas generation (Department of Energy & Climate Change, 2012a).

It is not the purpose of this research to propose a market design and policy mechanisms to deliver a low carbon electricity system. Rather the objective is to gain a greater appreciation of the fundamental challenges associated with increased renewable generation. However, within Chapters 5, 6 and 7 the policy implications of the analysis are discussed. Further, a summary of the consequences of the research for UK energy policy is discussed in Chapter 8.

This chapter has provided an introduction to the challenges associated with integrating variable renewable generation into power systems. Chapter 3 provides an overview of the models and techniques that can be used to gain a greater understanding of these challenges. Further, Chapter 3 identifies some of the specific challenges associated with modelling power systems with increasing variable renewable generation.

3 Overview of Energy System and Power Market Modelling

A safe, secure and affordable energy supply is a prerequisite for the development of any economy. As such, policy-makers are aware of the strategic importance of enhancing and maintaining energy security. Since the early 1970’s the requirements for both industry and government to have an understanding of both the short term operation and long term planning of the energy system has been recognised. This recognition has led to the modelling and analysis of energy systems being considered as a distinct field, often broadly termed “energy systems modelling”. Encompassed within this field is power system and market modelling, which is often used for detailed operational analysis and long term planning within the electricity system. This section provides an introduction to the field of energy systems modelling, a brief overview of the different classifications of energy systems models, an overview of several of the most widely used models and a selection criteria for the models that have been used in this study. Further, this section considers some of the challenges for energy system modellers with relation to integrating high levels of variable renewable generation.

3.1 Introduction

Energy policy and energy systems modelling began as a distinct field in the wake of the 1973 oil crisis, with both government and industry realising the requirements for having a long term energy strategy (Pfenninger et al., 2014). The International Energy Agency (IEA), established in 1974, had the initial role to help to co-ordinate a collective response to major disruptions in oil supply (International Energy Agency, 2015b). Soon after the IEA’s formation, the Energy Technology Systems Analysis Program (ETSAP) was established in 1976 with the aim to develop, maintain and expand a consistent multi-country, energy, economy, environment and engineering modelling capability. Today the ETSAP has national teams in nearly 70 countries that share a common and comparable methodology that is mainly based on the TIMES/MARKAL family of models (International Energy Agency, 2015a).

As with the IEA's ETSAP programme, the International Institute for Applied System Analysis (IIASA) also sought to develop energy systems modelling capability soon after it being founded in 1972. IIASA was established to promote scientific collaboration between the east and west, with the 12 original members focussing on global problems, including energy and climate change, food and water and poverty and equality (International Institute for Applied Systems Analysis, 2014). The MESSAGE family of models was developed to support IIASA's energy program and the models have been used to provide inputs for major studies and assessments by the Intergovernmental Panel on Climate Change (IPCC), World Energy Council (WEC) and the European Commission (International Institute for Applied Systems Analysis, 2012).

The standard forms of the MARKAL/TIMES and MESSAGE models are referred to as bottom-up, partial equilibrium optimisation models. Alternative to this type of model are top-down models, these models have also been used to calculate costs associated with new policies and energy system transformation. Top-down models often apply a broader economic framework than bottom-up models, considering multiple sectors and the feedback effects between different markets through changes in prices (Bataille et al., 2006, Rutherford and Böhringer, 2006). Both top-down and bottom-up approaches have limitations. For example, bottom-up partial equilibrium models may contain a high level of technological detail, but can lack a detailed representation of the individual behaviour of agents (Capros, 1995). Also, partial equilibrium models may only focus on the energy sector and therefore fail to recognise the interactions and feedbacks to other areas of the economy (Rutherford and Böhringer, 2006). Top-down models on the other hand may not have a detailed representation of technology and may also violate fundamental physical restrictions (Rutherford and Böhringer, 2006).

Recognising some of the earlier limitations, both ETSAP and IIASA have adapted and developed a sophisticated range of MARKAL/TIMES and

MESSAGE models. For example, hybrid modelling techniques have been developed that aim to combine the strengths of top-down and bottom-up models, seeking to retain the technological detail of bottom-up models while retaining the characteristics of a general equilibrium model (Loulou et al., 2004). An example of this kind of model is the UK MARKAL-MACRO model, developed by Strachan and Kannan (2008). Along with a hybrid version, elastic demand, stochastic, spatial and temporal versions of MARKAL have been developed to address some of the earlier limitations (Loulou et al., 2004).

While the focus of many researchers throughout the 1980's and 90's was adapting, developing and combining top-down and bottom-up approaches, some modellers have developed new market-oriented approaches, often referred to as "new generation models" (Capros, 1995). Some of these models could be characterised as both partial equilibrium, if they only considered the energy sector, and generalised equilibrium, as they describe the behaviour of different economic agents (Capros, 1995). An example of this type of model is the National Energy Systems Model (NEMS), used by the Energy Information Administration (EIA) in the US to project the energy, economic, environmental and security impacts of alternative energy policies and assumptions on the US energy markets (U.S. Energy Information Administration, 2009). One of the main purposes of NEMS, since its first use in 1994, is to produce the baseline projections for publication in the Annual Energy Outlook (U.S. Energy Information Administration, 2009). In Europe, PRIMES (Price-Induced Market Equilibrium System) has been developed by the Energy-Economy-Environment Modelling Laboratory at the National Technical University of Athens since 1993. The model is now used for medium and long term studies that concern the restructuring of the EU energy system, notably quantifying outlook scenarios for the DG TREN and DG ENER (E3MLab, 2013).

Another model, LEAP (Long range Energy Alternatives Planning System, developed by the Stockholm Environment, is widely used for energy policy analysis (Heaps, 2012). Different from simulation models (such as PRIMES and NEMS) and optimization models (such as standard MARKAL/TIMES and MESSAGE), LEAP provides a flexible accounting framework to examine the implications of a specified scenario (Heaps, 2012). As such, rather than identifying a least cost energy mix or simulating the decisions of agents, LEAP accounts for the outcome of decisions (Heaps, 2012). The software is considered to be intuitive and often has lower data requirements than other energy system models and for these reasons LEAP is used by thousands of institutions in over 190 countries. Significantly, LEAP is used by countries to report to the UN Framework Convention on Climate Change (UNFCCC) (Heaps, 2012).

While the energy system models described previously may be sufficient in considering costs associated with high level energy policies, such as the costs associated with decarbonisation, sector specific models are often required for detailed sector specific policy design. For example, designing a subsidy support scheme for renewable technologies, such as a renewable obligation or feed-in-tariff, will require the use of a detailed electricity system model. As with bottom-up energy system models, these models may have a high level of sector specific detail, but may fail to recognise feedback effects into the wider energy system and the wider economy. Consider a power market model that is set up to minimise total power system costs. The model may commit and dispatch a combined heat and power plant to satisfy the requirements of the power system. However, without a representation of the wider energy system, it is unknown whether the operation is well suited to the needs of the heat sector. An introduction to power market modelling is included in Section 3.2.4.

The following sections will include a description of some of the most commonly used and widely recognised energy and power market models. However, it should be recognised that the analysis of energy and power systems is complex and successful policy design will require the use of a range of models and approaches. Indeed, Deane et al. (2012a) recommend that *“one specific energy modelling tool cannot address all aspects of the full energy system in great detail and greater insights and progress can be gained by drawing on the strengths of multiple modelling tools rather than trying to incorporate them all into once comprehensive model”.*

As this study is concerned with the optimal and cost-effective deployment of variable renewable generation into power systems, the focus of this section is directed towards simulation and optimization methods.

3.2 Classifying Energy System Models

While the previous section only mentioned a number of the most widely known and applied energy systems models, there are many more that have been developed and are used at global, regional, national and local levels. For this reason, modellers and analysts should have a clear understanding of the uses, purposes and limitations of different models, along with a clearly defined research objective, to ensure that the most relevant model is applied to the defined problem.

Many studies have attempted to characterise energy models. For example, Pfenninger et al. (2014) considered four model paradigms, including; energy system optimization models, energy system simulation models, power systems and electricity market models and qualitative and mixed-method scenarios. Pfenninger et al. (2014) also reported four 21st century modelling challenges, including; resolving details in time and space, uncertainty and transparency, complexity and optimization across scales and capturing the human dimension. These challenges are discussed further in Section 3.3. Connolly et al. (2010b) reviewed 37 computer tools that can be used for the analysis of the integration of renewable energy into various energy systems. The authors defined seven different energy tool types; namely; simulation tools, bottom-up tools, top-down tools, scenarios tools, equilibrium tools, operation optimization tools and investment optimisation tools. Connolly et al. (2010b) noted that most tools will not be exclusively defined by one category. For example, MARKAL could be defined as a bottom-up, investment optimisation model where partial equilibrium is computed for each time step. Further MARKAL can be used for scenario analysis.

A rigorous approach to categorising models was developed by Van Beeck (1999). The classification approach developed, built on earlier studies by Grubb et al. (1993) and Hourcade et al. (1996) to provide an overview of nine ways of classifying energy models. Grubb et al. (1993) reported that there *"is no universal or accepted way of classifying models",* before classifying models according to six dimensions including i) top-down vs bottom-up, ii) time horizon, iii) sectoral coverage, iv) optimisation vs simulation techniques, v) level of aggregation, and vi) geographic coverage, trade and leakage (Van Beeck, 1999). Hourcade et al. (1996) differentiated models by considering their purpose, structure, and external or internal input assumptions.

The nine approaches described by Van Beeck (1999) are listed in Table 3.1. For a full description of each of the approaches and for categorisation examples, see to Van Beeck (1999).

Characterisation Approach	**Possible Characteristics**
General and specific purposes of the models	**General** (i) to predict the future, (ii) to explore the future, and (iii) to look back from the future from the present. **Specific** (i) energy demand, (ii) energy supply, (iii) impacts, (iv) appraisal, (v) integrated approach (several specific purposes), and (vi) modular build up.
The model structure: internal assumptions and external assumptions	(i) Degree of endogenization, (ii) description of non-energy sectors, (iii) description of end-users, and (iv) description of supply technologies.
The analytical approach	(i) top-down, and (ii) bottom-up.
The underlying methodology	(i) econometric, (ii) macro-economic, (iii) economic equilibrium, (iv) optimization, (v) simulation, (vi) spreadsheet/toolbox, (vii) backcasting, and (viii) multi-criteria.
The mathematical approach	(i) linear programming, (ii) mixed-integer, programming, and (iii) dynamic programming.
Geographical coverage	(i) global, (ii) regional, (iii) national, and (iv) local or project.
Sectoral coverage	(i) energy sectors, and (ii) overall economy.
The time horizon	(i) short, (ii) medium, and (iii) long term.
Data requirements	(i) qualitative, (ii) quantitative, (iii) monetary, (iv) aggregated, and (v) disaggregated.

Table 3.1 – Nine ways of classifying energy systems models (Van Beeck, 1999).

It should be noted that column two in Table 3.1 does not present an either/or choice. For example, consider the MARKAL-MACRO model; the MARKAL component is bottom-up and the MACRO component top –down. Thus, the methodology for the MACRO component is macro-economic and for the MARKAL component is partial equilibrium and optimization. The model can be used for regional, national and local level analysis, covering all sectors over a medium to long term time horizon and will require qualitative, quantitative, monetary, aggregated and disaggregated data.

As this study is interested in the integration of variable renewable generation into the energy system a detailed representation of technologies is required. As such this study will implement only bottom-up models. A further description of the model selection process for the each research area is discussed in Section 3.5. While all of the approaches to model categorisation are very important, perhaps the most distinctive and relevant for categorising bottom-up models is the underlying methodology, as this often determines the purpose of the model. Table 3.2 provides an example of how energy models can be categorised, using five of the approaches outlined by Van Beeck (1999). MARKAL/TIMES, PRIMES, EnergyPLAN and PLEXOS are discussed in more detail in the following sections.

	MARKAL TIMES	**PRIMES**	**EnergyPLAN**	**PLEXOS**
Purpose	Exploring	Predictive	Exploring	Predictive Exploring
Underlying Methodology	Optimisation	Simulation	Simulation	Optimisation Simulation
Mathematical Approach	Linear Programming	Non-linear Mixed Complementarity (MCP) Formulation	Analytical Programming	Mixed Integer and linear programming
Geographical Coverage	Local National Regional	Regional (Europe)	National Regional	National Regional
Time Horizon	Medium Long Term	Medium Long Term	Medium Term (1 Year)	Short – Long Term

Table 3.2 – Example of energy and power market model characterisation.

As this study is concerned with the optimal and cost-effective deployment of variable renewable generation into power systems, the focus of this section is directed towards simulation and optimization methods. For this reason, LEAP will not be reviewed within this study.

3.2.1 Overview of MARKAL/TIMES

TIMES (The Integrated MARKAL-EFOM System) and MARKAL (MARKet ALlocation) are widely recognised energy system optimization models that have developed as part of the Energy Technology Systems and Analysis Program (ETSAP), established by the IEA in 1976. While the IEA have promoted the use of TIMES since 2008, MARKAL is used by 77 institutions in 37 countries and features widely in the academic literature (Taylor et al., 2014). As ETSAP now promotes the use of TIMES and as the models both share the same paradigm, only the TIMES model will be described in this section. Loulou et al. (2004) provides a full description of the MARKAL family of models.

Modelling an energy system in TIMES requires four main input components, including; demand components (end-use energy demands, for example residential lighting or car mileage), supply components (resource availability and associated costs, for example oil, coal and/or gas reserves), policy component (scenarios, for example emission reduction constraints, technology subsidies, technology constraints) and techno-economic components (technical and economic description of technologies and processes that transform commodities). With a full representation of the energy system, TIMES aims to supply the defined energy service demands at the minimum cost according to the primary energy supply and technology/process options available, subject to the defined constraints.

While there are many differences between MARKAL and TIMES, both models share the same paradigm (Loulou et al., 2005). Both models are bottom-up, partial equilibrium, least cost optimisation models. The models have many important differences, for example MARKAL has fixed length time periods, however, TIMES allows the modeller to define the period lengths (Loulou et al., 2005). This allows the modeller to represent the near future in more detailed short term periods and the longer term future that is more uncertain, in less detail. Another important difference is the flexibility in defining time slices within TIMES. In MARKAL, time slices are defined rigidly, however, in TIMES the user can choose the time slice representation for any commodity and process according to three groups, including, seasonal, weekly and daily. Loulou et al. (2005) provides a detailed comparison of the models.

3.2.2 Overview of PRIMES

Development of the PRIMES model started in 1993 and the model was designed to *“focus on market-related mechanisms and explicitly project prices influencing the evolution of energy demand and supply technology development”* (E3MLab, 2013). The model was peer reviewed by the European Commission in 1997 and 2011. PRIMES covers 35 European countries and the time horizon is from 2010 – 2050 in 5-year steps.

PRIMES is used for multiple purposes but the four key focus areas include; (i) analysing the prospects and economics associated with new energy supply and demand technologies, (ii) evaluating policy instruments associated with the energy system and environment (for example, carbon taxes and regulation), (iii) analysing the implications of competition on the European internal market for energy, and (iv) understanding the increasingly global nature of energy supply (Capros, 1995).

PRIMES can be described as both a top-down and bottom-up model as it computes partial equilibrium for the European energy system, while taking into consideration the micro-economic behaviour of agents (E3MLab, 2013). As with MARKAL/TIMES and MESSAGE, PRIMES contains a detailed representation of technologies. However, PRIMES is clearly different to the standard versions of the optimisation models, due to the consideration of agent behaviour. As PRIMES focusses on the calculating energy prices, and demand is an endogenously calculated function of price, it can also be described as a simulation model.

The behaviour of specific agents (for example a demander or supplier of energy) is represented within sub-modules that are linked together by an algorithm that determines both the equilibrium prices and equilibrium volumes in multiple markets. The demand modules represent agents that are seeking to maximise benefits (profit, utility, etc.), subject to constraints (prices, budget, fuel availability, etc.). The supply modules represent agents (for example suppliers) that are seeking to minimise cost or maximise profits to meet demand, subject to constraints (installed capacity, fuel availability, etc.) (E3MLab, 2013).

The modular structure of PRIMES enables each sector and sub-sector to be represented at the level that is considered appropriate. Demand sectors include residential, commercial and agriculture, industry, transports and transport modes. These sectors are further divided into sub-sectors and energy use technology types. For example, the industry model contains 9 sectors, namely; iron and steel, paper and pulp, engineering, chemicals production, food drink and tobacco, building materials, non-ferrous, textiles and other industries. Each of these sectors then has further sub-models. For example, fertilizers, petrochemical, inorganic chemicals and low enthalpy chemicals are sub-models of the chemical sector. Each of these sub-models then has multiple energy uses. For example, air compression, lighting, thermal processing and electric processing are associated with the fertilizer sub-model.

PRIMES is typically used for medium and long term studies that concern the restructuring of the EU energy system, notably quantifying outlook scenarios for the DG TREN and DG ENER.

3.2.3 Overview of EnergyPLAN

EnergyPLAN is a whole system energy simulation tool that is maintained by the Sustainable Energy Planning Research group at Aalborg University in collaboration with PlanEnergi and EMD A/S (Department of Development and Planning Aalborg University, 2015). EnergyPLAN is a much simpler tool than MARKAL/TIMES and PRIMES and is considered to have a much shorter learning curve and is less data intensive. The model was originally developed in 1999 and was implemented in EXCEL, before being re-programmed in Delphi Pascal in 2002 (Lund, 2012). The model has been continuously updated and expanded to take into consideration new technologies, for example Vehicle to Grid (V2G) and biomass-to-gas conversion technologies (Lund, 2012).

The main purpose of the model is to assist and contribute to energy planning strategies. The model is capable of both technical simulations, where the least fuel consuming solutions are identified and market-economic simulations, where electricity production, based on the business-economic marginal cost of the different generation types is reported (Lund, 2010).

Within EnergyPLAN, users are required to define an energy system for a given year; the system is then optimised based on either the technical or market-economic strategy. Because the model is deterministic and based on analytical programming, simulations take only a few minutes to run on a standard desktop computer and thus the model is well-suited to scenario analysis.

Defining a reference energy system in EnergyPLAN is relatively straightforward. Users are required to input hourly demand distributions and total annual demand for a reference year. The supply technologies within the system are then defined. As EnergyPLAN aggregates plants by type, modellers are required to calculate average efficiencies for the different technologies. Renewable generation is modelled deterministically with user's inputting hourly distribution profiles and installed capacities for each technology. EnergyPLAN can be used solely for technical analysis and as such cost data is only required when the market-economic regulation strategy is employed. When a market-economic analysis is required, cost input data, including investment, fixed operation and maintenance, variable operation and maintenance, fuel and external electricity market prices, is required.

Outputs from a technical simulation may include; fuel consumption, CO_2 production, critical excess electricity production (CEEP) and hourly and yearly electricity generation by type. Outputs from a market-economic simulation may include; investment costs, operation costs and taxes. The application of EnergyPLAN within the academic literature is discussed in Chapter 4.

3.2.4 Power Market Modelling

Deane et al. (2012a) developed a soft-linking methodology to highlight the benefits of drawing on the strengths of multiple modelling tools to provide insights into energy system challenges. Within the study, a model of the Irish power system was soft-linked to a model of the Irish energy system. This approach enabled the authors to transfer information from the power market model to the energy system model and gain important insights into the future development of the power system. The results highlighted the importance of modelling key technical constraints to prevent undervaluing flexible resources, underestimating wind curtailment and overestimating the use of baseload plant. While power system models have been considered separately from energy system models in the past, 21st century modelling challenges, as discussed in Section 3.3, will require drawing on the strengths of multiple models in order to understand the requirements for energy system decarbonisation.

Used by governments, utilities and academics, electricity market modelling began in the 1950's to support power system capacity expansion decisions (Foley et al., 2010). Since the 1950's the number of power system models and their applications have increased markedly. With the liberalisation of electricity markets around the world since the 1990's, electricity market modelling has grown increasingly more complex (Foley et al., 2010).

As power system and market models tend to focus solely on the electricity system, a richer degree of detail is permitted. The degree of detail required will of-course depend on the purpose of the model. Power system models are developed for a wide variety of purposes, including, capacity expansion planning, portfolio optimisation, reserve and response modelling, renewable integration analysis, unit commitment and economic dispatch and generation adequacy analysis.

As the models are capable of considering a high temporal resolution, typically 1 hour or 30 minutes is used, the models have a greater capability of representing the characteristics of variable renewable generation. Depending on the configuration, models may also be capable of reporting the specific costs associated with increased renewable generation, for example increase in reserve requirements or cycling costs. Along with the costs associated with integrating renewables, power system models may also offer greater insight into the flexibility requirements of future power systems with increasing variable generation. For these reasons, the effective use and development of power system models will be relevant to this study.

3.2.5 Overview of PLEXOS

The PLEXOS Integrated Energy Model is a power system and market modelling software, developed by Energy Exemplar. First released in 2000, its use by both commercial organizations and academic institutions has continued to increase and in 2015 there were over 1050 installations across 175 sites in 37 countries (Energy Exemplar, 2015). Unlike the energy system models discussed thus far, PLEXOS is solely developed for assessment of power and gas systems. As only these sectors are taken into account, a high level of temporal and spatial detail can be taken into consideration, whilst retaining computer tractability. As the model was developed for a different purpose, PLEXOS is not suited to addressing some of the issues that MARKAL/TIMES and PRIMES are capable of. However, as Deane et al. (2012a) have highlighted, soft-linking power system models to energy system models can provide greater insights into both the short term operation and long term planning of the energy system.

PLEXOS is used by regulators, utilities, transmission system operators, investors and academics around the world for a wide range of purposes, including operations (generation scheduling, portfolio management, reserve provision, etc.), planning (capacity expansion, portfolio valuation, hydro resource management, etc.), market analysis (price forecasting, renewable integration analysis, market design, etc.) and transmission (transmission expansion, constraint analysis, etc.). The application of PLEXOS within the academic literature is discussed in Chapter 4.

PLEXOS is a highly sophisticated and flexible tool, and depending on the model set-up, can be used for both simulation and optimisation studies. Typically, optimisation studies will solve the unit commitment and economic dispatch problem, subject to a number of constraints. In this set up, the objective function may be set to minimise the cost of electricity production over a user defined time horizon for a given electricity demand, subject to any user defined constraints. PLEXOS also has the capability to forecast market prices and simulate company bidding strategies. By defining markets in PLEXOS, the objection function changes from minimisation of costs to the maximisation or profits. Within this set-up, generators will typically be assigned to companies and competitive behaviour is based on game theoretic methods.

Power market analyst's, planners and investors may be required to understand the short-term operational requirements (minutes to hours), medium-term resource allocation requirements (days to months) and the long term investment requirements (multiple years) for a given system. As PLEXOS contains four simulation phases (including long-term, medium-term, short-term and planned and scheduled outages) that can be used separately, or together, the model is well suited to a wide range of problems.

The short-term (ST) schedule is often used to model unit commitment and dispatch of generators and to determine market prices. In this schedule, each day of the time horizon (typically 1 year) is modelled in full resolution. The resolution can be customized, but typically 30 minute or 1 hour interval lengths are used. For example, defining a planning horizon of 1 year, with an interval length of 1 hour and a chronological schedule of 365 daily steps, will run 365 daily optimisations with a resolution of 1 hour.

The medium-term (MT) schedule is typically used to allocate resources and for constraint decomposition, for use in the ST schedule. Decomposition is required where the constraint period (i.e. week, month, year) is longer that the ST step size (typically 1 day). For example, for decomposing an annual emissions constraint for use in the ST schedule. Ideally, the entire planning horizon is solved in 1 simulation step within the MT schedule and to achieve this the resolution has to be reduced.

The long-term (LT) schedule is used to solve the capacity expansion problem. In the most basic form, the problem relates to finding the optimal combination of new builds and retirements that minimizes the net present value of the total costs of the system over a long-term planning horizon (Energy Exemplar, 2015). Within a full power system model, this will provide analysts with information about the timing and sizing of both infrastructure investments and retirements. As with the MT schedule, ideally the entire planning horizon is solved in one simulation step.

The projected assessment of system adequacy (PASA) phase in PLEXOS computes the maintenance schedules of units and the reliability metrics for the system. Based on user inputs, including; maintenance rates and mean to repair, optimum maintenance schedules are computed by an objective function that seeks to equalize capacity reserves across peak periods (Energy Exemplar, 2015). The unit maintenance schedules are then passed to the ST and MT simulation phases. PASA also computes the reliability statistics, such as loss of load probability (LOLP) and energy demand not served (EDNS), for the system. The default resolution for the PASA phase is one period per day, although this can be changed to one period every week, month or defined interval length.

If all phases are selected, the running order is as follows, LT-schedule, PASA, MT-schedule, ST-schedule. The use of phases and required detail will be dependent on the type of study. For example, an analyst may run a simplified capacity expansion model to find the least cost generation mix, subject to emission reduction constraints and an increasing system demand. The analyst may then run a detailed ST-schedule for a chosen year to understand the unit commitment and dispatch of the new generation mix throughout the year.

3.3 Challenges for Energy Systems Models

Energy system and power market modellers have had to develop new and innovative methodologies and techniques to address modelling challenges and criticisms since the first uses in the 1970’s. This remains the case today, where governments around the world strive to develop safe, secure and affordable energy systems. The requirement for decarbonisation and the integration of variable renewable generation provides modellers with new, and increasingly complex, challenges. This section relates some of the 21st century modelling challenges discussed by Pfenninger et al. (2014) to the characteristics of variable renewable generation as discussed in Chapter 2.

Pfenninger et al. (2014) report four 21st century modelling challenges, including; resolving details in time and space, uncertainty and transparency, complexity and optimization across scales and capturing the human dimension. This section considers the challenges of resolving details in time and space, uncertainty and complexity across scales. The issues of transparency and capturing the human dimension are considered to be beyond the scope of this research project, as we focus on the techno-economic aspects of integrating variable renewable generation into power systems. For a full discussion of these challenges see Pfenninger et al. (2014).

3.3.1 Modelling Challenge 1: Time and Space

Energy systems modellers have always had the challenge of balancing resolution, data availability and computer tractability. Large, partial equilibrium optimisation and simulation models, including MARKAL/TIMES, MESSAGE and PRIMES typically use time slices or load duration curves to represent the changing patterns of energy supply and demand. While this approach has been effective in the past, when temporal and spatial resolution were not so important, it may fail to account for some of the important characteristics of variable renewable generation, as discussed in Chapter 2 (Pfenninger et al., 2014).

Energy generation technologies in pre variable renewable power systems could mostly be described as dispatchable and could be classified as base-load, mid-merit or peaking capacity. As such, the rigid time-slicing methods, used in the standard version of MARKAL, were sufficient to represent the use and contribution of these technologies to the power system. Using this approach for variable renewable generation technologies, where the availability and dispatchability is dependent on a variable and uncertain resource, may be inappropriate. Within models that use a coarse temporal and spatial resolution, the output from variable renewable technologies may simply be represented as an average of the availability within a given time period. Thus, in systems where a security constraint is calculated according to the average availability, the contribution to power system security from variable renewable generation may be over or under stated. Also, by failing to take into consideration specific resource related scenarios, such as extended periods of low wind speeds during high demand periods, or the over-supply from variable renewable generation during periods of low demand, a coarse temporal resolution may overstate or understate both electricity supplied from variable renewable generation and variable renewable curtailment. Models that account for the characteristics of variable renewable generation will be required to ensure that technologies are not over, or under, valued. As such, models will require a much stronger representation of the system in time and space.

3.3.2 Modelling Challenge 2: Complexity and Optimisation Across Scales

As with a coarse temporal and spatial resolution, pre variable renewable energy system models did not necessarily require to optimise across scales. As energy supply technologies were characterised mainly as dispatchable, the least cost portfolio as selected by an energy systems model, would likely satisfy both the long term security of the system and the short term operational requirements. Consider a large centralised power system with a number of base-load, mid-merit and peaking power plants. A standard MARKAL model represents electricity demand and generation in six time-slices, including; three seasonal (winter, summer and intermediate) and two daily (day and night). Even in this highly simplified representation, the variations in demand, as represented according to the time-slices, combined with a peaking reserve constraint will highlight the requirement for a mix of generation technologies with different technical and cost characteristics. Therefore, in the past analysts may have been satisfied that the least cost generation portfolio from an energy system model would not only satisfy the long term planning requirements in terms of system security, but also the short term operational requirements.

With an increasing level of electricity supplied from variable renewables, greater analysis is required to ensure that the least cost generation portfolio is capable of satisfying both the long term planning requirements and the short term operational constraints. Therefore, ideally energy system models should have the capability to model both the long term planning of the energy system and the short term operation. The challenge then becomes retaining a high level of temporal and spatial detail over a long term planning horizon (typically over 30 years). Even with improvements in computer performance, retaining a high level of detail over a long time horizon will be challenging.

Again, failing to take into consideration the characteristics of variable renewable generation may lead to energy system models generating technology portfolios that appear to satisfy the long term requirements of the system in-terms of system capacity and margins, but are technical infeasible to operate. Alternatively, failing to take into consideration the short-term fluctuations of variable renewable generation may lead to an underestimation of the long term requirements for dispatchable and flexible generation and demand reduction technologies.

3.3.3 Modelling Challenge 3: Uncertainty

Energy system and power system planners have always had to deal with high level of uncertainty, both in terms of the electricity supply and forecasted demand. For example, power plants can experience forced outages with very little or no prior warning and sudden and unexpected spikes or reductions in electricity demand can occur at short notice. While supply and demand forecasting has continued to improve, there remains significant uncertainty within the power system.

Not only is the end-user demand and generation supply uncertainty important. In the context of energy and power system planning, many input assumptions, such as technology learning rates, are highly uncertain. Capturing the cost reduction of energy technologies within an energy systems model, is required if the models are to be trusted to provide insights for policy makers, system planners and investors. For example, the costs of solar technology has reduced significantly over the last decade (International Energy Agency, 2014b). Models that fail to recognise the cost reduction potential of technologies may underestimate their potential contribution to the energy supply in the future. Projecting the end-user service demands also carries significantly uncertainty. While we may have a realistic idea of how demand growth is related to economic growth, the latter carries significant uncertainty. Also, an important input to energy system and power system models are fossil fuel price projections. As with economic growth, forecasting these prices carries significant uncertainty. These are just some examples of the uncertainties within energy system and power market analysis.

The treatment of uncertainty becomes increasingly important with the increased integration of variable renewable generation. As mentioned in Chapter 2, one of the key characteristics of variable renewables is uncertainty. While energy system and power system planners have had to deal with uncertainty in terms of technology learning rates, fossil fuel price projections and demand growth, there is less experience in dealing with a high level of the supply side uncertainty within the power system. As mentioned in Chapter 2, the uncertainty of renewables will pose challenges in the short term due to the balancing effect, and in the longer term due to the utilisation effect.

3.4 Modelling Progress and Developments

Section 3.3 related the challenges of resolving time and space, complexity across scales and uncertainty described by Pfenninger et al. (2014) to the characteristics of variable renewable generation. Clearly, some of the traditional energy systems and power market models will not be suited to all renewable integration studies. This is not to say that those models are not useful, but it important that modellers are aware of the capabilities of the models.

Energy system modellers have attempted to address some of the challenges outlined in the previous section. Researchers have developed models with increased spatial and temporal disaggregation in order to attempt to resolve the issues of time and space. In the UK, a temporal version of MARKAL has been developed to better understand the impacts of electricity peaking (UCL Energy Institute, 2013). ESME (Energy Systems Modelling Environment), a cost optimisation model developed for the Energy Technologies Institute (ETI) splits the UK into 12 regions and considers 10 time slices. ESME has been developed to inform the ETI, government and industry about the types and levels of investment to make in low carbon technologies to meet the carbon reduction targets.

Models and techniques have also been developed to attempt to address the issues of complexity across scales. Welsch et al. (2014) developed an enhanced version of OSeMOSYS (Open Source Energy Modelling System) that has the capability to capture the impacts of short-term variability on system adequacy and security. Deane et al. (2012a) developed a methodology to soft-link an energy system model and a power system model. In the field of power system modelling, new approaches to the long term capacity expansion problem have been developed that enable the chronological detail to be retained throughout the planning horizon (Nweke et al., 2012). The approach involves fitting a step function to a load series using a least-squares technique.

As energy system modellers have long had to deal with uncertainty, a stochastic version of MARKAL was developed in the early 1990s. For a detailed description of Stochastic MARKAL, see Loulou et al. (2004). Instead of using single values for all the variables, modellers are required to specify possible distributions for the parameters. The distributions are then taken into consideration in the optimisation problem. While these approaches have been used for a long time for planning energy systems, the use of these approaches at an operational level is more recent. Power market modellers have also sought to utilise stochastic optimisation theory. Stochastic techniques can be used for many purposes in PLEXOS, including stochastic unit commitment and economic dispatch and stochastic long term planning (Energy Exemplar, 2015).

3.5 Appropriate Selection of Energy Models

Using models that are fit for purpose is important for any renewable integration study, or indeed any other energy systems analysis study. Section 3.2 discussed some of the major energy system models that are used around the world to support policy and investment decisions. This section discusses important criteria that must be taken into consideration when selecting models.

Before considering the capability of models to address the specific research topics, a number of key logistical points must be taken into consideration. Energy models can be; data intensive, non-transparent, very complex, inaccessible and expensive. Therefore, the following points must be considered:

i. Is the model open-source or can the software be licensed to researchers at a reasonable cost? Some models, such as PRIMES, are not readily available or accessible. Other models, including MARKAL and TIMES require a commercial solver to be purchased or licenced. Due to the fact that licence fees for solvers and models can be several thousand pounds (Heaps, 2012), cost is often a key consideration when selecting an appropriate energy model.

ii. Is the model widely recognised and does it feature in the scientific literature? Applying models that have been used in previous studies offers the opportunity to contribute to a specific topic of interest within the wider field.

iii. How much training is required to become competent with the model? Energy system models can require a high level of knowledge across multiple disciplines and can take several months, or years, of highly specialist training to gain competency. Consideration must be given to both the cost of the training and the expertise available within the institution. Energy system models, such as MARKAL/TIMES, are often managed by large modelling communities, such as ETSAP. Even at a regional level, energy system models tend to be managed by research groups. In the UK, the University College London Energy Institute manages a large range of energy models, including UK MARKAL. Modelling departments will often consist of a number of PhD students, post-doctoral researchers, research associates, lecturers and professors from a range of backgrounds that may include engineering, economics, computer science, social science, mathematics and physics. Therefore, it is important to consider the institutions experience when selecting energy and power system models.

iv. Is the model data intensive and is the data required to run the model available? Energy models can require data ranging from detailed plant data, such as heat rates, minimum stable levels and outage rates, to national economic data, such as gross domestic production (GDP). Therefore, understanding the availability, and significance, of the necessary inputs before model selection is made is very important. Further, consideration must be given to the costs of obtaining the data as large commercially managed databases can be very costly.

v. Is the model computationally intensive? The computational requirements will depend both on the model used and the application. For example, running a one year model in PLEXOS with few constraints will not be computationally intensive. However, running a model with numerous technical constraints (such as minimum up/down times, minimum stable levels, ramp rates, etc.) at a high temporal resolution (5 minute intervals) will require mixed integer programming. Therefore, this type of model will be much more computationally intensive.

After considering the logistical issues, the applicability of the model to the defined research objectives, can be considered. In this research, the models should be capable of capturing the characteristics of variable renewable generation and/or addressing the relevant 21st century modelling challenges as identified by Pfenninger et al. (2014). With these points in mind, some key considerations include:

i. Can the model be run at a spatial and temporal resolution that considers the variability of renewable generation? Recent studies have highlighted the importance of sub-hourly modelling, for example see (Deane et al., 2014, Troy et al., 2012).
ii. Do the models consider the entire energy system? If the researcher is interested in high level energy policy design, an energy system model may be more relevant than a power system model. Conversely, if the policy to be designed is sector specific, then a power system model may be more relevant.
iii. Are the models capable of modelling individual power plants at a high level of technical detail? If the model is considering the operational implications of increased variable renewable generation then a detailed power system model may be more relevant than an aggregated energy system model.
iv. Can the model use a variety of approaches to treat uncertainty? Monte Carlo or stochastic optimisation techniques may be useful in understanding uncertainty; however, these approaches may be computationally intensive. Alternatively, models that are capable of running a large number of scenarios in quick succession may be useful in understanding sensitive model parameters.
v. What is the purpose of the model? For least regret options analysis then a least cost optimisation model may be the most appropriate.

However, for forecasting future energy prices, simulation models may be more appropriate.

vi. Can the model be easily set-up to run multiple scenarios? Running successive scenarios, where only a few parameters are changed, can allow the modeller to quickly understand the most sensitive model parameters. Also, the ability to run multiple scenarios can allow analysts to easily compare results.

vii. Can the model consider both system operation and long term planning? As has been discussed in Section 3.3.2, the ability to optimise across scales is significantly important in power systems with increased renewable penetration.

This section has outlined some of the important logistical and technical factors that must be taken into consideration when selecting models that are suitable for addressing the research topics outlined in this study. Each of the research topics, as outlined in Chapter 4, will involve tailoring a modelling approach to satisfy the particular needs of the research topic. Further, each modelling approach is placed in the context with other literature in Chapters 5, 6 and 7.

4 Outline of Research Topics

Drawing on the literature reviewed in Chapters 2 and 3, this chapter highlights a number of key topics for research. It should be noted that the research fields of energy systems analysis, power market modelling and renewable integration are vast and as such this section only provides some examples of where the research can be improved. Further topics of research that are not addressed in this study, due to both the logistical constraints discussed in Chapter 3 and time constraints, are given greater attention in Chapter 8. As will be discussed in the conclusions to Chapters 5, 6 and 7, while the reference systems analysed throughout this study are based on the British system, the technical, policy and economic findings will have consequent implications for systems around the world.

4.1 Introduction

In Chapter 2, the specific characteristics of variable renewable generation and the impacts of increased penetration on both the power system and markets were summarised. Sections 2.4.1 and 2.4.2 identified some of the important power system and market properties that must be taken into consideration when analysing the impacts of integrating high levels of variable generation into the system. Further, the characteristics of the resource will be highly dependent on the location. It is for these reasons that the results from renewable integration studies are highly specific to the region, or nation, that is being considered (International Energy Agency, 2014b). While the results are indeed different, the trends, which include a reduction in average wholesale market prices, increase in reserve requirements and increased transmission costs, are similar across all power systems. Chapter 2 also identified the need for a whole systems approach when considering the impacts associated with a higher level of variable renewable generation.

Chapter 3 provided an introduction to energy system models and power market models. The number of models applied to address the energy system challenges has continued to grow throughout the second half of the 20th century. With the requirement for energy system decarbonisation widely recognised, and due to the specific characteristics of variable renewable generation, modellers in the 21st century will have to address new and more complex challenges (Pfenninger et al., 2014). With multiple techniques and models available, researchers should have an understanding of both the capabilities and limitations of both their tools and analytical approaches. As Deane et al. (2012a) report, no single model is capable of addressing all of the energy systems challenges and, where possible, modellers can provide greater insights by drawing on the strengths of multiple models.

Chapter 3 identified several different types of energy system models and some of the challenges that 21st century energy modellers must address. Some of the challenges relate specifically to the characteristics of variable renewable generation. In systems where variable renewable generation is to be increased, modellers must consider resolving issues of time and space, uncertainty and complexity (Pfenninger et al., 2014). As variable renewable generation is integrated into the power system, many systems will move away from the more traditional centralised systems, where power plants can be categorised as base-load, mid-merit or peaking (International Energy Agency, 2014b). Power systems will become more decentralised and, depending on the market arrangements, the dispatch of conventional plants will become more uncertain and dependent on the output from variable renewable resources. For all of these reasons, energy system models that were developed for providing insight to policy makers and investors in the 20th century, may fail to accurately represent the characteristics of the technologies in 21st century systems (Pfenninger et al., 2014).

While the challenges for energy system modellers grow increasingly more complex, modellers should be aware of the opportunities to develop new innovative approaches at a higher rate. With the improvements in information and communication technology, modellers have the opportunity to form effective multi-national and multi-disciplinary collaborations and can share knowledge, data and approaches. Further, with an emphasis on transparency, both model and data accessibility should become easier. Also, with the advancements in computing technology, modellers should be able to trial new approaches, run new scenarios and employ techniques that were not possible in the past due to computational limitations.

4.2 Research Topic 1 – Technical Benefits of Energy Storage and Interconnections

The introductory research topic was developed on the basis of the literature reviewed in the early part of the project. Some of the earlier literature that considered the impacts of renewable generation on the electricity system did not consider the whole system. For example, Oswald et al. (2008) used MET office data to calculate a theoretical output profile from 25GW of wind capacity in Britain. By subtracting the calculated hourly wind generation from the total system demand, a residual demand time series was reported. According to Oswald et al. (2008), the demand placed on the incumbent plant would be significant. While the conclusions from the study were interesting, Gross and Heptonstall (2008) argued "*there is consensus amongst power system engineers that the only way to quantify and assess the impact of power swings on a power system is through a time series representation of demand and supply using statistical analysis and/or a power system simulation".* Thus considering a detailed representation of supply and demand is highly important for power system analysis.

Also, much of the reviewed literature concerning the impacts on increased renewable generation focusses on the costs and impacts to the power system, with less focus on how the system could adapt. While multiple studies have recognised the benefits that technologies, including energy storage, demand side response, dispatchable generation and interconnection can bring to the power system (Lynch et al., 2012, Grünewald et al., 2011, Denny et al., 2010) there were few studies that that quantified the technical benefits that these technologies could bring to future GB systems with increasing renewable penetration.

For these reasons, the first research chapter seeks to re-iterate the requirement for a whole system approach and to quantify the technical benefits that enabling technologies could bring to the operation of the power system. By using a technical optimisation approach, rather than an economic optimisation, a greater understanding of the compatibility of different technologies in the context of the whole system can be realised. Thus, the first study in this thesis will optimise the system to minimise the fuel consumption and CO_2 emissions. The first research topic provides a starting point for the more detailed, power system and market studies that will be conducted in the second and third research topics. The first research topic will also serve to identify important issues for further analysis within the second and third research topics.

4.2.1 Modelling Approach – Research Area 1

The first research chapter considers the potential technical benefits of enabling technologies in future British systems with increased renewable penetration. Technical optimisation can offer some insight into the potential CO_2 reductions if the system was to be operated in an efficient manner. Further, and importantly for this study, by using a technical optimisation the technical benefits of enabling technologies can be understood. As enabling technologies, including energy storage, interconnection, demand side response and dispatchable generation, all have different characteristics; they can each bring different benefits to the system. For example, dispatchable generation can only increase supply and cannot prevent wind curtailment during times of excess generation. Energy storage can both increase demand and supply, but the size of the storage is often a limiting factor. Interconnections are the only options for connecting to other systems, and thus have the ability to increase the size of the balancing area. Therefore, the modelling approach within the first research topic should be able to identify some of the technical benefits that different technologies bring to the operation of the GB system.

Gross and Heptonstall (2008) report that it is important to consider the whole power system when conducting renewable integration studies. The

EnergyPLAN model is used for the first research topic (Department of Development and Planning Aalborg University, 2015). The tool is open source, is widely recognised and has been used in a number of academic studies. Studies have considered large scale integration of renewable energy (Le and Bhattacharyya, 2011, Liu et al., 2011, Lund, 2005), 100% renewable energy systems (Connolly et al., 2011, Lund and Mathiesen, 2009) and the benefits of energy storage (Lund and Salgi, 2009). The tool has been used to simulate both national and regional energy systems (Hong et al., 2012, Gota et al., 2011, Connolly et al., 2010a). While EnergyPLAN has been used for a study of the GB system previously, the aim was to find the optimal level of wind generation, based on the total cost of the electricity supply (Le and Bhattacharyya, 2011). In this study, the tool is used to understand the technical benefits of energy storage and electricity interconnections in future British power systems.

The model selection is considered to be applicable to this specific research area, based on the review of energy system models included in Chapter 3. A full description of the modelling approach and methodology for this research topic is discussed in Chapter 5. As this study considers a technical optimisation (in this case minimising fuel consumption), costs will not be included. However, it should be noted that the optimisation will seek to reduce total fuel consumption and, therefore, when available, renewable resources will be given priority dispatch. Due to the low short run marginal costs of variable renewable generation, this represents the actual situation in many systems (Steggals et al., 2011).

In each of the three research sections, scenarios will be used to evaluate the sensitivities of different modelling assumptions. For example, in research topic 1 the capacity of interconnections and energy storage will be varied to evaluate the benefits of increasing deployment. As McDowall (2014) reports, scenarios are widely used to inform thinking in the face of uncertainty. Scenario analysis can be described as exploratory rather predictive. Therefore, scenarios are often used to inform stakeholders about potential possibilities and to provide new insights (McDowall, 2014). It is for these reasons that scenario analysis is considered to be very important in policymaking in highly complex systems with significant uncertainty, for example energy systems. For a full discussion of the importance of scenarios in policy making, see McDowall (2014).

4.3 Research Topic 2 – Impacts of Increased Renewable Penetration on Incumbent Power Plants

The literature reviewed in Chapter 2 focusses both on the characteristics of variable renewable generation and the impacts on the power system and markets. Much of the literature reviewed on the costs and impacts focusses on the costs associated with the deployment of variable renewable generation, with less emphasis on the impacts on the incumbent power plant within the power system. As reported by International Energy Agency (2014b), the classic approach towards variable generation integration is to focus on deployment, with less emphasis on considering the requirement for system adaption. However, as load growth is slow in stable systems, increased renewable generation capacity can reduce the profitability of incumbent plants (Traber and Kemfert, 2011). It is for this reason that the International Energy Agency (2014b) report that *“the greater challenge may be managing the costs associated with scaling down the old system”*. Thus, International Energy Agency (2014b) recommend considering the total system costs when calculating the costs associated with increased renewable penetration. Therefore, an important topic for research is to consider the implications of increased renewable generation on both the operation of incumbent plant and the total system costs.

As discussed in Chapter 2, under the current deployment and market arrangements the characteristics of variable renewable generation can impact on the operation and utilisation of incumbent plants in a number of different ways. As variable renewable generators have low-short run marginal costs, they are often amongst the first plants to be dispatched. Further, in many systems where variable renewable generation is subsidised, they may be given grid priority. As variable renewable generation has very low-short run costs, this will cause the depression of average wholesale prices. Further, the utilisation of initially mid-merit and subsequently base-load plants will be reduced. This will have consequent implications on the profitability of the power plants. Over time, should power plants be prematurely mothballed or even decommissioned early because they are unprofitable, power systems will face a reduction in system security. Through time this is likely to lead to the requirement for government and/or system operator intervention to procure more capacity. Failing to capture, and fully understand, the impacts on both the profitability and utilisation of thermal generation, may lead to an understatement of the costs associated with increased renewable penetration. Further, the variability and uncertainty of variable renewable generation will cause the increased cycling of thermal plant. While the issue of plant cycling has been studied in other systems with increasing renewable penetration, for example see Troy et al. (2010), there is less focus in GB. Therefore, the second research topic will consider the utilisation and operational requirements of thermal plants in future GB power systems with increasing renewable penetration.

4.3.1 Modelling Requirements – Research Topic 2

This section provides only a brief introduction to the modelling requirements for capturing the impacts of increased renewable generation on the utilisation of incumbent power plants. A detailed model description and justification for the modelling approach is included in Chapter 6.

As variable renewable generation output shows significant variability within the hour, a sub-hourly resolution will be required for this model (Deane et al., 2014). Further, as the study seeks to identify the impacts on the thermal plants, a full representation of the individual units within the British system will be required. Also, the technical constraints must be modelled to ensure that the system has the flexibility to respond to the variation in renewable generation output. Examples of plant constraints that must to taken into consideration include the minimum stable level, minimum up/down times and ramp rates.

As this research topic is aimed at simulating the realistic operation of power plants within the British system, mixed integer programming can be used to solve the unit commitment and economic dispatch (UCED) problem, subject to constraints. Here, unit commitment refers to the on-off decisions of the generating units and economic dispatch refers the generation dispatch level (Energy Exemplar, 2015). The objective of the UCED problem is to co-optimise the unit commitment and economic dispatch decisions across all generators, such that the costs to meet the system demand is minimised (Energy Exemplar, 2015). As the research is concerned with understanding the operational and utilisation requirements of thermal plant, technical constraints must be included.

Solving the UCED problem is considered to be the most appropriate approach for this research and the PLEXOS Integrated Energy Model is considered to be the most appropriate model. The approach and software is widely used for both commercial and non-commercial applications and features extensively in the academic literature. For example Deane et al. (2014) and Deane et al. (2012b) used a model of the Irish Single Electricity Market (SEM) to highlight the requirements for sub-hourly modelling in power systems with increasing renewable penetrations and for considering the economic impacts of adding 500MW of wave power to the Irish system. Again, modelling the Irish system, McGarrigle et al. (2013) determined the requirements for wind curtailment in 2020 and Denny and O'Malley (2009) analysed the impact of carbon prices on generation cycling costs. PLEXOS has also been used to assess the impacts of electric vehicles on the Irish power market (Calnan et al., 2013, Foley et al., 2013b). In Australia, Molyneaux et al. (2013) compare a transition to a gas based power system to a renewable generation based system, reporting higher wholesale prices in the gas based system. Nweke et al. (2012) used the capacity expansion capabilities of PLEXOS to highlight the benefits for retaining chronology in the long term optimisation problem in South Australia.

PLEXOS has also been used to soft-link power system and energy system models. Deane et al. (2012a) link the TIMES energy system model to PLEXOS, reporting that failing to capture the short-term variability in energy system models may lead to an under estimation of the costs of integrating variable renewable generation technologies.

4.4 Research Topic 3 – Market Requirements in Power Systems with Increasing Renewable Penetration

The work included within the third research topic builds on the findings from the second research topic to provide further insights into the longer term impacts of variable renewable generation. The research seeks to utilise improvements in computing performance in combination with innovative modelling approaches to understand the longer term implications of increased variable renewable generation on price formation and electricity market design.

Many renewable integration studies develop a model of a future power system and simulate the operation of the system for that year. For example, McGarrigle et al. (2013) developed a model of the Irish power system to calculate how much wind energy will be curtailed in 2020. Also, Wagner et al. (2014) developed a model of the Australian National Electricity Market in 2035 to evaluate the magnitude of the impact of a shift from coal to gas under a carbon price. While these approaches are very useful for outlining specific characteristics and requirements for the future power system (such as the operational requirements for thermal power plants), a drawback is that these approaches may fail to recognise how the system will develop through time, as a result of policies and measures to increase renewable penetration. For example, an analyst may assume a high level of dispatchable thermal capacity that is only used when renewable resources are not available. However, in reality, these plants may be prematurely mothballed, or even decommissioned, during the transition to the future power system if they are unprofitable (MacCormack et al., 2010). This provides an example of where different modelling approaches are required to provide further insights into a specific problem.

In research topic 2, a highly detailed model, run at sub-hourly resolution is required to understand the operational requirements and utilisation of a power plant for a given time period. In research topic 3, a model with reduced detail (the model set-up is fully discussed in Chapter 7) is required to provide the insights into how the system may develop through time.

Clearly, drawing on the results from both studies is important, since failing to take into consideration the short term operational requirements when planning (or investing) in infrastructure may lead to a system that may not have adequate flexibility (Deane et al., 2014, Welsch et al., 2014, Deane et al., 2012a).

This research topic provides a contribution to the literature that concerns the costs and impacts of renewable integration as it will utilise innovative modelling approaches to outline the requirements for long term capacity provisions during the transition to low carbon power systems. Further, the research will highlight the importance of considering both the deployment of renewable generation and the utilisation of existing plant during the transition to power systems with increased variable renewable penetration. PLEXOS has been selected as the most appropriate model for this research due to the capacity expansion capabilities of the model.

4.4.1 Modelling requirements – Research Topic 3

Again, this section only provides a brief introduction to the modelling requirements that will be used to address the issues highlighted in the section above. A full description of the modelling approach is described within Chapter 7.

Research topic 2 utilised the production cost modelling capabilities of PLEXOS. However, this section requires the use of capacity expansion modelling, as we are interested in the long term development of the power system. Capacity expansion modelling is concerned with finding the optimal combination of power generation new builds that minimizes the net present value (NPV) of the total costs of the system over a defined planning horizon, subject to a number of defined constraints (Energy Exemplar, 2015). As such, the model decides the timing and size of new builds. The objective function considers both the capital and production costs, and the optimiser attempts to minimise the combination of the two (Energy Exemplar, 2015). The capital costs include the cost of generator new builds, which comprises: build costs, retirement costs and finance costs. The production costs relate to the cost of operating the existing set of generators and include; fuel costs, start-up costs and carbon costs.

To ensure that unserved energy does not occur, a security constraint must be included in the model set-up. The reliability standard for the British power system, as set by the Secretary of State for Energy and Climate change as part of the implementation of the capacity market from autumn 2018/19, limits the loss of load expectation to 3 hours per year (National Grid, 2014e). Emission reduction scenarios are also included within the model set-up to evaluate the total system costs and prices associated with different levels of decarbonisation commitment.

As we are concerned with understanding how the value of firm capacity may change in systems with increasing variable renewable penetration, we analyse the capacity shadow price in each of the systems. The capacity shadow price is the incremental cost to the system of adding the last unit of capacity. Thus, the value represents the capacity revenue (£/kW/year) in addition to that from the energy market that is required for a positive expected NPV for added generation capacity.

Each plant will be represented in the same detail as in research topic 2. However, as the model considers a long term time horizon, additional model details are required, including capacity expansion candidates, long term demand projections, long term fossil fuel and carbon price projections. A number of annual emission production constraint scenarios are also included to represent commitments to emission reduction policies. System security constraints are also modelled to ensure that future power systems are sufficiently resilient and reliable.

This chapter has provided the justification for undertaking three key research topics. The following three chapters provide a detailed description of the research, results and implications for these topics. Suggestions for further research are discussed in Chapter 8.

5 Technical Benefits of Energy Storage and Electricity Interconnectors

5.1 Introduction

Chapter 4 provided the motivation for completing a study that re-iterates and highlights the requirements for a whole system approach when analysing the impacts of increased variable renewable energy in power systems. Further, Chapter 2 highlights the necessity for studies that consider the benefits of enabling technologies, such as electricity interconnectors and energy storage, in future systems with increasing variable renewable generation. The research within this chapter is based on research completed by the author (Edmunds et al., 2014).

This chapter considers a variable renewable integration study that analyses the potential benefits that energy storage and electricity interconnections can provide to the British power system. While the analysis is focussed on the GB system, it is expected that the results may offer insights to researchers and policy makers in other countries and regions where renewable penetration is increasing. The structure of the chapter is as follows. Initially, the background and context for the study is described, discussing the relevant literature and energy policy in the UK. Subsequently, the methodology will be described. The methodology section contains a description of the EnergyPLAN tool, model parameters and the plausible future scenarios that are to be analysed are introduced. The results section provides a discussion of the simulation outputs from the four discrete scenarios. Finally, conclusions and policy implications from the analysis are drawn.

5.2 Background and Context

This section provides the background to the research area and places the study in the context of this wider research project.

As a result of the Climate Change Act 2008, the UK is required to reduce emissions by 80% on 1990 levels by 2050 (Committee on Climate Change, 2011). It is considered that in order to reduce emissions by 80% then the electricity system will have to be almost completely decarbonised (HM Government, 2011, Parliamentary Office of Science and Technology, 2007). Also, European legislation requires the UK to reduce its emissions by 20% on 1990 levels by 2020, and for this reason the government has set targets for 40% of electricity to be generated by low carbon technologies by 2020 (HM Government, 2009). Beyond 2020, the UK is required to meet the targets set within the fourth carbon budget, a 50% emissions reduction on 1990 levels by 2025 (Committee on Climate Change, 2013a). To meet these targets the Climate Change Committee have stated that 30-40GW's of low carbon capacity needs to be added to the power system through the 2020's (Committee on Climate Change, 2010). In 2012, renewables (11.3%) and nuclear (19%) contributed to 30.3% of the UK's electricity generation (Department of Energy & Climate Change, 2013c). In order to meet the targets, it is expected that wind power will contribute to a significant proportion of the UK's low carbon electricity generation (HM Government, 2009).

The characteristics of variable renewable generation are discussed in depth in Chapter 2, however, a short summary is also included here. Variable renewable generation can be differentiated from conventional thermal generation by six specific characteristics (International Energy Agency, 2014b). The output from variable renewable generation is dictated by resources that are uncertain, variable and location constrained. Further, the technologies are modular and do not connect to the grid in the same way as conventional thermal generators, therefore can be described as non-synchronous. Finally, when operational, variable renewable generation produces electricity at very low short run marginal costs. A full description of these characteristics and their impacts on the power system and markets is included in Chapter 2.

As output from wind and solar generation is variable, uncertain, non-synchronous, modular and non-dispatchable, increasing the penetration will provide challenges to the operation of the power system. As discussed in Chapter 2, studies have shown that the technical and economic impacts of additional wind capacity on the power system are very system specific (International Energy Agency, 2014b). The impacts of increased variable renewable penetration are a function of many factors; not least, wind and solar resources, geographical aggregation of technologies, interconnections to neighbouring electricity systems, market and trading arrangements and the integration of the electricity sector with other energy sectors, specifically heat and transport. Thus, in the case of Denmark, a country with a significant wind penetration, the system has a high level of interconnection (Norway (1.04GW), Sweden (2.64GW) and Germany (2.38GW southbound, 2.1GW northbound), large integration of heat and electricity (due to a high level of combined heat and power plants) and a strong wind resource (Energinet.dk, 2012). In the case of GB, there is little integration between electricity and heat. While the GB system has a number of interconnectors (to France 2GW, Ireland 1GW and Netherlands 1GW), relative to the size of the peak demand this is very small (National Grid, 2013a). In summary, relative to the Danish system, GB has a very rigid energy system. For a further discussion of the characteristics of variable renewable generation and the important power system and market properties that will influence the impacts of increased penetration, see Chapter 2.

As the level of variable generation in the GB system increases, it will become increasingly important to ensure that the system remains resilient. As there is no certainty that periods of high electricity demand will coincide with periods of high variable generation output, the power system will have to have a high level of dispatchable capacity and/or an increasing level of demand response. As Wilson et al. (2010) suggest, a means of achieving this is to increase the level of energy storage within the power network. Wilson et al. (2010) provide a review of the technology options and suggest that further research is required into the amount and location of energy storage that should be incorporated into the electricity grid. In Section 5.3.3.2, some potential options and locations for energy storage are discussed.

In order to understand the requirements of interconnection and/or energy storage in a future GB high wind electricity system, a full analysis of the electricity system is required. Gross and Heptonstall (2008) have reported that it is not adequate to analyse independent generators to understand the costs and impacts of intermittency. Connolly et al. (2010b) presented a comprehensive review of the computer tools used for analysing the integration of renewable energy into various energy systems. In this study, the EnergyPLAN tool has been employed. The deterministic, hourly simulation model optimises the operation of the system and allows for a choice of regulation strategies. An overview of the EnergyPLAN tool is included in Chapter 3. The tool is open source and has been used in a number of academic studies. Studies have considered large scale integration of renewable energy (Lund, 2005, Liu et al., 2011, Le and Bhattacharyya, 2011), 100% renewable energy systems (Lund and Mathiesen, 2009, Mathiesen et al., 2011, Connolly et al., 2011) and the benefits of energy storage (Lund and Salgi, 2009). The tool has also been used to simulate both national and regional energy systems (Connolly et al., 2010a, Hong et al., 2012, Gota et al., 2011). While EnergyPLAN has been used for a study of the GB system previously, the aim was to find the optimal level of wind generation, based on the total cost of the electricity supply (Le and Bhattacharyya, 2011).

Uniquely, this study, specific to GB, considers an in depth analysis of a number of system structures in order to quantify the technical improvements that energy storage and interconnection can bring to a high wind GB power system in the years 2020 and 2030.

5.3 Methodology

The EnergyPLAN tool considers the three main energy sectors of an energy system: electricity, heat and transport. However, in GB there is little integration between the three sectors and for this reason this study focusses solely on the electricity sector. In the future, to utilise renewable energy more effectively, GB may have to better integrate the energy system and it is expected that both the heat and transport sectors will become electrified (Department of Energy & Climate Change, 2012b). In reality, to move to an entirely decarbonised electricity system then the whole energy system will have to change; smart technology to reduce demand peaks, electrification in the transport sector and energy demand reduction through increased efficiency and behavioural changes may be required to ensure that the UK meets its strict emission reduction targets and maintains a secure energy supply.

Lund (2012) provides a full user manual for the tool and the overall tool structure is shown in Figure 5.1. There are many inputs that are required, including demand distributions, energy production distributions from renewable sources, generation capacities, efficiencies and a choice of regulation strategies.

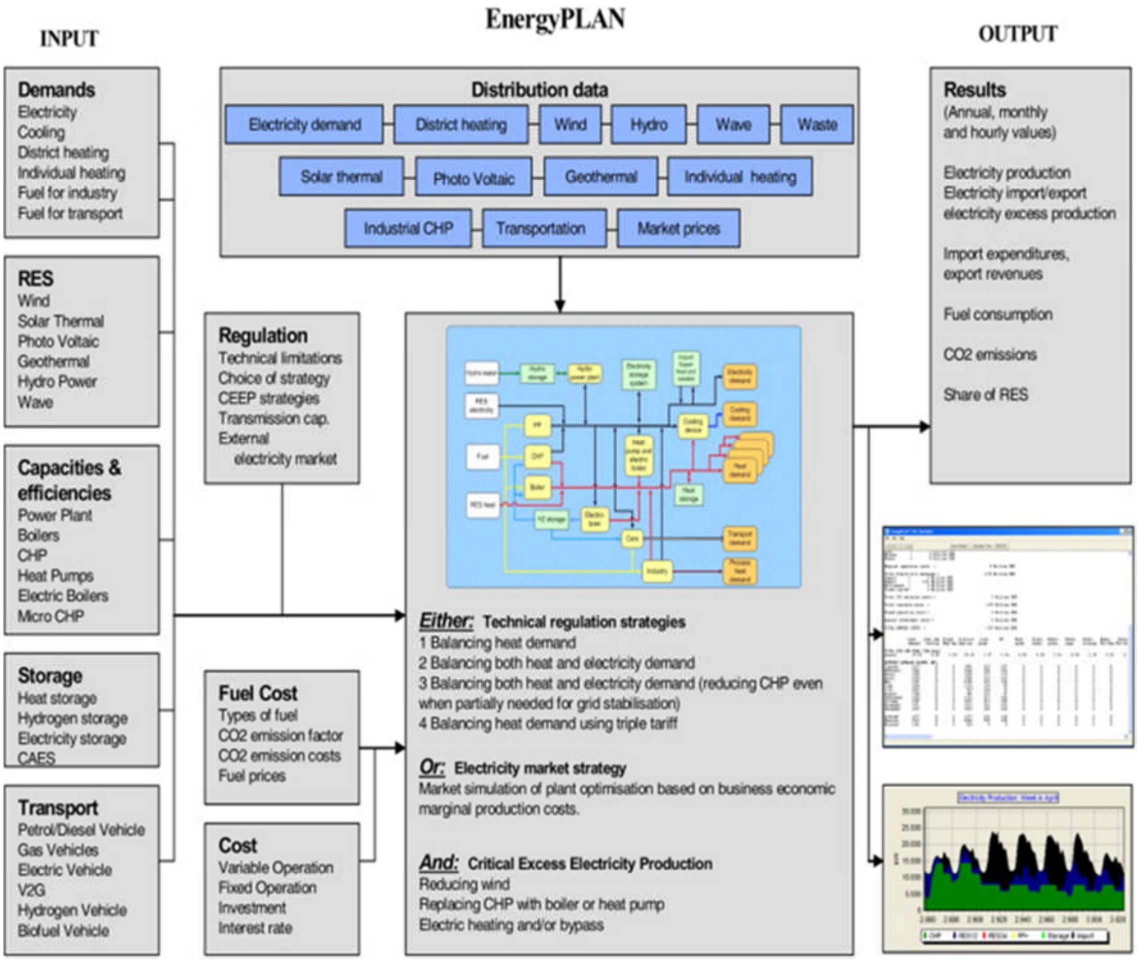

Figure 5.1 - Structure of the EnergyPLAN advanced energy system analysis tool (Connolly et al., 2010a).

5.3.1 Model Data

In this section the model inputs are discussed. It should be noted that the EnergyPLAN tool requires many inputs and assumptions and thus it is vital to ensure that the model is validated against actual data, a full description of the validation process is reported by Connolly (2010) and the validation for this study is discussed in Section 5.4.1. The year 2012 was chosen as the reference, due to the availability of recent and reliable data.[13]

Electricity Demand: Actual hourly demand and supply data is available for the GB electricity system and thus requirements for assumptions are

13 This research was completed in 2013 and thus the most recent data that was available was for the year 2012.

reduced. The first parameter to input is the electricity demand. The hourly demand was retrieved from National Grid and compared against government statistics (Department of Energy & Climate Change, 2013c, National Grid, 2012, National Grid, 2013b).[14,15] The total annual demand[16] (less demand for Northern Ireland[17]) was retrieved from Department of Energy & Climate Change (2013c).

Hydropower: The hydropower distribution was obtained from Gridwatch (2013). The GB hydropower capacity has been relatively stable for many decades, and while its relative energy contribution is small, it contributes significant balancing services to the system (International Renewable Energy Agency, 2012).

Pumped Storage: GB has four major pump storage stations with a total storage capacity of 27.6GWh (Energy Research Partnership, 2011). The power output, head, volume and energy stored for each of them is reported by Mackay (2008). At present, Scottish and Southern Electricity (SSE) are considering the construction of two plants in Scotland, Coire Glas and Balmacaan, and these would both have capacities between 300-600MW and would add a potential combined storage capacity of 60GWh to the GB system (SSE Renewables, 2012).

Nuclear: The planning and construction of new nuclear plants in GB is an extensive process. The potential extension in lifetime of the AGR reactors means that it is unlikely that the capacity will change significantly by 2020 (World Nuclear Association, 2015). Beyond 2020, it is exceptionally difficult to predict the nuclear capacity, due to the complexity of funding arrangements and construction challenges associated with new plant.

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14 Note that the DECC figures include the whole of the UK (England, Scotland, Wales and Northern Ireland). National Grid is the system operator for GB (England, Wales and Scotland) and thus there is a difference between the figures. This study is concerned with the GB system and thus the system demand is the total UK demand minus the demand for Northern Ireland (including station loads, pumping demand and losses).

15 Within the UK Future Scenarios Report, the total GB demand is listed as 328TWh for 2012. However, this does not include continental exports, pumping loads and station loads.

16 In this study the demand refers to the total electricity demand and includes losses, pumping demand imports and station loads and net Imports.

17 A value of 8TWh was subtracted for Northern Ireland, equal to the average generation for 2009, 2010 and 2011. The 2012 sub national statistics were unavailable at the time of publishing.

Conventional Generation: Under the Large Combustion Plant Directive, the operation of unabated coal power plants is being significantly reduced and there are currently no plans for any unabated coal plants to be built (Department of Energy & Climate Change, 2012e). While the coal capacity is reducing, the capacity of combined cycle gas turbine (CCGT) plants continues to increase in the UK. The government has suggested that up to 41GW may be operational in 2030 (Department of Energy & Climate Change, 2012c). However, the 'slow progression' National Grid scenario show a greater level of gas capacity in 2030 (National Grid, 2012).

Wind: The wind power time series for the year 2012 was obtained from Gridwatch (2013). The time series contains 8784 aggregated hourly output values for all wind farms in GB. A correction factor was applied to the data to reflect the increase in offshore wind that is expected in a high wind GB system. This factor takes into account the likelihood that many of the new wind farms will be built offshore in locations that have a greater wind resource. The correction correlates to load factors of 0.262 and 0.352 for onshore and offshore wind, respectively, in line with the average load factors achieved in 2012 (Department of Energy & Climate Change, 2014b).

Interconnectors: GB has a number of existing interconnectors (France 2GW, Netherlands 1GW, Ireland 1GW) and further projects have been proposed to Norway, Belgium and France (National Grid, 2013a). These are discussed in more detail in Section 5.3.3.1.

Solar PV: Given the greater load factor for wind, in each of the scenarios presented it is unlikely that solar would generate more than 15% of what wind generates in GB. Consider an example of a high nuclear scenario, (see Table 5.1) with 25GW of wind and 8GW solar. Using the 2012 load factors reported by Department of Energy & Climate Change (2014b), 29% for wind and 10% for solar, wind would generate 63.5TWh and solar 7Wh (or 11% of that of wind) in a year with 8760 hours. However, it is important to model solar as it is a form of variable renewable generation that can have an impact on critical excess electricity production (CEEP) and primary energy supply (PES). A time series of solar was obtained with the EnergyPLAN software.[18] The output was validated against (Department of Energy & Climate Change, 2014b).

5.3.2 Energy System Scenarios

After the reference model has been validated against actual data, a full technical system analysis can be completed. The scope of this study is to quantify the potential technical benefits that storage and interconnection can bring to electricity systems that have a high level of renewable penetration. Four scenarios, shown in Table 5.1, have been developed for the years 2020 and 2030, drawing on the National Grids own energy scenarios (National Grid, 2012, National Grid, 2013b);

- Scenario 1 (Slow Progression 2020): Uses assumptions from the National Grid slow progression scenario for the year 2020.
- Scenario 2 (Slow Progression 2030): Models the year 2030. The scenario uses a combination of the National Grid slow progression scenarios and some of the authors own interpretations for the year 2030.
- Scenario 3 (Gone Green 2030): In this scenario the system has a much greater level of wind energy in the electricity system.
- Scenario 4 (High Nuclear 2030): A scenario with increased demand and nuclear capacity. This scenario has a lower level of solar and wind than the gone green scenario.

[18] A number of solar time series for different years and different countries are available with the EnergyPLAN software. The sensitivity of these was checked to ensure that the series used was not critical to the results. In all cases the distributions had little impact on the overall results, due to the low solar capacity and low load factor in comparison to wind. In 2012, solar also contributed less than 1% of total system demand.

	Slow Progression 2020	Slow Progression 2030	Gone Green 2030	High Nuclear 2030
Demand (TWh)	343.00	327.00	353.00	375.00
Unabated Gas (GW)	36.70	48.50	40.00	50.00
Unabated Coal (GW)	13.70	0	0	4.00
Biomass (GW)	5.00	5.00	4.20	5.00
CCS (GW)	0	0	4.60	0
Nuclear (GW)	9.00	9.30	12.70	20.00
Wind (GW)	17.60	34.40	57.00	25.00
Solar (GW)	3.40	6.10	15.80	8.00
Hydropower (GW)	1.55	1.55	1.55	1.55
Pumped Storage (GW)	2.74	3.94	3.94	3.94
Reservoir Storage Capacity (GWh)	29.30	89.30	89.30	89.3
Interconnector (GW)	5.20	8.40	7.10	8.00
Total Plant Capacity (GW)	94.89	117.19	146.89	125.49

Table 5.1 - Generation mixes for the four different scenarios.[19]

[19] The difference between the National Grid annual electricity demand of 328TWh and DUKES demand (minus Ireland) of (368TWh) has been taken into consideration. Thus when using National Grid future energy scenario demands, 40TWh has been added to the value. The difference is due to the considerations of station load, pumping load, interconnector flows and embedded generation.

5.3.3 Energy Storage and Interconnection Scenarios

The technical analysis in EnergyPLAN uses an optimisation strategy that seeks to minimize fuel consumption, for a full description see Lund (2012). After performing a technical optimisation of each of the original systems, the energy storage and interconnection levels within the scenarios are varied to assess the technical benefits. This section provides the rationale for the levels of energy storage and interconnection that could be technically achievable within the 2020 and 2030 electricity system scenarios.

5.3.3.1 Interconnection Scenarios

The operational and proposed GB interconnectors were listed in Section 5.3.1 and there are a total of 7.35GW that are currently being considered, see Table 5.2. The price and volume of electricity flows through interconnectors are determined by the price imbalance between the two connected regions (Wilson et al., 2010). As Wilson et al. (2010) discuss, the ability of interconnectors to increase resilience is dependent on the difference in the plant mix across the two connected regions. The price across Europe may be high at low wind periods and it is for this reason that there is a concern over the feasibility of using Norway, a country with almost half of Europe’s hydropower reservoir capacity, as an energy battery for Europe (Statkraft, 2009). If many European countries move towards high wind systems, the demand and value of dispatchable capacity may increase significantly. Therefore, detailed modelling of the interconnected regions is required to fully understand the profitability of interconnectors.

Name	Capacity (MW)	Status
GB – France	2000	Operational
GB – Northern Ireland (Moyle)	500	Operational
GB - Netherlands	1000	Operational
GB – France	800	Under Development (2020)
GB – Ireland	350	Under Development
GB – Ireland	500	Operational
GB - Norway	1200	Proposed (2020)
GB - Belgium	1000	Proposed (2018)
Total	7350	

Table 5.2 – Capacity and status of GB electricity interconnectors (Wilson et al., 2010).

This study considers a technical optimisation and initially assumes that 75% of the interconnector capacity is available for export during high wind scenarios. This value was assumed as much of the existing and planned interconnection capacity is to countries with low wind penetration. Specifically, 4GW of the planned and operational capacity is to France and Norway, neither of which have high wind systems. A sensitivity study of this parameter is included, see Section 5.4.5. In addition, further work is required to understand the ability of interconnectors to contribute to supply security and this will likely require a pan European electricity market model, which is out of the scope of this study.

The potential change to the maximum technically feasible wind capacity is assessed under differing interconnection scenarios and the total interconnection capacities of 0GW, 3GW, 6GW, 9GW and 12GW are assessed. While 12GW is considered to be highly ambitious, it has been included to highlight the technical benefits of a well-connected GB electricity system.

5.3.3.2 Energy Storage Scenarios

As discussed in the introduction, a large increase in renewable generation will create new challenges for the operation of the electricity system and storage has been outlined as a technology to manage some of these challenges (Wilson et al., 2010). A number of storage technologies exist and are at varying stages of development.

Pumped hydroelectric storage has existed in the GB system for a number of decades and the largest station, Dinorwig, was developed under the Central Electricity Generating Board (CEGB). While, at present, no large scale sites have been developed since the liberalisation of the electricity market, SSE has proposed two schemes. Coire Glas and Balmacaan are considered to be technically feasible and each could have a capacity of 600MW with 30GWh of storage (SSE Renewables, 2012, SSE Renewables, 2010).

A second potential bulk energy storage technology is liquid air. At present the technology is not fully commercialised, however, the potential for liquid air in the UK was outlined in a report by the liquid air network (Centre for Low Carbon Futures 2050, 2013).

As with interconnection, a number of energy storage scenarios are considered. Installed capacities of 0 – 8GW and a range of volumes are modelled. It should be noted that the storage volumes are site dependent. For example, Dinorwig (1700MW) has a storage volume of 9GWh, yet the storage volume at Coire Glas (300MW+) has a potential for 30GWh. A single LNG storage tank could have the ability to store enough liquid air to generate 16.6GWh of electricity (Centre for Low Carbon Futures 2050, 2013). These statistics show that when discussing storage, it is not only important to discuss the capacity of the storage device but also the quantity of stored energy. Historically, storage units may have been used for rapid response and to stabilise the grid. However, with the increase in variable renewables, optimising the level of stored energy becomes increasingly important, so that energy can be either generated or used for a longer period of time.

5.3.4 Maximum Technically Feasible Wind Penetration Concept

This section describes the method for calculating the maximum technically feasible penetration of wind.

As the level of wind in the system increases, excess production of electricity becomes a greater issue. Due to a grid stabilisation share of 30%, as used by Connolly et al. (2012), and an inflexible nuclear capacity, at periods of low electricity demand and high wind speeds (with high installed wind capacity), excess wind generation is likely. The EnergyPLAN tool calculates the critical excess electricity production (CEEP); this is a summation of the excess electricity at each hour. Also, the EnergyPLAN tool calculates the primary energy supply (PES).

In this study, the maximum technically feasible penetration for wind has been calculated using the same approach as described by Connolly et al. (2010a). This approach calculates a compromise coefficient (COMP), namely from the changes in CEEP and PES between increasing levels of wind generation.

As described by Connolly et al. (2010a) the maximum technically feasible level of wind occurs when the increase in electricity that has to be exported is greater than the reduction in energy required to power the electricity system. The COMP coefficient is used to define this value. The COMP coefficient is the ratio between the reduction in PES (ΔPES) and the increase in CEEP (ΔCEEP) in each simulation.

$$COMP = \frac{\Delta PES}{\Delta CEEP}$$

Equation 5.1- Compromise coefficient used for calculating the maximum technically feasible penetration of wind.

Table 5.3 provides an example of the calculation of the COMP coefficient for the reference system, showing that between 45 and 46GW wind capacity, CEEP increases by 1.09TWh/year and PES reduced by 1.14TWh/year.

Between 46 and 47GW, CEEP increases by 1.14TWh/year and PES reduced by 0.99TWh/year. Thus moving from 46 – 47 GW shows an increase in CEEP that is greater than the reduction in PES. This is past the technically optimum point defined by the COMP coefficient. When COMP is greater than 1, the PES reduction is greater than the increase in CEEP. When COMP is less than 1, the PES reduction is less than the increase in CEEP and hence is past the maximum technically feasible wind penetration. For a further example of this, refer to Connolly et al. (2010a).

Wind Capacity (GW)	**Wind Generation (TWh)**	**CEEP (TWh/year)**	**PES (TWh/year)**	**COMP ΔPES/ΔCEEP (-)**
42	119.93	11.59	664.5	
43	122.78	12.55	663.05	1.51
44	125.64	13.55	661.71	1.34
45	128.49	14.59	660.46	1.20
46	***131.35***	***15.68***	***659.32***	***1.05***
47	134.2	16.82	658.33	0.87
48	137.06	18.02	657.49	0.70

Table 5.3 - CEEP, PES and COMP for increasing wind penetrations for the reference system.

The increase in CEEP and reduction in PES is further highlighted in Figure 5.2 and Figure 5.3. In Figure 5.2, until approximately 15% wind penetration, there is virtually no CEEP in the system; however this increases at around 25%. Figure 5.3 illustrates the change in PES for an increasing wind penetration and at around 35% the PES begins to increase.

Using this COMP coefficient, the maximum technically optimised level of wind in the reference system occurs at a wind penetration of 31% (46GW). At this level, renewables account for 42% of the electricity supply and the PES is 659.32TWh. The emissions at this wind penetration level are 290.4gCO_2/kWh. While such a system would be a significant improvement on the 2012 system, in order to meet the carbon targets, emissions will require to be significantly reduced beyond this value.

The sensitivity of the CEEP curves for the four scenarios will be tested against different levels of energy storage and interconnection, in order to better understand the technical benefits to the electricity systems.

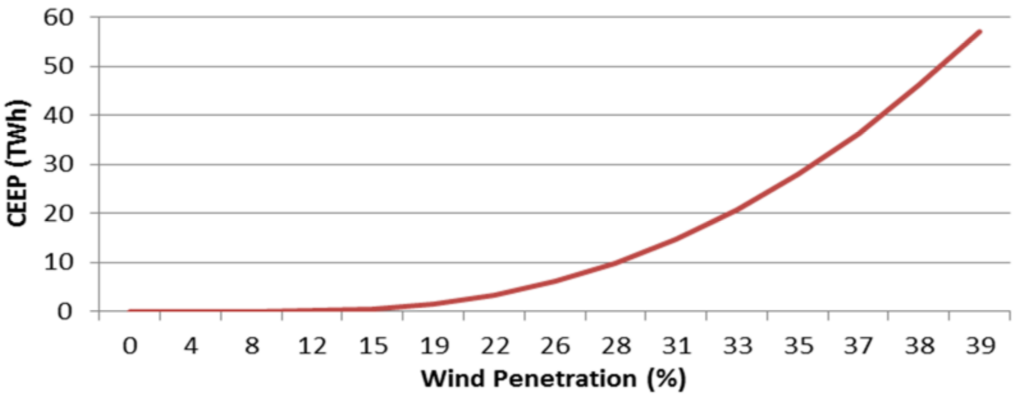

Figure 5.2– Curtailment in the GB electricity system under increasing wind penetration.

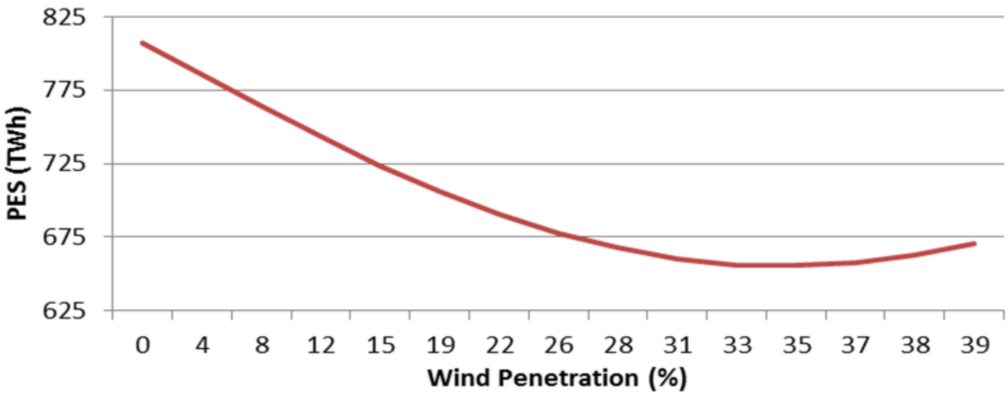

Figure 5.3 - Change in PES with increasing wind penetration.

5.4 Results and Discussion

5.4.1 Reference Model Accuracy

As mentioned in Section 5.3.1, the validation procedure for the reference model is discussed by Connolly (2010) and therefore is not described in detail here. The calculated annual and monthly electricity demand was compared against the National Grid values and found to be simulated correctly, as shown in Table 5.4[20] (National Grid, 2014a).

Month	Average Monthly Electricity Demand (MW)		Difference (MW)	Percentage Difference
	Modelled GB (2012)	**Actual GB (2012)**		
January	39820	39280	540	1.37
February	40616	40682	-66	-0.16
March	36374	36596	-222	-0.61
April	34996	34868	128	0.37
May	33494	33578	-84	-0.25
June	31442	31626	-184	-0.58
July	31325	31196	129	0.41
August	31111	31102	9	0.03
September	31988	32093	-105	-0.33
October	35123	34834	289	0.83
November	38037	37864	173	0.46
December	38733	39037	-304	-0.78

Table 5.4 – Comparison of the modelled monthly electricity demand to the actual electricity demand.

After validating the demand side of the model, the electricity from the various generators was compared against the actual annual production (Department of Energy & Climate Change, 2014b). Table 5.5 shows that the modelled production from wind, hydro, solar, power plants and nuclear was within reasonable tolerance of the actual production.

[20] For the reference model a demand of 368TWh has been used. To ensure that the demand was being simulated correctly, National Grid INDO data was used for the validation. However, the INDO data does not take into consideration station load, pumping loads and interconnector exports.

Production Type	Modelled Production (TWh)	Actual Production (TWh)	Difference TWh	Percentage Difference
Wind	19.65	19.58	0.07	0.36
Hydro	5.25	5.28	-0.03	-0.57
Solar	1.17	1.18	-0.01	-0.85
Power-Plants	263.37	264.40	-1.03	-0.39
Nuclear	71.54	70.05	1.49	2.13

Table 5.5 – Comparison of the modelled and the actual electricity production.

Due to the aggregation of power plant units in the EnergyPLAN model, the production for coal, oil and gas plants could not be validated independently. However, the annual fuel consumption for each fuel could be compared against Department of Energy & Climate Change (2013c). Table 5.6 shows that the model is within reasonable tolerance. Therefore, having compared the model data to actual 2012 figures the reference model was considered to be accurate and a suitable platform for the four scenarios.

Fuel	Modelled Fuel Consumption (TWh)	Actual Fuel Consumption (TWh)	Difference TWh	Percentage Difference
Natural Gas	206.53	214.15	-7.62	-3.56
Coal	398.32	399.25	-0.93	-0.23
Oil	8.85	9.08	-0.23	-2.53

Table 5.6 – Comparison of the modelled fuel consumption to the actual fuel consumption.[21]

[21] As sub national fuel consumption statistics are not available from DECC, the whole UK system (i.e. demand equal to 376TWh/yr) was modelled to validate fuel consumption data. It should be noted that Northern Ireland's contribution to UK capacity is less than 3% and of this 83% is conventional thermal generation. As thermal units are measured as a single unit in EnergyPLAN, the total consumption is not affected significantly.

5.4.2 Scenario Results

Table 5.7 shows the results of the technical optimisation for the four scenarios. As with the reference system results, the coal, oil and gas consumption are included. As expected, the gas consumption increases in each of the systems, as more coal and oil power stations are limited in their operation.

Parameter	**Slow Progression 2020**	**Slow Progression 2030**	**Gone Green 2030**	**High Nuclear 2030**
Natural Gas (TWh/yr)	349.65	332.34	256.77	309.42
Coal (TWh/yr)	132.44	0	0	29.12
Oil (TWh/yr)	0	0	0	0
Wind (TWh/yr)	50.05	93.18	124.41	68.33
Hydro (TWh/yr)	5.25	5.25	5.25	5.25
Nuclear (TWh/yr)	64.74	64.74	91.95	143.86
Solar (TWh/yr)	3.73	6.51	16.85	8.53
CEEP (TWh/yr)	0.03	5.04	38.35	3.05

Table 5.7 – Fuel consumption and power production for the four scenarios.

The wind and solar generation levels vary significantly across the scenarios and as expected the systems with a higher renewable penetration experience the greatest levels of CEEP.

The wind in each of the scenarios was then varied from 0 – 60GW, in increments of 5GW, and the wind curtailment calculated. The maximum technically feasible wind penetration was calculated using the COMP coefficient, described in Section 5.3.4. Figure 5.4 shows that under each of the scenarios, the patterns for wind curtailment are very similar.[22] Further, until 20GW of wind capacity, there are few periods with CEEP. However, after 20GW this increases very quickly. To be technically beneficial,

[22] The point in which the solid line becomes dashed illustrates the maximum technically feasible wind penetration in each of the scenarios.

increasing the storage and interconnection capacity should reduce both wind curtailment and primary energy supply.

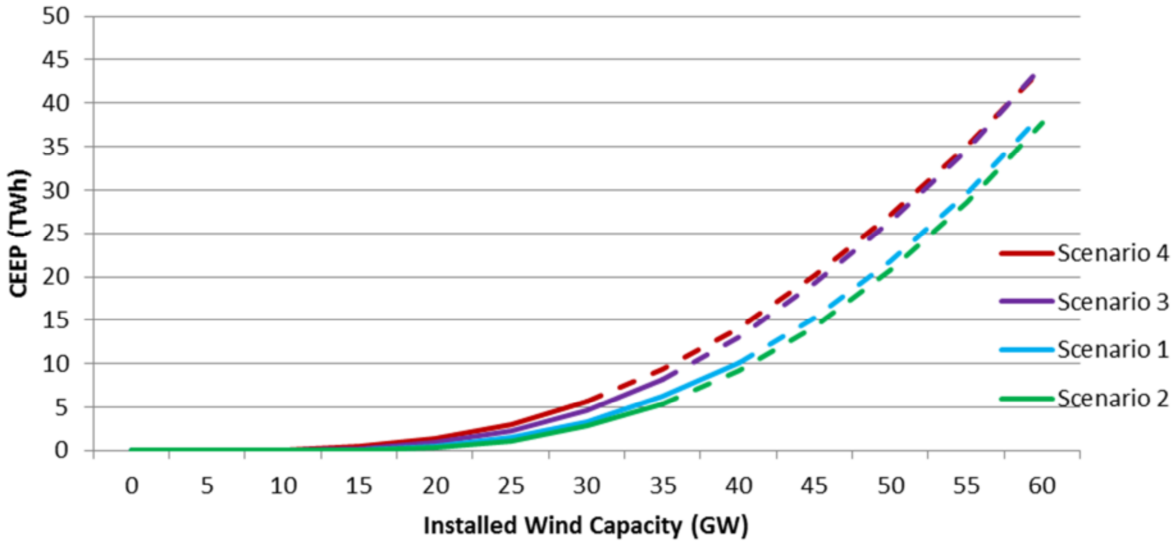

Figure 5.4 – Increase in the curtailment with wind capacity.

Table 5.8 shows the specific values for the maximum technically feasible wind penetration, both in terms of percentage of electricity supply and wind capacity. The system emissions at the maximum penetration are also shown.

	Slow Progression 2020	Slow Progression 2030	Gone Green 2030	High Nuclear 2030
Maximum Technically Feasible Wind Penetration (% of supply)	31	30	26	21
Maximum Technically Feasible Wind Capacity (GW)	42	37	35	30
Emissions at Maximum Wind Penetration (gCO_2/kWh)	260	202	174	185

Table 5.8 – Maximum technically feasible wind penetration and system emissions for each scenario.

As shown in Table 5.8, the gone green scenario has a maximum technically feasible wind penetration of 26% (35GW), the equivalent to 91.73TWh, well below the 57GW listed in Table 5.1. In this case there is a difference of 24GW between the technically optimised penetration and the scenario value. The CEEP within this scenario (at 57GW wind capacity) is the equivalent to over 10% of the total electricity demand. Thus the system is not operating in a technically efficient manner. While installing the maximum technically feasible capacity of wind would significantly reduce emissions, the potential for further emission reductions is limited and thus remains well above that required to decarbonise the electricity supply.

It is acknowledged that the market may provide the opportunity for a greater level of wind to be installed. For example, if the cost of coal and gas is so high that even with a high rate of wind curtailment, then new wind capacity could remain a profitable investment. Le and Bhattacharyya (2011) calculate the optimum level of wind to be integrated into the UK system to be 80TWh, using the 2012 wind data; this would be the equivalent to 28GW. This suggests that the gone green scenario will neither be technically or economically optimised. For example, building 57GW of wind into a system that has a total supply cost optimised wind capacity of 28GW, and a technically optimised wind capacity of 32GW, would lead to a very expensive and inefficient system. Further, the emissions remain well above the level required to decarbonise the system.

The maximum feasible wind penetration in the high nuclear scenario is just 21% (or 27GW). While the wind level shown in Table 5.1 is technically feasible, the system does not have much scope to further increase the wind capacity. Should the GB system develop to have a high level of inflexible nuclear capacity and wind generation, a high level of CEEP would be expected, unless significant measures were taken. These measures may include, but are not limited to, interconnection, energy storage, greater integration with the transport sector (for example electric vehicles) or demand side response.

Both slow progression scenarios are technically feasible; however if the wind capacity was increased to the maximum wind penetration, the emissions in both systems remain in excess of 200gCO_2/kWh. While compared to 2012, this is a significant emissions reduction; the requirement for 2050 is the near decarbonisation of the electricity system. It is clear that the system has to operate in a more technically optimised manner to meet the emissions targets and a high capacity of wind and solar alone will not provide sufficient carbon reductions.

From a systems perspective, CEEP and PES can be reduced by demand side response, energy storage, and interconnection and by increasing plant flexibility. In this study we now investigate the impact of the changes in energy storage and interconnection.

5.4.3 Changes to Energy Storage and Interconnection

The initial results can give some insight into the operation of the system. It is clear that the systems are not technically optimised and at high wind penetrations will be subject to high levels of curtailment. The scope of this study is to understand the potential benefits of increasing energy storage and interconnection to the maximum technically feasible level of wind and we show that this can be done by increasing interconnection and energy storage.

For clarity, only the gone green scenario has been included within the results. (It should be noted that the results of all the scenarios follow the same general trends.) It is perhaps unlikely that a high level of interconnection, energy storage and wind will be installed by 2020 and for this reason the results obtained from the gone green scenario was chosen to be included within this paper.

5.4.3.1 Benefits of Increased Energy Storage

Many studies have considered the benefits of energy storage in future highly renewable national and regional energy systems (Rasmussen et al., 2012, Heide et al., 2011, Grünewald et al., 2011). This study considers the technical benefits of a range of potential storage scenarios in future GB power systems. In Section 5.3.3.2, the energy storage options were briefly reviewed. The scenario capacities and storage volumes shown in Table 5.9 are considered to be technically plausible by the year 2030, although the higher levels have been included to show the advantage of greater storage volumes and these are seen to be highly ambitious.

Storage Capacity (GW)	Storage Volume (GWh)	Maximum Wind Capacity (GW)	Maximum Wind Penetration (%)	CEEP at Maximum Penetration
2	100/200	36/37	0.27/0.28	5.91/6.48
4	200/400	37/38	0.29/0.29	4.82/5.16
6	300/600	38/40	0.30/0.31	4.02/4.70
8	400/800	40/42	0.31/0.33	4.07/4.35

Table 5.9 – Effect of storage capacity and volume on the gone green scenario.

Table 5.9 shows the change in the maximum wind penetration as both the storage capacity and storage volume are increased within the gone green system. It is observed that increasing the energy storage from the current level of capacity to 8GW, with a storage content of 800GWh, would increase the maximum wind penetration from 26% - 33%.

As illustrated in Figure 5.5, under the 6GW and 300GWh storage scenario the CEEP is reduced from 8.21 to 4.02TWh and, significantly, the maximum wind penetration is increased from 26% - 30%. In the initial gone green system, the maximum wind penetration is achieved at 35GW capacity. However, in this energy storage scenario, the maximum penetration level is achieved at 38GW. Thus for only a 9% increase in wind capacity the wind penetration can be increased by 15%. It should also be noted that without energy storage, 38GW would only provide 28% of the electricity demand and the CEEP level would be 11TWh.

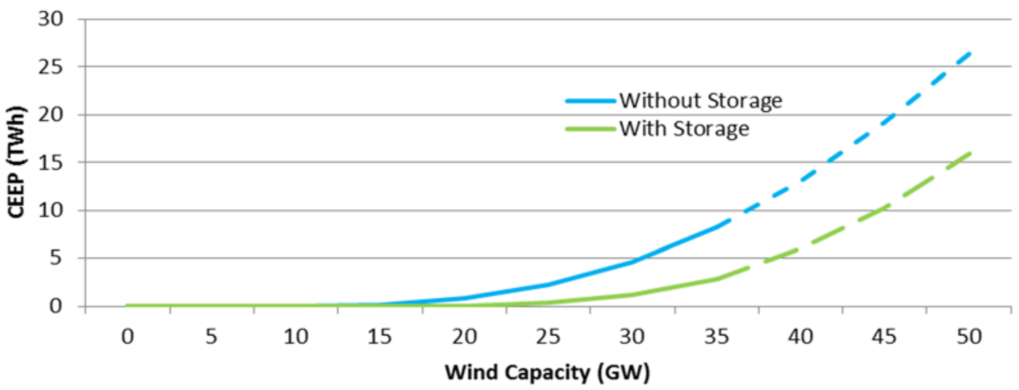

Figure 5.5 – The change in CEEP when energy storage is added to the system.[23]

As would be expected, under all storage scenarios, the CEEP is significantly reduced. The storage provides an opportunity for excess energy generation, during periods of high wind and low electricity demand, to be absorbed. Indeed by adding just 4GW of storage, with a volume of 200GWh, CEEP can be reduced by approximately 50% and the maximum wind capacity increased from 35 – 37GW. While this is a significant improvement, it remains below the 57GW outlined within the gone green scenario.

5.4.3.2 Benefits of Additional Interconnection

As outlined in Section 5.3.3.1, the level of interconnection could increase significantly in GB over the coming decades. However, as discussed in Section 5.3.3.1, the ability to rely on interconnections for electricity will depend on the market arrangements and plant mix within the two connecting regions.

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[23] The maximum technically feasible wind penetration is illustrated as in Figure 5.4.

Interconnection Capacity (GW)	Maximum Wind Capacity (GW)	Maximum Wind Penetration (%)	CEEP at Max Penetration (TWh)
0	31	0.21	13.79
3	33	0.24	10.02
6	35	0.26	7.26
9	36	0.28	4.66

Table 5.10 – Effect of interconnection capacity on CEEP and maximum wind penetration.

Table 5.10 shows that interconnection can significantly increase the maximum wind penetration. Also, as with energy storage, interconnection significantly reduces the CEEP. Further, it should be noted that in the gone green scenario a moderate level of interconnection is already installed. Thus, as expected, the 0GW and 3GW interconnection scenarios show a reduction in the maximum wind penetration, compared to Table 5.8. It was acknowledged that the ability of interconnections to either have the capacity to import or export as and when required is dependent on the market conditions. However, it is unlikely that investors would support a scheme that didn’t compliment both systems.

By increasing interconnection, the maximum wind penetration can be significantly increased. Similarly, moving towards a gone green scenario without increased interconnection would result in a large amount of CEEP and reduced maximum wind penetration. Again, as with the energy storage scenarios, the CEEP is significantly reduced.

5.4.3.3 Combined Interconnection and Energy Storage

The final analysis is to assess a combination of increased interconnection, increased energy storage and decreased minimum plant capacities (to be discussed within Section 5.4.4). A number of combination strategies have been developed and these strategies are as follow;

- Strategy 1: Storage capacity increased by 2GW, with a storage volume of 100GWh. Interconnection capacity of 6GW and minimum plant capacity of 10GW.

- Strategy 2: Storage capacity increased by 4GW, with a storage volume of 200GWh. Interconnection capacity of 9GW and minimum plant capacity of 7.5GW.
- Strategy 3: Storage capacity increased by 6GW, with a storage volume of 200GWh. Interconnection capacity of 12GW and minimum plant capacity of 5GW.

As shown in Figure 5.6, the curtailment is significantly reduced as the energy storage and interconnection are increased and the minimum power plant capacity decreased. Table 5.11 shows the maximum wind capacity and penetration for each of the scenarios, along with the CEEP at the maximum wind penetration.

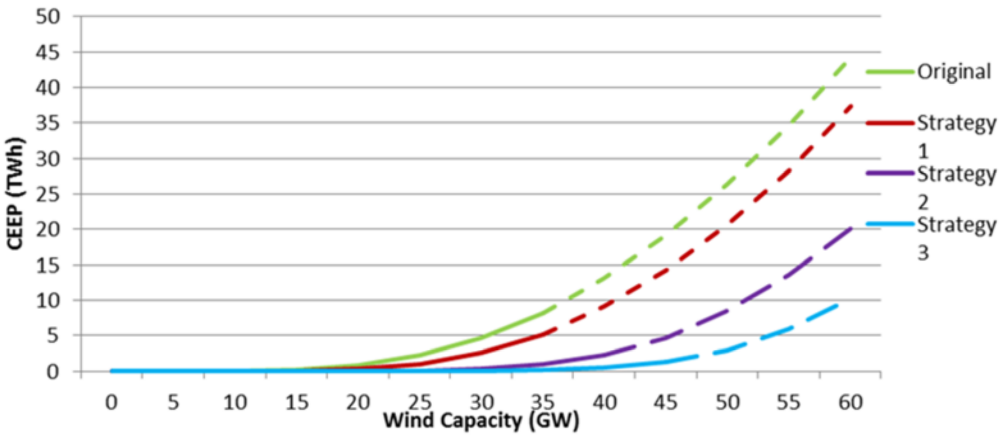

Figure 5.6 – Change in CEEP for each combined interconnection, energy storage and minimum plant capacities.[24]

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24 The maximum technically feasible wind penetration is illustrated as in Figure 5.4.

Strategy	Maximum Wind Capacity (GW)	Maximum Wind Penetration (%)	CEEP at Maximum Penetration (TWh)
Original	35	26	8.21
1	36	27	5.12
2	44	34	4.10
3	48	39	2.09

Table 5.11 – Effect of storage, interconnection and minimum plant capacity on CEEP and maximum wind penetration.

It should be noted that strategy 1 is similar to the original gone green scenario, with an increased level of storage. Within this scenario, the maximum wind capacity is increased to 36GW and wind supplies 27% of the electricity demand.

Strategy 2 produces a significant increase in the maximum wind penetration through the development of a more flexible system and increase in storage and interconnection capacity. The ability to build a further 6GW of interconnection and 4GW of storage is considered to be technically plausible, with the two potential SSE pumped hydro sites alone providing 1.2GW of storage capacity. The storage volume of 200GWh is large; however, as outlined in Section 5.3.3.2, a single LNG tank alone could provide 16.6GWh of storage.

The final strategy would require a high level of interconnection, beyond what is being considered today. This strategy has been included to highlight the levels of interconnection and storage that would be required to have a system in which about 40% of electricity is supplied by wind power. Within this scenario the electricity system emissions are reduced to 113gCO_2/kWh, a significant improvement on the original gone green scenario that had an emissions intensity of 174gCO_2/kWh.

It is clear, in all of the scenarios that storage and interconnection do indeed increase the maximum technically feasible level of wind in the system. While the 57GW is not realised in any of the systems, because the system is operating in a more technically efficient manner the utilised wind production, about 135TWh[25] (for 48GW), is much greater than the 124TWh used within the original gone green scenario (for 57GW). These figures provide a very strong case for building a more technically efficient system, for less wind capacity the penetration level is greater, and this confirms the case for the need for a whole systems approach. A combination strategy significantly increases the maximum capacity of wind that can be integrated into the electricity system. The CEEP is significantly reduced and for this reason the maximum wind penetration is increased. Comparing the third strategy to the gone green system, shows that the wind capacity can be increased from 35GW to 48GW and the penetration increases from 26% to 39%.

5.4.4 Sensitivity of Minimum Power Plant Capacity

It was mentioned in Section 5.3.4 that there is a requirement for grid stabilisation and this was assumed to be 30%, in line with (Connolly et al., 2012). In GB, this share could be the equivalent to 6.6GW, at the lowest demand level, and 17.7GW at the highest demand level (National Grid, 2014a).[26] EnergyPLAN also requires an input for the minimum power plant level. The minimum plant capacity refers to the conventional plant that must be operational at any given hour. As the level of wind increases, it is expected that plants will operate at this level for increasing lengths of times. The minimum power plant within the reference model has been assumed to be 10GW.

The reason for varying the minimum power plant capacity parameter was to understand how increasing flexibility, by reducing the minimum power plant capacity, could increase the maximum technical feasible level of wind in the power system. Operational gas and coal plants have a minimum stable generation level. During a storm, in a system with high wind penetration, the output from wind power would be very volatile. Ramping gas and coal plants

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25 Utilised wind production is equal to total wind production minus curtailed wind production. For combination strategy 3 this is equal to 137.06TWh – 2.09TWh = 134.97TWh. For the original gone green scenario, at 57GW wind capacity, the utilised wind production is 162.76TWh – 38.35TWh = 124.41TWh.

26 This is based on the total gross system demand and includes station load, pump storage pumping and interconnector exports.

according to the volatile wind output to ensure that demand is met would be challenging. Determining the minimum power plant capacity within a high wind system requires further research and this will likely require a more detailed model. However, based on the information reviewed in this paper it is unlikely that the GB system in 2030 could operate without conventional power plant capacity, and even if it could on a temporary basis, it is unlikely it would be possible to do so for an extended period of time.

Minimum Power Plant (GW)	**Maximum Wind Capacity (GW)**	**Maximum Wind Penetration (%)**	**CEEP at Maximum Penetration (TWh)**
10	35	26	7.39
7.5	40	30	8.13
5	43	33	7.61

Table 5.12 – Effect of minimum power plant capacity on CEEP and maximum wind penetration.

The sensitivity of the minimum power plant capacity to the gone green system was tested and the results shown in Table 5.12. While decreasing the minimum plant capacity significantly increases the maximum wind penetration, the CEEP values remain high. This is because there remains no technology that can use excess energy from wind power. Thus, even if plants were flexible enough to meet the demand requirements within a system that is constantly under strain, due to a high wind capacity, energy storage and/or interconnection will be required to use excess generation.

5.4.5 Sensitivity of Interconnection Capability

It was acknowledged in Section 5.3.3.1, that the ability of interconnectors to deliver resilience will depend on the plant mix across the interconnected regions. Further, detailed modelling of the interconnected regions would be required to fully understand the profitability of interconnectors. If many countries move towards high wind systems, the demand and value of dispatchable capacity will likely significantly increase. Also, in future highly interconnected power systems, PES in GB could be significantly decreased by importing electricity from other countries. However, this is dependent on a number of uncertain factors including, trading arrangements, market design, future plant construction and demand profiles in other countries.

While detailed pan European electricity market analysis to determine the profitability and flows across interconnectors is not within the scope of this study, it is important to test the sensitivity of available interconnector capacities.

Originally a value of 75% was assumed for export capability during high wind scenarios, this value was assumed as much of the existing and planned interconnection capacity is to countries with low wind penetration. Specifically 4GW of the planned and operational capacity is to France and Norway, neither of which have high wind systems. Beyond 2020, in a European system with a very high variable renewable penetration, the ability to export excess wind generation may reduce. As discussed in Section 5.3.3.1, understanding interconnector flows in future high variable renewable energy systems will require a pan European electricity market analysis and this is not within the scope of this study.

Table 5.13 shows the sensitivity of interconnector capabilities for the gone green scenario. Export capabilities of 40, 60, 80 and 100% have been assessed. Becker et al. (2014) suggest in a highly interconnected high renewable energy system that 40% of the excess generation may be exportable. It should be noted that the interconnector capacities suggested within the scenarios are not excessive, with a maximum capacity of 12GW by 2030, this may be considered to be a highly ambitious scenario. It should also be noted that the wind penetration in the most ambitious 2030 scenario is 40%.

Interconnector Export Capability (%)	Maximum Wind Capacity (GW)	Maximum Wind Penetration (%)	CEEP at Maximum Wind Penetration (TWh)
100	35	26	5.93
80	34	25	6.90
60	33	24	8.02
40	33	23	10.30
75 (Original)	***35***	***26***	***7.39***

Table 5.13 - Sensitivity of Max Wind Capacity, Penetration and CEEP to Interconnector Capability.

As shown in Table 5.13, the impact of interconnector export capability is as expected. CEEP increases as the export capability decreases, thus in a highly interconnected European system with high variable renewable penetration, CEEP would be expected to increase. Although, this is highly dependent on how the plant mix across Europe and interconnector capacity changes over the next two decades. Further, as interconnection capability is reduced, the maximum wind penetration decreases, due to a reduction in the maximum wind capacity and increase in CEEP.

While the results are indeed sensitive to the assumed interconnector export capability, it should be noted that even with 40% export capability, the maximum wind penetration increases and CEEP reduces from a system with no export capability. Therefore there remain technical benefits to increasing interconnection capacity.

5.5 Conclusion

Under legally binding legislation, the UK is required to reduce emissions by 80% on 1990 levels by 2050. To meet these targets, the Committee on Climate Change has stated that 30-40GW of low carbon generation will have to be built through the 2020's. It is currently unclear whether the UK will be able to construct such a large amount of new capacity within the timescale required. This chapter has shown that increasing interconnection and energy storage within the GB power system has the potential to reduce the amount of new low carbon generation infrastructure that must be built in order for the UK to meet its emissions targets. Interconnections and energy storage enable increased penetrations of wind energy to be used more effectively, and in turn this reduces system emission intensity.

After developing and validating a model of the GB power system using the EnergyPLAN tool, four future energy scenarios were analysed and the maximum technically feasible wind penetration calculated. The results have shown that without an increase in the storage and interconnection capacity, even in the most ambitious 'gone green' scenario the emissions remained in excess of 170gCO_2/kWh. While this is a significant improvement compared to the 483gCO2_2/kWh intensity of 2012, it is clearly above the 50gCO_2/kWh recommended by the Committee on Climate Change (Department of Energy & Climate Change, 2013a, Committee on Climate Change, 2010, Committee on Climate Change, 2013b).

To evaluate the effect of increased interconnections, further scenarios analysed the impact of building a further 4GW of cross-border interconnections in addition to the 4GW already in existence. The benefits of these projects have been clearly demonstrated in this study, showing that under the gone green scenario the maximum penetration of wind can be increased from 21 – 28%. Not only is the maximum wind penetration increased, but the critical excess electricity production is reduced from 13.79 to 4.66TWh. Also, energy storage was found to be significantly beneficial to the system, with a capacity of 6GW increasing the maximum wind penetration from 26 – 30% and reducing the critical excess electricity production to 4.02TWh.

Of the scenarios considered combining electricity storage with strengthened interconnections was found to provide the most effective means of increasing wind penetration. Indeed, with 9GW of interconnection and 4GW of storage, the maximum technically feasible wind capacity is increased from 35 – 44GW. Further, in this scenario wind energy supplies 34% of the electricity generation and the critical excess electricity production is reduced to 4.1TWh.

The best case scenario shows an emission intensity of 113gCO_2/kWh for the GB electricity system. Within this case, 48GW of wind capacity provides a higher level of usable energy to the system than the 57GW within the original ‘gone green’ scenario. Thus, as a result of energy storage and interconnection, a system with less wind capacity has a lower carbon intensity. This clearly demonstrates the importance of a whole systems approach for the planning of future low carbon electricity systems.

If the UK is to meet its carbon reduction targets the electricity system will have to be decarbonised. However, the GB electricity system has a limited capacity to absorb variable renewable generation at the levels likely to be required by the ambitious policy targets. This chapter has demonstrated that additional interconnection and energy storage can enable a greater maximum wind penetration and as a result, a reduced system carbon intensity. In the cases considered the lowest emissions achievable though large scale wind deployment combined with significant storage and interconnector development was approximately 113gCO_2/kWh. While a considerable improvement on current levels, this remains above the 50gCO_2/kWh recommended by the Committee on Climate Change. Hence it is difficult to see how further quantities of wind capacity could realistically reduce emissions significantly further by 2030. To achieve further reductions, it seems likely that the UK electricity system will need better integration with other energy sectors, such as the electrification of the heat and transport sectors.

6 Operational Regimes of Thermal Power Plants

6.1 Introduction

The research in Chapter 5 concluded that increasing cross-border electricity interconnections and energy storage can increase the maximum technically feasible wind penetration. Further, the chapter highlighted that a systems approach that combines increased variable generation with energy storage and interconnections can reduce primary energy consumption, decrease wind curtailment and deliver further reductions in system emissions intensity. Further work is suggested, and notably a greater understanding of the impact of increased wind penetration on the operational regimes of conventional thermal plant is required.

The EnergyPLAN advanced energy system analysis computer model was used to complete the analysis in Chapter 5. A full description of the tool can be found on the EnergyPLAN website (Department of Development and Planning Aalborg University, 2015). Either fuel consumption (technical optimisation) or the cost on the basis of each production unit (market-economic optimisation) can be minimised (Lund, 2012). While suitable and very useful for some technical and economic studies, specific power market analysis software is required for capturing the detailed operation of individual power plants within the system.[27] This is because EnergyPLAN aggregates the conventional plants within the electricity system, and thus a detailed representation of the costs associated with the operation of individual plants cannot be extrapolated from these results. Also, by neglecting to take into consideration detailed technical constraints, such as minimum stable levels (MSL), ramp rates, minimum down time (MDT) and minimum up time (MUT),

[27] Chapter 3 includes an overview of a number of models that can be used for analysing the costs and impacts associated with increased renewable penetration. Further, as Deane et al. (2012a) suggest, greater insights can be provided by drawing on the strengths of a range of energy models and one model is not capable of solving all of the challenges within the energy sector.

the technical feasibility of discrete scenarios may not be captured sufficiently. Therefore, the aim of this Chapter is to develop a full power market model of the GB system to enable the technical and economic feasibility of discrete scenarios to be analysed. In this chapter, specific focus is given to the operation of thermal power plants in future power systems with increasing variable renewable penetration.

The study uses the PLEXOS Integrated Energy Model, developed by Energy Exemplar (Energy Exemplar, 2015). In this application of the model, the unit commitment and economic dispatch problem is solved. As capturing short term constraints, including MSL's, MDT, and MUT introduces decision variables, mixed integer programming is required to solve the problem. A number of solvers can be employed through PLEXOS to solve the equations; this research uses Xpress MP (provided by FICO) due to the high efficiency in solving mixed integer problems (FICO, 2015).

The structure of the chapter is as follows, Section 6.2 provides the background and context for the research, Section 6.3 describes the methodology and the discrete scenarios to be analysed. Results are discussed in Section 6.4. Finally, the concluding remarks and policy implications are included in Section 6.5.

6.2 Background and Context

As mentioned in the introduction, the aim of this chapter is to capture and analyse some of the characteristics of variable renewable generation discussed in Chapter 2 that could not be analysed using the EnergyPLAN tool. Further, the chapter will utilise improvements in optimisation techniques and computing performance to address some of the challenges associated with 21st century modelling techniques, as discussed in Chapter 3. This section summarises the key variable generation characteristics that will have an impact on the operational regimes of thermal power plants in the future. Of the six properties of variable renewable generation, low-short run marginal costs, variability and uncertainty will have the most profound effect on the dispatch of thermal plant. A full description of the impacts of the characteristics of variable renewable generation is included in Chapter 2 and as such only a summary is included here.

6.2.1 Low-Short Run Marginal Costs, Variability and Uncertainty

As variable generation has very low short-run marginal costs it is generally dispatched when it is available (Steggals et al., 2011). Therefore, as variable renewable generation increases, average prices are depressed. While the methodologies are different, studies in Ireland (Clifford and Clancy, 2011), Australia (Forrest and MacGill, 2013), Spain (Sáenz de Miera et al., 2008), Germany (Traber and Kemfert, 2011) and Italy (Clò et al., 2015) have agreed that under the existing market arrangements, increased variable renewable generation lowers wholesale prices. This reduction in wholesale prices is known as the merit order effect and this effect will cause the displacement of plants at the middle and top of the merit order. In the period before a structural shift to a more flexible electricity system, this displacement will lead to the reduction in the utilisation of the mid-merit plant. Depending on the market design, level of government intervention and trading arrangements this could lead to the mothballing, or premature decommissioning or these plants. Such a scenario has been experienced across many European states in the early 2010’s (International Energy Agency, 2014a). As the plant that are displaced are often both flexible and dispatchable, these closures may lead to a significant reduction in system adequacy (MacCormack et al., 2010).

As the output from variable renewable generation is dictated by the availability of the resources and the prevailing weather conditions, the generation is subject to significant variability. This differentiates variable generation from conventional thermal generation (including nuclear, gas and coal), where units are typically dispatched at a planned and predefined level, subject to restrictions from constraints and outages. The impacts of increased variability on the operation of power systems and markets can occur over short and long term times scales.

In the short term (minutes to days), increased variability leads to the requirement for greater power system flexibility. Even with a highly distributed wind and solar capacity, the aggregated output from renewable generation will be subject to significant variability. On occasions when the output varies rapidly, sufficient flexible resources will be required to ensure that supply and demand remain balanced (International Energy Agency, 2014b). The greater requirement for flexibility will cause additional cycling of thermal plants and the costs associated with additional plant cycling are discussed in Section 2.5.2.1. In the medium to long term (months – years), the variability will have impacts on the utilisation of incumbent plant. This is due to the steepening of the net load duration curve (LDC), as shown in Section 2.5.2.2. The net LDC steepens due to periods of scarcity (when wind output is very low and the net load is a very high percentage of total load) and abundance (when the wind output is high and the net load is a very low percentage of the total load). The utilisation effect can be described in two phases. In the first stage, variable generation is added to systems that have not undergone structural transformation. In this stage (transitional utilisation effect), incumbent marginal plant are affected and may become unprofitable. In the second stage (persistent utilisation effect), the power system experiences a structural shift to a more flexible system. It should be noted that moving to the second stage requires a reduction of inflexible capacity and thus a reduced baseload capacity. Static systems with low load growth may struggle to move from the first stage if significant levels of both variable renewable generation and baseload capacity are developed. For a full discussion of the impacts of transitional and persistent utilisation effect, see Chapter 2 or International Energy Agency (2014b).

The final characteristic of variable renewable generation that is relevant for this chapter is uncertainty. Unlike generation from conventional power sources, forecasting the output from variable resources is subject to significant uncertainty. While power system operators have been well equipped to deal with demand uncertainty in the past, high level variable generation adds significant uncertainty to the supply side. As power systems have to be continuously balanced, operators are required to procure a number of reserve services. The exact specification of reserve products purchased is highly system specific, but normally operators will procure a number of different types. For example, in GB, National Grid procures; fast reserve (available within 2 minutes), BM start-up (available within 90 minutes) and short term operating reserve (available within 240 minutes) (National Grid, 2014b). As increased variable generation adds significant uncertainty, operators will have to procure increasing levels of reserve services. Holttinen et al. (2011) provide a summary of the results from a number of studies that calculate the costs associated with increased reserve provision. For further information see Chapter 2.

6.2.2 Summary of Variable Generation Characteristics

The characteristics of variable generation will affect thermal plant operation in a number of different ways. Short term effects, such as the requirements for additional balancing may subject plants to more frequent and intense ramping events. Over longer time scales, due to the low short run marginal costs and variability of renewable generation, mid-merit plant are likely to be used less frequently. Therefore, it will be fundamental that the revenue of plants under increasing renewable penetration is sufficient to prevent mothballing or premature decommissioning. While in time, the power system structure will adapt to be more flexible; to retain security of supply, revenue adequacy of marginal plant in the transition period will be vital.

By modelling a number of potential future GB power system scenarios, the operational regimes of thermal plants can be captured and compared against the operation in 2012. While an increased penetration of variable generation will contribute significantly to the future operational requirements, other factors, including fuel price projections, carbon costs, plant mix and market design, will also have an impact. Detailed power market modelling using a variety of scenarios will allow for the operating regimes, in terms of ramping intensity, plant start-ups, time spent at minimum stable level and capacity factors, to be assessed. This study develops models to better understand how these characteristics affect the power system. Also, it provides recommendations as to how these issues can be moderated.

6.3 Methodology

This section describes the methodology and modelling approach. Section 6.3.1 describes this application of PLEXOS Integrated Energy Model and Section 6.3.2 describes the inputs to the 2012 reference model and the 2020 test model.

6.3.1 PLEXOS Model

In this study the PLEXOS Integrated Energy Model has been used (Energy Exemplar, 2015). An overview of the software is included in Section 3.2.5. Therefore, this section includes a brief description of the model and the set-up for this research.

PLEXOS is a power system modelling software that has been used in research globally (Deane et al., 2012a, Deane et al., 2012b, Foley et al., 2013a, Molyneaux et al., 2013). In this application, the model solves the unit commitment and economic dispatch problem, using either linear or mixed integer programming. The basic formulation of the unit commitment and economic dispatch problem is described in Appendix B. This study is concerned with analysing the operation of thermal power plants in future electricity systems and thus will require numerous technical constraints to be modelled. Modelling technical constraints, including; minimum stable levels, ramp rates and start costs introduces decision variables and integer programming is required to solve the problem. A number of solvers can be employed through PLEXOS to solve the equations; this study uses Xpress MP (provided by FICO) due to the high efficiency in solving mixed integer problems (FICO, 2015).

In this study the objective function minimizes the generation cost for a given load at a range of model resolutions. The objective function considers fuel costs, start costs and carbon costs and a number of environmental, policy, economic and technical constraints are included. In PLEXOS, power plants are modelled by the generator object class and defined by fuel type objects and technical data properties including; minimum stable levels, ramp up/down rates and minimum up/down times. In this study, minimum and maximum load constraints are also placed on nuclear power plants to replicate practical operation. Environmental constraints on hydro reservoir levels are simulated by assigning a maximum energy production per year (based on historical total hydro output data) and seasonal constraints on minimum and maximum generation to ensure that hydro generation is reasonable according to historic data. Pumped hydro plants are assigned upper and lower reservoirs and input information includes storage contents, initial content and minimum and maximum levels. The modelling approach taken requires that the upper reservoir level should be equal at the start and end of every chronological phase, in this case each day.

Output from wind and solar generation can be determined deterministically or by using stochastic methods in PLEXOS. In this study, wind was defined by a rated capacity and historic 30 minute wind output data files were obtained from ELEXON (2014). For the future scenarios, the rated capacity was increased to 22 or 26GW and for both the 2012 and 2020 models the wind data file was identical. While it is acknowledged that in 2020 the wind capacity may be more geographically aggregated, due to further development of the offshore wind resource, there will remain significant variability due to an increased wind capacity. Thus, while a different wind output file may change the values reported in the results section, the general trends remain the same and hence the conclusions remain unchanged. Solar PV was modelled using the same method to that of wind. Demand is defined by half hourly output data obtained from National Grid and is described in more detail in the next section.

PLEXOS solves the problem over a user defined planning horizon with a user defined chronological phase. A choice of 14 interval lengths (between one minute and 24 hours) can be selected and the step size within the chronological phase can be set. For example, defining a planning horizon of 1 year, with an interval length of 1 hour and synchronized chronological schedule of 365 daily steps will run 365 daily optimisations with a resolution of 1 hour. Deane et al. (2014) highlight the benefits of sub-hourly modelling when system flexibility is of interest. Given the interest in plant operating regimes and system flexibility, this study uses a 15 minute resolution.

Within this application, the model determines the maintenance schedule based on the maintenance rates and mean time to repair for each unit. The objective function of the maintenance scheduling formulation is to equalize the capacity reserves across all peak periods (Deane et al., 2012a).

The initial dataset in this study was developed by Deane et al. (2015). The data was updated and modified as described in Sections 6.3.2.1 and 6.3.2.2. The freely available dataset developed by Deane et al. (2015) includes technical power plant data, load profiles and projected renewable and interconnection capacities, all of which was obtained or derived from publically available sources. Deane et al. (2015) considered 7 countries in the North West region of Europe and the model was run over a range of scenarios, including a number of carbon price scenarios. Outputs from the models included, annual average shadow prices, country imports and exports, CO_2 emissions and total generation costs.

6.3.2 Model Descriptions

This study uses a scenario analysis to compare the operation of thermal power plants in 2012 and 2020. A 2012 base model has been developed and validated against actual data. Also, a 2020 test model was developed and this provides the platform to test a number of potential future power system scenarios where the fuel and carbon prices are varied and the generation mixes are different. This section provides the description of both models and the scenarios.

6.3.2.1 2012 Base Model

We initially developed a model of the 2012 GB power system and validated it against a number of data sources to ensure accuracy, including a full list of TEC (transmission entry capacity) (National Grid, 2014c). The total system capacity was approximately 80GW, including coal, biomass, OCGT (open-cycle gas turbines), CCGT (combined-cycle gas turbines), nuclear, wind and hydro power plants.[28] The total capacity by each plant type can be compared to that within Department of Energy & Climate Change (2013c). Further, the coal off take was limited to ensure that the generation from coal plants was not greater than that reported within Department of Energy & Climate Change (2013c). Each plant was defined by the heat rate; start cost, minimum up/down times, minimum/maximum ramp rates, forced outage rates and mean time to repair. This data was obtained from previous work completed by Deane et al. (2015). A list of the technical parameters is included within Appendix A, for a full description see Deane et al. (2015).

Current and future gas and coal price projections were obtained from Department of Energy & Climate Change (2013b). The fuel prices were input in £/GJ and where appropriate the International Energy Agency (IEA) unit converter and recommended exchange rate was used for conversion (International Energy Agency, 2014c, Department of Energy & Climate Change, 2013f). The carbon price used for the reference model was £5.8/tonne and was included to represent the EU ETS (European Union Emission Trading Scheme) prices for 2012 (Department of Energy & Climate Change, 2012f). The emission production rates, 103.86kgCO_2 e/GJ for coal and 56.77kgCO_2 e/GJ for gas, were obtained from Department of Energy & Climate Change (2012d).

The demand profile for 2012 was obtained from National Grid.[29] The profile was scaled to match the total GB demand reported in DUKES and the 2012 peak demand of 61.1GW as reported in National Grid (2013b).[30] To reduce the modelling complexity, interconnector flows were not included in the analysis. It is acknowledged that there are cross-border interconnectors from GB to France, Ireland and Netherlands, however developing a pan-European model was not within the scope of this study. In the future, increased interconnection and coupled markets may enable cross-border balancing; however, with a peak demand of 58GW+ and a potential wind

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[28] Solar PV was ignored in the reference model. In 2012, solar PV contributed less than 0.5% of the total electricity production in GB.

[29] The National Grid INDO (Initial Demand Out-turn Data) demand profile was used.

[30] The DUKES total demand value includes Northern Ireland (8TWh), net interconnector imports (12TWh) and pumping demand (4TWh). Thus, the value used for the 2012 model was calculated, 376 – 8 – 12 - 4 = 352TWh.

capacity of 30GW+ even if GB had 8GW+ of interconnectors, flexibility elsewhere in the system would be required. A more complete understanding of interconnector flows in future highly interconnected European power systems would require a pan-European power market model and this was considered to be out with the scope of this study.

6.3.2.2 Scenario Test Model

After validation of the 2012 model, a scenario test model was developed. The model is developed based the 2020 National Grid Future Energy Scenarios. The year 2020 is considered sufficiently close so that the generation mix tested is tangible, but there will be sufficient adaptation, such as the increase of variable renewable penetration and closure of a number of coal power stations, to gain an appreciation of the changing operational regimes and utilisation of thermal plants over time.

The total plant capacity modelled is 97GW, consisting of; 36.7GW CCGT, 13.7GW coal, 9GW nuclear, 2.8GW pumped storage, 5GW biomass, 1.6GW hydro, 6GW solar and 22GW wind. The initial model database was adapted to take into consideration the change in plant capacities. For example, a number of additional biomass units were added to the 2020 model database to account for the expected increase in biomass capacity between 2012 and 2020. Further, the CCGT's that have been decommissioned since 2012 were taken offline.

In the 2020 test model an annual demand of 334TWh was used, based on National Grid projections (National Grid, 2013b).[31] The high demand scenario uses an annual demand of 355TWh, based on the UK's NREAP (National Renewable Energy Action Plan) submission (European Commission, 2009).

Having developed a 2020 test model, a number of scenarios have been considered; based on National Grid Future Energy Scenarios. The capacity

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[31] As with the 2012 demand profile the difference between the reported National Grid annual electricity demand of 328TWh and DUKES demand (minus Ireland) of (368TWh) has been taken into consideration. Thus when using National Grid future energy scenario demands, 31TWh has been added to each scenario figures. The difference is due to the considerations of station load, pumping load, interconnector flows and embedded generation.

of pumped storage, nuclear and hydro remains constant across all of the scenarios. This was intentional as the operation and utilisation of thermal plants is the main focus of the paper and by altering only a few parameters general trends can be better understood.

The capacity factor of coal plants is limited to 60% in the scenarios. This assumption is to try and capture the impact of the Industrial Emissions Directive (IED). Under the IED, power plants are required to satisfy stringent emissions limits or close by the 31st December 2023 (Gross et al., 2014). Owners have three options, namely; Compliance, Limited Life Derogation (LLD) or Transitional National Plan (TNP). Full compliance may require retrofitting plants to meet the emission limits. Plants selected for LLD must close after 17,500 hours of operation from 1st December 2016, or close by 31st December 2023. TNP allows the decision over compliance to be delayed until 2020; however a descending emission production ceiling is placed on plants between 2016 and 2020. As plant owners to do not have to confirm their choices until January 2016, there is significant uncertainty around the UK coal capacity in 2020. Also, if many operators select the LLD option, plants will be limited in their hours of operation. It is for this reason that the coal capacity and maximum capacity factor assumption was varied across two of the scenarios.

The generation capacity in each scenario is listed in Table 6.1 and key parameters are shown in Table 6.2.[32] The four scenarios investigated are as follows:

- Scenario 1 (Slow Progression): Uses assumptions from the National Grid slow progression scenario for the year 2020.
- Scenario 2 (Low Coal Availability): Considers the implications of a greater demand than that used in scenario 1. This scenario also assumes a low maximum capacity factor of 25% for coal. Coal plants opting out of the IED (Industrial Emissions Directive) will have 17,500 running hours between 2016 and 2023 (European Commission,

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[32] Some of the values used are slightly different. For example, the Solar PV capacity in 2020 in the National Grid slow progression scenario is 3.4GW. In March 2013 the UK solar capacity was 1.9GW and therefore by 2020 will likely be greater than 3.4GW.

2015). This low capacity factor has been included to consider a scenario where opting-out coal plants have used a high proportion of their allocation prior to 2020 and therefore have lower availability.

- Scenario 3 (Low Gas Price): Considers a scenario with a high coal and low gas price. This scenario was included to understand how plant operating regimes would change if the marginal cost of electricity generation from gas was lower than from coal. The high coal and low gas prices were taken from Department of Energy & Climate Change (2013b) and were converted using the same method as discussed in Section 6.3.2.1.
- Scenario 4 (Reduced Coal Capacity): This scenario represents a reduced coal capacity and higher demand scenario, more likely to be seen around 2022/23 due to the closure of coal plants opting out of the IED. This loss is compensated by increasing gas, wind and solar capacity to 44.5GW, 26GW and 12GW, respectively. This scenario has been included to understand the longer term implications of a reduced coal capacity on the remaining plant in the system.

Finally, it is acknowledged that by 2020, there could be significant changes in the plant mix, beyond those analysed. However, the portfolios chosen are considered to reflect a plausible range of generation mixes and will provide a platform to complete the required analysis.

	2012	Scenario 1 (2020)	Scenario 2 (2020)	Scenario 3 (2020)	Scenario 4 (2020)
Gas	36.2	36.7	36.7	36.7	44.5
Coal	22.5	13.6	13.6	13.6	8.9
Wind	7.6	22	22	22	26
Solar	-	6	6	6	12
Nuclear	9.9	9	9	9	9
Pumped Storage	2.8	2.8	2.8	2.8	2.8
Hydro	1.6	1.6	1.6	1.6	1.6
Biomass	2	5	5	5	5

Table 6.1– Generation capacity (GW) in each of the four scenarios.

	2012	Scenario 1 (2020)	Scenario 2 (2020)	Scenario 3 (2020)	Scenario 4 (2020)
Maximum yearly load factor for Coal (%)	-	60	25	60	60
Carbon Price (£/tonne)	5.8	18	18	18	25
Gas Price (£/GJ)	5.82	6.99	6.99	4.00	6.99
Coal Price (£/GJ)	2.35	3.06	3.06	3.46	3.06
Demand (TWh/yr)	352	334	355	355	355

Table 6.2 – Selected parameters for each of the four scenarios.

6.4 Results and Discussion

Higher resolution models are required when flexibility of the system is of interest (Deane et al., 2014). For this reason the results presented in this section have all been produced using a resolution of 15 minutes and this was considered high enough to capture the trends in operational changes in thermal plant utilisation. In this section, power plant operating regimes in a number of 2020 scenarios will be compared to the operating regimes obtained from a validated 2012 model.

Table 6.3 compares the annual modelled output by generation type to the actual outputs from Department of Energy & Climate Change (2013c). As shown in Table 6.3, the modelled results are within reasonable tolerance to the actual outputs, as reported in Department of Energy & Climate Change (2013c). Differences in the results are due to a number of factors. For example, the DUKES figures contain the total demand for the UK, whereas this study is considering only the GB system. In the 2012 model, the gas plants are the marginal plant and due to relatively low coal and carbon prices, the average gas capacity factor was found to be very low as reported in Department of Energy & Climate Change (2013c).

	Base 2012 (GWh)	**Actual (GWh)**
Coal	143,153	143,181
Gas	97,099	100,073
Nuclear	70,396	70,405
Wind	19,748	19,580
Hydro	5,284	5,284
Biomass	15,721	15,198

Table 6.3 – Total generation output by plant type.

Table 6.4 provides some high level scenario results. As would be expected, scenario 3 (Low Gas Price), has the lowest total system costs, and this is due to the displacement of coal by gas, due to a low gas and high coal price. Coal, here acting often as the marginal generator, has a lower generation cost than gas in the other scenarios. In this scenario the emissions, both in terms of total production and intensity, are the lowest, again due to the displacement of highly polluting coal plant. Scenario 2 (Low Coal Availability) is the most expensive in terms of total costs. This is due to a low capacity factor constraint being placed on coal to simulate a scenario when coal plants have used a high proportion of their IED allocated operating allowance prior to 2020. Scenario 2 (Low Coal Availability) has a lower emission intensity than scenarios 1 (Slow Progression) and 4 (Reduced Coal Capacity) and this scenario highlights the benefit, in terms of emission reductions, in displacing coal with gas. Scenario 4 (Reduced Coal Capacity) is comparable to scenario 2 (Low Coal Availability) in terms of total system costs (start-up + generation costs) and emissions production but has the highest wholesale price. This is due to a reduced coal capacity. In all but the low gas price scenario, the average wholesale price rises, and this is due to the increase in carbon costs and higher fuel prices.

	2012	**Scenario 1 (2020)**	**Scenario 2 (2020)**	**Scenario 3 (2020)**	**Scenario 4 (2020)**
Total System Costs (£000)	10,019,291	10,954,027	12,646,888	8,849,804	12,245,973
Average Wholesale Price (£/MWh)	52.52	64.87	66.28	46.06	67.12
Emissions Production ($MTCO_2$)	176.15	110.15	95.95	80.84	98.83
Emissions Intensity (gCO_2/kWh)	500.43	329.79	270.28	227.72	278.39

Table 6.4 – Key cost, price and emissions values for each scenario.

In the next section the capacity factor, generation, ramping intensity and average number of start-ups will be compared for each of the scenarios to better understand the utilisation and operational regimes of thermal plants and pumped storage in potential future power systems.

6.4.1 Utilisation of Thermal Plant

Table 6.5 provides the total generation from each plant type under the four scenarios. As is expected, the coal generation in each of the scenarios decreases due to the plant closures between 2012 and 2016.

	2012 (GWh)	**Scenario 1 (GWh)**	**Scenario 2 (GWh)**	**Scenario 3 (GWh)**	**Scenario 4 (GWh)**
Coal	143,467	72,161	30,081	1,805	47,037
Gas	96,881	103,660	166,519	195,061	135,954
Nuclear	70,403	64,845	64,848	64,848	63,953
Wind	19,747	55,876	56,011	56,010	65,705
Hydro	5,281	5,286	5,289	5,290	5,281
Pumped Storage	1,786	1,607	1,596	2,382	1,975
Solar	-	4,993	4,993	4,993	9,986
Biomass	15,870	26,783	26,803	26,798	26,791

Table 6.5 –Generation output for each of the scenarios.

In scenario 1 (Slow Progression), the coal output remains relatively high, contributing to over 20% of the total demand in GB. In scenario 2 (Low Coal Availability), the coal output is significantly reduced due to a stricter capacity factor constraint being placed on coal plants. Coal has replaced gas as the marginal plant and experiences very low utilisation, due to a high coal price in scenario 3 (Low Gas Price). While coal experiences very low utilisation in this scenario, all of the coal power stations are still used and thus are required for system security; without them significant unserved energy would be expected. The fourth scenario simulates a system where further coal plants have been closed due to the IED, and in this scenario the capacity factor for the remaining four coal plants remained high but the total output falls, see Figure 6.1. In this scenario, coal supplies about 13% of the electricity in GB. It should be noted that the emission intensity of coal generation is about 1000gCO_2/kWh, therefore any significant contribution from coal, as seen in three of the four scenarios, will have significant implications for overall system emissions and carbon reduction targets, as shown in Table 6.4.

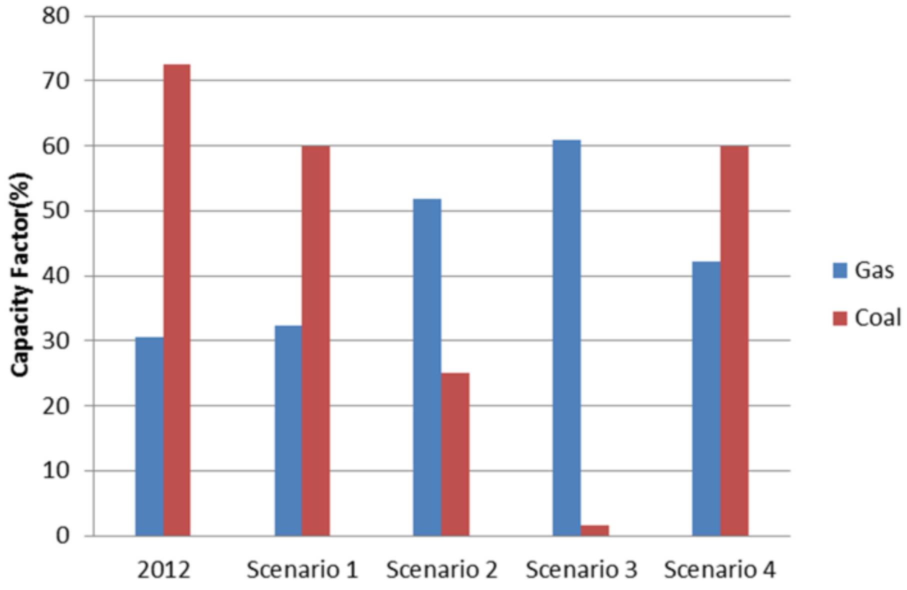

Figure 6.1 - Capacity factors of the gas and coal plant in each of the scenarios.

As expected, the hydro, biomass and nuclear generation remain similar in each of the scenarios, as discussed in Section 6.3.2.2. This was deliberate in order to isolate the effects of some constraints on the gas and coal operation. In three of the four scenarios, gas remains the marginal plant and for this reason the capacity factors for gas are significantly below that of coal in scenario 1 (Slow Progression) and 4 (Reduced Coal Capacity), see Figure 6.1. In each of the scenarios, the utilisation effects discussed in International Energy Agency (2014b) are apparent. While gas generation experiences an increase in output, the average capacity factor remains relatively low, with the exception of the Low Gas Price scenario, see Figure 6.1. These results follow the same general trends as discussed by Traber and Kemfert (2011), Forrest and MacGill (2013) and Di Cosmo and Malaguzzi Valeri (2014) who considered the impacts of increased wind on thermal plant utilisation in Germany, Australia and Ireland. These studies reported that average prices are reduced and the marginal generators displaced when variable renewable penetration increases.

The consequences of low plant utilisation are that revenue adequacy may not be sufficient to prevent mothballing or decommissioning. This study considers potential plant operation regimes and utilisation in future power system scenarios. However, further work is required to understand the revenue adequacy of infrequently used marginal plant under the current market conditions in GB. As discussed in Chapter 4 , a capacity expansion model should be developed to complete this research. Three of the scenarios consider a gas capacity of 36.7GW, but if gas plants are unprofitable then it is unlikely that new plants will be built. While explicit support for capacity provision may reduce this threat, moving towards such a system where plant is underutilised may be inefficient and long term questions will arise. This point is discussed further in the Section 4.4 and has formed the basis of the research undertaken in Chapter 7.

These results show that the current unfavourable market conditions for gas are expected to continue, unless a point is reached where the marginal cost of gas is lower than that of coal, or when the coal capacity decreases significantly. Relative to other systems around the world, GB can be labelled as a static power system with low load growth and short term infrastructure requirement. Therefore, with an increasing variable renewable capacity the transitional utilisation effect will be experienced until at least 2023 when further coal is decommissioned or converted, unless the cost of gas significantly decreases or the cost of coal increases. While in theory the existence of a significant carbon price would lead to an increase in the short run marginal cost of coal generation, the collapse of the EU ETS (European Union emissions trading scheme) and the decision to reform the carbon price floor in the UK, makes such a scenario unlikely in the short and medium term (HM Revenue & Customs, 2014).

6.4.2 Plant Cycling and Ramping

Variable renewable generation has been shown to increase the requirement for system balancing (Holttinen et al., 2011). While separate balancing markets and mechanisms were not included in the model, and increases in balancing requirements have not been quantified, some outputs can be extracted and analysed to gain an appreciation of how conventional plants will be required to operate in a number of future scenarios, where the requirement for balancing is greater.

The ramping up intensity is calculated by dividing the total sum of ramping up throughout the year for all plants in a category by the total ramping time for those plants (Deane et al., 2014). As shown in Figure 6.2, in all the scenarios the ramping intensity of gas plants increases. While the ramping intensity does not significantly increase in two of the scenarios, the total ramp and minutes spent ramping does increase. The reason for this is primarily due to the increase in variability introduced by wind and solar, with increases in periods where the output changes significantly. The largest variation occurs on the 14th of May with a wind output varying between 15.5GW at 0100 to 3.6GW at 2200. Also, there are over 300 occasions when the wind output varies by over 1GW between each hour.

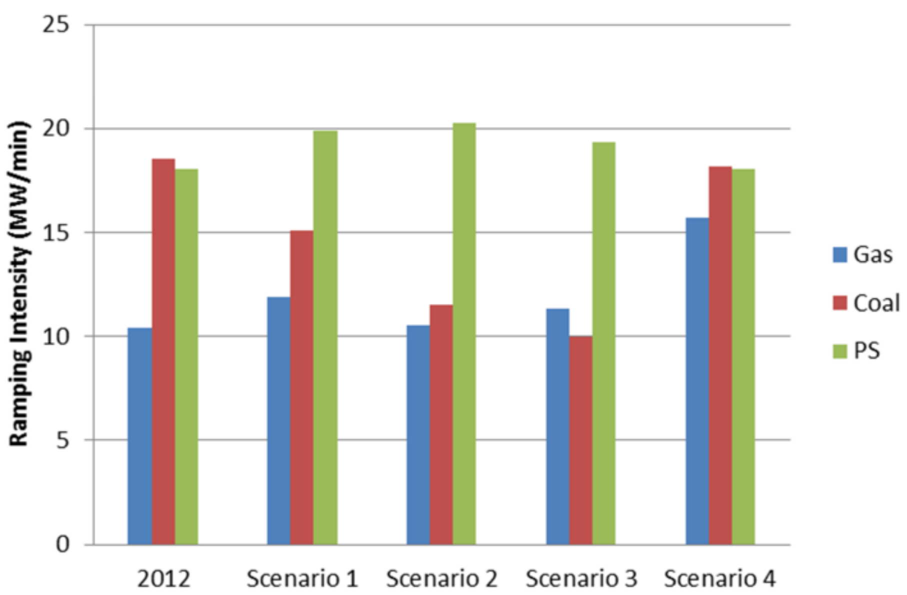

Figure 6.2 - Ramping intensity of gas, coal and pumped storage in each scenario.

In all four scenarios investigated, the ramping intensity of coal plants is seen to decrease; this is due to an increase in time spent offline and an increase in time spent operating at minimum stable level, as shown in Figure 6.3. In the 2012 model, coal plants stay online for a greater period of time, ramping throughout the day and night. In the 2020 scenarios, coal is constrained by reduced maximum capacity factors and thus is used more frequently in the winter, due to the higher demand. The increased time spent at minimum stable level will have consequent implications for the profitability of coal generation. Operators will have to ensure that coal plants are efficient at low output in order to generate maximum revenue.

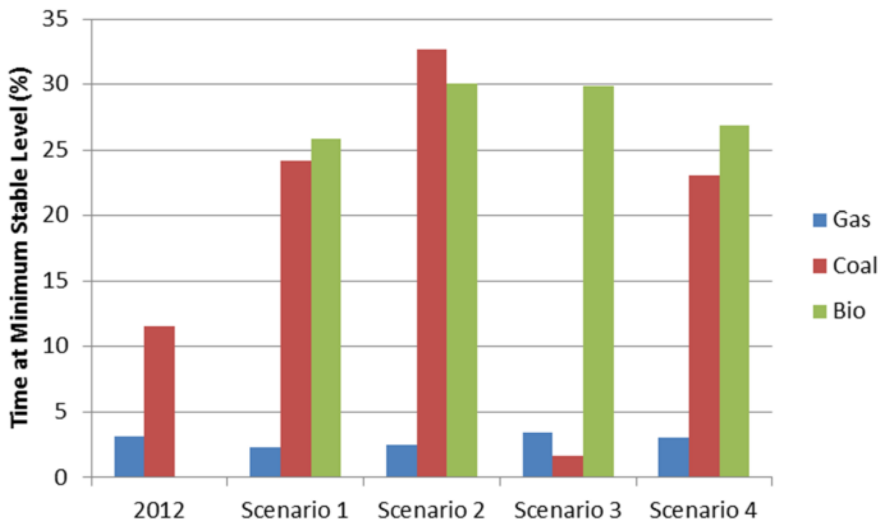

Figure 6.3 – Percentage of time spent at minimum stable level.

Figure 6.4 shows the average number of start-ups per year. This is the summation of the total number of starts for each plant type divided by the number of units for that plant type. For three of the four scenarios, coal plants experience a much greater number of start-ups in 2020. The number of gas start-ups reduces in three of the scenarios. This is due to the reduction in coal output, leading to an increase in the gas output.

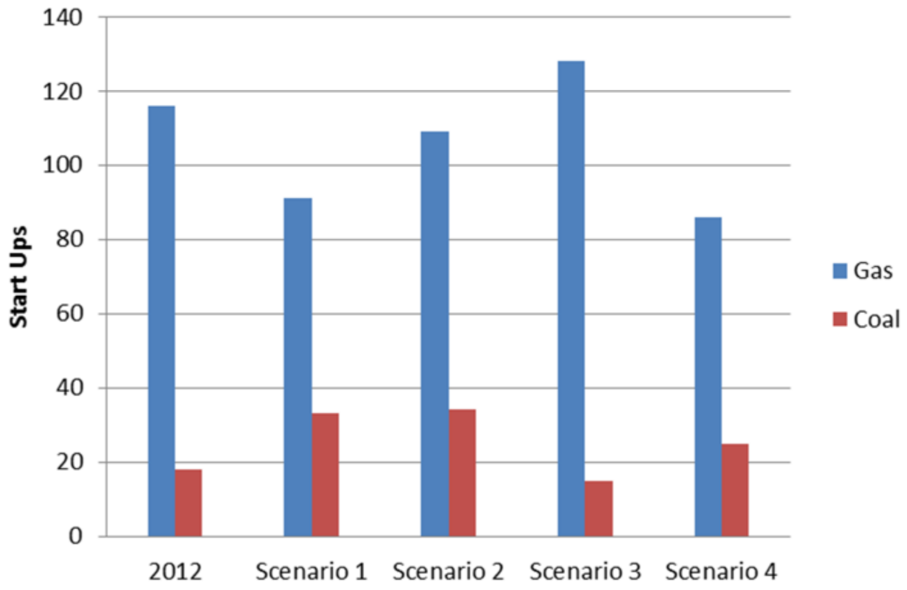

Figure 6.4 - Average annual start-up of gas and coal plants in each scenario.

The cycling and ramping results show that coal will be used differently in 2020. With an increase in the number of start-ups and an increased proportion of operating time spent at minimum stable level, operators will have to ensure plants are efficient and flexible enough to maximise profits. Pumped storage ramping is seen to increase, due to the additional balancing requirements as wind and solar penetration increases. In the scenarios considered, gas plants are used in much the same way with slight increases in ramping intensity in scenarios 1, 2 and 3 and a significant increase in scenario 4. Most concerning for gas plant owners is the low capacity factors and whether there is revenue adequacy, as discussed in Section 6.4.1.

It should be noted that this study only considered moderate wind penetrations of between 15 and 20%, as it is unlikely that the GB system will have a greater penetration by 2020. As a result, in the scenarios modelled, the utilisation of coal plants remains high and the increased cycling of coal units is mainly due to the enforced maximum capacity factor constraints, rather than the increased wind capacity. However, due to the low short run marginal costs, as variable renewable penetration increases beyond 20%, coal units will experience greater cycling under the current market arrangements. Also, as long as gas remains the marginal plant the utilisation will decrease as variable renewable penetration increases.

All power markets are different with unique generation mixes, demand profiles and market arrangements. Also, the aggregated output of variable generators will be dependent on many regional resource characteristics (International Energy Agency, 2014b). However, while the results from this study are not directly comparable to studies completed for other countries, the broad trends can be related.

Troy et al. (2010) present a comprehensive study of base load cycling in the Irish SEM with wind penetrations of up to 45%, reporting that CCGT units experience significant increases in start-stops and decreases in utilisation. Also, coal units experience increased part load operation and ramping. However, in this study, Ireland has a much greater penetration of wind, leading to the increased cycling of base load units. A wind penetration of 45% by 2020 was considered unrealistic for GB. However, the trends of decreased utilisation of gas units and increased part load operation of coal units are seen in both studies. Both studies highlight the importance of efficient operation at minimum stable level in future power systems with increase renewable penetration.

This study highlighted that utilisation of gas units may be low in future GB power systems with increasing wind penetration. These trends agree with studies by Traber and Kemfert (2011) and Di Cosmo and Malaguzzi Valeri (2014) where the German and Irish systems were studied, concluding that in systems with increasing wind penetration new gas unit investments may be unattractive. This will lead to a reduction in system security and the requirements for additional capacity provisions.

While this study is specific to GB, it is likely the results will be interest to other countries and regions that are increasing variable renewable energy penetration. Most concerning for power systems with increasing variable penetration is that plant flexibility is not incentivised sufficiently under the current market conditions. As variable penetration increases, greater plant flexibility will be required, not only by mid merit units but also by base load units (International Energy Agency, 2014b, Troy et al., 2010). Therefore, while provisions for capacity may be sufficient to increase system security, the flexibility required in systems with increasing wind penetration may not be brought forward.

6.5 Conclusion and Policy Implications

Legally binding legislation requires that the UK reduces GHG emissions by 80% on 1990 levels by 2050. Government interventions in the electricity market over the last decade have led to an increase in renewable generation. With the electricity market reforms and other interventions, renewable penetration is set to increase further, with the largest contributions coming from onshore wind, offshore wind and solar PV. However, there are concerns that the GB power system will not be able to absorb the level of variable renewable generation required to meet the decarbonisation targets, whilst retaining an affordable and secure electricity supply, due to the power system and market impacts associated with the properties of variable generation. This study was concerned with assessing the operating requirements of thermal plant in a variety of possible future power system scenarios. Particular attention was given to the utilisation, cycling and ramping requirements of thermal power plants.

Initially, a model of the 2012 GB power system was built using PLEXOS and validated against actual data. The validated 2012 model provided the platform to develop a 2020 test model for the analysis of a number of possible future electricity system scenarios. The results have shown, in all of the scenarios, that the average capacity factor of gas power plants is below 62% and in three of the four scenarios the average capacity factor is below 52%. However, in all of the scenarios considered, gas is vital to the security of supply in GB. With the unfavourable market conditions leading to low utilisation of gas plants, the requirement for significant government interventions to ensure that the plants have sufficient revenue and are not prematurely mothballed or decommissioned will likely be required.

In three of the scenarios, the gas utilisation remained low to moderate. Only in the high coal/low gas price scenario was the gas capacity factor above

60%. Also, in three scenarios the coal generation remains significant and while not considered in this study this will have significant implications for the decarbonisation targets. Three of the scenarios considered highlight the transitional utilisation effect, where gas has a low capacity factor and the ramping intensity increases, with gas remaining fundamental to the security of supply. The high coal/low gas price scenario highlights the persistent utilisation effect, which is expected beyond 2023 in GB due to the expected reduction in coal capacity and increased renewable capacity. In this scenario, gas utilisation is much greater at 61%, but again ramping intensity increases for gas and pumped storage generation, highlighting the importance of flexibility in future power systems and the requirement for a structural shift to more dispatchable plant.

In all of the scenarios considered, the pumped storage ramping intensity increases due to the high ramping capabilities and increased balancing requirements associated with increased variable renewable penetration. Also, in two of the scenarios, the pumped storage generation increases. While not the focus of this study, it is important to note that pumped storage, particularly those schemes located in Scotland, will have additional benefits beyond those considered in this paper. Future variable renewable generation will be deployed disproportionally across GB, with a high capacity expected in Scotland, a region with relatively low demand. In the event that increased grid reinforcements do not align with increased renewable capacity, grid constraints will become more prevalent. In this event, the ability to absorb loads through pumping will help to alleviate grid constraints and reduce curtailment.

This research has highlighted that dispatchable generation is vital for security of supply in all scenarios. Therefore, a market design that provides sufficient incentives for flexible generation to compete will be fundamental in the successful transition to a lower carbon, secure and affordable power system. It should be noted that this study has only considered 2020 and potential 2023 scenarios, beyond which the wind and solar, and potentially nuclear and biomass capacity, in GB is set to increase. With the potential for increasing interconnection capacity and lower cost imports, gas plants may be further underutilised. Reducing confidence in gas plant investment is likely to lead to further requirements for capacity payments and expensive government interventions. For these reasons, further work is required to understand how flexible power plant revenue adequacy can be achieved through more effective policy and efficient market design in the transition to a lower carbon power system.

7 Capacity Provisions and Market Requirements in Future Power Systems with Increased Variable Renewable Penetration

7.1 Introduction

Chapter 6 developed a power market model of the British power system using the PLEXOS Integrated Energy Model. The aim was to evaluate the impacts of an increased penetration of variable renewable generation on the operational regimes of thermal power plants in future British power systems. In three of the four scenarios considered, the capacity factor of gas was reported to be below 52%. However, in all of the scenarios considered, gas remained vital to security of supply. The low utilisation of marginal gas plants raised concerns over the profitability of firm capacity investment and ownership. If firm capacity is unprofitable, government interventions may be required to ensure that these plants remain operational. This section aims to address some of the further work recommendations from the previous chapter. A capacity expansion model of the British power system will be developed to analyse some key market characteristics during the transition to a system with increased variable renewable penetration.

Chapter 6 considered a detailed operational analysis of a number of plausible future power system scenarios. The approach used is similar to many renewable integration studies, where researchers develop a model of a future power system and simulate the operation of that system for that future year (McGarrigle et al., 2013). The outputs from the model can then be compared with the results from a validated model for a reference year. This approach is very useful for analysing specific characteristics, such as analysing the technical benefits of energy storage and electricity interconnectors (Edmunds et al., 2014), or quantifying the impacts of national renewable electricity ambitions in North-West Europe (Deane et al., 2015). However, a drawback of this approach is that it may fail to recognise how the system will develop through time, as a result of policies and measures to increase renewable penetration. For example, an analyst may assume a high level of dispatchable thermal capacity that is used only when renewable resources are not available. However, in reality, the plants may be prematurely mothballed, or even decommissioned, during the transition to the future power system if they are unprofitable. Corrective, and potentially expensive, government interventions may then be required to ensure that supply and demand can be continuously balanced. For this reason the development of a long term capacity expansion model to evaluate the key market characteristics, such as capacity shadow prices, during the transition to a lower carbon power system is recommended.

Capacity expansion modelling seeks to find the optimal combination of power generation new builds that minimizes the net present value (NPV) of the total costs of the system over a defined planning horizon, subject to defined constraints (Energy Exemplar, 2015). The objective function considers both the production and capital costs, with the optimiser seeking to minimise the combination of the two. Along with some key market characteristics, such as the capacity shadow price and long run marginal costs, the total costs of different scenarios can be compared. International Energy Agency (2014b) report that analysing the total costs may offer the greatest insights into the costs associated with the integration of variable renewable energy into power systems. For example, a low carbon scenario may have lower fuel costs but greater capital expenditure requirements than a business as usual scenario. By only considering one component of the total costs, such as the build, fuel, emission or reserve costs, the results may prove deceptive.

The structure of the chapter is as follows: Section 7.2 provides the background and context. Section 7.3 describes the modelling approach, describing the software used and development of the models. Section 7.4 provides the results and discussions and Section 7.5 provides some concluding remarks and policy implications.

7.2 Background and Context

Over the past decade, energy policy reforms around the world have been driven largely by the need to provide secure and lower carbon energy at the least cost to society. These wide ranging reforms have led to significant increases in variable renewable generation, with installed wind capacity rising from 59GW in 2005 to 318GW in 2013 (Global Wind Energy Council, 2015a, Global Wind Energy Council, 2006). Solar PV has also experienced significant growth, increasing from 5GW to 139GW over the same period (European Photovoltaic Industry Association, 2014). With the number of countries implementing renewable energy targets increasing from 48 in 2004 to 144 in 2014 and the intensifying awareness of the need to reduce greenhouse gas emissions, the growth trend in variable renewable generation is set to continue (REN21, 2014).

Integrating wind and solar generation into power systems and markets is not without its challenges, not least due to the variability and uncertainty of the resources. The variability and uncertainty of wind output can cause operational issues for balancing the electricity system, leading to an additional requirement for reserves (Holttinen et al., 2011, Holttinen et al., 2006). Also, the uncertainty of the wind resource can pose issues for the incumbent thermal plant, whose operators are often required to commit to operational regimes many hours before dispatch. As the wind output can only be accurately forecasted a few hours ahead of delivery, unit commitment may be changed at short notice, leading to the increased cycling of the plant. As Troy et al. (2010) state, additional cycling will incur significant costs.

Along with the operational issues, increased variable generation also significantly affects the power markets. As wind turbines generate electricity at very low marginal costs, they are amongst the first generators to be dispatched. Consequently, additional wind and solar generation will depress average wholesale prices, especially in systems where renewable generation is given priority and/or subsidies (Clò et al., 2015, Steggals et al., 2011, Traber and Kemfert, 2011). This is known as the merit order effect and will cause the existing marginal plant, often mid-merit gas, to be used increasingly intermittently (International Energy Agency, 2014b). During periods of high wind, the marginal plant may be forced offline and during times of low wind the same plant may be required to provide system security. In the absence of capacity provisions, this may lead to mothballing or premature decommissioning, as has been the case in many European states (International Energy Agency, 2014a). It should be noted that in liberalised power markets it is often not the role of the generation company to provide system security: a market design that does not attract firm capacity investments will see a significant reduction in generation adequacy, which in time will lead to the requirement for government intervention to ensure reliability.

While the insights reported from integration studies are often very similar, there tends to be great disparity between the reported numerical values. The extent to which increasing variable generation will impact on system operation is highly dependent on a number of system properties, including; balancing area size, generation portfolio, the correlation between demand and variable renewable supply, demand growth and infrastructure retirement (International Energy Agency, 2014b). Also, the extent to which variable generation impacts the market prices will be dependent on the market structure, trading arrangements and dispatch arrangements.

Many approaches to studying the impacts of increased variable renewable energy on power systems and markets have been developed. Connolly et al. (2010b) provide a review of some of the tools used for analysing the integration of renewable energy into energy systems, concluding that the type of tool used ought to depend on the impact to be assessed. To assess the impacts of increased renewable energy on power markets, mixed integer programming is often used to solve the unit commitment and economic dispatch (UCED) problem, subject to a number of technical and economic constraints (Deane et al., 2014).

Solving the UCED problem, many studies have compared a future power system for a given year, for example 2020 or 2030, and optimised the dispatch of the power plants over a year (McGarrigle et al., 2013). The results of the analysis can be compared to the results from a reference year. While this type of study is very useful in understanding some detailed operational characteristics of the power system, such as the requirement for increased reserves, a drawback is that they may fail to recognise the burden placed on incumbent plant, both operationally and financially, during the transitional period (i.e. the period between the present and the year to be studied). For example, researchers or analysts may assume a high level of dispatchable thermal capacity, in a future power system with a high level of variable renewable generation. However, in reality, these plants may be prematurely mothballed or even decommissioned during the transition period if they are unprofitable.

Understanding the issues during the transition period is increasingly important if the shift to a low carbon power system is to be technically and economically efficient. Also, support-scheme design informed by a greater understanding of the long term impacts of variable renewable generation may avoid the necessity for corrective government interventions. Government interventions have been considered a necessity in many of the countries that developed renewable energy policies in the early 2000's. For example, the depression of average wholesale prices in Europe, partly due to the merit order effect induced by renewable polices, has led to the requirement for capacity provisions (International Energy Agency, 2014a). With these points in mind, the aim of this chapter is to complete a variable generation integration study that provides insights into the development and operation of the power system and markets through the transition period.

To undertake this analysis, we use the PLEXOS Integrated Energy Model, developed by Energy Exemplar, to model the expansion of the Great Britain (GB) electricity system from 2015-2045 constrained by emission reduction targets and a security of supply standard (Energy Exemplar, 2015). We utilise recent improvements in computing performance, optimisation techniques and power market modelling software to better understand some key power market characteristics during the transition to a lower carbon power system. We compare the long run and short run marginal costs and evaluate the capacity shadow price required for all plants to recover costs, under a range of emission reduction scenarios. We aim to gain a greater understanding of the long term requirements for flexible and dispatchable capacity. Further, we compare the build costs, fuel costs, total costs and generation portfolio in each of the scenarios. Finally, based on the results, we provide insights into the requirements for policy to take a long term and holistic view when designing energy market interventions.

7.3 Modelling Approach

This section describes the modelling approach. Initially, the PLEXOS Integrated Energy Model that has been used for this study is introduced. Subsequently, some of the specific details of the GB expansion model and data requirements are described.

In this study, the PLEXOS Integrated Model has been used (Energy Exemplar, 2015). PLEXOS is a power market modelling software that has been used extensively in commercial and academic research globally (Deane et al., 2015, Molyneaux et al., 2013, Deane et al., 2012a). This study utilises the capacity expansion capabilities of PLEXOS. Capacity expansion modelling is concerned with finding the optimal combination of power generation new builds that minimizes the net present value (NPV) of the total costs of the system over a defined planning horizon, subject to a number of defined constraints. As such, the model decides the timing and size of new builds. The objective function considers both the capital and production costs, and the optimiser attempts to minimise the combination of the two. The basic formulation for the capacity expansion problem is described in Appendix B. The capital costs include the cost of generator new builds, which comprises: build costs, retirement costs and finance costs. The production costs relate to the cost of operating the existing set of generators and include; fuel costs, start-up costs and carbon costs. PLEXOS offers the choice of a number of different solvers, and this study has used FICO, due to the high efficiency in solving mixed integer problems (FICO, 2015).

7.3.1 GB Expansion Model Overview

The model requires a number of constraints to be defined to represent the realistic operation of the power system. For example, resource and environmental constraints on hydropower reservoirs are simulated by assigning a maximum energy production per year and seasonal constraints on the minimum and maximum generation to ensure that the generation is reasonable according to historic data. Pumped storage generators are assigned upper and lower reservoirs, defined by storage content, initial content and minimum and maximum levels. The modelling approach taken here requires that the upper reservoir level should be equal at the start and end of each phase, in this case each day.

Under the default capacity expansion settings in PLEXOS, capacity is only built if it is economically feasible, with the economic feasibility dependent on the trade-off between the cost of unserved energy and generation expansion costs. Even with a high value of loss load, up to £10,000/MWh, based only on this trade off, periods of unserved energy can be expected. As such, a hard constraint, in the form of a security standard, is required to ensure that unserved energy does not occur. In this study, the security standard limits the loss of load expectation to no greater than 3 hours per year, equal to a loss of load probability of 0.03%. This is the same reliability standard as set by the UK Secretary of State for Energy as part of the implementation of the Capacity Market from autumn 2018/19 (National Grid, 2014e).

In GB, National Grid is responsible for balancing the system and as such is required to procure a number of reserve services to continually match supply and demand. National Grid procures three types of supply side reserves; frequency, primary and (STOR) short term operating reserves (National Grid, 2014b). Modelling frequency response requires a temporal resolution that is exceptionally computationally intensive and as such is incompatible with a long term model. However, primary reserves and STOR are taken into account. In this model, the minimum reserves are based on a demand risk, namely 1.6% for primary reserves and 3.2% for STOR in 2012. The reserve requirement increases to 3% and 5.5% for primary and STOR respectively, beyond 2014, and this is in line with data from a National Grid report on operating the transmission system in 2020 (National Grid, 2011).

Output from wind and solar energy can be determined deterministically, or through using stochastic methods in PLEXOS, with the resolution defined by the user. Previous integration studies have used both methods, with the approach taken generally dependent on the focus of the study. In this study, wind was defined by a rated capacity and historic 30 minute wind output data for the years 2012 and 2013 were obtained from ELEXON (ELEXON, 2014). Typically, these present-day capacity factors are applied to the different expanded wind capacities in the modelled scenarios. A complexity not directly captured in such an approach is the expected fall in variability and volatility arising from wider geographical disaggregation. To take this into account, we apply scaling factors to the wind output time series. Using this approach, the annual capacity factor of the potential offshore and onshore wind farms is between 30-37% and 26-31%, respectively, dependent on whether the 2012 or 2013 profile is used. This is considered to be a sufficient range to consider years with both high and low yields from wind generation. The approach used to define solar was similar, with the data obtained from the Bright Solar Resource Model, for a full description see Bright et al. (2015). The output time series corresponds to a capacity factor of 10%, in-line with the realised capacity factor for the year 2013 (Department of Energy & Climate Change, 2014b).

Within this application, the model determines the maintenance schedule based on the maintenance rates and mean time to repair for each unit. The objective function of the maintenance scheduling formulation is to equalize the capacity reserves across all peak periods (Deane et al., 2012a).

Expected commissioning and decommissioning closure dates for all power plants in GB have been listed within the model, with data obtained from a range of sources, including National Grid’s Transmission Entry Capacity register (National Grid, 2014c). A full list of expansion candidates has been defined based on the plant types listed within reports commissioned by the Department of Energy and Climate Change (DECC) on the cost of electricity generation (Department of Energy & Climate Change, 2013d).

Expansion candidates are defined by maximum capacity, minimum stable levels, heat rates, variable operation and maintenance charges, fixed operation and maintenance charges, start costs, ramp up/down rates, minimum up/down times, maintenance rates, forced outage rates, mean time to repair, build costs, technical life and economic life. Power plants that are currently under construction are not listed with expansion candidates as they are almost guaranteed to be commissioned.[33]

The size of the optimisation step is an important simulation consideration for capacity expansion models as accurate investments decisions require a certain level of foresight. A single optimisation, spanning the whole planning horizon is ideal, but computationally intensive. A model with a 20 year planning horizon, solved with 1 single step and full chronology may contain over 500 million non-zeros, rendering the problem unsolvable on most desktop PC's. Further, due to the integer nature of build decisions, mixed integer programming is required to solve the problem. The problem size can be reduced by increasing the number of steps and/or reducing the chronological detail of the problem. There are two methodologies commonly used for representing the data series in the optimisation problem. Load duration curves (LDC's) can be formed for each day/week/month year with the user defining the number of blocks in each LDC. As an alternative to LDC's, the input data series can be fitted with a step function using the least-squares technique.

In this study, we use the traditional load duration curve approach with a resolution of 24 blocks per month. Recent studies have reported the benefits of using the fitted approach. For example, see Wartsila and Energy Exemplar (2014) and Nweke et al. (2012). However, we are concerned with capacity requirements and long term pricing results, rather than the dispatch and operational requirements. Thus, the LDC approach is considered appropriate for this study. While the use of the fitted approach may lead to slight difference in the generation portfolio, the insights drawn from the key

[33] Power plants that are under construction are defined by the same technical data as the existing plants and are assigned a commissioning date.

outputs, including capacity shadow prices, long run marginal costs and short run marginal costs would be expected to be similar.

7.3.1.1 GB Expansion Model Data

The power plant list used in the model was obtained from the Digest of United Kingdom Energy Statistics (Department of Energy & Climate Change, 2014a). We have updated the dataset so that the base year, 2015, consisted of 10GW onshore wind, 4.5GW offshore wind, 3.3GW biomass (co-firing and dedicated), 36GW gas, 18.8GW coal, 9.5GW nuclear, 2.7GW pumped storage, 1.6GW hydro and 5GW solar. Each thermal plant was defined by heat rates; start cost, minimum up/down times, minimum/maximum ramp rates, firm capacity, forced outage rates and mean time to repair. Deane et al. (2015) developed a comprehensive open source database of the technical characteristics of over 1000 power stations in North West Europe. As with Chapter 6, the technical parameters provided by Deane et al. (2015) have been used for this research.

Fuel and carbon price projections were obtained from DECC and units were converted where appropriate using an IEA unit converter and DECC's recommended exchange rates (International Energy Agency, 2014c, Department of Energy & Climate Change, 2013b, Department of Energy & Climate Change, 2013e). Emission production rates for each fuel class were obtained from Department of Energy & Climate Change (2012d). As with the fuel and carbon price assumptions, the central emission cost assumptions were used for this study. Table 7.1 shows the capacity expansion candidates used in the analysis. Data, including; build costs, FO&M costs, VO&M costs, was obtained from DECC (Department of Energy & Climate Change, 2013d). In this study we use a discount rate of 8%. This value is within the typical range used when modelling future energy scenarios (Pollitt and Billington, 2015).

	Build Cost (£/kW)			**Fixed O&M (£/kW/year)**	**VO&M (£/MWh)**
	Low	Central	High		
Biomass	2015	2430	4540	94.4	5.0
Biomass CCS	-	3663	-	96.0	4.0
Biomass Conversion	360	460	760	41.0	3.0
CCGT	505	610	725	22.0	0.1
Coal CCS	2020	2225	2545	56.9	2.0
Gas CCS	1125	1330	1545	25.0	2.0
Nuclear	3810	4320	5070	72.0	3.0
OCGT	220	320	330	9.9	0.1
Pumped Storage	-	3655	-	24.9	8.0
Solar PV	800	900	-	21.9	(included in O&M)
Offshore Wind	1950	2370	2820	54.5	2.0
Onshore Wind	1130	1500	1940	37.1	5.0

Table 7.1 – Expansion candidates and costs.

An important property of each plant is the firm capacity. This parameter refers to the amount of MW capacity that each of the generator units contribute to the capacity reserve margin. De-rating factors, shown in Table 7.2, were obtained from Office of Gas and Electricity Markets, the industry regulator, and these were multiplied by the generation capacity to determine the firm capacity of each unit (Office of Gas and Electricity Markets, 2013).

Expansion Candidates	De-rating factor
Biomass CCS	0.85
Biomass Conversion	0.85
Dedicated Biomass	0.85
Combined Cycle Gas Turbine (CCGT)	0.87
Coal CCS	0.88
Gas CCS	0.87
Open Cycle Gas Turbine (OCGT)	0.94
Nuclear	0.81
Pumped Storage	0.94
Solar PV	0.00
Onshore Wind	0.09 – 0.05[34]
Offshore Wind	0.12 – 0.06

Table 7.2 – De-rating factors for expansion candidates.

The GB electricity demand profile for 2012 was obtained from National Grid (National Grid, 2014a). The profile was scaled to the year 2035 to match total annual electricity demand in National Grid 's gone green future energy scenario (National Grid, 2014d). To reduce modelling complexity, demand was taken net of interconnector flows. It is recognised that interconnectors may have an increasing role in the balancing of electricity supply and demand in GB and this can be considered to be a caveat of this work. Also, it is recognised that interconnection capacity is increasing with proposed new connections to Denmark, France and Norway (National Grid, 2013a). However, with a peak demand of 61GW, and total generation capacity of over 90GW, it is unlikely that interconnection will account for more than 15% of capacity and 15% of demand for much of the planning horizon considered in this study. Further work may consider the expansion of the entire North-West Europe power system; however, this was out of the scope of this research.

[34] The de-rating factor for both onshore and offshore wind decreases as capacity increases, due to the saturation effect.

Under legally binding legislation, the UK is required to reduce emission by 80% on 1990 levels by 2050. Therefore, we analyse a number of power system emission reductions scenarios. We consider emission reductions targets of 60, 70 and 80% on 1990 levels by 2030. Further, we also include a “no target 2030”. This represents a scenario where no emission reduction target is set beyond 2020.

7.4 Results and Discussion

Results have been obtained for three emission reduction scenarios and a no target scenario. It is important to clarify that the scope of this research is exploratory rather than predictive and as such we do not aim to predict or suggest the optimal pathway for the decarbonisation of the GB electricity system. We aim to provide insights into the potential development of the system and markets during a transitional period to a lower carbon electricity system. Further, as the modelling approach, assumptions and data are different, it is challenging to directly compare the results from this work to other studies. However, as Ekins et al. (2013) reports, different modelling approaches can mean that the general trends reported from a range of studies are likely to be robust. Therefore, general modelling trends are discussed and compared where appropriate.

7.4.1 Generation Portfolios and Build Costs

Table 7.3 and Table 7.4 show the installed generation capacity for each of the scenarios in the years 2025 and 2035. Most of the current thermal generation mix in GB is forecast to be decommissioned over the period 2015-2025. Over 7.5GW of nuclear capacity is expected to shut down in the early 2020’s and due to the Industrial Emissions Directive (IED), most of the coal plants may be decommissioned, converted to biomass or retrofitted (World Nuclear Association, 2015). National Grid also reports a reduced coal and nuclear capacity, for the year 2025, within the future energy scenarios analysis (National Grid, 2014d). The nuclear capacity is below 6.4GW in three of the four scenarios reported by National Grid. Only the ‘gone green’ scenario has a greater installed nuclear capacity at 10.4GW. Further, the coal capacity is reported to be below 5.9GW in each of the scenarios considered in the year 2025.

Only 5GW of the gas capacity that is operational in 2015 remains online in 2035. Therefore, most of the capacity built in the no target scenario, replaces the existing capacity. Thus, even in a no emission reduction target scenario, there will be a requirement for a high level of capital investment in new plants. In the no target scenario, decommissioned coal and nuclear plants are replaced largely by new CCGT’s and OCGTS’s. In addition, over 22GW of wind is installed by 2035. This may be greater than would be expected; however, it should be recognised that the installed wind capacity is currently 12GW, with a further 2.5GW under construction (RenewableUK, 2015). Further, over 16GW of capacity has been consented (RenewableUK, 2015). While large wind farms in GB are subject to a lengthy planning process and complex financial arrangements, it is highly likely that both the onshore and offshore wind capacity in GB continues to increase over at least the next 5 years. Scenarios reported by National Grid also indicate significant increases in wind capacity through the 2020’s and 2030’s (National Grid, 2014d).

It should be noted that in all of the scenarios investigated, there is no installed coal capacity in 2035. In GB, under the emissions performance standard, no capacity with an emissions rate of greater than 450gCO_2/kWh should be built (Department of Energy & Climate Change, 2012a). Further, many of the coal plants are converted to biomass between 2016 and 2023 within the more stringent emission reduction scenarios. Converting to biomass may offer significant carbon reductions compared to coal. However, the lifetime of biomass conversions is set to 10 years and as such converted plants will be decommissioned before 2035, thus they are not shown in Table 7.4.

	No Target	**60% Reduction**	**70% Reduction**	**80% Reduction**
Biomass	3.3	3.3	3.3	3.3
Biomass Conversion	0.0	0.0	4.0	4.0
Gas CCGT	59.0	59.0	54.5	55.1
Gas OCGT	7.0	7.0	7.0	7.0
Coal	2.6	2.6	2.6	2.6
Gas CCS	0.0	0.4	0.0	0.0
Coal CCS	0.0	0.0	0.0	0.0
Nuclear	2.3	3.9	2.3	2.3
Pumped Storage	2.8	3.6	3.6	2.8
Hydro	1.6	1.6	1.6	1.6
Onshore Wind	20.3	20.3	20.0	20.0
Offshore Wind	8.0	8.0	8.3	19.4
Solar	6.5	6.5	6.5	6.5
Total	***113.4***	***116.2***	***113.7***	***124.5***

Table 7.3 – Generation mix in 2025 (GW).

	No Target	**60% Reduction**	**70% Reduction**	**80% Reduction**
Biomass	2.0	2.0	2.0	2.8
Gas CCGT	59.0	59.0	53.9	53.3
Gas OCGT	7.0	7.0	7.0	7.0
Coal	0.0	0.0	0.0	0.0
Gas CCS	0.0	0.4	0.0	0.0
Coal CCS	0.0	4.6	0.0	0.0
Nuclear	12.8	8.0	16.0	16.0
Pumped Storage	3.6	3.6	3.6	3.6
Hydro	1.6	1.6	1.6	1.6
Onshore Wind	26.0	26.0	26.0	26.0
Offshore Wind	8.0	8.0	8.3	22.2
Solar	6.5	6.5	6.5	6.5
Total	***126.5***	***126.7***	***124.9***	***138.9***

Table 7.4 – Generation mix in 2035 (GW).

The total installed capacity in the “no target” scenario is significantly lower than that of the 80% reduction target scenario. This is due to the high de-rating factors associated with wind power. The contribution to the security constraints from variable renewable generation is low; however, these technologies do not generate emissions and as such are required to satisfy the more stringent emission reduction targets.

Comparing the results of the three emission reduction scenarios offers some valuable insights. Firstly, that gas capacity remains highly valuable to the system. Despite an increasing carbon price, new gas CCGTs continue to be built throughout the planning horizon. In each of the scenarios considered, new unabated CCGT’s operated at low capacity factors is considered a low cost option compared to renewable and other low carbon technologies. Another key insight is the increasing importance of nuclear generation. With a low de-rating factor; nuclear generation contributes significantly to both the security and emission reduction constraints. The nuclear expansion trends here are comparable to many future energy scenarios in the UK, for example the central coordination and market rules reported by Foxon (2013). For a detailed comparison of UK future energy scenarios, see Ekins et al. (2013) and for a detailed comparison of UK future electricity system scenarios, see Barton et al. (2013). Nuclear capacity decreases in the short to medium term, due to the decommissioning of existing plant and the long development time of new plant. However, capacity increases in the long term. Across all emission reduction scenarios, a significant capacity of onshore wind is installed. Of the three variable renewable technologies, onshore wind has the lowest costs and a non-zero contribution to the system security constraint.

In three of the four scenarios, neither gas CCS or coal CCS is deployed. This is due to the relatively relaxed maximum build constraint on gas CCGT's. The maximum build constraint on gas CCGT's was set relatively high, at 54GW, to give the model the flexibility to optimise investment subject mainly to the emission and system security constraints. By including restrictive and frequently binding constraints on capacity deployment, significant uncertainty would be added to the model. Further, it should be noted that this study is exploratory rather than predictive and the main purpose is not to suggest an appropriate pathway for decarbonisation. If the maximum build constraint on CCGT and OCGT was reduced, then a larger capacity of firm low carbon generation would be expected. Indeed, this is the case in the 60% emission reduction scenario, where the CCGT and OCGT constraints are binding and a significant deployment of coal CCS is realised. It is due to the relatively unrestrictive constraint on CCGT deployment that the unabated gas capacity reported in this analysis is greater, and the CCS capacity lower, than in some future energy scenarios. For example, those reported by National Grid (2014d).

Valuable insights can be drawn by comparing the build costs, fossil fuel costs and total costs in each of the scenarios. Figure 7.1 shows the difference in cumulative build costs for each of the emission reduction scenarios. As expected, the 80% scenario has the greatest build costs, due to a significantly increased system capacity to satisfy both the emission and security constraints. This scenario requires a high installed gas capacity to satisfy the security margin. Also, a large installed capacity of variable renewable generation, nuclear and biomass is required to achieve the emission reduction targets. Interestingly, the cumulative build costs for three scenarios are broadly similar; this is due to the large requirement for investment due to plant closures through the 2020's and 2030's.

An important insight from Figure 7.2 and Figure 7.3 is that fuel costs contribute a greater proportion to the total costs than the build costs. Here, total costs include fuel costs, emission costs, fixed costs, variable costs and annualized build costs. The International Energy Agency (2014b) advise that total costs may offer the greatest insights into the costs associated with the integration of variable renewable energy into power systems. If we only consider one component of the total costs, such as the build, fuel, emission or reserve costs, the results may prove deceptive. For example, the build costs required to satisfy the 80% reduction constraint are almost 30% greater than the no target scenario. However, the fuel costs in the 80% scenario are almost 25% lower than the no target scenario. Overall, when considering the total costs, the costs to achieve an 80% reduction are only 19% greater than the costs of a no target scenario. The costs associated with the 60% and 70% reduction scenarios are only 2% and 6%, respectively, greater than the no target scenario.

It is important to note that all four scenarios include a carbon price. The cumulative total cost of the no target scenario was reduced to £505Bn when the carbon price was removed. In this case, the total costs, for the period 2015-2045, are 38% lower than the 80% reduction scenario. Significantly, this is also 26% lower than the original no target scenario. However, with the current European Union energy and climate strategy, it is considered highly unlikely that emission reduction targets and emission allowances and caps will be removed over the next few years (da Graça Carvalho, 2012).

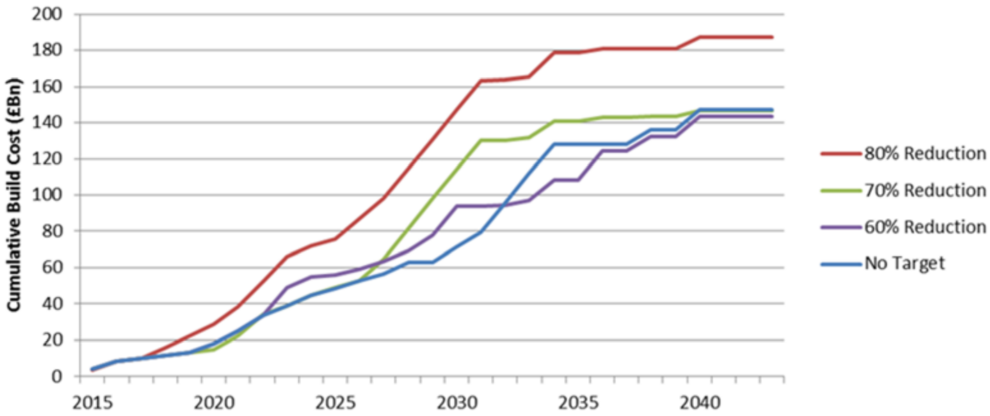

Figure 7.1– Cumulative build costs until 2045.

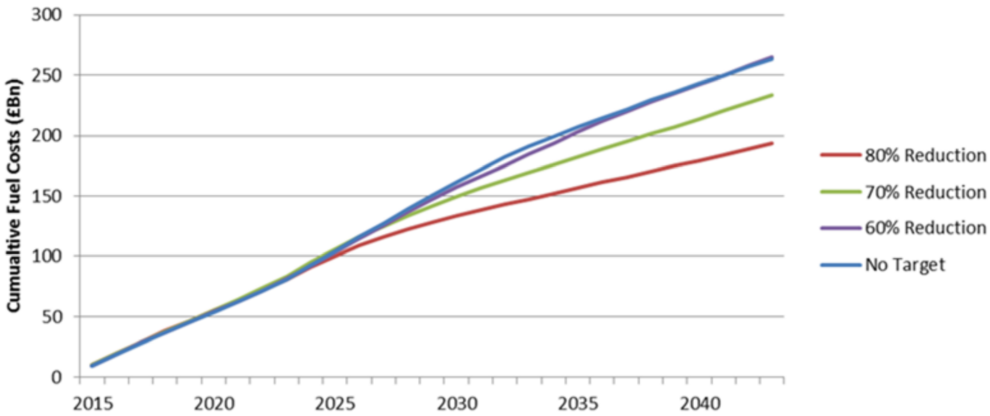

Figure 7.2 - Cumulative fuel costs until 2045.

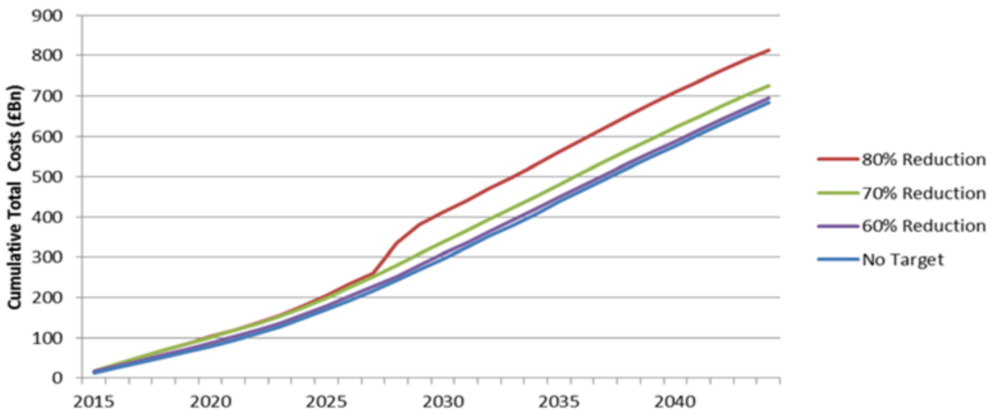

Figure 7.3– Cumulative total costs until 2045.

As discussed in the methodology section, the objective of the capacity expansion problem is to minimise the combination of the capital and production costs. Therefore, it should be noted that the results are a function of not only the capital costs, emission reduction constraints and security constraints but also system production constraints, such as required reserve margins. Further, this study considers the development of a capacity expansion model that is capable of providing insights into the important policy considerations for power systems with increasing variable renewable penetration. Therefore, the study is exploratory rather than predictive. Clearly, the sensitivity of many input assumptions would have to be assessed to attempt to predict the future development of the British power system; these assumptions include build costs, emission reduction scenarios, carbon costs, fuel price assumptions, technology learning rates, finance costs. However, this is not the within the scope of this work.

7.4.2 Long Term Pricing Trends

The previous sections offered some insight into the generation portfolio and total costs required to meet the emission reduction scenarios. However, a key ambition of this chapter is to understand the value of flexible and firm capacity in future power systems with increasing variable renewable penetration. In this section, we consider the costs associated with capacity provision and the long run costs in each of the scenarios.

Across much of Europe, the increasing penetration of variable renewable generation has caused the depression of average wholesale prices, leading to unfavourable conditions for mid-merit plants in many power systems. Over time, these conditions have led utilities to mothball or prematurely decommission these plants. As in many liberalised markets, generator companies do not have the responsibility of providing system security; the decision to retire plants from the energy market has reduced security margins in many systems. This market failure has forced governments to intervene. In GB, as part of the electricity market reforms, a capacity mechanism has been designed to provide remuneration for generators that can provide firm capacity (Department of Energy & Climate Change, 2012a).

As we are concerned with understanding how the value of firm capacity may change in systems with increasing variable renewable penetration, we report the capacity shadow price in each of the systems. The capacity shadow price is the incremental cost to the system of adding the last unit of capacity. Thus, the value represents the capacity revenue (£/kW/year) in addition to that from the energy market that is required for a positive expected NPV for added generation capacity.

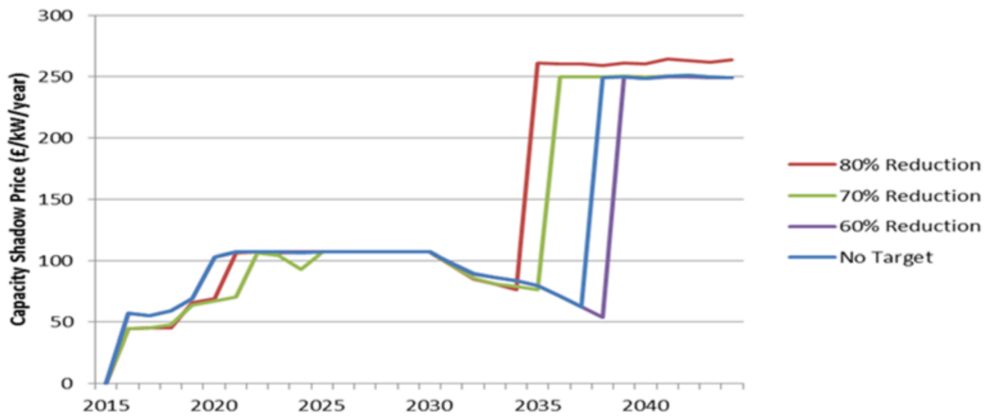

Figure 7.4 – Capacity shadow price (£/kW/year) until 2045.

Figure 7.4 shows the capacity shadow price in each year for each of the four scenarios. As expected, the capacity shadow price is above zero in all years after 2015. Based only on short-run marginal pricing, where there is no mark-up, generation capacity with the largest short run marginal cost (SRMC) will always fail to recover fixed costs. Further, depending on the form of the price duration curve, mid merit generation, may also fail to recover fixed costs. Figure 7.4 shows that in all of the scenarios the capacity shadow price increases significantly between 2015 and 2023. The price then plateaus throughout the 2020’s and the early 2030’s.

The increase in the capacity shadow price between 2015 and 2023 is due to both the rise in annualised build costs and the reduced utilisation of firm generation capacity, as shown in Figure 7.5. Thus, the pool revenue per unit of CCGT capacity decreases, while the annualised build cost increases. To compensate for the reduced pool revenue a higher capacity shadow price is required to ensure that the CCGT’s recovers costs. Figure 7.4 shows that at various points in the 2030’s the capacity shadow price increases significantly in each of the scenarios. This is due to a shift in the marginal investment from gas to nuclear. To satisfy both the security and emission reduction constraints beyond 2030, the capacity shadow price required to make the marginal investment break even, is in excess of £245/kW/yr.

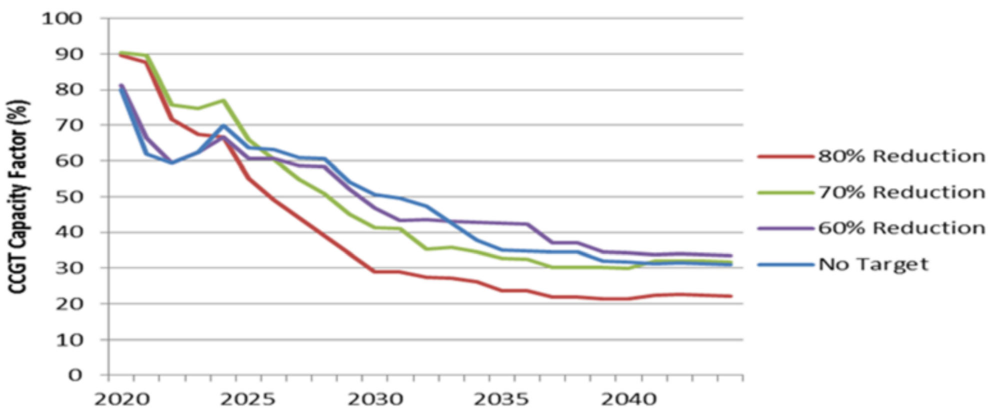

Figure 7.5 - New CCGT average annual capacity factor until 2045.

Figure 7.4 illustrates one of the fundamental policy and market issues that must be addressed if the transition to a power system with increased variable renewable generation is to be achieved cost-effectively. It is well documented that future power systems will require additional supply and demand side flexibility, see International Energy Agency (2014b). However, while each of the scenarios analysed do have an increase in flexible generation, they also have an increase in baseload capacity. With high annualised costs, new baseload nuclear capacity recovers insufficient revenue from the pool and thus sets a very high capacity shadow price to ensure all costs are recovered. From a policy perspective, this implies that, with current technologies, future power markets will require both capacity and energy markets.

Another metric for understanding the long term pricing trends is the long run marginal cost. The long run marginal cost (LRMC) represents the full cost of serving the load for the system, taking into consideration the cost of expansion as well as the cost of production. The cost is calculated by dividing the sum of the generator pool revenue and capacity payments by the system load. The capacity payments are calculated by multiplying the capacity shadow price by the firm capacity.

Table 7.5 shows that the LRMC increases at a much higher rate in each of the scenarios than the SRMC. The LRMC is expected to increase due to the rising annualised costs associated with new capacity. However, the increase in SRMC is limited to the increased costs associated with the fossil fuel and carbon prices. The increasing divergence between the SRMC and LRMC once again highlights that firm generation is unlikely to recover costs from energy only markets.

	No Target		80% Reduction		70% Reduction		60% Reduction	
	SRMC	**LRMC**	**SRMC**	**LRMC**	**SRMC**	**LRMC**	**SRMC**	**LRMC**
2020	53	72	64	77	64	76	57	76
2025	61	81	75	95	72	92	61	81
2030	73	94	76	97	75	96	74	95
2035	74	90	72	123	73	88	74	90
2040	74	122	72	123	73	122	74	124

Table 7.5 – SRMC and LRMC at 5 year intervals until 2040.

It is also interesting to report the levelized total costs, calculated by dividing the total costs by the total load. The levelized costs reported here represent a least levelized cost and thus do not take into account the capacity payments that are required to ensure that new investments recover costs. As shown in Figure 7.6, in each of the scenarios, the levelized costs increase due to the additional investment required to replace decommissioning plant and to satisfy both the emission reduction and security constraints. It is noted that there is a large divergence between the LRMC and levelized costs in the 2030's.

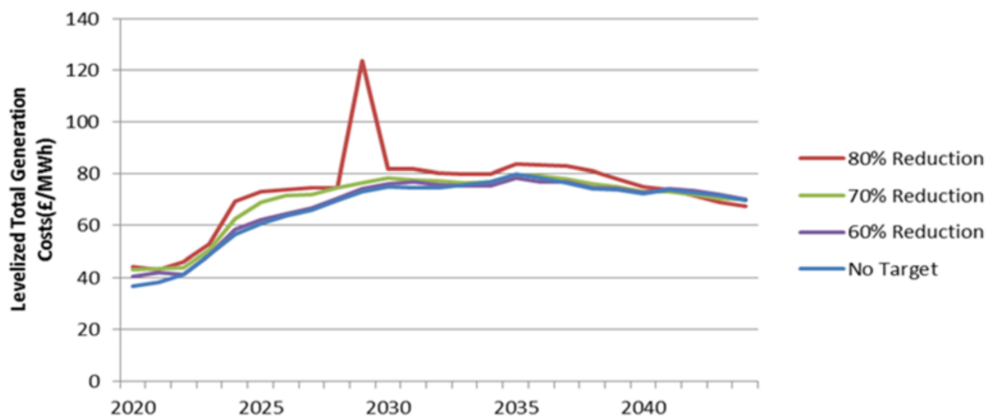

Figure 7.6 – Levelized total costs (£/MWh) until 2045.

The divergence between the LRMC and levelized costs in the 2030's is due to the very high capacity shadow prices required to ensure that new nuclear plants recover all costs. Also, as all plants receive capacity payments according to the capacity shadow price and contribution to firm capacity, new CCGT's receive payments far in excess of those required to recover costs.

It is important to recognise that new nuclear will only likely be built in Britain if the developers are offered a long term contract. The current contract offer for a new nuclear plant at Hinckley Point C includes a strike price of between £89.50 and £92.50/MWh for a 35 year period (Department of Energy & Climate Change, 2014c). Under the current and proposed arrangements, it is unlikely that new nuclear would be allowed to participate in capacity markets during the contract period. If this was taken into consideration in the model, new gas CCGT's would continue to set the capacity shadow price and overall capacity payments would reduce. In this case, the LRMC would tend back towards the levelized costs. However, further work, and the development of expansion models that account for strategic company behaviour, risk and market design would be required to provide a stronger view of the optimal market design for systems with increasing renewable penetration.

7.5 Conclusions and Policy Implications

Over the past two decades, variable renewable penetration has increased markedly in many power systems around the world. Many policy makers have focussed on the deployment of renewables in isolation, rather than the transformation of the entire power system. Energy policies have often failed to account for the impact that variable renewable generation will have on the incumbent thermal power plants. In regions with low load growth and short term infrastructure requirements, such as much of Europe, this will lead to the reduction in utilisation of mid-merit thermal plants. The reduction in utilisation has contributed to the reduced profitability of plants. These challenging conditions have led to many companies taking commercial decisions to mothball or prematurely decommission these plants. As mid-merit generators, often CCGT's, have high firm capacities they contribute significantly to system security. With reduced utilisation and increased mothballing, over time, system security is expected to decrease.

This research has centred on understanding the long term implications of increased variable renewable generation on the development of power systems and markets. To achieve the objectives, a capacity expansion model of the British power system was developed using the PLEXOS Integrated Energy Model. The model optimised the expansion of the GB power system over a 30 year planning horizon, from the year 2015-2045. Four scenarios, including a "no target scenario", were analysed.

The study provided a number of valuable insights into plausible future generation mixes and timing of investments. Within each of the four scenarios, CCGT's play a critical role in providing firm and dispatchable capacity to the system. Most of the nuclear reactors in GB are scheduled for decommissioning in the early 2020's and due to the Industrial Emissions Directive, most of the coal plants will be either decommissioned, converted to biomass or retrofitted to reduce emissions. Further, with an increasing variable renewable penetration in each of the systems, CCGT's offer significant flexibility. Another key finding is the increasing role of nuclear plants as the emission production constraint is tightened. In the scenarios considered, nuclear is built before CCS options and offshore wind.

The total costs provide some interesting insights into the costs associated with different emission reduction ambitions. As expected, due to both the higher build costs associated with low carbon technologies and the lower firm capacity of variable renewable generation, the 80% emission reduction scenario requires a larger generation capacity. These results clearly highlight the importance of careful consideration of the marginal cost of abatement. While it is beyond the scope of this study, it is important to recognise the marginal costs of abatement in each of the energy sectors to recognise the most cost effective approach to decarbonising economies.

The capacity shadow price is a useful metric to understand the cost associated with adding the last unit of capacity to the system.

Decommissioning of coal plants from 2016, combined with reduced capacity factors of CCGT's and increased annualised builds costs, leads to an increase in capacity shadow price in each of the scenarios between 2015 and 2023. Throughout the 2020's the capacity shadow price remains relatively stable in each of the scenarios, with new build CCGT setting the shadow price. In each of the scenarios, the capacity price increases significantly and plateaus in the mid to later 2030's. This is due to a shift from CCGT's to nuclear plants setting the new capacity shadow price.

As the SRMC does not increase at the same rate as the LRMC, revenues from the energy market are increasingly insufficient for nuclear plants to recover costs. However, it should be noted that the research considered a least cost model and competitive bidding behaviour was not taken into consideration. Competitive bidding behaviour is likely to lead to the increase in SRMC and thus the generators would recover a higher level of costs from the energy market – thus the capacity shadow price would likely decrease. However, it should also be noted that with an increasing level of variable generation, and low carbon technologies with low SRMC, it is highly unlikely that the SRMC would increase at the same rate as LRMC and thus increasing capacity provisions will likely be required.

This study raises a number of issues for policy makers in countries with increasing renewable penetration. Namely, with the technologies available today, it is difficult to foresee energy only markets as suitable for systems with increasing variable renewable penetration. Further, many policy makers remain committed to variable renewable penetration deployment and often expect capacity markets and provisions to be a short term necessity. However, this research highlights, with the technologies available today, it is unlikely that a shift away from capacity provisions will be possible. Further, with current available technologies, it is difficult to predict an exit point for government intervention in power markets.

It is acknowledged that this study has concentrated on current technologies. Breakthroughs and innovations may lead to cost reductions and new technologies that are capable of satisfying the long term emission reduction constraints, capacity constraints and the operational constraints on the system. However, decisions in the power system are often required years, or even decades, ahead of commissioning and thus understanding these challenges now is required to develop energy polices for the future.

8 Discussion and Recommendations for Further Research

8.1 Introduction

Cost effective, high level integration of variable renewable technologies into power systems is considered to be one of the great challenges of the transition to a low carbon economy. By considering the fundamental characteristics of the resources and through utilising the most appropriate analytical techniques, this research provides insights into some of the policy, modelling and technical challenges of integrating a high level of variable renewable energy into power systems. Further, based on rigorous and detailed analysis, a number of recommendations for policy-makers, analysts and researchers are included within the three main research chapters.

The challenge of increasing variable renewable penetration is vast and has social, political, economic, business, and technical dimensions. Clearly, there is not simply one approach that is capable of addressing all of these issues. As outlined in Chapters 2 and 3, it is fundamental that researchers select the appropriate approach and model to address the research objectives when undertaking renewable integration studies. In this thesis, two tools have been used to develop three models to address three different, but interrelated, topics as set out in Chapter 4. This section draws on the results and insights from each of the three research topics. The chapter is organised as followed. Initially, a summary of the main research findings from all the chapters is provided, subsequently, a discussion of the modelling, policy and wider implications of the research is included. Finally, some recommendations for further work are discussed.

8.2 Summary of Research Findings

This thesis has aimed to contribute to the research fields of energy system analysis, power market modelling and renewable integration analysis. Three research topics that are considered to be novel and of significant interest to these fields are outlined in Chapter 4.

In Chapter 5, the analysis focussed on quantifying the technical benefits of energy storage and electricity interconnections in future British power systems with increasing variable renewable generation. The key findings highlighted the importance of whole system analysis and the benefits of enabling technologies. In the scenarios considered, the maximum technically feasible wind penetration increased and the critical excess electricity production decreased as energy storage and electricity interconnections increased. By increasing energy storage and interconnections, greater emission reductions could be achieved with a lower wind capacity. Significantly, a system with 6GW of energy storage capacity and an interconnection capacity of 12GW could integrate a wind penetration of about 40%, resulting in system emissions intensity of 113gCO_2/kWh at 48GW wind capacity by 2030. However, in the original gone green scenario, a system with less storage and interconnection, the maximum wind penetration was limited to about 26%, despite a much larger wind capacity of 57GW. Clearly, this highlights the importance of analysing the whole power system when considering energy polices and the advantages of enabling technologies.

A combination of increased storage and interconnection provides the greatest benefits to the system, due to the unique capabilities and characteristics of the technologies. For example, interconnections have the ability to import/export electricity on a continuous basis, depending on the trading arrangements and subject to outages. However, energy storage can only increase system demand until the storage volume is full. Further, while the study did not consider transmission constraints, it should be recognised that storage technologies also have the capability to alleviate grid constraints and reduce curtailment. As wind and solar technologies are modular and location constrained, capacity will likely be deployed disproportionally across GB, with a large capacity expected in Scotland, a region with strong wind resources. In the event that increased grid reinforcements do not align with increased renewable capacity, grid constraints will become more prevalent. In this case, the ability to absorb loads through pumping will assist in alleviating grid constraints and reduce curtailment.

A final key conclusion of the chapter was that by increasing variable renewable generation, energy storage and interconnections, significant emission reductions can be achieved. However, the most ambitious scenario considered achieved a system emission intensity of 113gCO_2/kWh. While this is a considerable improvement, the target remains much greater than the 50gCO_2/kWh target recommended by the Committee on Climate Change (Committee on Climate Change, 2010) .

A number of key areas for further work were identified based on the findings and methodological limitations of the research completed within Chapter 5. By using a full representation of the generation portfolio in GB, the research completed in Chapter 6 allowed for a greater understanding of the operational requirements of thermal power plants in future British power systems with increasing variable renewable generation. After developing and validating a model of the 2012 GB power system, four discrete scenarios were analysed to understand the changing operational regimes of thermal power plants in future systems with increased variable renewable generation.

The key findings related to the utilisation of gas plants. In three of the four scenarios, the average capacity factor for gas power plants was below 52%, suggesting that significant government interventions will be required in energy only markets with increasing variable renewable capacity to ensure that the revenue for gas plants is sufficient to prevent mothballing and premature decommissioning. Further, gas plants remained fundamental in each of the scenarios considered, due to flexibility of the assets and contribution to system security. Another significant finding was the importance of coal generation. While the coal capacity factor reduced significantly on 2012 levels in all of the scenarios, maintaining coal plants was required to prevent unserved energy.

Plant cycling was also investigated in Chapter 6, with the analysis focussing on ramping intensity, time spent at minimum stable level and average number of start-ups. The ramping intensity of coal plants decreased in all scenarios and this is due to an increased time spent offline. While the ramping intensity for coal plants decreased, the average number of starts increased in three of the four scenarios. The cycling results imply that coal will be used differently in 2020, with an increased number of start-ups, operators will have to ensure that plants are efficient and flexible enough to maximise profits. Further, constrained by the Industrial Emissions Directive, coal is used more frequently in the winter due to a greater system demand. The analysis of gas plant cycling found that the units are used in much the same way, with ramping intensity of gas power plants increasing slightly in each scenario due to the greater supply side variability introduced by increased wind and solar penetration. The largest issue for gas operators was found to be the utilisation of gas plants in systems with increasing variable renewable generation. While not the main focus of the study, the four pumped storage facilities in GB were found to be of considerable value to the future systems considered, with utilisation and ramping intensity increasing.

Based on the findings from Chapter 6, further work was warranted into the longer term implications of increased variable renewable generation on power systems. Many renewable integration studies develop a model of a future power system and simulate the operation of the proposed system for a future year. While this approach is very useful for understanding some specific power system requirements, such as reserve requirements, a caveat is that the analyst may fail to recognise how the system will develop through time. For example, an analyst may assume a high level of dispatchable thermal capacity that is only used when renewable resources are not available. However, in reality, these plants may be prematurely mothballed, or even decommissioned, during the transition period if they are unprofitable. Therefore, the aim of Chapter 7 was to develop a renewable integration study that provided insights into the development and operation of the British power system and markets through the transition period.

A capacity expansion model of the GB model was developed and a number of differing emission reduction scenarios analysed. Key model outputs included generation portfolios, build costs, fuel costs, total generation costs and long term pricing trends. A key insight from the analysis was the importance of considering the total generation costs. For example, the build costs to satisfy the 80% emission reduction scenario target was 30% greater than the no target scenario. However, the total generation costs were only 19% greater. While the build costs associated with the emission reduction scenarios are greater, the fuel costs were significantly lower than the no target scenario. Hence, by only considering one component of the totals costs, such as the build, fuel, emission or reserve costs, the results may prove deceptive. The insight provided here agrees with International Energy Agency (2014b), where the importance of considering total costs in understanding the economics of increased variable renewable generation is discussed.

Another key finding was that stringent emission reduction scenarios can be achieved with a high level of gas capacity. In each of the scenarios, gas capacity increases significantly and replaces retiring coal and nuclear plants. In these scenarios, gas is required to ensure that the security constraint on the system is met. However, as the emission constraints become more stringent, the utilisation of gas plants is reduced and increased capacity payments are required to ensure that the units recover costs. Despite the increased capacity payments, the total system costs associated with an 80% emission reduction target are only 19% greater than a system with no emission reduction target. Two key points can be deduced from this finding. Firstly, the stringent emission targets can be met with only a moderate increase in total system costs. Secondly, in the scenarios considered, it was cost effective to build unabated gas capacity and operate the plant at lower capacity factors.

The capacity shadow price was analysed to understand the cost associated with adding the last unit of capacity to the system. In the scenarios considered, capacity shadow prices increased for a number of reasons, not least; low load growth, increased renewable generation, stringent emission production constraints, increased annualised build costs and reduced CCGT capacity factors. Further, as the short-run marginal costs do not increase at the same rate as the long run marginal costs, revenues from the energy market are increasingly insufficient for firm generation capacity to recover costs. These results indicate that, with the technologies available today, it is difficult to foresee energy only markets as suitable for static systems with increasing renewable penetration. In GB, it is likely that provisions for capacity will continue to be required to ensure that firm generation capacity remains a profitable investment. Therefore, under the current market arrangements with current technologies, it is likely that a capacity mechanism will be required throughout the transition to a lower carbon power system. Further, an exit point for government intervention is difficult to foresee.

8.3 Methodological Implications

While the focus of the research was to provide insights into integrating variable renewable generation into power systems, a number of key methodological insights have been developed that warrant further discussion in this section.

Of particular interest is the requirement for a detailed understanding of the simulation settings on model outputs. For example, in Chapter 6, the objective was to solve the unit commitment and economic dispatch problem using mixed integer linear programming. A temporal resolution of 1 hour or 30 minutes may not be sufficient to consider key technical constraints. For example, ramping constraints of many plants may not bind at this temporal resolution and thus solving at 1 hour or 30 minute resolution may underestimate the flexibility requirements of the system. Deane et al. (2014) used a validated 2020 model of the Irish system to highlight the requirements for sub-hourly modelling in power systems with increased renewable generation. It is acknowledged that solving problems with a finer resolution is more computationally intensive and will increase simulation run time. However, computer performance and analytical techniques have improved markedly in recent years and it is important that researchers utilise these improvements effectively and have an understanding of the effect of the simulation settings on the model outputs.

Chapters 6 and 7 highlighted the importance of using different modelling approaches to address similar issues. The research in these chapters aimed to provide insights on the impacts of three characteristics of variable renewable generation, namely, low short-run marginal costs, variability and uncertainty. While Chapter 6 considered a detailed operational analysis and the requirements of thermal plants in future systems with increased variable renewables, Chapter 7 considered the long expansion of the power system. By considering a detailed operational analysis (see Chapter 6) and a long term planning analysis (see Chapter 7) the short and long term impacts could be identified and analysed. Of course, the modelling approaches to provide the insights had to be different. The research within Chapter 6 considered the operation of the power system over one year and thus the development of a model with a fine temporal resolution was possible. The approach used in Chapter 6 is common within the literature. Researchers often develop a model of a system for a future year and analyse a number of discrete generation portfolio scenarios. Indeed, this approach was also used in Chapter 6. While this approach is very useful in offering insights into the detailed operational issues of increased renewable penetration, a caveat is that the future generation portfolio has to be assumed. It is for this reason that the research and insights gained from Chapter 7 are so important to understand the policy implication of increased variable renewable penetration.

A caveat of assuming a future generation mix is that challenges associated with the transition from the present until the assumed future year may not be fully recognised. An example of this has occurred in many static power systems across Europe, where utilities have prematurely decommissioned or mothballed unprofitable capacity. As variable renewable generation has low-short run marginal costs, average prices have been depressed. Increased renewable capacity and depressed prices has been compounded by low load growth, this leading to the unprofitability of marginal plants. By only considering a future generation mix, conclusions may focus solely on recommendations for effective operation of power systems with increased renewable penetration and may neglect the requirement to design power markets that enable the transition to be cost effective. Thus, by considering both the short term operational requirements and the long term requirements, greater insights can be offered on policy requirements to enable the transition to be achieved cost effectively.

8.4 Policy Implications

Policy implications of the research outputs were discussed in the conclusions of Chapter 5, 6 and 7. Two of the main policy implications reported include; the requirement for whole systems analysis and an integrated energy policy and the requirement for a market design that values firm and flexible capacity.

It was clear from the findings from all three research topics that efficient integration of variable renewable energy will require increased power system flexibility. In Chapter 5, using a technical optimisation, the technical benefits of increased energy storage and electricity interconnections was reported. Due to the ability of interconnections to export electricity during times of high wind output, and the ability of energy storage devices to increase demand, both storage and interconnections have the capability of reducing the amount of excess electricity supply. In Chapter 6, considering a representation of the generation portfolio in GB, the operational requirements of the thermal plants in systems with increasing variable renewable penetration was assessed. The analysis highlighted that, due to the intra-hour changes in variable renewable generation output, understanding the sub-hourly flexibility requirements of the system is fundamental to ensure that firm and dispatchable capacity is not undervalued. Chapter 7 considered a number of capacity expansion scenarios with a planning horizon to 2045. In three of the scenarios considered, variable renewable generation increases rapidly. Further, as most of the coal and nuclear capacity is scheduled to retire over the period, 2016 – 2025, an increased CCGT capacity is required to satisfy the security constraints of the system. While the nuclear capacity increases as the emission reduction targets become more stringent, overall the plant mix is considered to be more flexible with reduced baseload capacity.

Technologies that are capable of providing flexibility include; energy storage, electricity interconnections, flexible generation and demand side response. As reported by International Energy Agency (2014b), these technologies have different characteristics and provide the system with difference services. For example, flexible generation can only increase supply but energy storage is capable of both increasing supply and demand. Designing a power market that supports the commercialisation of enabling technologies will be fundamental to ensure the cost effective integration of variable renewable energy. Further, markets that value flexibility will be required to prevent premature decommissioning and mothballing of firm and flexible generation capacity. As discussed in Chapter 7, it is important that the policy makers have an understanding of the long term implications of increased variable generation on the power system, so that short term government interventions can be prevented in the future.

The outputs from the analysis in Chapter 5 suggested that power system emissions could be reduced significantly by increasing energy storage, interconnections and variable renewable generation. However, even the most ambitious scenario did not achieve the emission reductions level suggested by the Committee on Climate Change (Committee on Climate Change, 2010). It is suggested that greater integration between the heat, electricity and transport sectors will be required to ensure that emissions in the power sector can be further reduced.

While the research has both policy and methodology implications for researchers, analysts and decision-makers in many regions with increasing renewable generation, it is important to outline the implications for UK energy policy. One of the key findings of Chapter 6 was that gas plants may be subject to challenging economic conditions and low utilisation. These challenging conditions are widely recognised and a Capacity Market mechanism has been implemented as part of the EMR package to address security of supply concerns (Department of Energy & Climate Change, 2012a). However, as the first Capacity Auction cleared at a price of £19.40/kW/year, only one large CCGT (Trafford 1.8GW) was successful (National Grid, 2015). Further, over 8.8GW of existing CCGT capacity exited the auction above the clearing price (National Grid, 2015). Also, over 17GW of the total capacity procured was contracted to existing coal/biomass and nuclear generation (National Grid, 2015). Therefore, while the Capacity Market may be considered to have been successful in procuring the GW capacity required at a low price, it has not necessarily been successful in procuring the flexible capacity that is required for high level renewable integration.

A concluding remark from Chapter 7 was that *"under the current market arrangements with current technologies, it is likely that a capacity mechanism will be required throughout the transition to a lower carbon power system. Further, an exit point for government intervention is difficult to foresee".* Also, Chapter 6 reported *"a market design that provides sufficient incentives for flexible generation to compete will be fundamental in the successful transition to a lower carbon, secure and affordable power system".* Further, the International Energy Agency (2014b) report that to accommodate an increased variable renewable generation capacity, a structural shift to more flexible, and reduced baseload, capacity will be required. With these points in mind, and given the outcome of the first capacity auction, significant questions remain as to whether the current form of the capacity mechanism is compatible with the overriding energy policy objectives of achieving a secure, low carbon and affordable energy system.

It should also be recognised that the first capacity auction requires delivery in 2018. However, supply margins are forecast to be tight in the interim winters (Office of Gas and Electricity Markets, 2014). To mitigate the risks of inadequate supply, OFGEM approved the Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR) as tools to allow National Grid to continue to balance the system (Office of Gas and Electricity Markets, 2015). This confirms that further measures are required to procure additional capacity in the short-term. Also, it confirms that alone the capacity mechanism does not incentivise enough capacity to satisfy the system security standard.

Chapter 7 reported that it is likely that a higher capacity shadow price will be required to satisfy the security and carbon reduction constraints in the longer term. Given the fundamental characteristics of variable renewable generation, reported in Chapter 2, and the operational requirements of thermal plant, reported in Chapter 6, it is considered likely that measures beyond the current capacity mechanism will be required to incentivise the type of capacity that is compatible with a secure and low carbon power system. Overall, the results of the research points towards the need for a market design that values both firm capacity and the operational capabilities of plant. Further, it was concluded in Chapter 5 that to achieve the 50gCO_2/kWh emissions intensity recommended by the Committee of Climate Change, it is likely that the GB electricity system will need better integration with other energy sectors, such as the electrification of the heat and transport sectors. Therefore, while the electricity market reforms may be successful in the deployment of low carbon electricity generation technologies to a point, in the long term a more integrated energy policy may be required to meet the 2050 emission reduction targets.

While this research has centred on developing models of the British system to understand the challenge of integrating increased levels of variable renewable generation into power systems, it is important to note that the findings should be of value to policy-makers, researchers and analysts around the world. In 2014, over 140 countries had implemented renewable energy polices (REN21, 2014). As discussed in Chapter 2, the impact of increased variable generation is a factor of many power system and market properties. Hence, the challenges associated with variable generation integration will depend on the system that is being studied. While the challenges are different, the fundamental characteristics of variable renewable generation do not change. Therefore, the policy and methodological insights provided in this thesis should be of interest to researchers and analysts around the world. For example, in regions where increased variable renewable generation has been found to lower average wholesale prices, such as Ireland (Clifford and Clancy, 2011), Australia (Forrest and MacGill, 2013), Spain (Sáenz de Miera et al., 2008), Germany (Traber and Kemfert, 2011) and Italy (Clò et al., 2015), researchers may be interested in the development and application of the British capacity expansion model to study the longer term implications of the properties of variable renewable generation on price formulation and electricity market design, see Chapter 7. Further, using this approach to understand the requirements for capacity provisions may be of particular interest to policy makers and researchers in regions where the implementation of capacity mechanisms are being considered to ensure revenue adequacy for firm generation capacity.

In Europe, there has been a long standing commitment to develop a single electricity market. During the course of this study, day-ahead markets have been harmonised and, in February 2015, multi-regional coupling covered 19 countries, accounting for 85% of European power consumption (EPEX SPOT, 2015). As many European systems can be described as static, the challenges associated with integrating variable renewable generation into European power systems have similarities to those in GB. It is for these reasons that researchers are increasingly considering the development of the whole European electricity system to understand the implications of increased variable renewable energy, for example, see Deane et al. (2015). With progressive harmonisation of electricity markets and increasing interconnection capacity, it is important that researchers and policy makers understand the limitations of enabling technologies when considering systems in isolation. For example, an increased interconnection capacity across Europe may offer significant value as the output of variable generation will be aggregated across a greater area. However, a saturation effect will ultimately be realised. Further, during extended periods of low wind and solar output across the whole of Europe, the use of alternative capacity will be required. Therefore, it is important to recognise that interconnections and storage have an increased role in the transition to a single European market with increased renewable penetration, but these technologies alone will not provide the whole solution.

8.5 Recommendations for Further Work

This study has focussed on the development of models to better understand the implications of increased variable renewable generation on the British power system. As with all models, the models developed in this thesis have limitations and through systematically addressing these limitations, new approaches can be developed to provide greater insights. New analytical techniques and methodologies, combined with increased computational performance continue to enable researchers to complete more sophisticated analyses. However, as power system models are highly complex, it is of great importance that modellers understand the contribution of each parameter to the total problem size. Further, modellers should understand the significance of each parameter to the model outputs and ultimately, the research insights. For example, modelling reserve requirements in detail may significantly contribute to the total problem size. However, modelling reserves in detail may not be significant to the model outputs. By fully understanding both the significance and contribution of each model parameter, improvements in computing requirements and analytical approaches can be utilised more effectively.

Improvements in computing performance allows for much larger systems to be modelled. For example, Deane et al. (2015) have recently developed a model of the North-West Europe power system in 2020 to quantify the costs of National Renewable Energy Action Plans. Great insights can be provided from these models. A caveat of the approach used in the Chapters 5 and 6, was the exclusion of modelling the interconnected flows to other systems in Europe. While it was acknowledged that is unlikely that interconnection capacity will amount to more than about 15% of the total installed capacity in GB, interconnection flows will certainly have an impact on power system prices. Further work could include the improvement of the GB model developed in Chapter 6 to account for the flows across interconnectors. However, it should be noted that development of such a model would not be free from limitations. For example, sub-hourly modelling is required for understanding the operational requirements of power systems with increasing renewable generation, and for this reason the problem size of the model developed in Chapter 6 was large. Expanding the GB model to represent North-West Europe, and analyse interconnector flows, will increase problems size and lead to the requirement for a coarser temporal resolution. Thus, while the model may be improved by accounting for interconnector flows, the model would be limited by the temporal resolution. Again, this highlights the importance of drawing on insights from multiple models.

As with the operational model that was developed in Chapter 6, the capacity expansion model developed in Chapter 7 could also be further developed. Researchers are inevitably required to make assumptions when developing models and as systems grow increasingly more complex, the treatment of uncertainty becomes increasingly more important. Deterministic scenario analysis, as used in Chapters 5, 6 and 7, is one approach to understand the implications of different model assumptions and constraints. This approach is highly valuable in understanding the impacts of certain inputs, for example emission reduction targets. However, long term expansion models require many assumptions, such as capital costs, fuel and carbon costs and potential build rates. Thus, the number of scenarios required to account for the possibility of all input scenarios is significant. If some information about the potential range of inputs is known, then stochastic optimisation can be used as an alternative to deterministic scenario analysis. Stochastic optimisation aims to provide a single solution that is hedged against the uncertainty represented in the stochastic samples (Energy Exemplar, 2015).

PLEXOS has the capability to apply stochastic optimisation techniques to the long term capacity expansion problem, with the objective to minimise the net present value of the total costs given a range of possible future outcomes and uncertainties. Therefore, another topic of further research could be the development of a stochastic long term expansion model. This type of model would be a useful for policy makers who are required to make decisions long before outcomes are realised. Again, such a model would not be free from limitations. Stochastic modelling is computationally intensive and thus simplifications elsewhere in the model would likely be required if GB was to be modelled. A coarser temporal resolution may be required to ensure that the stochastic problem can be solved. In this event, the optimal generation portfolio reported from a stochastic model could be analysed in a detailed operational model to ensure that the system has sufficient flexibility. The operational model should ideally include a sub-hourly resolution and ensure that all relevant constraints are binding.

The research within this thesis has focused primarily on the supply side options to integrate variable renewable generation. However, innovative approaches to both reducing and time shifting power demand may offer significant benefits to the integration of variable renewables. The models developed within this study could be further developed to analyse the value of increasing demand side response to facilitate the integration of variable renewable generation.

The analysis within this thesis has focussed solely on the power system. Clearly, to achieve the reductions in emissions required to meet the recommendations set by the Committee on Climate Change, large decarbonisation across the entire energy sector, and indeed the wider economy will, be required. Whole energy system models, such as MARKAL and TIMES, have been used traditionally to explore the costs associated with energy policies, including decarbonisation policies, however the temporal and spatial resolution is often not sufficient to capture the characteristics of variable renewable generation, see Chapter 3. It is for this reason that new models and hybrid modelling approaches are being developed to capture important characteristics of variable renewable generation in energy system models, see Welsch et al. (2014) and Deane et al. (2012a). These approaches offer significant value in regions with low load growth, low short term infrastructure requirements and low integration between the three main energy sectors, namely transport, heat and electricity. In GB, there is currently low integration between the three main energy sectors, however, the wider electrification of the energy sectors, for example through heat pumps and electric vehicles, is seen as an option for decarbonisation. Understanding the value and benefits that electrification within the heat and transport sectors can bring to the power system is seen as an important topic of further research.

9 Conclusions

A secure energy supply is a prerequisite for the development of any successful modern economy. With a growing global population, where over 1 billion people do not yet have access to electricity, energy consumption is forecasted to continue to grow throughout the first half of the 21st century (International Energy Agency, 2014d). However, with an increasing scientific consensus that climate change is real, and exacerbated by human activity, the way by which energy is procured will have to change. Achieving the emission reductions that climate scientists recommend will require links between population growth, energy consumption and economic growth be broken. Further, the development, commercialisation and deployment of technologies with fundamentally different characteristics to the fossil fuel generators that have contributed to the growth and prosperity enjoyed throughout the industrialised world will be required. Therefore, major research is required, not only to facilitate innovation and technological breakthroughs, but to understand the technical and economic implications of a transition to a lower carbon energy system.

This research has focussed on one part of the energy sector in one country: the electricity system in Great Britain. The aim of the research was to gain a greater appreciation of the implications of variable renewable generation on electricity systems. Specifically, based on a review of the literature and the identification of research gaps, three research questions were formulated. The first question relates to the importance of enabling technologies in electricity systems with increasing renewable penetration and was formulated as follows:

1) *What are the technical benefits of energy storage and electricity interconnectors in electricity systems with increasing renewable penetration?*

Following a review of available energy system models and tools, the EnergyPLAN tool was selected to address the research question and to evaluate the technical benefits of increasing energy storage and electricity interconnectors in future British power systems. In the four discrete future power systems analysed, increasing the level of energy storage and interconnectors permitted a greater maximum technical feasible wind penetration. Further, these enabling technologies can serve to reduce wind curtailment. Significantly, increased energy storage and interconnection capacity can lead to a reduced system emission intensity at lower wind capacity. In the most ambitious scenario considered, a system with 6GW of energy storage capacity and interconnection capacity of 12GW could integrate a wind penetration of about 40%, resulting in a system emission intensity of 113gCO_2/kWh at 48GW of wind capacity by 2030. However, in the original gone green scenario of National Grid, a system with less storage and interconnection, the wind penetration was limited to 26%, despite a much larger wind capacity of 57GW. These key findings highlight the importance of analysing the whole power system when considering energy policies and the significant technical benefits of energy storage and electricity interconnections with increasing renewable penetration.

The second question was formulated on the basis that a greater understanding of the implications of increased renewable penetration on thermal plant operation will be required to ensure that the transition to a lower carbon power system is cost effective. The question was formulated as follows:

2) *How will the operation and utilisation of coal and gas power stations change in electricity systems with increasing renewable penetration?*

The PLEXOS Integrated Energy Model was selected due to the capability of considering a full representation of the British power generation portfolio and the ability to apply a sub-hourly resolution. The most significant findings relate to the utilisation of gas plants in power systems with increasing variable renewable generation. In three of the four scenarios considered, the average annual capacity factor of the gas plants remains below 52% in 2020, suggesting that government interventions will be required to ensure that revenue is sufficient to prevent mothballing of the plants. In each of the scenarios considered, gas is fundamental due to both the flexibility and contribution to system security of the assets. The importance of coal generation in the period 2015 – 2020 was also acknowledged. While utilisation decreases significantly compared to 2012 levels in all scenarios, maintaining coal plants was required to prevent loss of load. Plant cycling was also investigated in Chapter 6, with the analysis of the results focussing on the time spent at minimum stable level, number of start-ups and ramping intensity. However, the most significant findings related to the utilisation of gas plants in system with increasing renewable penetration.

The final question considers the importance of gaining an appreciation of the challenges encountered during the transition to a future low carbon power system with significant variable renewable penetration. The question was formulated as follows:

3) *What are the longer term implications of the properties of variable renewable generation on price formulation and electricity market design?*

Again PLEXOS was selected due to the capacity expansion modelling capabilities of the model. Key findings related to the importance of considering total generation costs, the use of gas generation and the increase in capacity shadow price. While the build costs in the emission reduction target scenarios considered are greater, the fuel and emissions costs are lower. Therefore, by only considering one cost component the results may be deceptive. For example, the build costs in the 80% reduction scenario were 30% greater than the no emission target scenario. However, the total costs were only 19% greater, and this is due to the lower fuel and emission costs. Another important insight was drawn from the analysis of the capacity shadow price. In the scenarios considered, the capacity shadow price increased for a number of reasons, not least: low load growth, increased renewable generation, stringent emission reduction constraints, increased annualised build costs and reduced CCGT capacity factors. As the short-run marginal costs do not increase in-line with the long-run marginal costs, revenues from the energy market are increasingly insufficient for firm generation capacity to recover costs. The results are significant as they indicate that, with the technologies available today, it is difficult to foresee energy only markets as suitable for static power systems with increasing renewable generation. Therefore, it is likely that a capacity mechanism will be required through-out the transition to a lower carbon power system.

The three research questions have been answered using relevant, and rigorous, analytical approaches. The findings and insights drawn from the results should be of interest to researchers in the fields of energy systems modelling, renewable integration analysis and power market modelling. Further, the policy implications of the findings should be of interest to decision-makers and policy strategists in regions with increasing variable renewable penetration.

As discussed in Chapter 5, much of the previous literature has centred on outlining the benefits of enabling technologies, such as interconnections, flexible generation and energy storage. However, there has been less emphasis on quantifying the benefits that these technologies can bring to electricity systems with increasing renewable penetration. Therefore, by addressing the first research question, and contributing to the literature in this area, researchers in the field of renewable integration can gain a greater appreciation of the importance, and benefits, of enabling technologies. Further, through the use of the well-known EnergyPLAN tool, and by analysing recognised outputs, such as critical excess electricity production, emissions intensity and primary energy supply, researchers within this field should be able to relate to the both the model and outputs.

The research undertaken in Chapter 6 is considered to be very timely and relevant to current energy policy issues. The depression of average wholesale prices, partly due to increased renewable penetration, has reduced the profitability of marginal plant investments and seen firm generation capacity across Europe, notably combined cycle gas turbines, mothballed or prematurely decommissioned. Therefore, the results and insights provided within Chapter 6 should be of interest to many researchers and policy makers in regions with increasing variable renewable penetration. The findings that the operational regimes and utilisation of thermal plants will change significantly under the current market arrangements will have significant implications for the costs associated with the transition to a lower carbon power system. Further, the suggestion that government interventions will be required to ensure that security of supply is maintained may be of significant interest to policy makers. This research should enable policy makers to gain a greater appreciation of the requirements to consider the implications of renewable deployment on thermal power plants when designing energy policy.

The third research question addresses the longer term implications of increased variable renewable generation. A caveat of many renewable integration studies is that the future power system scenarios that are to be analysed have to be assumed. While this approach is very useful for understanding specific characteristics of the future power system, for example the reserve requirements, important implications of increasing variable renewable penetration during the transition to the future power system may be overlooked. An example of this is the reduced utilisation of gas power plants in many European power systems with increasing renewable penetration and low demand growth. As the research provides a greater appreciation of the requirements for capacity provisions in electricity systems with increasing renewable penetration, the analysis should be of interest to policy makers and researchers with an interest in electricity market design for a low carbon future. As with Chapter 6, the insights gained in Chapter 7 reflect on the importance of looking beyond renewable deployment when considering the transition to lower carbon power systems.

Along with the policy and modelling implications, discussed fully in Chapter 8, the importance of applying the appropriate modelling approach should not be overlooked. While modellers must always try to improve model capability to address new challenges, it is important that researchers realise the importance of developing multiple modelling approaches to address interrelated energy system challenges. In this study, two models have been used to address three different research questions that relate to the field of renewable integration.

Based on a review of the available options, EnergyPLAN was considered to be the most appropriate tool to address the first research question. The deterministic, hourly simulation model uses an optimisation strategy that seeks to minimise fuel consumption. Further, the open source tool has been used widely within the academic research that considers the large scale integration of renewable energy. While this tool has the capability to address the first research question, a more detailed model was required to address the second research question, as the full generation portfolio had to be represented. By using the PLEXOS Integrated Energy Model to develop detailed operational models, a greater appreciation of the requirements of thermal plant operating regimes could be gained. However, a caveat of the modelling approaches taken in Chapters 5 and 6 was that the future power system had to be assumed. It was for this reason that a capacity expansion model was considered to be the most appropriate means to address the third research question. By considering both a detailed operational analysis, in Chapter 6, and a long term planning analysis in Chapter 7, both the short term and long term trends can be identified. Thus, by considering both the short term operational and long term planning requirements, greater insights can be drawn from the analysis.

While common insights drawn from multiple modelling approaches are likely to be more robust than individual analyses, it is important to recognise some of the limitations of the models developed. For example, as power systems across Europe become increasingly interconnected and electricity markets harmonised, it is important that researchers and analysts understand the limitations of enabling technologies. By modelling only one, or a few regions, the benefits of increased interconnections and/or energy storage capacity may be overstated. For example, while the hydro resource in Norway is large, alone it will not provide the storage required to achieve a high level of variable renewable penetration across Europe. Also, while increased interconnectivity and market harmonisation will increase the size of the balancing area and reduce the variability of the aggregated output from wind generation, periods of low aggregated output are inevitable. For these reasons the research could be further improved by widening the models developed to take into consideration the interconnected European systems.

In doing so, the value of energy storage projects and interconnectors could be evaluated on a case by case basis.

While scenario modelling is an approved scientific method for exploring plausible future energy scenarios and exploring uncertainties, other more sophisticated methods are available. Stochastic analysis can be used where some information about the uncertain variables is known, for example future fossil fuel or carbon prices, to provide a single solution that is hedged against the uncertainty represented in the input parameters. The development of stochastic models may serve to investigate least regret options. For example, technologies that are consistently deployed under a range of future fuel and carbon price projections, may be considered to be more favourable than those that are only deployed in extreme scenarios.

Developing large European models and complex stochastic models may further enhance our understanding of the challenges and opportunities associated with increasing the penetration of variable renewable generation technologies. However, it is important to recognise the challenge with increasing model size and complexity. While computing performance has improved significantly in recent years, modellers remain restricted by the size of the optimisation problem. Therefore, while the development of a large European power system model or a stochastic capacity expansion model will offer further important insights, the approaches will not be free from limitations. For example, solving a detailed European market model will be computationally intensive. Again these points highlight the importance of developing multiple modelling approaches.

In summary, this research has addressed three relevant research questions that relate to the challenges associated with the transition to electricity systems with increased variable renewable penetration. The methodological insights drawn from the results have focussed on the importance of using multiple modelling approaches to address different but interrelated electricity system issues. The policy insights focus on the importance of developing policies that value flexibility, recognise the importance of enabling technologies, consider total system costs and account for both the short and long term needs of the electricity system. Clearly, there is scope for further work. By enhancing the models, for example by accounting for greater physical infrastructure and market harmonisation across Europe, new insights could be drawn.

Finally, it is important to realise that electricity system decarbonisation is only one aspect of the energy challenge faced today. In order to achieve the emission reductions that climate scientists recommend the entire energy system, including transport, heat and electricity will have to be largely decarbonised. Further, it must be acknowledged that the decarbonisation challenge is not limited to energy supply, but the entire economy. Other emission intensive industries, such as construction and agriculture, will also have to achieve stringent emission reduction targets. Therefore, decarbonising the world’s most emission intensive economies will require global collaboration on an unprecedented level.

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Appendix A – Thermal Plant Technical Parameters

Fuel Type	MW Capacity (MW)	Minimum Stable Level (MW)	Efficiency (%)	Ramp Up/Down Rate (MW/Min)	Minimum Up/Down Time (Hrs.)	Maintenance Rate (%)	Forced Outage Rate (%)	Mean Time to Repair (Hrs.)	Start Cost (€)
Coal	50	20	33.00%	5	8	6	10	50	10,000
Coal	100	40	35.00%	5	8	6	10	50	20,000
Coal	300	120	36.00%	5	8	6	10	50	80,000
Coal	600	240	38.00%	5	8	6	10	50	150,000
Natural Gas	25	10	32.00%	5	0.5	5	10	24	2,000
Natural Gas	50	20	33.00%	10	0.5	5	10	24	5,000
Natural Gas	100	40	35.00%	10	4	5	10	24	10,000
Natural Gas	200	80	49.00%	30	4	5	10	33	40,000
Natural Gas	400	160	51.00%	30	4	5	10	33	120,000
Natural Gas	600	240	52.00%	30	4	5	10	33	170,000
Natural Gas	1800	720	57.00%	30	4	5	10	33	450,000
New Gas	400	160	52.00%	30	4	5	10	33	120,000
Nuclear	800	-	-	-	24	10	10	50	250,000

Table A.1 – Thermal Plant Technical Parameters

As discussed in Chapter 6, the technical plant data was obtained from previous work completed by Deane et al. (2015). The dataset is freely available. Start costs and efficiencies for each plant were linearly interpolated.

Appendix B – Basic Problem Formulations

This appendix describes the basic formulations for the capacity expansion problem and the unit commitment and economic dispatch problem.

Capacity Expansion Formulation

The objective function aims to minimise the net present value of build costs, fixed operation and maintenance costs and fuel costs. The core formulation is reported by Energy Exemplar (2015) as follows:

Minimize

$$\sum_{(y)}\sum_{(g)} DF_y \times \left(BuildCost_g \times GenBuild_{(g,y)}\right)$$
$$+ \sum_{(y)} DF_y$$
$$\times \left[\text{FOMCharge}_g \times 1000 \times \text{PMAX}_g \left(Units_g + \sum_{i \le y} GenBuild_{g,i}\right)\right]$$
$$+ \sum_{t} DF_{t \in y} \times L_t \times \left[\text{VoLL} \times USE_t + \sum_{g} (\text{SRMC}_g \times GenLoad_{g,t})\right]$$

Subject to:

Energy balance:

$$\sum_{(g)} GenLoad_{(g,t)} + \text{USE}_t = \text{Demand}_t \ \forall t$$

Feasible energy dispatch:

$$GenLoad_{(g,t)} \le PMAX \times \left(Units_g + \sum_{i \le y} GenBuild_{g,i}\right)$$

Feasible builds:

$$\sum_{i \le y} GenBuild_{g,i} \le MaxUnitsBuilt_{g,y}$$

Integrality:

$$GenBuild_{(g,y)} integer$$

Capacity adequacy:

$$\sum_{(g)} PMAX_g \times \left(Units_g + \sum_{i \le y} GenBuild_{g,i}\right) + CapShort_y \ge PeakLoad_y + ResereMargin_y \ \forall_y$$

Indices

g=generator

t=dispatch period

y=year

Variable	Description	Variable type
GenBuild $_{(g,y)}$	Number of generating units built in year y for generator g	Integer
GenLoad $_{(g,t)}$	Dispatch level of generating unit g in period t	Continuous
USE_t	Unserved energy in dispatch period t	Continuous
$CapShort_y$	Capacity shortage in year y	Continuous

Table B.1 – Variable definitions for the capacity expansion problem.

Element	Description	Units
D	Discount rate. The discount factor D_f in then derived: DF = $1/(1+D)^y$	
L_t	Duration of dispatch period t	Hours
$BuildCost_g$	Overnight build cost of generator g	£/kW
MaxUnitsBuilt $_{(g,y)}$	Maximum number of units of generator g allowed to be built by the end of year y	
$PMAX_g$	Maximum generating capacity of each unit of generator g	MW
$Units_g$	Number of installed generating units of generator g	
VoLL	Value of lost load	£/MWh
$SRMC_g$	Short-run marginal cost of generator g	£/MWh
$FOMCharge_g$	Fixed operations and maintenance charge of generator g	£/kW/year
$Demand_t$	Demand in dispatch period t	MW
$PeakLoad_y$	System peak power demand in year y	MW
$ReserveMargin_y$	Margin required over maximum power demand in year y	MW
CapShortPrice	Capacity shortage price	£/MW

Table B.2 – Parameter definitions for capacity expansion problem.

Unit Commitment Formulation

The objective function is to minimise total system operating costs subject to a number of constraints. Deane et al. (2014), Vithayasrichareon and MacGill (2014), Morales-Espana et al. (2013) and Dieu and Ongsakul (2008) provide a description of the objective function:

$$min \sum_{t=1}^{T} \sum_{i=1}^{I} \left[C_i.\left(P_{i,t}\right) + S_i\left(u_{i,t}\right)\right]$$

$$u_{i,t} = \{0,1\}$$

Constraints:

- System demand

$$\sum_{i=1}^{I} (v_{i,t}.P_{i,t}) + USE_t = D_t \quad \forall t$$

where USE_t is unserved energy is dispatch period t.

- Generator capacity constraints

$$v_{i,t}.P_i^{min} \leq P_{i,t} \leq v_{i,t}.P_i^{max} \quad \forall i,t$$

- Ramp rates

$$\left(P_{i,t} - P_{i,t-1}\right) \leq UR_i \quad \forall i,t$$
$$\left(P_{i,t-1} - P_{i,t}\right) \leq DR_i \quad \forall i,t$$

- Minimum up and down time

$$V_{i,t} = \begin{cases} 1 & if\ Ton_{i,t} < TU_i \\ 0 & if\ Toff_{i,t} < TD_i \\ 0\ or\ 1 & otherwise \end{cases} \quad \forall i,t$$

where Ton is the continuous on time and Toff is the continuous off time.

<u>Indices</u>

i=generating unit

t=dispatch period

Decision Variables	**Description**	**Unit**
$P_{i,t}$	generation output for unit i in dispatch period t	MW
$v_{i,t}$	Unit commitment variable in period t (0 if offline, 1 if online)	
$u_{i,t}$	Start-up variable in period t (1 if started, 0 otherwise)	

Table B.3 – Variables for unit commitment and economic dispatch problem.

Parameters	**Description**	**Unit**
C_i	Production cost of unit i	(£/MWh)
S_i	Start costs	£
D_t	System load in period t	MW
P_i^{min}	Minimum stable level of unit i	MW
P_i^{max}	Maximum output of unit i	MW
TU_i	Minimum up time of unit i	Hours
TD_i	Minimum time down of unit i	Hours
UR_i	Maximum ramp up rate of unit i	MWh/hr
DR_i	Maximum ramp down rate of unit i	MWh/hr

Table B.4 – Parameters definitions for unit commitment and economic dispatch problem.

Appendix References

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