NEW METHODS FOR PLANNING AND OPERATING MODERN ELECTRICITY SYSTEMS WITH SIGNIFICANT WIND GENERATION

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Contents

Contents .................................................................................................................. ii
Abstract .................................................................................................................... vii
Acknowledgements ..................................................................................................... ix
Publications Arising From Thesis .............................................................................. x
Nomenclature ............................................................................................................... xi
Acronyms ................................................................................................................... xiv
List of Figures ............................................................................................................. xvi
List of Tables .............................................................................................................. xviii

1 Introduction ............................................................................................................. 1
   1.1 Modern Electricity Systems ............................................................................. 1
   1.2 Challenges in Integrating Renewable Energy ................................................ 2
   1.3 Focus of Research ............................................................................................ 3

2 Challenges Facing the Electricity Industry ............................................................... 5
   2.1 Market Liberalisation ....................................................................................... 5
      2.1.1 Establishing Successful Electricity Markets ........................................... 6
      2.1.2 Addressing Other Issues in a Liberalised Market ................................. 7
      2.1.3 Summary ............................................................................................... 8
   2.2 Renewable Energy ........................................................................................... 8
      2.2.1 Background ............................................................................................ 8
      2.2.2 Reducing Emissions in the Electricity Industry ....................................... 9
      2.2.3 Wind Generation .................................................................................... 10
   2.3 Integration of Wind Power into Modern Electricity Systems ......................... 10
      2.3.1 Planning Issues ...................................................................................... 11
      2.3.2 Connection Issues ................................................................................ 11
      2.3.3 System Operation and Dispatch Issues ............................................... 12
   2.4 The All-Ireland System ................................................................................... 13
      2.4.1 Market Liberalisation in Ireland ............................................................ 13
      2.4.2 The Role of Wind Generation in Ireland .............................................. 14
2.4.3 Wind Power Integration in Ireland ................................. 15
2.5 Summary ........................................................................ 16

3 Generation Resource Planning for the All-Ireland System 18
3.1 Background ................................................................. 18
3.2 Approach and Inputs ..................................................... 20
  3.2.1 Generator Inputs ..................................................... 21
  3.2.2 Fuel Prices ........................................................... 24
  3.2.3 Carbon Costs ........................................................ 24
  3.2.4 Electricity Generation Costs ..................................... 25
  3.2.5 Load Growth and Load Duration Characteristics ........ 26
  3.2.6 Wind Generation Profiles ....................................... 27
  3.2.7 Hydro, Pumped Storage and Interconnection ................ 28
3.3 Generation Adequacy ..................................................... 29
  3.3.1 Capacity Credit Methodology .................................. 29
  3.3.2 LOLE Calculation .................................................. 31
  3.3.3 Capacity Credit Calculations .................................. 32
3.4 Portfolio Optimisation Algorithm ................................... 34
3.5 Least-Cost Generation Portfolio Results and Discussion .... 36
  3.5.1 Initial Generation Portfolio Results ......................... 36
  3.5.2 Effect of Carbon Tax on the Least-Cost Generation Portfolios ... 39
  3.5.3 Sensitivity Analysis of Discount Rate on Least-Cost Portfolios ... 41
  3.5.4 The Role of Wind Generation in Least-Cost Portfolios ....... 42
3.6 Fuel Price Volatility and Portfolio Diversification .............. 44
  3.6.1 Fuel Related Electricity Cost Volatility ..................... 46
  3.6.2 Application of Mean-Variance Portfolio Theory .......... 47
  3.6.3 Price-Volatility Trade-Off ..................................... 51
3.7 Possible Benefits of Nuclear Energy ............................... 51
  3.7.1 Feasible Operational Nuclear Capacity ....................... 52
  3.7.2 Nuclear Plant in Least-Cost Generation Portfolios ......... 53
3.8 Benefits of Active Load Participation .............................. 54
3.9 Summary ................................................................. 57

4 Quantifying Operating Reserve Requirements with Significant
  Wind Capacity ............................................................... 59
4.1 System Operating Reserve ............................................. 59
4.2 Methodology ................................................................. 63
  4.2.1 System Reliability Criterion ........................................ 63
  4.2.2 Generator Outages ................................................... 64
  4.2.3 Inclusion of Wind Power and Load Forecast Errors ............ 64
  4.2.4 Reserve Calculation .................................................. 65

4.3 Application to the All-Ireland Electricity System ................. 69
  4.3.1 Wind Power Forecasting ............................................. 70
  4.3.2 Wind Farm Size and Geographical Dispersion ................. 71
  4.3.3 Total Wind Power Forecast Error .................................. 73
  4.3.4 Variable Wind Power Forecast Accuracy ......................... 74
  4.3.5 Load Forecast Error and Total System Forecast Error .......... 75
  4.3.6 Units, Outage Rates and Dispatches .............................. 75
  4.3.7 Results ............................................................... 76
  4.3.8 Conventional Reserve Categories ................................. 78

4.4 Implications for System Operation .................................... 80
  4.4.1 The Test Day ........................................................ 81
  4.4.2 System Operation Scenarios ....................................... 81
  4.4.3 Impact on System Reserve and Conventional Generation Needed 83
  4.4.4 Impact on System Emissions ....................................... 85

4.5 Adapting Methodology for Reserve Markets .......................... 89
  4.5.1 Suitability of Markets for Reserve for the All-Ireland System 89
  4.5.2 Basic Concepts for Reserve Markets .............................. 91
  4.5.3 Reserve Demand Curves ............................................ 91

4.6 Summary ................................................................. 93

5 Ensuring Short-Term Frequency Control in System Dispatch ......... 94
  5.1 Background ........................................................... 94
  5.2 Market Clearing Formulation ......................................... 96
    5.2.1 Formulation ..................................................... 97
  5.3 Frequency Control Constraints ...................................... 98
    5.3.1 Rocof Constraint ............................................... 98
    5.3.2 Minimum Frequency Constraint ................................ 99
  5.4 System and Scenarios ................................................ 103
    5.4.1 Scenarios ...................................................... 104
    5.4.2 Hydro and Pumped Storage ..................................... 104

Abstract

The context in which many electricity systems find themselves is changing rapidly. Once viewed as a basic public service, many electricity systems are now facing the challenge of market liberalisation, pressure to reduce greenhouse gas emissions and increasing fuel prices and fuel price volatility. This new context has increased awareness in the industry to the possible benefits of wind generation. Many systems around the world have already seen rapid increases in installed wind capacity. However, wind generation characteristics differ from those of conventional generation in many ways, making the assessment of the impacts and benefits of wind generation a difficult task. Wind generation’s uncertain and variable nature is of concern to system operators, especially in smaller more weakly interconnected systems. This thesis presents three new methods for planning and operating electricity systems with significant wind generation. Conceptually new perspectives are taken on traditional problems to successfully deal with them in the context of the modern electricity industry.

A new methodology is developed to aid in the planning of optimal generation resource portfolios for modern electricity systems. Capacity and other system-based considerations are used to establish accurately the role played by wind generation and other generation types in least-cost portfolios. The need for fuel diversification within generation resource portfolios is examined and consideration is also given to the possible benefits of nuclear generation and load participation. Analysis found that wind generation had a significant role to play in least-cost generation portfolios for a large range of scenarios tested.

New system operation methodologies have been developed to ensure that the unique and uncertain characteristics of wind generation are adequately assessed when dealing with system reserve issues. A probabilistic technique considers load and wind generation forecast errors along with unit outage rates to link system reliability to the system reserve level. The impact of the level of wind capacity and forecast horizon is assessed and analysis shows that system operation based on incorporation of wind forecasts is favourable over other approaches.
Short-term frequency control constraints are developed to ensure the security of the system immediately after a large loss of generation. These constraints consider units’ running levels, load and reserve responses along with inertial responses so that the system may be dispatched in a least-cost manner while ensuring system security. The incorporation of generator inertial responses into the dispatch is important for smaller systems with significant wind capacity and/or asynchronous interconnection. The methodology also produces marginal prices for energy, reserve and generator stored kinetic energy.
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Publications Arising From Thesis

Journal Publications. These publications can be found in the appendix.


Conference Publications. These publications can be found in the appendix.


In Preparation


Reports Arising From Thesis.

Nomenclature

NOMENCLATURE FOR CHAPTER 3

$\text{Avail}_n$ availability of generation type $n$ -

$B_{WP}$ set of net-load duration bins corresponding to a wind penetration of $WP$ megawatts -

$\text{CapC}_{WP}$ capacity coefficient corresponding to a wind penetration of $WP$ -

$C c_n$ annuitised capital cost and annual operation and maintenance cost for generation type $n$ in € per MW installed / year €/year

$C c_{WP}$ annuitised capital cost and annual operation and maintenance cost of $WP$ megawatts of wind capacity in € per MW installed / year €/year

$C f_n$ fuel cost for generation type $n$ €/MWh

$E_{b,n}$ energy delivered by generation type $n$ in load duration bin $b$ MWh

$f_C$ fraction of total energy served by coal plant -

$f_G$ fraction of total energy served by gas plant and interconnection -

$H_b$ number of hours in net-load duration bin $b$ -

$I_n$ installed capacity of generation type $n$ MW

$M_b$ centre value of net-load duration bin $b$ MWh

$N$ set of dispatchable generation technologies being considered -

$WP$ installed wind capacity in portfolio MW

$\rho_{C,G}$ correlation coefficient of the cost of electricity from coal plant versus gas plant and interconnection -

$\sigma_C$ standard deviation of the cost of electricity from coal plant MWh

$\sigma_G$ standard deviation of the cost of electricity from gas plant and interconnection MWh

$\sigma_P$ standard deviation of cost of electricity from generation portfolio MWh
**NOMENCLATURE FOR CHAPTER 4**

\[ F \]  
number of wind farms

\[ FOP_{i,h} \]  
full outage probability. The probability of generator \( i \) becoming fully unavailable in hour \( h \)

\[ FOR \]  
Forced outage rate

\[ \Phi(x) \]  
normalised Gaussian distribution function

\[ G \]  
number of generators

\[ Hr \]  
number of hours until the reliability of the system is restored after a generator outage

\[ MTTR \]  
Mean time to repair \( h \)

\[ PLSFO_{i,h} \]  
probability of load shedding after the full outage of generator \( i \) in hour \( h \)

\[ PLS_{h} \]  
probability of load shedding in hour \( h \)

\[ PLSNOh \]  
probability of load shedding during normal operation in hour \( h \)

\[ PLSPO_{i,h} \]  
probability of load shedding after the partial outage of generator \( i \) in hour \( h \)

\[ Pnafio_{i,h} \]  
power not available after a full outage from generator \( i \) in hour \( h \) MW

\[ Pnapo_{i,h} \]  
power not available after a partial outage from generator \( i \) in hour \( h \) MW

\[ POP_{i,h} \]  
partial outage probability. The probability of generator \( i \) becoming partially unavailable in hour \( h \)

\[ R_{h} \]  
reserve carried by the system in hour \( h \) MW

\[ \rho_{m,n} \]  
correlation coefficient of wind power forecast errors between farms \( m \) and \( n \)

\[ \sigma_{load,h} \]  
standard deviation of load forecast error for hour \( h \) MWh

\[ \sigma_{m,h} \]  
standard deviation of wind power forecast error for farm \( m \) in hour \( h \) MWh

\[ \sigma_{total,h} \]  
total system forecast error for hour \( h \) MWh

\[ \sigma_{total,t} \]  
total system forecast error over \( t \) seconds MWh

\[ \sigma_{wind,h} \]  
standard deviation of wind power forecast error for hour \( h \) MWh
### NOMENCLATURE FOR CHAPTER 5

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Unit</th>
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<tbody>
<tr>
<td>( bp_i )</td>
<td>energy bid of generator ( i )</td>
<td>€/MWh</td>
</tr>
<tr>
<td>( br_i )</td>
<td>reserve bids of generator ( i )</td>
<td>€/MW</td>
</tr>
<tr>
<td>( f_0 )</td>
<td>nominal system frequency</td>
<td>Hz</td>
</tr>
<tr>
<td>( G )</td>
<td>set of generators</td>
<td>-</td>
</tr>
<tr>
<td>( H_{\text{system}} )</td>
<td>system inertial constant</td>
<td>-</td>
</tr>
<tr>
<td>( KE_i )</td>
<td>stored kinetic energy provided by each unit</td>
<td>MWs</td>
</tr>
<tr>
<td>( KE_L )</td>
<td>stored kinetic energy from the load</td>
<td>-</td>
</tr>
<tr>
<td>( KE_{\text{system}} )</td>
<td>total stored kinetic energy on the system</td>
<td>MWs</td>
</tr>
<tr>
<td>( L )</td>
<td>system load</td>
<td>MW</td>
</tr>
<tr>
<td>( N )</td>
<td>number of generators</td>
<td>-</td>
</tr>
<tr>
<td>( P_i )</td>
<td>power from each unit, and thus the size of the contingency resulting from the loss of the unit</td>
<td>MW</td>
</tr>
<tr>
<td>( R_i )</td>
<td>primary reserve from each unit</td>
<td>MW</td>
</tr>
<tr>
<td>( R_T )</td>
<td>system reserve target</td>
<td>-</td>
</tr>
<tr>
<td>( S_b )</td>
<td>rating of the system</td>
<td>MVA</td>
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Acronyms

ALP  Active Load Participation
ANLP  Active Net-Load Participation
AER  Alternative Energy Requirement
AFOP  Average Forced Outage Probability
CCGT  Combined Cycle Gas Turbine
CER  Commission for Energy Regulation
DETI  Department of Enterprise, Trade and Investment
ESB  Electricity Supply Board
ESB NG  Electricity Supply Board National Grid
FB  Fluidised Bed
FOP  Full Outage Probability
FOR  Forced Outage Rate
HVDC  High Voltage Direct Current
IGCC  Integrated Gasification Combined Cycle
IRP  Integrated Resource Planning
LMP  Locational Marginal Pricing
LNG  Liquefied Natural Gas
LOLE  Loss of Load Expectation
LP  Linear Programming
LSI  Load Shedding Incidents
MTTR  Mean Time To Repair
NEMCO  National Electricity Market Management Company
NIAER  Northern Ireland Authority for Energy Regulation
NIE  Northern Ireland Electricity
OCGT  Open Cycle Gas Turbine
PF  Pulverised Fuel
PJM  Pennsylvania, New Jersey, Maryland
POP  Partial Outage Probability
PWR  Pressurised Water Reactor
Rocof  Rate Of Change Of Frequency
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>SM</td>
<td>Scheduled Maintenance</td>
</tr>
<tr>
<td>SONI</td>
<td>System Operator for Northern Ireland</td>
</tr>
<tr>
<td>STMO</td>
<td>Short Term Maintenance Outages</td>
</tr>
<tr>
<td>VIU</td>
<td>Vertically Integrated Utility</td>
</tr>
<tr>
<td>VoLL</td>
<td>Value Of Lost Load</td>
</tr>
</tbody>
</table>
List of Figures

Figure 3-1. Cost of electricity achievable from the various technologies at maximum output for low fuel price scenario and no carbon tax .................................................. 25
Figure 3-2. Cost per MW imposed by each dispatchable generation type as a function of the number of full load hours for the low fuel price scenario and no carbon tax .................. 26
Figure 3-3. Load and net load duration curves with and without 3800 MW of wind capacity .......... 28
Figure 3-4. Daily system peak load and generation capacity after maintenance outage scheduling .... 31
Figure 3-5. Standard deviation of the final LOLE results versus number of years .......................... 32
Figure 3-6. Wind generation capacity credit versus increasing wind capacity ............................. 33
Figure 3-7. Value of objective function versus wind capacity for the high fuel price scenario and 3 different carbon tax scenarios .................................................. 38
Figure 3-8. Value of objective function and total installed capacity versus wind capacity for the high fuel price scenario and a 20 € / Tonne of CO₂ carbon tax ................................. 38
Figure 3-9. CO₂ emissions for both fuel price scenarios as percentage of no carbon tax case .......... 41
Figure 3-10. Optimal wind capacity for a range of gas prices, carbon taxes, and discount rates ....... 43
Figure 3-11. Standard deviation of electricity price from the least-cost portfolios for various fuel price and carbon tax scenarios .................................................. 47
Figure 3-12. Mean-variance portfolio analysis for high fuel price scenario and no carbon tax ........ 48
Figure 3-13. Mean-variance portfolio analysis for high fuel prices scenario and a 30 € / Tonne of CO₂ carbon tax ................................................................. 49
Figure 3-14. Cumulative probability of electricity price for various portfolios ............................... 51
Figure 3-15. Available nuclear capacity and daily minimum and peak load profiles ........................ 52
Figure 3-16. Mean-variance portfolio analysis with nuclear generation for high fuel price scenario and a 30 € / Tonne of CO₂ carbon tax .................................................. 53
Figure 3-17. Load and net-load with and without ALP and ANLP for a single day on the all-Ireland system in 2020 ................................................................. 55
Figure 3-18. Capacity credit for wind generation with ALP and ANLP against increasing wind capacity 56
Figure 4-1. Illustrative plots of the probability of load shedding and reserve level against time during a full generator outage .................................................. 66
Figure 4-2. Gaussian distribution of total system forecast error in hour $h$ .................................... 67
Figure 4-3. Calculation flow chart ................................................................. 69
Figure 4-4. Plot of typical standard deviation of wind power forecast errors per MW of installed capacity for an individual farm versus the forecast horizon .......................... 70
Figure 4-5. Plot of correlation coefficient between individual wind farms’ forecast errors versus distance .................................................. 71
Figure 4-6. Future per county distribution of installed wind power capacity as percentage of total 72
Figure 4-7. Standard deviation of total wind power forecast error for an installed wind capacity
of 1500 MW versus the forecast horizon. ............................... 73
Figure 4-8. Standard deviation of average wind power forecast errors along with the best and
worst case scenarios versus installed wind capacity for a forecast horizon of 6 hours ................................. 74
Figure 4-9. Percentage increase in the total system forecast error versus the installed wind capacity for
forecast horizons of 1 and 6 hours .................................................. 75
Figure 4-10. System reserve level for a various number of load shedding incidents per year
and a forecast horizon of 3 hours against wind power penetration ............................................................. 76
Figure 4-11. System reserve level for an installed wind capacity of 1500MW and for various load
shedding incidents per year versus the forecast horizon ................................................................. 77
Figure 4-12. System reserve level for the average, best and worst case scenarios for a forecast
horizon of 3 hours versus installed wind capacity for a reliability criterion of 3 load
shedding incidents per year .......................................................... 78
Figure 4-13. Conventional reserve categories versus installed wind capacity ............................. 80
Figure 4-14. Load and wind power production for the 24 hour period ................................................. 81
Figure 4-15. Conventional generation capacity needed under the different modes of system operation .... 84
Figure 4-16. NO\textsubscript{X} emissions characteristics for a CCGT and an OCGT ................................. 87
Figure 4-17. System reliability versus reserve for different scenarios .................................................. 90
Figure 4-18. Reserve supply and demand curves .............................................................. 92
Figure 5-1. Generator reserve and kinetic energy characteristics ......................................................... 97
Figure 5-2. Maximum response of a unit which is taken to provide 30 MW of reserve ......................... 99
Figure 5-3. Outline of simplified system frequency model ................................................................. 100
Figure 5-4. Black box model of generator reserve responses .............................................................. 100
Figure 5-5. Response of models to slow frequency drop with 252 MW of reserve ............................ 101
Figure 5-6. Response of models to fast frequency drop with 403 MW of reserve .............................. 101
Figure 5-7. Illustration of the frequency-based constraints .............................................................. 102
Figure 5-8. Wind generation output for test days as a percentage of installed capacity .......................... 104
Figure 5-9. Frequency traces with and with out different Turlough Hill pumps tripping ..................... 105
Figure 5-10. Number of problem contingencies during May 2004 test day .......................................... 108
Figure 5-11. Number of problem contingencies during May 2010 test day ........................................ 108
Figure 5-12. Number of problem contingencies during July 2004 test day .......................................... 108
Figure 5-13. Number of problem contingencies during January 2010 test day .................................... 109
Figure 5-14. Operation of the largest unit during the January 2004 test day ........................................ 110
Figure 5-15. Operation of the largest unit during the January 2010 test day ......................................... 110
Figure 5-16. Market prices for July 2004 test day for (a) Energy, (b) Reserve and (c) Kinetic Energy ....... 111
List of Tables

Table 3-1. Generation costs and characteristics .............................................. 22
Table 3-2. Low and high fuel price scenarios for the all-Ireland system in 2020 ........ 24
Table 3-3. Load duration bins for the all-Ireland system in 2020 .......................... 27
Table 3-4. Dispatchable unit outage characteristics ...................................... 30
Table 3-5. Base case generation portfolio for generation adequacy and capacity credit analysis .................................................. 31
Table 3-6. Installed capacities and proportion of energy served by technologies in the least-cost portfolio for low fuel price scenario and no carbon tax .................... 37
Table 3-7. Least-cost portfolios for various carbon taxes for the low fuel price scenario .......................................................... 40
Table 3-8. Least-cost portfolios for various carbon taxes for the high fuel price scenario .......................................................... 40
Table 3-9. Sensitivity of least-cost generation portfolios to discount rate for low fuel prices scenario and a 10 € / Tonne of CO₂ carbon tax ........................................ 42
Table 3-10. Significant portfolios for high fuel price scenario and no carbon tax ........ 48
Table 3-11. Significant portfolios for high fuel prices scenario and 30 € / Tonne of CO₂ carbon tax ........................................ 50
Table 3-12. Significant portfolios for high fuel prices scenario and 30 € / Tonne of CO₂ carbon tax with and without nuclear capacity option ........................................ 54
Table 4-1. Part of matrix of county distances ................................................. 72
Table 4-2. Time frames of conventional reserve categories and standard deviation of total system forecast error within time frame for 1500 MW of installed wind capacity. ........... 79
Table 4-3. Average reserve needed during the day under different system operation modes .......................................................... 83
Table 4-4. Approximations of cost of reserve availability per year .................. 85
Table 4-5. CO₂ emission under each scenario for test day ............................ 86
Table 4-6. NOₓ emission under each scenario for test day ............................ 87
Table 4-7. NOₓ emissions from CCGTs under each scenario for test day ........... 88
Table 4-8. SO₂ emissions under each scenario for test day ............................ 88
Table 5-1. Change in cost and revenue using the dispatch with frequency-based constraints .................................................. 112
Table A-1. Probability of having 1, 2 and 3 unit outages in the same hour ........ 136
Chapter 1 – Introduction

This chapter introduces at the highest level the work presented in this thesis and aims to convey the nature of the work in relation to the challenges faced by the modern electricity industry.

1.1 MODERN ELECTRICITY SYSTEMS

Affordable and reliable electricity is one of the pillars on which modern society has been built. Electricity continues to be crucial to every aspect of the modern economy and governing powers continually strive to improve the efficiency, cost-effectiveness and reliability of electricity supply. In the past many of these improvements came in the form of significant engineering advancements. The engineering-focused environment of the vertically integrated utility (VIU) may have played an important role in achieving this. However, in more recent times improvements in efficiency and cost-effectiveness have been sought by trying to introduce competitive forces into the industry with liberalised markets. The impetus for this change is largely political, with directives such as the EU Directive 2003/54/EC on Electricity Markets (EU, 2003a) and the Federal Energy Regulatory Commission Order 2000 (FERC, 1999) defining the broad requirements for such markets.

As scientists continue to uncover the true extent of global warming, the international community has slowly begun to take the first steps to address the problem. The Kyoto Protocol (UNFCCC, 1997), ratified on the 16th of February 2005, and the European emission trading scheme (EU, 2003b) are seen as only the first of a wide range of measures needed to effectively combat the problem of global warming. The electricity industry is seen as an area with significant potential for reduction of harmful greenhouse gasses and there has been a recent push towards renewable electricity generation for this reason (EU, 2001a).

The electricity industry is a major consumer of fossil fuels. The rapid economic growth of populace countries such as India and China, along with certain international conflicts have caused significant increases in fossil fuel prices. This upward trend is likely to
continue as the global fossil fuel resources become more depleted (EIA, 2004). The increasing concentration of remaining fossil fuel resources in certain regions may also make fossil fuel prices more volatile. The future fossil fuel price characteristics will have a significant impact in electricity industries and the societies that rely on them.

It is in this context the modern electricity industry finds itself. Dealing with the challenges of volatile fuel prices and the integration of renewable energy is made more difficult given that they must be managed in a way that does not conflict with principles of the liberalised market.

1.2 CHALLENGES IN INTEGRATING RENEWABLE ENERGY

Increasing the proportion of electricity served by renewable sources is cited as a means to reduce greenhouse gas emissions and reduce the reliance on fossil fuels (Zervos, 2003; Neuhoff, 2005). Hydro electricity has played a crucial role as a cheap source of energy in the early stages of many power systems. However, the potential for further hydro expansion in most developed countries is limited by a shortage of suitable sites. There are many other renewable technologies, which have the capability of providing large amounts of energy, but most have not developed sufficiently to be competitive in the short to medium term with conventional fossil fuel plant (SEI, 2004a). There is however one notable exception to this: wind power. Wind generation has developed rapidly over the last decade, with significant advancements in turbine technology and site construction. Wind generation is fundamentally different to generation from conventional fossil fuel plants in many ways. It does not utilise conventional synchronous generators, which has implications for voltage control and the wind generators ability to stay connected during system disturbances. It has been described as “non-dispatchable” as its generation output is limited by the wind available at the time. The limited extent to which wind power can be forecasted also has significant implications for system scheduling and operation.

The unique nature of wind generation has led to difficulties in foreseeing how it will impact on systems. Present power system operation and planning methods have evolved to accommodate conventional fossil fuel generation and many are now found to be inadequate in systems with large penetrations of wind generation. Even studies (ESB
NG 2004a; RAE, 2004) assessing wind generation on an economic basis deal inadequately, or in a piece-meal way, with the complicated cost elements associated with unique characteristics of wind generation.

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

1.3 Focus of Research

Three new methods for planning and operating electricity systems with significant wind generation are presented. These methods deal with diverse aspects of system planning and operation. Conceptually new perspectives are taken on traditional problems to successfully deal with them in the context of the modern electricity industry.

Chapter 2 gives a general overview of the modern electricity systems and the problems facing them. Particular attention is given to the problems currently facing the all-Ireland system. These problems are seen as indicative of the problems that may face other systems as wind penetrations increase.

Chapter 3 starts with a review of the role of central generation planning in a liberalised electricity industry. A new methodology is developed to help in the planning of optimal generation resource portfolios. The methodology uses capacity and other system based constraints to find a least-cost generation mix for various fuel price and carbon tax scenarios. The extent of the role played by wind generation and other generation types in least-cost portfolios can then be properly established. Techniques from financial theory are then applied to examine the benefits of portfolio diversification given the uncertain nature of future fuel prices. The possible role that nuclear fission and active load participation may play in the future are also examined.
Chapter 4 describes the problem of quantification and provision of system reserve with significant wind penetrations. The difficulties arising from increased wind penetrations are discussed and a new probabilistic methodology to deal with the issue is presented. Wind power forecast and load forecast information is used along with conventional units’ outage data to relate the amount of reserve to a system security criterion. The forecast horizon and dispatch time are shown to be an important factors in the amount of reserve required. Some adaptations of the methodology are then shown to illustrate how it can be incorporated into modern market structures.

The short-term frequency control problem is dealt with in Chapter 5. This problem is more pertinent in smaller isolated systems like the all-Ireland system. The increasing amount of High Voltage Direct Current (HVDC) interconnection and wind generation has led to concerns that their may not be sufficient kinetic energy available to the system to avoid sudden drops in system frequency following a generation outage. A new method to address this issue is presented. Starting from a validated dynamic system model, constraints are derived which relate the load level, generation operating points, primary reserve level and system kinetic energy to system security criteria. A rate of change of frequency constraint and a minimum frequency constraint are created. These constraints are then incorporated into a co-optimised energy, reserve and kinetic energy dispatch to illustrate the nature of the trade-offs involved with secure least-cost dispatch. The methodology can encapsulate the characteristics of generation that may not provide any inertial response such as wind generation, and also produces the marginal prices for energy, reserve and units’ stored kinetic energy.

A general conclusion regarding the entire work is given in Chapter 6 along with suggestions for future research.
Chapter 2 – Challenges Facing the Electricity Industry

Since its inception in the 1880’s the electricity industry has faced and overcome a varied array of challenges. Some of the challenges that the modern electricity industry has to deal with are far removed from the purely technical problems that faced the founders of the industry 120 years ago. Many problems were definitively dealt with during the evolution of the industry (EEI, 2005), other issues, like optimising fuel choice, persist. This chapter outlines the main challenges faced by modern electricity systems particularly in relation to the integration of renewable energy. The specific challenges facing the all-Ireland system are also described.

2.1 Market Liberalisation

In recent times the political climate in many countries has lead to a trend towards the introduction of competitive market forces into the electricity industry (Hunt and Shuttleworth, 1996). The general hope is that market forces will be able to prompt increased performance and efficiency in the electricity industry as it has done elsewhere in the free market economy. However, the electricity industry is unique in nature and it remains unclear whether market liberalisation will result in a better outcome than would have been achieved by regulated monopolies or vertically integrated utilities. Despite this, most electricity systems in the developed world have liberalised or are undergoing restructuring to some extent. The EU Directive 2003/54/EC on Electricity Markets (EU, 2003a) and the Federal Energy Regulatory Commission Order 2000 (FERC, 1999) are two of the most significant measures in this respect.

Frequently electricity industry liberalisation involves the introduction of a competitive market and while the extent of market benefits is unknown, electricity markets do present the industry with significant challenges. At the highest level these challenges fall into two categories. The first is the challenge of introducing, operating and regulating a competitive market for electricity. The second category is the difficulties that market liberalisation may cause while trying to address other issues.
2.1.1 Establishing Successful Electricity Markets

The establishment of a successful electricity market requires the appropriate market design, the correct regulatory framework and an insight into what aspects of the industry can benefit from a competitive market. A multitude of electricity markets have been implemented around the world with varying degrees of success. Among the first to establish a competitive market was the England and Wales system in 1990. This was initially set up as a gross pool market with capacity payments (Newbery, 2004). As a result of insufficient competition and some market design flaws, the gross pool market was strategically exploited by participants (Wolfram, 1998) and was replaced by a physical bilateral market in 2001. It is generally accepted that the bilateral market is performing better than the previous market (Currie, 2000). In 2000, the California system saw systematic price gouging by colluding market participants and a series of rolling blackouts due to a lack of capacity (Narinder, 2002). This was the most high-profile market failure and has been generally attributed to poor handling by the regulatory bodies (Slye, 2001). Other electricity markets have been established relatively successfully. The Pennsylvania New Jersey Maryland Interconnection (PJM) is the world’s largest competitive wholesale electricity market and was one of the first to implement Locational Marginal Pricing (LMP) (PJM, 2005). Established in 1998, the market is held in high regard as being of sound design and well operated (Rourke, 2003). Australia’s national electricity market, managed by the National Electricity Market Management Company (NEMMCO), started operation in 1998. Since then it has proved relatively successful in fostering and controlling competitive forces with 5 and 30 minute energy markets along with futures and derivative markets (NEMMCO, 2004a).

It is important to understand the difficulties that surround implementing competitive electricity markets. Global experience has shown that fully liberalised markets can be implemented successfully with good regulatory insight and market design. However, the consequences of getting market liberalisation wrong are potentially disastrous, as has been illustrated in places like California.
2.1.2 Addressing Other Issues in a Liberalised Market

Along with the challenge of establishing a successful electricity market, liberalisation also presents the problem of having to deal with other issues through a market system which might not be suitable to deal with such issues. These issues include, but are not limited to the problems of sufficient system capacity, fuel diversification, and the integration of renewable energy. The possible consequence of this is frequent direct intervention in the market, which itself is not desirable.

Some markets, which do not provide direct capacity payments have shown difficulties in attracting new private investment (Smith, 2005). This has lead to either tender competitions for power purchase agreements (CER, 2003a) or calls to build more publicly owned generation (Bush, 2001). Fuel diversification to reduce exposure to price shocks is often of concern to national electricity systems, especially in countries that import large proportions of their primary energy needs (Awerbuch, 2004a). It has been pointed out that there is little incentive for generation investors to consider fuel price shocks as they are often passed on fully to customers leaving generator profitability relatively unaffected (Fitz Gerald, 2002). The integration of renewable electricity into electricity markets has posed many problems. Wind generation in particular has caused difficulties due to its variable and uncertain nature (Hirst, 2001). Its nature may not be in direct conflict with the fundamental objective of providing cheap reliable electricity but in electricity industries that have been tailored to suit conventional generation it can be argued that it is not always treated equitably (Bathurst, 2001; Neuhoff, 2005).

Market liberalisation means that these problems must now be dealt with in a different manner than they would have been by in the past with VIUs. With vertical integration the utilities could simply build new capacity, diversify fuel sources, or increase wind generation and would be in a position to centrally coordinate related generation, transmission and operational issues (Kirschen and Strbac, 2004). In a liberalised market, behaviour must be incentivised but to date no implemented market design has proved capable of providing correct incentives for all the requirements demanded from electricity systems by society.
2.1.3 Summary

Electricity industry liberalisation is now a reality in systems all around the world. The regulatory, institutional and market implications of this must be understood in order that work aiming to progress modern electricity systems is carried out in the correct context. The nature of electricity markets must be properly understood, but so must their shortcomings and limitations. It must be remembered that while the national interest may, in general, be served by having a electricity market, the national interest is not always of concern in an electricity market. Fully realising this and what markets can and cannot do is as important to the success of the electricity industry as the establishment of the market itself.

2.2 Renewable Energy

2.2.1 Background

Over the last decade the body of work examining global warming has grown rapidly (IPCC, 2001). The reality of climate change is now broadly accepted with the exception of a few groups with vested interests and credible research in the area is generally now focused on examining the extent and effects of climate change (EPA, 2003; Root et al. 2003). Climate change presents the global community with an unprecedented challenge and one which demands global cooperation. The emergence of such problems have been envisaged as far back as 1968 by Hardin (1968) and which, according to his theory are a result of aspiring to infinite growth on a finite planet.

On the 16th of February 2005 the international community took a major step towards addressing this problem (CAN, 2005). The ratification of the Kyoto Protocol (UNFCCC, 1997) commits industrialised nations to reducing emissions of greenhouse gases, principally carbon dioxide, by around 5.2% below their 1990 levels by the period 2008-2012. This is seen as only the first corrective step in a wide range of measures needed to combat the problem of climate change (IEA, 2003a).

Although many countries in the world have very low per capita emissions, these counties have legitimate expectations for future economic development (Jenkins, 2001). China and India, the world's two most populous countries have already shown sizable
economic growth over the past years, and this is predicted to continue into the future (NIC, 2005). This puts the onus on the high emitting developed countries to reduce their emissions and develop the new technologies required to achieving this. The European Union has lead the way on this with the establishment of a emissions trading scheme (EU, 2003b), and a directive obliging all member states to achieve a given percentage of their electricity consumption from renewable sources (EU, 2001a).

2.2.2 Reducing Emissions in the Electricity Industry

The electricity industry has been specifically sighted as having potential for emissions reduction (Helm, 2005). Nuclear energy, renewable energy, carbon dioxide sequestration of emissions from fossil fuel plant and demand reduction from increased end-use efficiency have all been touted as a means to reduce emissions in the electricity industry (IEA, 2002). Each of these measures however, comes with associated challenges.

Carbon dioxide capture and sequestration technology is costly and still in development. Doubts also surround the permanence of the carbon dioxide storage (Gielen, 2003). Nuclear energy is a relatively developed technology capable of supplying cheap electricity (RAE, 2004) and even some leading environmentalists have advocated it as the only realistic solution to climate change (Lovelock, 2004). However, public opposition to nuclear energy in many countries is strong due to concerns over safety, security and radioactive waste disposal. This opposition is likely to restrict the development of nuclear facilities in many countries in the near future (EIA, 2004).

With reductions in energy consumption proving difficult to achieve, partially due to the diverse nature of energy consumption, renewable energy is seen as the only option for emission reduction in many countries (Zervos, 2003; Neuhoff, 2005). The range of renewable technologies is wide and varied. Tidal stream, wave energy, on and off-shore wind generation, hydro, photovoltaic, and various types of biomass and biogas projects are all forms of renewable generation currently being developed. Hydro generation is probably the most competitive and well-established renewable technology and it has played an important role in the early days of many electricity systems (ESB, 2005). The potential for future development of hydro projects is limited in many countries due to
the lack of suitable sights. Of the remaining renewable technologies wind power is generally seen as the most competitive (SEI, 2004a).

2.2.3 Wind Generation

Wind generation has seen a large expansion over the last decade with an annual growth rate of around 30% each year (EWEA, 2004). Almost three quarters of the total installed wind capacity worldwide is in Europe and wind turbine technology and construction continues to develop at pace. Some sources (EWEA and Greenpeace, 2002), suggest that wind power can supply 12% of the of global electricity demand, assuming that global demand doubles from 2002 by 2020.

Wind generation is based on extracting kinetic energy from the wind and consequently differs in many ways from conventional thermal generation. Wind turbines are generally based on induction generators (Heier, 1998) while conventional plant almost exclusively utilise synchronous generators. The necessity for wind turbines to be sited where there is a good wind resource results in wind farms being dispersed around the system and often embedded in the distribution system (Jenkins et al. 2000). Also, the energy production from a wind turbine is variable (Hurley and Watson, 2002) and limited by the wind conditions at any given time. The output of the wind farms is also only forecastable to a certain extent (Watson and Lanberg, 2003). These characteristics differ greatly from those of typical thermal generation, and while they may not conflict with the fundamental objective of supplying cheap reliable electricity to consumers, the unique nature of wind generation does present significant challenges in its incorporation into modern electricity systems.

2.3 Integration of Wind Power into Modern Electricity Systems

The secure and continuous operation of the power system is the first priority for any system operator. With wind capacity increasing worldwide many system operators and planners are beginning to analyse the effects of wind power on their systems. There is a notable similarity in the issues being addressed in different systems (Garrad Hassan, 2005; Parsons et al., 2004).
2.3.1 Planning Issues

From a high level perspective, system planners around the world are endeavouring to determine the financial impact of integrating large amounts of wind generation into systems. Some of this work has focused on immediate development, system and operational costs (DTI, 2002; DETI, 2003; Dena, 2005). Other work has taken a higher level perspective and has tried to determine the longer term social and financial benefits of wind power (Awerbuch, 2004a; Kennedy, 2005). The unique characteristics of wind generation introduce complicated cost elements into the generation supply analysis (Khatib, 2003). There are transitional costs involved, such as the initial impact of wind power on the conventional units (ESB NG, 2004a) which may be distinct from the cost of wind generation in a portfolio of plant which has evolved to complement the wind generation. Least-cost generation planning is the subject of the work presented in Chapter 3 of this thesis.

2.3.2 Connection Issues

Voltage regulation, harmonic emissions and the sustainability of generation following disturbances in the network are of concern in power systems. These issues may be exaggerated when wind-farms are located within an electrically weak region of the network (Mullane, 2003). Unfortunately the most favourable locations for wind energy often correspond to weak areas of the network. System operators are now starting to develop grid codes specifically for wind farms (ESB NG, 2004b) with the aim of communicating the minimum technical requirements necessary to maintain the integrity of the system. Ongoing improvements in wind turbine technology and electronics (Mullane et al., 2005) and the development of active control systems for the transmission and distribution system (Shafiu et al., 2004) will no doubt play an important role in the continuing safe operation of the system from a network perspective.

The actual cost of network expansion to facilitate the connection of wind power can be significant and assessments of the necessary network reinforcement costs have already been undertaken in some systems (DTI, 2002; DETI, 2003; Dena, 2005). Other work is focused on the optimal siting and sizing of renewable projects on the existing network.
to maximise the capacity of renewable that can be accommodated (Kuri et al., 2004; Keane and O’Malley, 2005).

### 2.3.3 System Operation and Dispatch Issues

The unique nature of wind generation poses serious challenges for systems in relation to the dispatching of energy and reserves. The limited extent to which wind power can be forecast and the variability in the forecast accuracy (Pinson and Kariniotakis, 2003) makes assessing how much reserve a system needs to cover for likely generation shortfalls more complex. In Chapter 4 a new methodology is presented which quantifies the required amounts of reserve in systems with significant wind capacity.

The variability that surrounds many aspects of the wind generation introduces a more stochastic dimension to the scheduling and dispatch. While sophisticated scheduling and dispatch algorithms (Baldick, 1995; Walsh, 1998) have been developed to deal with multiple constraint problems for conventional generation plant, large amounts of wind power require a significantly different approach to be adopted. This will probably require that systems or markets be dispatched and redispached more frequently to better reflect the changing circumstances in the system (Hirst, 2001). No system to date has developed a full unit commitment and dispatch methodology that fully incorporates the characteristics of wind generation.

Wind turbines generally do not provide frequency responsive reserve as they are generally designed to run at maximum available output. Some turbine configurations do not make their stored kinetic energy available to the system (Holdsworth et al., 2004), due to turbine control circuits being decoupled from the system frequency. This has significant consequences for control of frequency (Lalor et al. 2005a) after the loss of a large infeed and is of particular concern in smaller weakly interconnected systems. A new methodology in Chapter 5 uses dispatch constraints to account for the characteristics of the generation units and ensures adequate frequency control after the loss of any single unit.


2.4 The All-Ireland System

The all-Ireland electricity system consists of both the Northern Ireland and Republic of Ireland systems. It currently has an installed capacity of approximately 8000 MW and just one HVDC interconnector from the Northern Ireland system to Scotland. Energy demand in Northern Ireland is roughly one third of that in the Republic of Ireland system. The relatively small and weakly interconnected nature of the system makes frequency control and system operational issues more challenging than they would be in other systems. Although both the Republic of Ireland and Northern Ireland systems are currently operated separately, there are plans for single all-Ireland market and system operator (AIP, 2005a). There is currently a reserve sharing agreement between the two jurisdictions. Due to the small system size and corresponding operational constraints, there is a limit to the size of generation unit that it is feasible to develop. Currently the largest unit, whose output can be lost due to a single failure, is rated at 422 MW, (ESB NG, 2005). The existing interconnector has a capacity of 500 MW, but due to operational reasons is limited to a capacity of 400 MW. There are plans to build at least one more similar interconnector from the Republic of Ireland to Wales (CER, 2004a). There is one 292 MW pumped storage station located at Turlough Hill. This station plays an important role in system operation and reserve provision. The all-Ireland system has a relatively old generation portfolio with gas plant making up about 52% of the installed capacity, coal 16%, oil 12%, interconnection 6%, peat 4%. Wind generation, pumped storage and hydro make up the remainder.

2.4.1 Market Liberalisation in Ireland

In both the Republic of Ireland and Northern Ireland market liberalisation has been slow. In the Republic of Ireland industry restructuring formally commenced in 1999 (DCMNR, 1999a), instigated by the EU directives on markets (EU, 1996). Since then a transitional market based on physical bilateral contracts and a “top up and spill” balancing mechanism, has been in operation. This market is dominated by the incumbent state-owned regulated utility. Despite full retail market opening in 2005 the objective of increased competition was only partially achieved with only a few large-scale independent generating stations being built since liberalisation began. The lack of investment in Ireland has been blamed on the dominance of the incumbent utility, the Electricity Supply Board (ESB), and on significant market and regulatory uncertainty.
(Slye, 2001; GEC, 2002). In 2004 the energy regulator in the Republic of Ireland, the Commission for Energy Regulation (CER), tried and failed to establish a LMP spot market (CER, 2003b). The proposed market was deemed to be inappropriate by almost all stakeholders.

In Northern Ireland, all non-domestic customers are eligible to choose a supplier since April 2005 and full retail market opening is expected by 2007 (NIAER, 2005). Responsibility for the regulation of the industry is in the hands of the Northern Ireland Authority for Energy Regulation (NIAER). Competition in generation is also limited with the market dominated by a few incumbent privately owned companies. These generators are generally required under a series of power procurement agreements and generating unit agreements to sell all their output to the incumbent supplier Northern Ireland Electricity (NIE), (UNEP FI, 2003).

Market liberalisation in both jurisdictions has been hampered by the relatively small nature of the systems. In 2004, CER and NIAER signed a memorandum of understanding agreeing a set of principles on which to base a single wholesale electricity market on the island (AIP, 2004). The proposed larger market should lead to lower risk of entry for generators and suppliers as well as allowing better economies of scale to be achieved. In June 2005 the regulatory bodies published their high level design decision, stating that it should be a gross pool market with central commitment and capacity payments (AIP, 2005b).

2.4.2 The Role of Wind Generation in Ireland

Ireland’s on-shore wind resource is among the best in Europe, particularly along the western seaboard (SEI, 2004b). In the Republic of Ireland the first governmental initiative towards increasing renewable energy was set out in the green paper on renewable energy (DCMNR, 1999b). This set an additional target of 500MW of renewable capacity to be installed in the Republic of Ireland by 2005. Although this target has not yet been achieved progress has been made and there is a significant amount of projects in the planning stages (CER and OFREG, 2003). Under the European Directive (EU, 2001a) the Republic of Ireland is required to supply 13.2% of its energy from renewable sources by 2010. It is thought that in meeting this target wind energy would supply about 10% of energy demand. The UK government, in its energy
white paper (DTI, 2003) set out a target of 10% of electricity to be provided from renewable sources by 2010. In line with this the Department of Enterprise, Trade and Investment (DETI) in Northern Ireland indicated that they aim to set a development target for renewables equivalent to 12% of consumption by 2012 (DETI, 2004). Again, it is thought that wind energy will comprise most of this target.

### 2.4.3 Wind Power Integration in Ireland

At the end of May 2005 the installed wind capacity in the Republic of Ireland was 383 MW and 103 MW in Northern Ireland. On the island there is close to another 1000 MW with either connection agreements or in the advanced planning stages. This means there could be around 1500 MW of installed wind capacity on the island by 2007. Given the size of the all-Ireland system and the current projections wind capacity is likely to comprise a significant portion of the system. At times of relatively high wind generation and low load wind generation will be capable of supplying a considerable percentage of demand.

Due to high imported fuel prices and a good wind resource, wind generation in Ireland is reasonably competitive with conventional plant, but there is a divergence of opinion in Ireland on whether wind generation needs an additional support mechanism (CER, 2005; SEI, 2004a). In Northern Ireland the DETI have decide to support renewable energy by placing a legal requirement on suppliers to source a specified proportion of their electricity from renewable sources and to pay a 'buy-out' fee for any shortfall in meeting that requirement (DETI, 2005). Despite having a stated renewable energy target of 12% by 2012, the DETI has decided to only set a renewable obligation of 6.3% for 2012. In the Republic of Ireland renewable energy support took the form of competitive tender power purchase contracts under the Alternative Energy Requirement (AER) programmes (DCMNR, 2004). Successful AER applicants are those who offer to sell the electricity for 15 years to the ESB at the lowest price at or below a cap price. This program was not completely successful as many projects that were awarded contracts were later unable to develop the project because the agreed price was too low (Feasta, 2004). The government are currently planning to incentivise additional renewable energy through a direct feed-in tariff (Dempsey, 2005).
Although there are plans to build further HVDC interconnector to Wales (CER, 2004a), the all-Ireland system will remain relatively isolated, a fact that will make the incorporation of a large amount of wind capacity more challenging (Persaud, 2000). Due to concern over the increasing amount of wind generation applying for connection, the respective system operators restricted the development of wind capacity in both jurisdictions until they were satisfied that system security would not be compromised. At the end of 2003 the system operator in the Republic of Ireland, the Electricity Supply Board National Grid (ESB NG) placed a moratorium on connection offers for wind projects (CER, 2004b). In the intervening time both system operators developed wind grid codes (ESB NG, 2004b; SONI, 2005) which outline minimum technical requirements needed for wind farms to be granted connection. In July 2004 the moratorium was lifted in the Republic of Ireland and the system operator is working with the wind developers towards full compliance with the new grid code.

Current wind generation in Ireland is relatively small and from an operational point of view the variations from the wind dissolve into the much larger variations from the load. This will not be the case with higher penetrations of wind capacity. Both system operators are developing wind power forecasting capabilities but as yet have not indicated how they propose to schedule and dispatch the system with large quantities of wind generation. This challenge has been complicated further by the incomplete plans for a future all-Ireland market (AIP, 2005b). The system operator in the Republic of Ireland system has indicated that wind generation may have to be curtailed at times for system operational reasons (ESB NG, 2004c). If wind generation is not compensated for this lost production it may start to impact on the viability of projects as wind generation capacity becomes more significant.

### 2.5 SUMMARY

This chapter has outlined at a high level the challenges facing modern electricity systems. Market liberalisation and the role of renewable energy have been discussed and the problems surrounding the integration of wind generation into system have been introduced. A general description of the all-Ireland system and the challenges facing it has also been given.
The next three chapters will present new methodologies and analysis relating to some of the challenges faced by modern electricity systems. In Chapter 3 a methodology to assess the optimal generation portfolio for the all-Ireland system is presented. This aims to establish a truer picture of the value of wind generation and other generation types in least-cost portfolios.

In Chapter 4 a methodology is presented which quantifies the amount of reserve needed in systems with large wind penetrations. This methodology can be applied to methods of market based dispatch, and can be used to derive demand curves for reserve.

In Chapter 5 the methodology presented establishes system dispatch constraints that will ensure that system frequency criteria are maintained during the loss of a single infeed. The constraints can encapsulate characteristics of wind generation and are also compatible with liberalised market structures.

Each chapter begins with a discussion and further literature review of the relevant topic.
Chapter 3 – Generation Resource Planning for the All-Ireland System

This chapter begins with an overview of generation planning, and how its role has changed as a result of the industry restructuring. A new methodology is developed to determine least-cost generation portfolios for the all-Ireland system. The effect of wind generation on system capacity and load duration characteristics is modelled to determine accurately the role that wind generation plays in least-cost energy portfolios. The characteristics of the resultant portfolios are assessed for various carbon tax and fuel price scenarios. Mean-variance portfolio theory is applied to examine the benefits of portfolio diversification in terms of avoiding exposure to volatile fuel prices. The possible benefits of nuclear generation and active load participation (ALP) are also examined.

3.1 Background

Integrated Resource Planning (IRP) seeks to identify the mix of resources that can best meet the future electricity needs of consumers, the economy and society (Khatib, 2003). In the past, VIUs carried out IRP and were in a position to coordinate and execute such plans. Planning methods grew increasingly sophisticated considering not just least-cost energy but also other objectives such as the robustness of generation resource plans in relation to uncertainties.

Tanabe et al. (1993) develop a multi-objective optimisation algorithm to determine a flexible generation mix in light of production cost uncertainties. The state of uncertain variables is weighted in the analysis and the generation mix is solved for using a dynamic programming technique. Burke et al. (1998) present a generic technique for multi-objective planning with uncertainty. The technique allows for a fair comparison of alternative plans in an attempt to resolve multiple conflicting objectives. This approach to decision making allows the identification of robust plans which may not be optimal in the strictest sense, but represent a reasonable compromise. Hobbs and Meier (1994) compare different multi-criteria decision making methods in the context of...
electricity utilities. Of the methods examined, no one method proved to be significantly better than the others. It was found that the need to assign weighting to various criteria in objective functions introduced the potential of method bias previously identified by psychologists.

With the recent onset of market liberalisation in many systems there has been a corresponding de-emphasis on central planning and many modern planning techniques now focus on shorter-term generation expansion problems and often from the perspective of a profit maximizing market participant (Siddiqi, 2000; Botterud et al., 2005). Market driven planning may not always result in the most desirable outcomes for the economy and society that the electricity system is serving (Fitz Gerald, 2002). Systems that have been exposed to the adverse effects of market failures such as California, and others in the north west of the United States have recently, again resorted to more comprehensive long-term central resource planning with the aim of ensuring reliable and economic supply of electricity (CEC, 2003; NPCC, 2005). Helm (2005), commenting on the evolution of the electricity industry states that, “the two simplistic ways forward – pure markets and planning – have given way to a mixture of both”.

Implementing any type of generation resource plan in many systems today is more challenging than it may have been in the past, as it must, in general, be done in parallel with an electricity market. A combination of market design features, direct or indirect subsidies, policy measures, or even new state owed generation may be necessary to implement a plan. However, initiating the correct regulatory interventions or policies cannot be done without analysis and insight into how the system evolves into the future.

Wind generation, due to its unique characteristics, is often dealt with inadequately in generation planning and generation cost comparisons. While most types dispatchable thermal generation have very similar characteristics in terms of contributing to generation adequacy, wind generation’s characteristics are quite different. This is often overlooked (Awerbuch and Berger, 2003). The nature of the interactions of wind generation with the load and other generation types means that simple per kWh electricity cost comparisons (RAE, 2004) are not appropriate to assess the relative merit of wind generation.
The following sections will outline a new methodology to assess the optimal generation portfolio for the all-Ireland system in 2020. Section 3.2 will outline the overall approach and presents the problem inputs such as generator costs and characteristics, fuel prices, carbon taxes and wind and load characteristics. Section 3.3 makes an assessment of the capacity contribution of wind generation and other types of generation to system adequacy. Section 3.4 presents the least-cost portfolio optimisation algorithm. Least-cost portfolio results and scenario analysis is presented in Section 3.5. The issue of generation portfolio diversification is dealt with in Section 3.6. Illustration of the possible benefits of Active Load Participation and nuclear generation follow along with a summary.

3.2 APPROACH AND INPUTS

This section describes the approach and inputs adopted to try and determine least-cost generation portfolios for the all-Ireland system in the future. A single target year was chosen to gain insight into the generation resource problem and transitional issues are not considered to reduce the dimensionality of the problem. The year 2020 was chosen and the analysis assumes all existing plants except hydro, pumped storage and interconnection are retired by this year. This assumption is reasonable as most of the units on the all-Ireland system are quite old and would be decommissioned by 2020. Load duration characteristics and system capacity are dealt with and the unique characteristics of the wind generation are incorporated. This is done by assessing the wind generation’s impact on the net-load profile of the system. The approach allows the extent of the role played by wind generation in least-cost portfolios to be determined more accurately than it has been in the past.

The aim of the work is to formulate the problem in such a way as the least-cost generation portfolios can be found using a linear programming (LP) optimisation. Least-cost portfolios can be interpreted as what would be the result of a cost reflective market place by 2020 provided transitional issues did not greatly affect the evolution of the generation mix. Various scenarios are considered in the analysis to gain insight into the possible shortcomings of these generation portfolios and to gain insight into appropriate policy decisions.
3.2.1 Generator Inputs

A comprehensive list of generator data was gathered. Unit sizes, characteristics, efficiencies and costs were gathered from many sources (RAE, 2004; ESB NG, 2004a; CER, 2004c; GE-E, 2004; SEI, 2004a; Junginger et al., 2004). Table 3-1 shows the generators and their characteristics assumed for this work. Other types of generators were also considered but later deemed to be irrelevant as they had similar characteristics to generation listed in Table 3-1 but higher production costs. Oil fired generation was one such technology. Liquefied Natural Gas (LNG) infrastructure and generation is not considered here as it is generally accepted to be uneconomic in Ireland (DCMNR, 1999c; Bergin et al., 2005).

Although the algorithm solving for generation portfolios will not consider generation plants of any discrete size, the costs and characteristics are based on units of a certain size shown in Table 3-1. The small size of the all-Ireland system limits the size of generation units that it is feasible to build. It is assumed here that the units can be no larger than 400 MW. Restrictions on the size of unit that can be built has cost implications which other systems may not be exposed to.

The capital costs and operation and maintenance costs shown in Table 3-1 are expressed in current value, € 2005. Capital costs are shown in €/MW installed and include the cost of interest on the phased capital expenditure during construction. The practice of phasing of capital expenditure during the build time of the plant is modelled here by assuming the full capital cost is incurred half way through the build time. Operation and maintenance costs are simply expressed here in €/MW per year rather than in fixed and variable costs. The costs shown here reflect the assumed engineering, procurement and construction costs of the plant. The costs do not include the cost of land purchases, relevant permits, the costs of electricity transmission over the network, developer costs, financing charges or other costs commonly called soft costs. It is assumed that the decommissioning of the plant is cost neutral, except that of nuclear which has the cost of decommissioning included in its capital cost (RAE, 2004). Future reductions have been factored in for the cost of the wind capacity as it is assumed that the technology is still maturing and benefiting from upsizing of units (Junginger et al., 2004).
<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Notional Size of Installation (MW)</th>
<th>Plant Life (Years)</th>
<th>Build Time (Years)</th>
<th>Average Efficiency (%)</th>
<th>Capital Cost (€/MW)</th>
<th>Op &amp; Main (€/MW p.a.)</th>
<th>CO₂ Emissions (Tonnes Co₂/MWh)</th>
<th>Avail (%)</th>
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<td>1,479,200</td>
<td>34,800</td>
<td>0.92</td>
<td>84</td>
<td>-</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>2 x 400</td>
<td>25</td>
<td>5</td>
<td>48</td>
<td>1,761,321</td>
<td>69,000</td>
<td>0.71</td>
<td>85</td>
<td>-</td>
</tr>
<tr>
<td>Peat FB</td>
<td>150</td>
<td>25</td>
<td>4</td>
<td>37</td>
<td>1,223,807</td>
<td>55,200</td>
<td>1.15</td>
<td>87</td>
<td>1000</td>
</tr>
<tr>
<td>OCGT</td>
<td>110</td>
<td>20</td>
<td>1</td>
<td>43</td>
<td>518,411</td>
<td>36,000</td>
<td>0.47</td>
<td>92</td>
<td>-</td>
</tr>
<tr>
<td>CCGT</td>
<td>390</td>
<td>20</td>
<td>2</td>
<td>56</td>
<td>537,500</td>
<td>50,000</td>
<td>0.36</td>
<td>88</td>
<td>-</td>
</tr>
<tr>
<td>Nuclear Fission</td>
<td>2 x 400</td>
<td>30</td>
<td>5</td>
<td>-</td>
<td>1,999,758</td>
<td>59,500</td>
<td>0</td>
<td>88</td>
<td>-</td>
</tr>
<tr>
<td>Wind 1 (On-Shore)</td>
<td>30</td>
<td>20</td>
<td>2</td>
<td>-</td>
<td>981,475</td>
<td>34,800</td>
<td>0</td>
<td>100</td>
<td>1200</td>
</tr>
<tr>
<td>Wind 2 (Mix)</td>
<td>30</td>
<td>20</td>
<td>2</td>
<td>-</td>
<td>1,028,775</td>
<td>54,250</td>
<td>0</td>
<td>100</td>
<td>2600</td>
</tr>
<tr>
<td>Biomass &amp; Biogas 1</td>
<td>10</td>
<td>20</td>
<td>2</td>
<td>-</td>
<td>2,418,750</td>
<td>80,000</td>
<td>0</td>
<td>78</td>
<td>70</td>
</tr>
<tr>
<td>Biomass &amp; Biogas 2</td>
<td>10</td>
<td>20</td>
<td>2</td>
<td>-</td>
<td>3,386,250</td>
<td>90,000</td>
<td>0</td>
<td>78</td>
<td>50</td>
</tr>
<tr>
<td>Biomass &amp; Biogas 3</td>
<td>10</td>
<td>20</td>
<td>2</td>
<td>-</td>
<td>4,353,750</td>
<td>90,000</td>
<td>0</td>
<td>78</td>
<td>500</td>
</tr>
</tbody>
</table>


Table 3-1. Generation costs and characteristics.

The costs and characteristics assumed here for nuclear fission generation are conservative and are based at the higher end of the range of values estimated in RAE (2004). The costs are based on the nuclear plant fitting into the greater nuclear infrastructure of the UK. This may well be possible for a plant in Ireland. Much modern nuclear capacity is based on Pressurised Water Reactor (PWR) designs. This type of nuclear generating facility generally has single generating units greater than 1 GW. This size of unit would not be suitable for the Irish system, however it is assumed here that technological advances in this form of reactor or another reactor technology will mean that single units of 400 MW will be available at the costs assumed by 2020.

The nominal discount rate of 7.5% is applied to the capital cost of all the generation plant (RAE, 2004; CER, 2004c). In reality different plant may have different discount rates applied to them based on the perception of the risk associated with each project. However, it is difficult to speculate how this perception of risk may change by 2020. A sensitivity analysis on the discount rate is included in Sections 3.5.3. and 3.5.4. Discount rates may also apply to fuel costs and operation and maintenance costs (Awerbuch, 2004b). However, given the many different ways and time scales that fuel and maintenance services may be acquired and the relatively small impact it will have when compared with other factors, it has been ignored here.

The average efficiency here is assumed to be the average efficiency of the plant during the whole plant life. These values also factor in improvements that are likely to be
realizable in the medium term. Specifically, it is assumed that a new generation of aerodervative Open Cycle Gas Turbines (OCGT) will offer significant improvements in term of efficiency and cost (GE-E, 2004). It is also assumed that the Integrated Gasification Combined Cycle (IGCC) coal plant will also evolve giving significant improvements in efficiency over conventional Pulverized Fuel (PF) coal plant by 2020 albeit at a higher capital cost.

Typical plant availability over the life of the plant was assumed here. The capacity factor of wind generation is defined as the average power output divided by the installed capacity. There is assumed to be a possible 1200 MW of on-shore wind capacity that can be practically developed with a capacity factor of 0.35. This is categorised here as “Wind 1”. It is assumed that there is a further 2600 MW of potential development which consists of on-shore wind generation with a lower capacity factor, and off-shore wind with a higher capacity factor and higher costs. Both these types of developments are grouped together as “Wind 2” and approximated with an average capacity factor of 0.35 and a higher capital cost. In reality there may be a higher usable wind resource in Ireland however the limit of this resource remains unclear. As installed wind capacity becomes a significant portion the total system capacity, many system operational issues arise that may have significant cost implications, which cannot be included here, e.g. curtailment. A unit commitment model that fully incorporates wind generation would be needed to examine this issue further. It is for these reasons that the maximum installed wind capacity is assumed limited to 3800 MW.

The various biomass and biogas technologies and the extent of their resource have been grouped together in three categories based on electricity production cost. The amount of biomass and biogas generation that can be installed is assumed to be limited by the availability of the various fuels at different cost levels (SEI, 2004a). Peat is a native Irish fuel source and is usually burnt in Fluidised Bed (FB) plant. The potential peat generation capacity is limited by the amount of peat that can be supplied by the state owned peat utility. This is assumed here to limit peat capacity to 1000 MW of base loaded plant.

CO₂ emissions are expressed here in tonnes of CO₂ per MWh generated. This is based on the typical carbon content of the fuels (O’Mahony, 2004) and the average efficiency
of the plant. Wind and nuclear generation are taken to emit no CO$_2$, and while there are
some complexities surrounding the emissions of various biomass and biogas
technologies (Serchuk, 2000), they were also assumed to be carbon neutral.

### 3.2.2 Fuel Prices

The all-Ireland system imports a large proportion of its fuel (IEA, 2003b) and as a result
is exposed to fuel prices that are generally higher than those of other European
countries. Two Irish fuel price scenarios are used in this work, a low fuel price scenario
which is based on 2005 fuel prices and a high fuel price scenario based on projected
2020 fuel prices. These are given in Table 3-2. The fuel price scenarios were compiled
from several sources (CER, 2004c; SEI, 2004a; ESB NG, 2005; EC DGET, 2003) and
are all expressed in current value, €2005. The gas price for the low scenario, 4.31 €/GJ,
is derived from the average price at the UK national balancing point for the first quarter
of 2005, 39 UKpence/therm, plus a 15% charge for transportation from the UK to
Ireland. Forecasting long-term future fuel prices is a difficult task and the high fuel
price scenario here is loosely based on those in EC DGET (2003). The most notable
feature in the high fuel price scenario, compared to the low is the relatively higher price
of gas relative to the other fuels.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Low €/GJ</th>
<th>High €/GJ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>4.31</td>
<td>5.54</td>
</tr>
<tr>
<td>Coal</td>
<td>1.59</td>
<td>1.65</td>
</tr>
<tr>
<td>Peat</td>
<td>2.64</td>
<td>3.12</td>
</tr>
</tbody>
</table>

*Table 3-2. Low and high fuel price scenarios for the all-Ireland system in 2020.*

Biomass and biogas technologies have a diverse range of fuel sources. It is assumed that
on average the fuel costs are 20, 31 and 43 €/MWh of electricity generated for the
biomass and biogas categories 1, 2 and 3 respectively (SEI 2004a). This applies to both
fuel price scenarios. It is assumed that fuel costs add 5.8 €/MWh to electricity produced
by nuclear fission in both fuel price scenarios (RAE, 2004).

### 3.2.3 Carbon Costs

Under the EU emissions trading scheme the all-Ireland system will be part of a greater
emission trading scheme across the whole of the Europe (EU, 2003b). From a macro-
economic perspective the all-Ireland system is exposed to the cost of carbon, and
whether the carbon credits are grandfathered or bought in the trading scheme the cost of
carbon should be included when considering the future generation portfolio. Decreasing carbon dioxide production will either avoid having to procure credits, or free up grandfathered credits for use elsewhere in the economy or for sale back into the trading scheme. This principle is included in the analysis here in the form of a carbon tax which is applied to the energy output of each generation technology in accordance with the values given in Table 3-1. The carbon tax scenarios analysed here range from 0 €/Tonne of CO\(_2\) to 50 €/Tonne of CO\(_2\).

### 3.2.4 Electricity Generation Costs

Figure 3-1 shows the cost of electricity achievable from each of the technologies for the low fuel price scenario and no carbon tax. This is calculated based in the units running at full output for their respective maximum availabilities, or in the case of the wind categories, based on its capacity factors. Figure 3-2 shows the cost of each generator per year as a function of the number of full load hours for the low fuel price scenario and no carbon tax. The intersection of the plots with the y-axis equates to the annuitised capital cost plus the yearly operation and maintenance cost. The fuel cost is a function of the level of generation and determines the slope of the respective lines.

![Figure 3-1. Cost of electricity achievable from the various technologies at maximum output for low fuel price scenario and no carbon tax.](image)

It can be seen from Figure 3-1 that with the low fuel price scenario and no carbon tax nuclear fission and PF coal plant are the cheapest on a per unit basis. CCGTs and wind generation are the next cheapest on a per unit basis. Figure 3-2 shows for this scenario...
CCGTs are the most cost effective for the range of 2000 – 5000 full load hours per year and OCGT are the most cost effective for units running for 2000 full load hours per year or less.

![Figure 3-2. Cost per MW imposed by each dispatchable generation type as a function of the number of full load hours for the low fuel price scenario and no carbon tax.](image)

### 3.2.5 Load Growth and Load Duration Characteristics

Forecasting the electricity demand in 2020 for the all-Ireland system is a difficult task. Historic electricity demand as been strongly linked to economic growth, although there is some evidence that this link may be weakening (SEI, 2005). Forecasting the electricity demand growth for the all-Ireland system is made more challenging by the fact that the system comprises essentially of two separate economies. Although the actual real rate of load growth will not affect the concepts and results presented in this work, care has been taken to ensure the assumed load levels for the all-Ireland system in 2020 are as realistic as possible.

The Electricity Supply Board National Grid (ESB NG) median load growth scenario forecasts an average annual increase in demand of 3.9% between the years 2004 and 2010 (ESB NG, 2003a). Load growth information for the Northern Ireland system is limited, however, it is assumed that the average annual increase in demand will be somewhat less than that in the Republic of Ireland due to continuing lower economic
growth. Forecasting load growth for the period 2010-2020 is even more difficult due to the uncertainties surrounding the performance of both economies, the extent of decoupling between economic growth and electricity demand and the uncertainty surrounding the proportion of the country’s primary energy needs served by electricity. Given this uncertainty, this work assumes an average annual load growth of 3% for the all-Ireland system between for the period 2003 – 2020. An hourly load profile was created for the all Ireland system for the year 2003 using data supplied by ESB NG. From this series the 2020 all-Ireland hourly load profile was created based on the 3% annual growth rate.

In planning a generation portfolio, it is of the utmost importance that consideration be given to the duration characteristics of the load. It is crucial for finding the appropriate mix of base-loaded, mid-merit, and peaking type plant in the portfolio. For inclusion in the portfolio algorithm the load was broken up into 18 separate load bins. Each bin is 500 MW wide and records the number of hours during the year when the load fell within the range of the bin. This is illustrated in Table 3-3. The energy to be served in each bin is found by multiplying the number of hours in the bin by the centre value of the bin. It was found that this approximated the overall energy demand during the year very accurately with just a 0.03% difference between the actual yearly load and the load approximated by the bins.

<table>
<thead>
<tr>
<th>Load Bin Centre (MW)</th>
<th>No. of Hours in Bin</th>
<th>Load Bin Centre (MW)</th>
<th>No. of Hours in Bin</th>
</tr>
</thead>
<tbody>
<tr>
<td>750</td>
<td>0</td>
<td>5250</td>
<td>1046</td>
</tr>
<tr>
<td>1250</td>
<td>0</td>
<td>5750</td>
<td>1078</td>
</tr>
<tr>
<td>1750</td>
<td>0</td>
<td>6250</td>
<td>938</td>
</tr>
<tr>
<td>2250</td>
<td>0</td>
<td>6750</td>
<td>1323</td>
</tr>
<tr>
<td>2750</td>
<td>0</td>
<td>7250</td>
<td>1327</td>
</tr>
<tr>
<td>3250</td>
<td>0</td>
<td>7750</td>
<td>786</td>
</tr>
<tr>
<td>3750</td>
<td>278</td>
<td>8250</td>
<td>320</td>
</tr>
<tr>
<td>4250</td>
<td>715</td>
<td>8750</td>
<td>128</td>
</tr>
<tr>
<td>4750</td>
<td>797</td>
<td>9250</td>
<td>24</td>
</tr>
</tbody>
</table>

Table 3-3. Load duration bins for the all-Ireland system in 2020.

### 3.2.6 Wind Generation Profiles

Due to its non-dispatchable nature, wind generation is included into the modelling here by assessing its effect on the net-load. Hourly wind generation profiles for the year 2003
were used in this work. These were developed in a previous study (SEI, 2004c) using real wind farm output data from around Ireland and then grown to match statistical parameters for various installed capacities. These profiles include the statistical benefits of diversity derived from spreading wind farms over a large geographical area, and also factor in the limit of diversity that can be achieved on a small island such as Ireland. Five separate wind profiles were used here for 77, 845, 1300, 1950 and 3900 MW of installed wind capacity. The effect of these wind profiles on the net-load profile was expressed in terms of the changes it caused to the load duration bins. These effects were then linearly interpolated to give a set of duration bin values for net-load profiles which corresponded to wind capacities ranging from 0 - 3800 MW in 200 MW steps. Figure 3-3 below shows the net-load duration curve with no wind capacity and with 3800 MW of wind capacity.

![Figure 3-3. Load and net load duration curves with and without 3800 MW of wind capacity.](image)

### 3.2.7 Hydro, Pumped Storage and Interconnection

It is assumed here that Ireland’s hydro generation is already fully exploited and further hydro projects are not considered in this work. The all-Ireland system has approximately 509 MW of installed hydro and pumped storage capacity at present. In the remainder of this chapter this capacity will simply be referred to as “Hydro”. The effect of these plant are incorporated into the model using their historic operation profile (ESB NG, 2005). The all-Ireland system currently has one interconnector to Scotland. There are plans for a similar interconnector from the Republic of Ireland system to Wales in the near future (CER, 2004a). In this work it is taken that there will be two interconnectors resulting in 800 MW of interconnection to Great Britain in 2020. It is
assumed that these interconnectors can import energy at a price which is 3 €/MWh less than the cost of energy from a CCGT in Ireland given the slightly lower gas price and the economies of scale achievable in Great Britain. The possibility of developing further interconnection has not been considered in this work for two reasons. Firstly, cost information on such a project is limited and secondly there are questions surrounding the transmission network capacity in Scotland and Wales to provide a large portion of the all-Ireland electricity demand. The possible benefits of export of energy to Great Britain has not been considered as it is assumed that energy costs there will generally be less than in Ireland.

3.3 GENERATION ADEQUACY

It is essential that each power system have enough capacity to serve the load to the extent defined by a system reliability criterion. The provision of capacity in a system is an important issue to consider when analyzing future generation portfolios as it can have significant cost implications. Intermittent, non-dispatchable sources of generation, like wind generation, make a different contribution to the generation adequacy of a system than conventional dispatchable generation. As can be seen from Figure 3-3 wind capacity can serve a significant amount of total energy without necessarily decreasing the hours of peak net-load by the same amount. This trait has been overlooked in other work (Awerbuch and Berger, 2003). In this work the system reliability criterion used in the Loss of Load Expectation (LOLE) which is defined as the number of hours in a year when there is insufficient generation to meet the demand. In the Republic of Ireland the system operator aims to have enough generation capacity to maintain a LOLE of 8 hours per year (ESB NG, 2003a). This work aims to produce generation portfolios for the 2020 all-Ireland system which will give the system a LOLE of 8 hours per year. The method deriving capacity credits which proportionality reflects the value of each type of generation capacity in achieving the LOLE of 8 hours is shown in this section. The capacity coefficients are then incorporated into the least-cost portfolios optimisation.

3.3.1 Capacity Credit Methodology

There are several ways to calculate a system’s LOLE and generation capacity credits (ESB NG, 2003a; Milligan and Parsons, 1997). The approach adopted here is a Monte Carlo method (Weisstein, 2005) similar to that used by Fitz Gerald (2004). Typical
Average Forced Outage Probabilities (AFOPs) the number of days needed each year for scheduled maintenance (SM) and the number of days needed for short-term maintenance outages (STMOs) were used for the dispatchable generation (O’Mahony, 2004). The AFOP is the probability of a unit being forced out during the hours when it is not scheduled out on maintenance. The SM days is the number of days per year that that a unit is scheduled out for maintenance. It is assumed that this type of outage occurs once a year. The STMO is the number of additional days that a unit is scheduled out on maintenance and this is assumed to be taken in blocks of 2 days. These values are shown in Table 3-4.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Unit Size (MW)</th>
<th>AFOP (%)</th>
<th>SM (Days)</th>
<th>STMO (Days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal PF</td>
<td>333</td>
<td>7</td>
<td>34</td>
<td>0</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>400</td>
<td>7</td>
<td>30</td>
<td>4</td>
</tr>
<tr>
<td>Peat FB</td>
<td>150</td>
<td>6</td>
<td>29</td>
<td>4</td>
</tr>
<tr>
<td>OCGT</td>
<td>110</td>
<td>5</td>
<td>12</td>
<td>4</td>
</tr>
<tr>
<td>CCGT</td>
<td>390</td>
<td>6</td>
<td>22</td>
<td>4</td>
</tr>
<tr>
<td>Nuclear Fission</td>
<td>400</td>
<td>3</td>
<td>36</td>
<td>0</td>
</tr>
<tr>
<td>Biomass &amp; Biogas 1,2 &amp; 3</td>
<td>10</td>
<td>8</td>
<td>55</td>
<td>4</td>
</tr>
<tr>
<td>Interconnection</td>
<td>400</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hydro</td>
<td>Various</td>
<td>2</td>
<td>15</td>
<td>2</td>
</tr>
</tbody>
</table>

Table 3-4. Dispatchable unit outage characteristics.

In power systems capacity is generally scheduled out for maintenance during periods of lower load when the system is assumed to have sufficient capacity. In the all-Ireland system this is generally during the summer. The scheduling of units for maintenance here was based on the daily peak load profile. Generation is scheduled as being out on maintenance in order of size, starting with the largest. Units are scheduled out at a time period were the minimum megawatt difference between daily peak load and the remaining capacity is largest.

In order to assess the generation adequacy of a system and to find capacity credits, a base case portfolio is needed as an initial point of reference for the analysis. For the 2020 all-Ireland hourly load profile a base case generation portfolio was created which gave a LOLE of 8 hours per year. This portfolio was made up of entirely dispatchable generation in what is thought to be a reasonable mix of base-load, mid-merit and peaking plant. It was found that the system required 10101 MW of dispatchable generation to have an LOLE of 8 hours. This is approximately 108% of the peak load.
The final capacity credits and portfolio results were found not to be sensitive to the make-up of this initial portfolio. This portfolio is shown in Table 3-5.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Size of Unit</th>
<th>No. of Units</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal PF</td>
<td>333</td>
<td>3</td>
<td>999</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>400</td>
<td>4</td>
<td>1600</td>
</tr>
<tr>
<td>Peat FB</td>
<td>150</td>
<td>6</td>
<td>900</td>
</tr>
<tr>
<td>OCGT</td>
<td>110</td>
<td>18</td>
<td>1980</td>
</tr>
<tr>
<td>CCGT</td>
<td>390</td>
<td>4</td>
<td>1560</td>
</tr>
<tr>
<td>Nuclear</td>
<td>400</td>
<td>4</td>
<td>1600</td>
</tr>
<tr>
<td>Biomass 1,2 &amp;3</td>
<td>10</td>
<td>15</td>
<td>150</td>
</tr>
<tr>
<td>Interconnection</td>
<td>400</td>
<td>2</td>
<td>800</td>
</tr>
<tr>
<td>Hydro</td>
<td>Various</td>
<td>18</td>
<td>509 (+3 MW extra unit)</td>
</tr>
<tr>
<td>Total</td>
<td>-</td>
<td>-</td>
<td>10101</td>
</tr>
</tbody>
</table>

Table 3-5. Base case generation portfolio for generation adequacy and capacity credit analysis.

Figure 3-4 shows the daily system peak load for the all-Ireland system in 2020 and the capacity retained on the system after the scheduling of annual maintenance and short-term maintenance outages for the base case portfolio of generation.

![Figure 3-4. Daily system peak load and generation capacity after maintenance outage scheduling.](image)

### 3.3.2 LOLE Calculation

For any portfolio of plant scheduled for maintenance by the method described above, a Monte Carlo simulation can then calculate the LOLE of the system. For each hour of the year the units that are deemed available by the maintenance schedule can find themselves forced out with the probabilities shown in Table 3-4. If in any hour there is insufficient capacity to meet the load the system LOLE is increased by 1 hour. At the end of the year the LOLE is the number of hours where the capacity was insufficient to
meet the load. The year was then run many times and the average of the yearly LOLEs was found. One hundred separate runs of the simulation were performed for up to a thousand years for each run to examine how accurately the final LOLE results converge. Figure 3-6 shows the standard deviation of the final LOLE results plotted against the number of years the answer is averaged over. It was found that simulations run over one thousand years gave good outcomes in terms of convergence with the final LOLE answers having a standard deviation of just 0.1056 hours per year around a mean of 8.012 hours per year. It was decided to calculate subsequent capacity credits based on LOLE calculations run over 1000 years.

Figure 3-5. Standard deviation of the final LOLE results versus number of years.

### 3.3.3 Capacity Credit Calculations

In order to find the capacity credit of the generation considered in this study, the impact of the installed capacity of the generation must be related to the LOLE of the system. To find the capacity credit of certain type of dispatchable generation, extra units of that type of generation were added to the base portfolio. The units added are of the size defined in Table 3-1. The portfolio of plant was then scheduled out on maintenance and the LOLE was calculated for the 2020 all-Ireland load profile. An increase in the system LOLE could be measured due to the increase in generation capacity. The load was then increased uniformly in increments of 1 MW during the year until the LOLE returned to 8 hours per year. The capacity credit was then found by dividing the amount of generation capacity added by the increase in load that it could serve at a LOLE of 8 hours per year. It was found that all the dispatchable generation had a capacity credit of approximately 0.99. This implies that 1 MW of conventional generation allows almost 1
MW of extra load to be served every hour in the year without decreasing system reliability. Despite having availabilities of around 86% the fact that the units can be scheduled out on maintenance at times of low load means that they have a high capacity credit.

To find the capacity credit of the wind generation the various wind profiles were subtracted in turn from the load profile. The LOLE calculations were carried out as before using the base case generation portfolio and the capacity credit was again found by dividing the corresponding installed wind capacity by the increase in load. This was done for the 5 different yearly wind profiles and Figure 3-6 shows the capacity credit for the wind capacity at different penetrations. It can be seen that the capacity credit of the wind capacity is initially about 0.4 for low penetrations of wind generation. However, this decreases as the penetration of wind generation increases and is about 0.19 for a wind capacity of 3800 MW. The wind generation’s capacity credit at low penetrations exceeds its capacity factor of 0.35. This is because there are strong seasonal and diurnal elements to the wind generation output. At times of system peak demand during winter daytime hours the wind can in general be expected to be producing more than its average yearly output. The decrease in the capacity credit as wind capacity increases is due to the correlated nature of individual wind farm outputs. Hours of high load and relatively low wind production are likely to also have relatively low wind production with large amount of wind capacity. These type of hours become more significant to the LOLE calculation as the wind capacity increases and this causes a decrease in the wind generation capacity credit.

![Figure 3-6. Wind generation capacity credit versus increasing wind capacity.](image-url)
Calculations of capacity credits for wind generation will vary from system to system as the nature of load profiles and wind generations profiles will differ. The capacity credit of wind generation in this work was found to be similar to those calculated in various studies in the Great Britain electricity system (SDC, 2005). Given the real load and wind data available for this work it is believed that Figure 3-6 provides an accurate reflection of the likely capacity credit of wind generation given the stated load growth assumptions for the all-Ireland system in 2020.

### 3.4 Portfolio Optimisation Algorithm

The objective of the work is to find the portfolio of generation that will deliver electricity at the least-cost. In order to fully determine the least-cost generation portfolios a unit commitment model that treats wind generation equitably is needed. As this type of model does not exist the methodology used here does not consider start-up and inter-temporal issues. The methodology, however, does consider the issues of system capacity, the plant utilisation and net-load duration characteristics. Rather than solving for the installed capacity of the various types of generations in the portfolio while trying to approximate when they may be used during the year, the approach adopted here is to optimize the installed capacities and when they are used. The approach solves for a least-cost generation portfolio for a given wind penetration $WP$. The level of wind generation is altered between 0 and 3800 MW in 200 MW steps and the level that results in the least-cost electricity indicates the optimal portfolio.

In this formulation the control variables are:

$I_n$ the installed capacity of each type of dispatchable generation $n$ in MW.

$E_{b,n}$ the amount of energy delivered in MWh by each type of dispatchable generation $n$ in each net-load duration bin $b$.

Although, the generation cost characteristics are based on a notional size of installation, the optimization algorithm allows the installed capacity of each technology to be a continuous variable from 0 to infinity or its resource limited amount as shown in Table 3-1. This allows the problem to be formulated as a linear program and the complications of discrete integer optimization to be avoided. The energy served in each load bin by each technology, $E_{b,n}$, is linked to the installed capacity, $I_n$, with the use of constraints.
The aim is to minimize the objective function in Equation 3.1. This is the cost of supplying the all-Ireland net-load for a given wind penetration.

$$\text{min} \quad WPCC_{WP} + \sum_{n \in N} Cc_n I_n + \sum_{n \in N} \sum_{b \in B_{WP}} Cf_n E_{b,n}$$

(3.1)

where

N is the set of dispatchable generation technologies being considered.

$B_{WP}$ is the set of net-load duration bins corresponding to a wind penetration of $WP$ megawatts.

$Cc_n$ is the annuitised capital cost and annual operation and maintenance cost of the dispatchable generation in € per MW installed / year.

$Cc_{WP}$ is the annuitised capital cost and annual operation and maintenance cost of $WP$ megawatts of wind capacity in € per MW installed / year.

$Cf_n$ is the fuel cost of the dispatchable generation in €/MWh.

This is subject to the capacity constraints which ensures every portfolio will have a LOLE of 8 hours per year.

$$\sum_{n \in N} I_n 0.99 \geq 10000 - WP CapC_{WP}$$

(3.2)

where

$CapC_{WP}$ is the capacity coefficient corresponding to a wind penetration of $WP$.

0.99 is the capacity coefficient of the dispatchable generation.

The value of 10000 in the constraint comes from $10101 \times 0.99$ and is coincidental.

The constraint in Equation 3.3 ensures that there is sufficient energy for the generation to serve the demand in each net-load bin.

$$\sum_{n \in N} E_{b,n} = H_b M_b \quad \forall \ b \in B_{WP}$$

(3.3)

where

$H_b$ is the number of hours in each net-load bin.

$M_b$ is the centre value of each net-load bin.

The energy served by each generation technology must not be greater than the installed capacity of that technology multiplied by its availability in hours per year, $Avail_n$, as shown in Table 3-1.
The constraint in Equation 3.5 is used to ensure that that one MW of installed capacity does not provide more than one MWh at a time.

\[ \sum_{b \in B_{\text{WP}}} E_{b,n} \leq I_n \text{Avail}_n \quad \forall \ n \in N \] (3.4)

The formulation given by Equations 3.1 – 3.5 solves for the installed capacity of conventional generation and the amounts generated from the capacity that will result in the load being supplied at least-cost. This approach takes into account the nature of the load duration curve and respects the need to have sufficient capacity to maintain a LOLE of 8 hours per year. The optimization algorithm is run several times for different wind penetrations producing a series of portfolios. The portfolio that results in the least-cost is then selected as the optimal. It is likely that start-up and inter-temporal issues could also be incorporated into the optimisation if a full unit commitment model existed to inform the necessary approximations.

### 3.5 Least-Cost Generation Portfolio Results and Discussion

This section contains results and discussion of the least-cost portfolios produced by the optimisation algorithm. Initial generation portfolios are presented to illustrate the nature of the optimisation algorithm in relation to the installed capacities and energy served by each type of generation. The effect of the wind capacity penetration of the portfolio is also illustrated. Portfolio results are then presented for a varied level of carbon tax for both fuel price scenarios. Sensitivity analysis is then carried out to assess the impact of the discount rate on the least-cost portfolio. The optimal level of wind capacity in generation portfolios is also established for a wide range of scenarios. All the results presented in this section assume that nuclear generation is not an available option in Ireland. This assumption will be changed in a later section.

#### 3.5.1 Initial Generation Portfolio Results

As an initial example of the type of results produced by the algorithm, Table 3-6 shows the installed capacities and the percentage of the total load served by each type of
technology for the optimal generation portfolio for the low fuel price scenario with no carbon tax.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity (MW)</th>
<th>Energy Served (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal PF</td>
<td>7060</td>
<td>96.5</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Peat FB</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>OCGT</td>
<td>1732</td>
<td>0.3</td>
</tr>
<tr>
<td>CCGT</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind 1 &amp; 2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Biomass 1,2 &amp;3</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Interconnection</td>
<td>800</td>
<td>1.6</td>
</tr>
<tr>
<td>Hydro</td>
<td>509</td>
<td>1.6</td>
</tr>
<tr>
<td>Total</td>
<td>10101</td>
<td>100</td>
</tr>
</tbody>
</table>

Table 3-6. Installed capacities and proportion of energy served by technologies in the least-cost portfolio for low fuel price scenario and no carbon tax.

It can be seen that for this scenario the optimal portfolio of generation plant consists of mainly pulverized fuel coal plant, which supplies most of the energy needs of the system and involves no CCGT or wind capacity. There is also 1732 MW of OCGT capacity, which, along with the interconnector serves as peaking capacity and helps ensure the LOLE of 8 hours per year. It is calculated that this OCGT capacity and interconnection supplies only about 2% of the energy needs. The interconnection is capable of importing 13% of the energy needs of the system, however, in this portfolio the low cost of energy from the coal plant has reduced the interconnection to a peaking role. In a real system the portion of energy served by peaking type capacity may be slightly larger as it may be used for inter-temporal and start-up issues.

In the above scenario the least-cost portfolio was found to contain no wind generation. Figure 3-7 shows the value of the objective function, i.e. the cost of electricity from the portfolio, versus the wind generation capacity for the high fuel price scenario and 3 carbon tax scenarios. It can be seen that various scenarios can cause different levels of wind generation to become optimal. In the scenarios shown, zero wind generation is optimal with no carbon tax, 1800 MW of wind generation is optimal for the 20 €/Tonne of CO$_2$ scenario and the assumed maximum amount of wind generation, 3800 MW is optimal for the 50 €/Tonne of CO$_2$ scenario.
Figure 3-7. Value of objective function versus wind capacity for the high fuel price scenario and 3 different carbon tax scenarios.

It can be seen from Figure 3-7 that the incremental benefit of wind generation to the system decreases as the wind capacity increases. This is due to the costs in the “Wind 2” generation category (above 1200 MW of wind capacity) being larger than those in the “Wind 1” category and also due to the reducing capacity credit of the wind generation as capacity increases. Figure 3-8 shows the objective function and the total capacity of the portfolio versus the wind capacity in the generation portfolio for the high fuel price scenario and a 20 €/Tonne of CO$_2$ carbon tax.

Figure 3-8. Value of objective function and total installed capacity versus wind capacity for the high fuel price scenario and a 20 € / Tonne of CO$_2$ carbon tax.
It can be seen that as the amount of wind generation in a portfolio increases the total installed capacity of the portfolio increases to maintain a LOLE of 8 hours per year. For this scenario the least-cost generation portfolio involves 1800 MW of wind generation and a 11% increase in total installed capacity over a portfolio with no wind generation.

The initial generation portfolios were fed back into the maintenance scheduling and LOLE algorithms described in Section 3.3 to check that they resulted in an LOLE of 8 hours per year. All portfolios, including those with wind generation were found to have a LOLE in the range of 7.9 – 8.1 hours per year. This confirms the accuracy of the capacity credits used.

### 3.5.2 Effect of Carbon Tax on the Least-Cost Generation Portfolios

Table 3-7 shows the generation portfolios for the all-Ireland system with various carbon taxes for the low fuel price scenario. If regulatory bodies can ensure that the cost of carbon is properly reflected in the market place, it is reasonable to assume that these are the sort of generation portfolios that the industry will be heading towards in the year 2020 if no other type of intervention takes place. In mid July 2005 carbon dioxide emission permits were being traded at about 30 €/Tonne of CO$_2$ (ECX, 2005). It can be seen for low fuel price scenario that CCGT based system is found to be least-cost once the carbon tax is 10 €/Tonne of CO$_2$ and above. This is consistent with the industry in Ireland at present where most proposed generation projects are for the development of new CCGTs. It can also be seen that optimal penetration of wind power increases as expected with increasing carbon tax.

Table 3-8 shows the generation portfolios for the all-Ireland system with various carbon taxes for the high fuel price scenario. The high fuel price scenario has a higher price for gas relative to that of coal. The result of this is that a coal-based system is the least-cost option up to a carbon tax of 30 €/Tonne of CO$_2$. It can be seen that the increased gas price accelerates the role of wind as a means to reducing carbon emissions in a least-cost manner with the maximum penetration of 3800 MW of wind capacity reached with a carbon tax of 40 €/Tonne of CO$_2$. 

39
<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity (MW)</th>
<th>0 €/Tonne CO₂</th>
<th>10 €/Tonne CO₂</th>
<th>20 €/Tonne CO₂</th>
<th>30 €/Tonne CO₂</th>
<th>40 €/Tonne CO₂</th>
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<tr>
<td>Coal PF</td>
<td>7060</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Peat FB</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>OCGT</td>
<td>1732</td>
<td>2278</td>
<td>2572</td>
<td>2156</td>
<td>2469</td>
<td>2405</td>
<td></td>
</tr>
<tr>
<td>CCGT</td>
<td>0</td>
<td>6289</td>
<td>5826</td>
<td>6241</td>
<td>5805</td>
<td>5782</td>
<td></td>
</tr>
<tr>
<td>Wind 1 &amp; 2</td>
<td>0</td>
<td>600</td>
<td>1200</td>
<td>1200</td>
<td>1800</td>
<td>2400</td>
<td></td>
</tr>
<tr>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Interconnection</td>
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<td>800</td>
<td>800</td>
<td>800</td>
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<td>800</td>
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<tr>
<td>Hydro</td>
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<td>509</td>
<td>509</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>10101</td>
<td>10476</td>
<td>10907</td>
<td>10906</td>
<td>11383</td>
<td>11896</td>
<td></td>
</tr>
</tbody>
</table>

Table 3-7. Least-cost portfolios for various carbon taxes for the low fuel price scenario.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity (MW)</th>
<th>0 €/Tonne CO₂</th>
<th>10 €/Tonne CO₂</th>
<th>20 €/Tonne CO₂</th>
<th>30 €/Tonne CO₂</th>
<th>40 €/Tonne CO₂</th>
<th>50 €/Tonne CO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal PF</td>
<td>7060</td>
<td>6560</td>
<td>5229</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Peat FB</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>OCGT</td>
<td>1732</td>
<td>1838</td>
<td>2469</td>
<td>2381</td>
<td>2374</td>
<td>2374</td>
<td></td>
</tr>
<tr>
<td>CCGT</td>
<td>0</td>
<td>0</td>
<td>576</td>
<td>5765</td>
<td>5700</td>
<td>5630</td>
<td></td>
</tr>
<tr>
<td>Wind 1 &amp; 2</td>
<td>0</td>
<td>1200</td>
<td>1800</td>
<td>2800</td>
<td>3800</td>
<td>3800</td>
<td></td>
</tr>
<tr>
<td>Biomass 1,2 &amp;3</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>70</td>
<td></td>
</tr>
<tr>
<td>Interconnection</td>
<td>800</td>
<td>800</td>
<td>800</td>
<td>800</td>
<td>800</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>509</td>
<td>509</td>
<td>509</td>
<td>509</td>
<td>509</td>
<td>509</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>10101</td>
<td>10907</td>
<td>11383</td>
<td>12255</td>
<td>13183</td>
<td>13183</td>
<td></td>
</tr>
</tbody>
</table>

Table 3-8. Least-cost portfolios for various carbon taxes for the high fuel price scenario.

Figure 3-9, calculated from the emission characteristics in Table 3-1, shows the effect of the various carbon taxes on the emissions from the generation portfolio. This is expressed as a percentage of the scenarios with no carbon tax. It can be seen from Tables 3-7 and 3-8 that the increasing carbon tax favours a CCGT based system and results in a significant reduction in emissions from that of a coal based system. Increasing wind penetration also serves to reduce emissions further but is limited by the resource assumed available.
The above analysis assumes that the traded cost of carbon is reflected in the market place and subsequently in the generation portfolios. However, if the regulatory bodies do not ensure that the traded cost of carbon was reflected in the market place then this may cause unnecessary cost to the all-Ireland system as unsuitable generation portfolios may emerge. Given the possible increases in cost and the long life span of generation plant it is important that regulatory bodies ensure that the traded cost of carbon is immediately reflected in the marketplace.

The Republic of Ireland currently aims to serve 13.2% of electricity from renewable sources by 2010 (EU, 2001a). The government has tried in the past to incentivise renewable development with subsidies (DCMNR, 2004) however, it can be seen from Tables 3-7 and 3-8 that allowing the all-Ireland electricity system to feel the effects of the European traded cost of carbon, something that would be correct macro-economic practice regardless, may result in significant development of renewable energy without the need for any subsidy.

### 3.5.3 Sensitivity Analysis of Discount Rate on Least-Cost Generation Portfolios

The discount rate is the opportunity cost of capital as a percentage of the value of the capital, i.e. the return on investments foregone elsewhere by committing capital to the project under consideration (Khatib, 2003). The discount rate comprises a premium to compensate for the risk of the project. The nominal discount rate used here is 7.5%.
Sensitivity analysis has been carried out to demonstrate the effect of the discount rate on the desired generation mix for the year 2020. Table 3-9 below shows the optimal generation portfolios under different discount rates of 6% 7.5% and 10% for the low fuel price scenario and a carbon tax of 10 €/Tonne of CO₂.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>Coal PF</td>
<td>5522</td>
</tr>
<tr>
<td>Coal IGCC</td>
<td>0</td>
</tr>
<tr>
<td>Peat FB</td>
<td>0</td>
</tr>
<tr>
<td>OCGT</td>
<td>2572</td>
</tr>
<tr>
<td>CCGT</td>
<td>304</td>
</tr>
<tr>
<td>Wind 1 &amp; 2</td>
<td>1200</td>
</tr>
<tr>
<td>Biomass 1,2 &amp;3</td>
<td>0</td>
</tr>
<tr>
<td>Interconnection</td>
<td>800</td>
</tr>
<tr>
<td>Hydro</td>
<td>509</td>
</tr>
<tr>
<td>Total</td>
<td>10907</td>
</tr>
</tbody>
</table>

Table 3-9. Sensitivity of least-cost generation portfolios to discount rate for low fuel prices scenario and a 10 € / Tonne of CO₂ carbon tax.

It can be seen that with a discount rate of 6% the optimal generation portfolio favours some of the more capital-intensive technologies such as pulverized fuel coal plant and wind generation. As the discount rate increases it can be seen that there is a switch away from a coal-based system to a system that uses CCGTs to serve the majority of its energy. A decrease in the amount of wind generation can also be noticed as the discount rate increases.

### 3.5.4 The Role of Wind Generation in Least-Cost Portfolios

An examination of the role of wind generation in least-cost portfolios was undertaken for a large range of scenarios. Three variables that have a significant uncertainty associated with them and have a large impact on the generation portfolios were altered over a large range to find the role wind generation plays in the subsequent least-cost portfolios. The three variables altered are gas price, carbon tax and discount rate. Figure 3-10 shows the optimal amount of wind generation versus the gas price and carbon tax for discount rates of 6%, 7.5% and 10%. The prices for the other fuels in the analysis are the same as those in the high fuel price scenario.
Figure 3-10. Optimal wind capacity for a range of gas prices, carbon taxes, and discount rates (DR).
It can be seen from the surfaces in Figure 3-10 that wind generation plays a significant role in least-cost portfolios for a large range of scenarios. It can also be seen that for a considerable amount of scenarios the optimal amount of wind capacity was found to be the maximum amount assumed available, 3800 MW. This indicates that wind generation may have an even larger role to play in future generation portfolios than has been indicated here. However, establishing the role of wind generation above this level requires analysis of other systems issues such as the curtailment of wind generation and the potential for energy storage.

3.6 FUEL PRICE VOLATILITY AND PORTFOLIO DIVERSIFICATION

The all-Ireland system relies heavily on imported fuel for electricity production. In 2003, in the Republic of Ireland, 88% of electricity produced was from imported fuels (IEA, 2003b). This high import dependence means that Ireland is very exposed to economic and political changes in other countries. This exposes Ireland to possible price hikes and even possible shortages in supply. This would have as detrimental effect on the economy of the island (Fitz Gerald, 2002). It is generally accepted that diversification of generation resources will serve to reduce this risk. Diversity in other aspects of the industry such as the technologies used, the number of separate fuel supplier states, the regional distribution of facilities and many other aspects is also desirable (Sterling, 1994) and should be sought if it does not come with a significant cost. This work, however, focuses solely on diversification as a means to reduce the exposure to fuel price risk.

Correctly quantifying how much to diversify generation resources and determining what to diversify with is a continuous challenge faced by policy makers. Most risk analysis in power system and elsewhere is based on either probabilistic or unknown-but-bounded models (Pereira et al., 2000). However, the problem of avoiding exposure to fuel price volatility, does not fit entirely into either of these modelling approaches. This is partially because of the great deal of unquantifiable uncertainty surrounding future fuel prices, which often change in value due to unpredictable international political events.

In an interesting paper, Awerbuch and Berger (2003) adopt the approach of mean variance portfolio theory to create generation portfolios, which can be analyzed on a
risk return basis. This is a standard technique often used in finance theory for stocks, shares, bonds etc. (Brealey and Myers, 2000). This approach requires probabilistic quantification of the uncertainty of various factors. The analysis includes fuel price risk, and the authors derive a cross correlation matrix for the price of electricity generated from gas, coal, crude oil and uranium. The analysis also examines the effects on the generation portfolios of uncertainty that surrounds operation and maintenance cost and construction time. It was found that these elements had a small effect when compared with the uncertainty introduced by fuel prices.

Sterling (1994) argues that mean-variance portfolio theory is not appropriate for dealing with exposure to fuel price fluctuations, as they have no pattern. The author states that diversification is a response to ignorance rather than quantifiable risk. The author creates generation resource portfolios, which have as their objective the minimization of cost and a maximization of diversity as defined by the Shannon-Wiener index. The author seeks diversity as a goal in itself rather than as a means of to reduce something specific such as fuel price risk. The author weights the diversity term in the objective function with a range of values derived from UK government policy intervention that had the purpose of fostering diversity. These values of course may not reflect the true comparative value of diversity as defined by the Shannon-Wiener index when compared with electricity cost.

These two methods of diversifying generation resources have essentially the same drawback, that is, the limited extent to which important factors can be quantified. In the mean-variance portfolio approach the problem is with the forecasted future fuel price volatility and correlations. With the approach adopted by Sterling the problem lies with quantifying the economic value of the somewhat abstract notion of diversity as defined by the Shannon-Wiener index.

For this work it was decided to adopt mean-variance portfolio theory as a means of analyzing the diversity issue. Although it has some drawbacks, it has many features to recommend it over the other technique. Firstly it does not directly equate the measures of diversity with cost but rather allows cost be analyzed as a function of diversity. This can give policy makers a better insight into the trade-offs involved. Secondly it actually allows specific factors such as exposure to fuel price risk to be analyzed. There is a
larger body of work dedicated to forecasting fuel price uncertainty and correlation than 
there is in relating diversity indices to economic value. Although these fuel price 
volatility forecasts will not be completely accurate, and it is impossible to know the 
extent of inaccuracy surrounding them, it would be unwise to assume that they cannot 
serve as some guide to the future. In a practical context, it would be expected that policy 
makers would act to deal with what is perceived across an industry to be a future 
problem even if this perception could not be more empirically articulated. In this section 
it is assumed that cost resulting from the least-cost portfolios relates directly to the price 
of electricity to the economy it is serving.

3.6.1 Fuel Related Electricity Cost Volatility

The standard deviation and correlation of the cost of electricity produced by gas and 
coal are the most important things to consider in order to apply mean variance portfolio 
theory. These were derived from historic data of the average annual fuel prices and 
forecasts of future real fuel price rises. The average fuel efficiency for coal and gas 
plants was factored in the calculations and the standard deviation and correlation of the 
resultant annual electricity prices were found. It was found that electricity produced 
from gas and coal plant had a standard deviation of 8 €/MWh and 4.2 €/MWh 
respectively over the set of years considered. The correlation coefficient was found to 
be 0.3. Energy imported over the interconnectors is assumed to have the same 
characteristics as gas plant. Given the small fuel cost element in nuclear generation and 
its detached nature for the other fuels, it is assumed that uranium has a zero standard 
deviceation and correlation with the other fuels. Given the detached and indigenous nature 
of the peat industry it is assumed that electricity from peat plant has a zero standard 
deviceation and correlation. These values and assumption are in-line with the literature 
(Fitz Gerald, 2002; Awerbuch and Berger, 2003; Bergin et al., 2005; Bolinger et al., 
2005) in assuming that gas price volatility is a good deal greater than coal price 
volatility and that the two are somewhat correlated. And also in assuming that wind, 
nuclear, biomass and peat are quite separate and generally not very volatile. The merits 
of more complex analysis into these values is questionable and it is assumed here that 
these values are reflective of the industry perception of the future and are sufficient here 
to gain insight into the portfolio diversification problem. The standard deviation of the 
cost of energy from the whole generation portfolio, \( \sigma_p \) which is used here as a measure 
of volatility, can be calculated from Equation 3.6.
\[ \sigma_p = \sqrt{f_C \sigma_C + f_G \sigma_G + 2 f_C f_G \rho_{C,G} \sigma_C \sigma_G} \]  \hspace{1cm} (3.6)

where

- \( \sigma_C \) is the standard deviation of the cost of electricity from coal.
- \( \sigma_G \) is the standard deviation of the cost of electricity from gas plant and interconnection.
- \( \rho_{C,G} \) is the correlation coefficient.
- \( f_C \) is the fraction of the total energy served by coal plant.
- \( f_G \) is the fraction of the total energy served by gas plant and interconnection.

Figure 3-11 shows the standard deviation of the cost of electricity from the portfolios in Tables 3-7 and 3-8. It can be seen that an increasing carbon tax may favour gas generation and lower emissions but a gas based system will significantly raise the exposure to fuel price volatility. It can also be seen, that even generation portfolios with a high penetration of renewable energy do not significantly reduce this volatility. If it is assumed that the electricity system will evolve in this manner with the carbon tax as its only signal of external factors, then the all-Ireland electricity industry may be evolving towards a situation where it is extremely exposed to fuel price shocks from abroad.

![Graph showing standard deviation of electricity price](image)

**Figure 3-11.** Standard deviation of electricity price from the least-cost portfolios for various fuel price and carbon tax scenarios.

### 3.6.2 Application of Mean-Variance Portfolio Theory

In order to find the trade-off between electricity price and electricity price volatility mean variance portfolio theory was used. The set of all possible portfolios was searched by altering the proportion of energy to be served by coal plant and gas plant. This was
done by running the portfolio optimization many times and constraining the amount of energy that could be served from coal plant and gas plant between 0 and 100% in steps of 2.5%. This analysis allows the efficient frontier to be found. The efficient frontier is defined as a curve along which the price cannot be reduced any further without accepting an increase in the standard deviation of the price. Again assuming no available nuclear option Figure 3-12 shows the results of the mean-variance portfolio analysis for high price scenario and no carbon tax. The portfolios that are made up of exclusively of coal and gas plant along with the fixed amounts of interconnection and hydro assumed are shown in dark grey. Portfolios that also include other sources of generation are shown in light grey. Table 3-10 shows the installed capacities of the different portfolios shown in Figure 3-12.

![Efficient Frontier](image)

**Figure 3-12.** Mean-variance portfolio analysis for high fuel price scenario and no carbon tax.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity for Portfolio (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>A</td>
</tr>
<tr>
<td>Coal PF</td>
<td>0</td>
</tr>
<tr>
<td>Coal IGCC</td>
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<td>Wind 1 &amp; 2</td>
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</tr>
<tr>
<td>Biomass 1, 2 &amp; 3</td>
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<tr>
<td>Interconnection</td>
<td>800</td>
</tr>
<tr>
<td>Hydro</td>
<td>509</td>
</tr>
<tr>
<td>Total</td>
<td>10101</td>
</tr>
</tbody>
</table>

**Table 3-10.** Significant portfolios for high fuel prices scenario and no carbon tax.
Portfolio A consists exclusively of gas plant along with the assumed amounts of hydro and interconnection and results in a relatively high price and very high level of price volatility. Portfolio B is the portfolio with the lowest possible price volatility for a portfolio consisting of exclusively of coal and gas plant. Portfolio C on the efficient frontier is the least-cost portfolio possible and consists of a very large amount of PF coal plant. Portfolio D, on the efficient frontier, is similar to B but also includes 1200 MW of wind capacity. This results in the same electricity price as portfolio B but reduces the electricity price volatility further than could be achieved by any combination of coal and gas plant. Portfolio E, also in the efficient frontier, has a diverse mix of plant, which includes 1000 MW of peat capacity, 3800 MW of wind capacity and 473 MW of biomass and biogas. This results in a very low volatility but increases the electricity price significantly. These results illustrate that a coal based generation portfolio will have relatively low price volatility. Wind may have a role in reducing the volatility of the generation portfolio but this will come at an increased price.

The same analysis was carried out for the high fuel price scenario with a 30 €/Tonne of CO₂ carbon tax. Figure 3-13 shows the results of the analysis and Table 3-11 shows the installed capacities of the different portfolios shown in Figure 3-13.

![Figure 3-13. Mean-variance portfolio analysis for high fuel prices scenario and a 30 € / Tonne of CO₂ carbon tax.](image-url)
<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity for Portfolio (MW)</th>
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<tr>
<td></td>
<td>A</td>
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<tr>
<td>Coal PF</td>
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<td>Coal IGCC</td>
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<td>Peat FB</td>
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<tr>
<td>Interconnection</td>
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<tr>
<td>Hydro</td>
<td>509</td>
</tr>
<tr>
<td>Total</td>
<td>10101</td>
</tr>
</tbody>
</table>

**Table 3-11.** Significant portfolios for high fuel prices scenario and 30 € / Tonne of CO₂ carbon tax.

Portfolio A, which consists mostly gas plant results in the lowest price possible from any combination of coal and gas plant, but results in a high price volatility. Portfolio B has the lowest price volatility possible for any combination of coal and gas plant and it can be seen that it consists of a significant amount of IGCC coal plant. The carbon tax means that the increased efficiency of the coal fired IGCC plant results in it being more cost effective that the traditional PF plant. Portfolio C is the portfolio with the lowest price, and it can be seen that 2800 MW of wind capacity results in a reduction in cost and a reduction in the volatility from portfolio A. Portfolio D, with increased quantities of wind capacity and a large amounts of coal plant shows a significant decrease in the price volatility while only causing a slight increase in price. Portfolio E has a diverse mix of plant and results in very low volatility but high price.

It can be seen from the results that wind capacity as part of the least-cost portfolio serves to reduce the volatility and price when compared with the all the gas system. However, the extent to which wind can reduce the overall volatility may be limited by the finite amount of wind capacity that can be installed or may be economic to accommodate. Increasing the amounts of coal fired IGCC plant in the portfolio serves to significantly reduce the volatility of the electricity price without significantly increasing the price itself. It appears to be difficult to reduce the price volatility much further in the all-Ireland system due the limited and expensive nature of peat and biomass technologies.
3.6.3 Price-Volatility Trade-Off

Deciding on how much to diversify a generation portfolio will basically depend on how risk adverse the power system planners or policy makers are. How risk adverse the all-Ireland system planners should be is a very challenging problem, and may depend on the exposure of other European economies to fuel price shocks (Fitz Gerald, 2002). Figure 3-14 illustrates the type of decision faced by system planners for the high fuel price scenario and a 30 €/ Tonne of CO$_2$ carbon tax. It shows the cumulative probability of having an electricity price above the value shown on the x-axis. It can be seen that there may be some merit in moving from the least-cost portfolio C to portfolio D in terms of reducing the possible exposure to high prices. However portfolio E would seem to have no benefit as it is effectively guaranteeing the high prices which it is the aim to avoid. The analysis assumes accurate Gaussian fuel price volatility, an assumption that is unlikely to be correct. However, the analysis does illustrate the core nature of the problem and can provide some guidance to policy makers and planners.

![Figure 3-14. Cumulative probability of electricity price for various portfolios.](image)

3.7 Possible Benefits of Nuclear Energy

Current policy on the island of Ireland would seem to rule out the development of any nuclear facility in the near future (O'Keeffe, 2005). It would be politically controversial and may be met with opposition. However, it may be unwise to rule out nuclear energy under all circumstances. Spiralling energy prices or fuel crises along with developments and safety improvements in nuclear fission plant may make nuclear a more palatable option in the future. Another benefit of nuclear energy is the fact that it does not emit
carbon dioxide, and some eminent environmentalists have advocated it as a crucial means to reduce emissions until other cleaner technologies are developed (Lovelock, 2004). Fully estimating the cost of a nuclear energy facility is a difficult task, and there may be economies of scale issues in Ireland. The costs here are based on the nuclear plant fitting into the greater nuclear infrastructure of the UK. The costs and characteristics assumed here are conservative and are shown and discussed in Section 3.2.1. Wider social costs relating to the potentially hazardous nuclear waste are not considered here. Analysis is limited to examining the possible benefits of nuclear sourced energy in least-cost generation portfolios.

### 3.7.1 Feasible Operational Nuclear Capacity

It is widely accepted that nuclear plant are not generally designed for continuous ramping or two shifting. While this may not be such a major problem in larger interconnected system with energy export options, the prospects of having large amounts of inflexible based loaded plant would cause serious operational problems in the small isolated all-Ireland system. For these reasons it was decided to limit the amount of nuclear capacity allowed on the system in this analysis to 3500 MW, enough to supply 50% of the energy needs. This limit is used here to illustrate the potential benefits on nuclear plant and is probably near the maximum amount that could be securely operated on the all-Ireland system. Figure 3-15 produced from the maintenance scheduling algorithm described in Section 3.3.1, shows the available nuclear capacity plotted along with the daily minimum and peak load profiles.

![Figure 3-15. Available nuclear capacity and daily minimum and peak load profiles.](image-url)
It is likely that a large amount of nuclear capacity on the all-Ireland system would limit the amount of wind generation that could be accommodated securely on the system. However, the assumption is made here that wind generation is not an option while there is significant amount of nuclear plant on the system. This assumption may not be totally realistic, but if it was the case that there was sufficient leeway to operate some wind capacity on top of the nuclear capacity, then it is likely that this margin should be used to facilitate even more nuclear plant, as nuclear has the same carbonless and non-volatile price characteristics as wind power but at a lower cost.

### 3.7.2 Nuclear Plant in Least-Cost Generation Portfolios

It was found that the maximum amount of allowable nuclear generation, 3500 MW was part of the least cost generation portfolio even with the low fuel price scenario and no carbon tax. It was found that his gave a slightly cheaper energy than the coal based system that results when the nuclear option was not considered. Figure 3-16, produced for the high fuel price scenario and a 30 €/Tonne of CO$_2$, shows the characteristics possible for portfolios which consists of exclusively coal and gas plant, portfolios which consists of coal, gas and other sources but no nuclear and portfolios which consist of coal, gas, nuclear and no wind.

![Figure 3-16](image)

**Figure 3-16.** Mean-variance portfolio analysis with nuclear generation for high fuel price scenario and a 30 € / Tonne of CO$_2$ carbon tax.
It can be seen that the nuclear capacity results in a significant reduction in cost and in the standard deviation of the price possible in the generation portfolio. Table 3-12 shows the installed capacities of the different portfolios shown in Figure 3-16.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Installed Capacity for Portfolio (MW)</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>A</td>
</tr>
<tr>
<td>Coal PF</td>
<td>0</td>
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<tr>
<td>Coal IGCC</td>
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<td>Interconnection</td>
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<tr>
<td>Hydro</td>
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</tr>
<tr>
<td>Total</td>
<td>12255</td>
</tr>
</tbody>
</table>

Table 3-12. Significant portfolios for high fuel prices scenario and 30 € / Tonne of CO$_2$ carbon tax with and without nuclear capacity option.

From the results here it can be seen that the portfolios that include nuclear generation and exclude wind generation can result in both lower cost and price volatility. Diversity analysis here has been limited to exposure to fuel price volatility, there however may be other diversity issues which may not favour supplying 50% of electricity demand from a limited number of nuclear facilities. The adoption of a significant amount of nuclear capacity calls for the consideration of more factors than has been examined here. Many of these are social in nature however the analysis does illustrate the nature of the possible benefits of nuclear generation.

### 3.8 Benefits of Active Load Participation

It is generally accepted that active load participation (ALP) in the electricity system will have significant benefits (Sioshansi and Vojdani, 2001). These benefits can be in terms of increased market liquidity, peak reduction and operational security and may come at little cost. Inducing ALP is not a straightforward task due to the disperse nature of the consumers, many of whom may view electricity as a basic service. However, substantial load participation in the electricity system can only come with a change of mind set, no longer viewing electricity consumption as a basic service but rather as market delivered commodity.
Here the potential benefits of ALP are examined by including ALP in the least-cost generation optimisation. The impact of ALP is examined under two scenarios. The first scenario (ALP) assumes that that 1% of the daily energy consumption moves from the hours of highest load to the hours of lowest load. The second scenario, assumes that 1% of the daily energy demand moves from the hours of highest net-load (i.e. load – wind generation) to the hours of lowest net-load. This is labelled here as Active Net-Load Participation (ANLP). This is a simple assumption about the nature of future load participation, but will be sufficient here to illustrate the extent of the possible benefits. Figure 3-17 illustrates the nature of the ALP scenarios for a sample day. It can be seen that the ALP has the effect of reducing the peak load and also increasing the amount of energy that may be served by base loaded plant.

![Figure 3-17. Load and net-load with and without ALP and ANLP for a single day on the all-Ireland system in 2020.](image)

In order to fully incorporate the ALP and ANLP scenarios into the portfolio optimization algorithm, LOLE and capacity credit studies were carried out for the new load profiles. It was found that for both ALP an ANLP profiles the system needed to only carry the equivalent of 9480 MW of dispatchable generation to have an LOLE of 8 hours per year. This compares with 10101 MW for the case with no ALP or ANLP. It was also found that the capacity credits associated with the wind generation had also changed due to the altered load profiles. Figure 3-18 below shows the capacity credits for the original load profile and the load profiles under ALP and ANLP scenarios. ALP
and ANLP was found to have no impact on the capacity credit of conventional generation which is 0.99.

![Figure 3-18. Capacity credit for wind generation with ALP and ANLP against increasing wind capacity.](image)

It can be seen in Figure 3-18 that the flatter load profile, ALP, causes the wind capacity to have a lower capacity credit than the case with no load participation. This is due to the wind generation itself having strong diurnal pattern. Even with ANLP where the active load is offsetting the net-load, the capacity credit is still below the case with no load participation and only slightly above the ALP scenario. This is due to the variation of the daily load profile dominating the smaller variations in the wind generation output even with 3800 MW of wind capacity.

The ALP and ANLP scenarios were included in the portfolio optimization algorithm with the new capacity values for wind generation and new net-load profiles expressed by load duration bins. The algorithm was run and results compared with the original case. It was found that for the low fuel price scenario with no carbon tax the ALP and ALNP scenarios both reduced the cost of providing electricity by about 3% for the year. This was a portfolio of generation which consisted mainly of coal plant and had no wind generation. For the high fuel price scenario with a 30 €/Tonne of CO₂ carbon tax, it was found that the ALP and ANLP again gave similar results and caused in a 1.4% reduction in the cost of electricity for the year. This portfolio consisted of large amounts of gas plant and also included 2800 MW of wind generation.

The possible annual savings calculated here do not include to additional value that the ALP may have for system security issues. The costs of implementing a comprehensive
load participation scheme are not within the scope of this work, but it would be likely that the costs would be much less that the benefits calculated here.

3.9 SUMMARY

This chapter has presented an analysis of least-cost generation portfolios for the all-Ireland system in 2020. The nature of the load and wind profiles has been included in the analysis as has issues of generation adequacy. The unique characteristics of wind generation have been incorporated to allow the role of wind generation in least-cost portfolios to be established. Various types of generation plant are considered and analysis is carried out for various fuel price and carbon tax scenarios.

Results give significant insight into future generation portfolios issues. With no carbon tax, analysis shows that a coal-based system may results in the cheapest energy for the all-Ireland system. With carbon taxes greater than 10 €/Tonne of CO$_2$ for the low fuel price scenario and 30 €/Tonne of CO$_2$ for the high fuel price scenario a gas based generation portfolio provides the cheapest energy for the all-Ireland system.

The extent of the role of wind power in least-cost portfolios has been established for a range of gas prices, carbon taxes and discount rates. It appears that wind generation has a significant role to play in future least-cost generation portfolios for the all-Ireland system.

Some alterations to the methodology could be made to encapsulate the possible effects that issues of unit start-up and inter-temporal would have on the least-cost portfolios. This would require a full unit commitment program that has been developed sufficiently to deal with wind generation adequately. To date such a model has not been developed.

Mean-variance portfolio theory was applied and results showed that exposure to fuel price volatility may be reduced by diversifying the portfolio. In some cases this may come at only a slight increase in cost to the system but would generally not result from market based planning with no intervention from policy makers. Coal generation appears to play an important role in reducing price volatility for the all-Ireland system. In particular IGCC coal plant may be important if carbon taxes are high. Increasing
wind generation also reduces the price volatility, however these benefits may be limited by the amount of wind capacity that it is feasible to operate on the all-Ireland system

A simple analysis of the possible benefits of nuclear generation showed that supplying 50% of the total energy demand from nuclear generation resulted in a reduction in electricity price for all scenarios. For high fuel price and carbon tax scenarios the reductions in cost were significant. The inclusion of nuclear generation was also shown to decrease the exposure of the all-Ireland generation portfolio to fuel price volatility.

The possible benefits of active load participation have been examined and results show that 1.4 - 3% reduction in electricity price is achievable by getting 1% of daily electricity consumption to move from hours of peak load to hours of minimum load. Active load participation also caused a decrease in the capacity credit for wind generation.
Chapter 4 – Quantifying Operating Reserve Requirements with Significant Wind Capacity

This chapter begins with a general description of system operating reserve, its quantification in the past and how wind generation affects the quantification process. A generic methodology is presented which quantifies the reserve needs of a system taking into account the uncertain nature of the wind generation. This methodology is applied to the all-Ireland system. Wind power forecasts and forecast errors are analysed and results are presented. A comparison of system operation using the new methodology and the fuel saver approach is made and system costs and emissions are analysed. Finally, some modifications to the methodology are presented to illustrate it can be used to produce reserve demand curves for use in the liberalised market place.

4.1 System Operating Reserve

Reserve can be generally be defined as the additional generation or decrease in load to restore balance between generation and consumer demand following a unexpected imbalance. System operators, and/or the liberalised marketplace must ensure that dispatches results in enough reserve to meet the needs of system (Stadlin, 1971). Often in systems reserve is defined in different categories based on how soon after a generator shortfall they are to act. The speed in which system reserve can be put in place immediately after a large system contingency is very important and depends on factors such as the inertial response of the system (Kundur, 1994). This is a dynamic problem and is dealt with in Chapter 5. Systems also require the ability to reduce generation in times of unexpected generation surplus. This is sometimes termed negative reserve. In this chapter the focus will be on quantifying the megawatt amounts of reserve that should be in place at the time of dispatch and assessing how an increasing wind capacity affects these amounts.
The quantification of system reserve has, until recently, been a relatively simple, and largely deterministic process. In many systems, the amount of reserve carried at any time is just enough to cater for the loss of the largest infeed. Although there is some uncertainty due to load forecast errors, system operators are familiar with this and can generally manage it. This approach does not guarantee a secure system at all times, but rather assumes any loss of generation greater than the largest infeed is so infrequent that it is deemed unnecessary to carry extra reserve all year round. When such an event does occur the system will have to shed some load. This simple approach to quantifying reserve needs has proven successful in many systems all over the world. However, as wind power penetration grows, there are concerns that the uncertain nature of wind power output will mean that amounts larger than the largest infeed are lost more frequently as significant unforecasted wind variations may coincide with large generator trips.

In some work aimed at analysing the impacts of wind generation on systems (CER and OFREG, 2003; DETI, 2003) a fuel saver approach was adopted. This assumed that the system is scheduled and dispatched with no consideration given to possible wind generation. If wind generation is present then conventional generation is backed off, but never turned off, thus saving fuel. This basic assumption removed the necessity to quantify the impact that wind capacity may have on the required amounts of system reserve, as there will always be sufficient capacity on-line. This operational assumption is overly simplistic and is a suboptimal approach to system operation with large wind capacities.

Interestingly some earlier work involved more sophisticated analysis. Farmer et al. (1980) establish that short-term variations from wind generation are mitigated by the diversifying effect of having machines spaced out around the country and found that that longer-term variations in the wind generation do require increased levels of operational reserve. The economically optimum steam reserve was assessed in relation to wind power dispersion and the scheduling lead-time.

Schlueter et al. (1983) discuss the modification of unit commitment, economic dispatch, and frequency controls when wind generation capacity is significant and attempts to determine a wind power penetration limit. This limit is based on the point at which the
total wind generation capacity that is affected by the passage of single thunderstorm is equal to reserve carried for the worst-case single conventional generation loss. However, the authors fail to consider the benefits of wind power forecasting.

O’Dwyer et al. (1990) assess the extent to which wind energy would be technically feasible and economically attractive on the isolated Irish electricity system. It analyses environmental and economic impacts along with capacity and frequency control issues from a 1990 perspective but also fails to consider the contribution that forecasting may have on the provision of frequency control reserve.

Grubb (1991) analyses the value of variable sources on power systems and develops a statistical approach to assessing the system operational impacts including thermal plant cycling and operating reserve requirements. The reserve penalties attributable to variable sources are found based on their effect on the standard deviation of the net-load variations.

Söder (1993) considers wind speed and load forecast errors and ramp rates of conventional thermal units to determine system reserve margins in the wind-hydro-thermal interconnected Swedish electricity system. Consideration is given to the correlation of wind farm forecasts within a region and between different regions and reserve levels are linked to a probability of too low a frequency due to load and wind fluctuations. The Swedish system has a need for a reserve pool for frequency control separate to that of the reserve allocated for generator and transmission line trips, however, this is not the case in many other electricity systems.

Watson et al. (1994) evaluate the impact of different forecasting techniques on fossil fuel savings and spinning reserve requirements on a large-scale electricity system. They conclude that that benefits in both fossil fuel savings and spinning reserve requirements can be gained by the use of more sophisticated forecasting techniques than the persistence method. However the increased spinning reserve requirement was calculated as a simple fraction of the predicted wind power or wind power prediction error.
Dany (2001), attempts to quantify the technical consequences of high wind penetrations in terms of primary, secondary and long-term reserve as they apply to the interconnected German power system. Reserve targets are obtained based on historic system practice and procedures with no wind capacity. The author suggests wind generation may cause a substantial change in the demand for certain types of reserve. The author also suggests a need for negative secondary reserve to avoid a surplus of power when wind farms produce a large unforecasted increase in power production.

In a study prepared for the DTI (2002) to examine the system cost of additional renewables in the UK system by 2020, the system reserve requirements were based on providing sufficient capability to cover for 99% of the possible imbalances between supply and demand. A probability distribution based on the standard deviation of the load and wind generation fluctuations was used as a basis for these targets.

A study by a large north west utility in the United States (PacifiCorp, 2004) estimated the incremental reserve requirements due to wind generation by also comparing the standard deviation of load changes to the standard deviation of net-load changes for various amounts of wind generation. The fractional difference in standard deviations was taken as an estimate of the increased need for operating reserves.

Although previous work provides much insight into the problem of reserve quantification, some have failed to consider the contribution that modern wind power forecasting may make. Some other work may not specifically had as its goal the formal quantification of reserve with wind capacity, but rather made approximations about the level of reserve needed in order to assess other issues such as system costs due to wind generation. Reserve quantification work for very large systems, where the load forecast error is the dominant factor in relation to reserves, was able to ignore the impact of conventional generator losses. This approach allowed the combined load and wind forecast error to set the reserve target, but is not a valid approach for many other smaller systems.

The next section will present a new generic methodology, which will formally quantify the reserve needs of any system. This methodology makes best use of modern wind
power forecasting techniques and allows the use of stochastic inputs in order to provide reserve targets based on the most up to date system information.

4.2 METHODOLOGY

The methodology presented here is similar to that published by Doherty and O'Malley, (2005) and can formally quantify the reserve demands of a system with significant wind power penetration. Reserve on a system is needed to cater for any possible unexpected generation deficit. This can be caused by generator outages, unexpected increases in the load or unexpected decreases in wind power production. The actual variability of the load and wind power itself will not impact on the system reserve levels, however, the accuracy of the load and wind power forecasts will have a significant bearing on the system reserve levels as they will introduce greater uncertainty on to the system. To analyse this phenomenon the probabilities of generator and forecasting events will have to be considered. This is in contrast with the largely deterministic and bounded approach adopted by operators before.

This methodology quantifies the amount of reserve needed on the system, however, any analysis into the actual nature of the response of the reserve is a subject for more detailed dynamic modelling (Lalor et al., 2005b). Aspects of this are dealt with in Chapter 5. The methodology can be applied to produce reserve targets for different classes of reserve categories based on the time frames over which these reserves are assumed to respond. When quantifying the reserve needed on the system, the reliability of the system should be used as an objective measure to assess the required reserve under different conditions.

4.2.1 System Reliability Criterion

There are many different reliability criteria used in power systems analysis (Billinton and Allan, 1996; IEEE, 1987). A lot of system reliability analysis focuses on generation adequacy calculations, which consider the probability of load and generation being out. This type of calculation formed part of the LOLE analysis carried out in Chapter 3. The methodology here, which is designed for system operation and dispatch, considers the probability of generation and load going out. It is this subtle difference in approach that allows the effect of wind and load variations to be included in the reserve calculations.
Here the reliability criterion is defined as being the number of Load Shedding Incidents (LSI) tolerated per year, where a LSI is defined as an incident when there is not enough reserve to meet a generation shortfall. The LSI can be related to the Loss of Load Expectation reliability criterion, LOLE, by multiplying by the average time that load is shed for. Both the LSI and LOLE reliability criteria quantify the likelihood of failure but do not quantify the magnitude of load shedding. Although the magnitude of load shedding incidents is not explicitly dealt with, the methodology can be adapted to allow for the extent of possible load shedding to be examined.

4.2.2 Generator Outages

The methodology considers the probability of both full and partial generator outages on an hourly basis. The Full Outage Probability (FOP) of a unit is the probability that the unit will stop providing all of its current output in an hour period. Here it is assumed that the trip causes the units output to be instantaneously unavailable. The hourly FOP of a unit can be related to the Forced Outage Rate (FOR), which is the fraction of the year that the unit is forced out, and Mean Time To Repair (MTTR) in hours.

\[
FOP = \frac{FOR}{MTTR}
\]  

(4.1)

Partial outages of units are modelled in a similar way to the full outages. The Partial Outage Probability (POP) is the probability of an instantaneous loss of a portion of the generation in an hour period. The methodology adopts a one state partial outage approach (Billinton and Allan, 1996) which assumes each generator can only lose one set amount of generation during a partial outage.

4.2.3 Inclusion of Wind Power and Load Forecast Errors

Like any forecast, load forecasts have an error associated with them. Due to the highly repetitive nature of the daily load profile, load forecast errors are not especially sensitive to the forecast horizon and are usually proportional to the size of the load at any given hour. The load forecast error \( h \) hours ahead can be modelled as a Gaussian stochastic variable (Billinton and Allan, 1996) with a mean of zero and a standard deviation of \( \sigma_{\text{load},h} \).
Wind power forecast errors usually increase as the forecast horizon increases. Like load forecast errors the total wind power forecast error for the system \( h \) hours ahead can generally be modelled as a Gaussian stochastic variable (Söder, 1993) with a mean of zero and a standard deviation of \( \sigma_{\text{wind},h} \).

Since it is assumed both the load and wind power forecast errors are uncorrelated Gaussian stochastic variables then the standard deviation of the total system forecast error \( \sigma_{\text{total},h} \) can be given by:

\[
\sigma_{\text{total},h} = \sqrt{\sigma_{\text{wind},h}^2 + \sigma_{\text{load},h}^2}
\]  

(4.2)

### 4.2.4 Reserve Calculation

The methodology presented here relates the reserve level on the system in each hour to the reliability of the system over the year. The reserve requirement between every hour will vary as the generator dispatch and forecast errors vary, therefore the reserve level must be related to the reliability of the system over one hour. It is assumed here that the reserve is allocated in such a way during the year as to keep the average risk of having a load shedding incident in each hour the same for all hours (i.e. each hour is operated such that if the year was comprised of 8760 such hours then the expected number of load shedding incident would be LSI). For any hour \( h \), the probability of load shedding \( PLS_h \) is the yearly reliability criterion divided by the number of hours per year.

\[
PLS_h = \frac{LSI}{8760}
\]  

(4.3)

The approach considers having a load shedding incident in three ways.

- By having just an unforecasted wind and load variation greater than the system reserve level.
- By having just one generator trip (full or partial) and an unforecasted wind and load variation greater than the system reserve level.
- By having a generator trip and an unforecasted wind and load variation some time directly after a previous generator trip.

Due to the small nature of the generator outage rates, \( FOP \) and \( POP \), the probability of having 3 or more generator outages in a short period of time is not considered as it will generally not meaningfully contribute to the number of load shedding incidents.
experienced over a year. See Appendix A. If, for some reason, it was deemed necessary to include this, perhaps in the case of a very large system, then the same concept could be expanded to consider the probabilities of having 3 or more units tripping out in a short period of time.

The number of load shedding incidents per year will correspond to the sum of the probabilities of having a load shedding incident in each hour. There are two parts that contribute to this. The first is the probability of having a load shedding incident under normal hours of operation, \( PLSNO \), illustrated by Area 1 in Figure 4-1. The second is the increased probability of having a load shedding incident in the time after the outage of a unit. This is illustrated by Area 2 and corresponds to the case when the system is operating with a reduced amount of reserve due to the outage of a unit. It is assumed that the reliability of the system is re-established in a linear fashion by restoring the reserve level over \( Hr \) hours.

![Figure 4-1](image)

**Figure 4-1.** Illustrative plots of the probability of load shedding and reserve level against time during a full generator outage.

The probability of shedding load during a normal hour of system operation, \( PLSNO \), comprises of three components, as shown in Equation 4.4. \( \Phi(x) \) denotes a normalised Gaussian distribution function.

- The probability of not having any sort of generator trip while having an unforecasted wind and load variation greater than the system reserve level. This scenario corresponds to the first term in Equation 4.4.
• The probability of having just one full generator trip and an unforecasted wind and load variation greater than the system reserve level. This scenario corresponds to the second term in Equation 4.4 and is illustrated in Figure 4-2 where the grey area corresponds to the probability of having a wind and load variation greater than the system reserve level, $R_h$ minus the power not available after the full outage of generator $i$ in hour $h$, $P_{nafo_{i,h}}$.

• The probability of having just one partial generator trip and an unforecasted wind and load variation greater than the system reserve level. This corresponds to the probability of having a wind and load variation greater than the system reserve level, $R_h$ minus the power not available after the partial outage of generator $i$ in hour $h$, $P_{napo_{i,h}}$. This corresponds to the third term in Equation 4.4.

$$\text{PLSNO}_{i,h} = \left( \prod_{j=1}^{G} (1-FOP_{i,j,h}) \right) \left( \prod_{j=1}^{G} (1-POP_{i,j,h}) \right) \left( 1 - \Phi \left( \frac{R_h - P_{nafo_{i,h}}}{\sigma_{total,h}} \right) \right)$$

$$+ \sum_{i=0}^{G} FOP_{i,h} \left( \prod_{j=1}^{G} (1-FOP_{i,j,h}) \right) \left( \prod_{j=1}^{G} (1-POP_{i,j,h}) \right) \left( 1 - \Phi \left( \frac{R_h - P_{nafo_{i,h}}}{\sigma_{total,h}} \right) \right)$$

$$+ \sum_{i=0}^{G} POP_{i,h} \left( \prod_{j=1}^{G} (1-FOP_{i,j,h}) \right) \left( \prod_{j=1}^{G} (1-POP_{i,j,h}) \right) \left( 1 - \Phi \left( \frac{R_h - P_{napo_{i,h}}}{\sigma_{total,h}} \right) \right)$$

A generator outage is a discrete event and may or may not happen in any given hour. This contrasts with the continuous nature of the wind and load variations. It is assumed in this methodology that reserve is replaced after a generator outage over $Hr$ hours while reserve used in offsetting unforecasted wind and load variations is not.

Figure 4-2. Gaussian distribution of total system forecast error in hour $h$. Gray area corresponds to the probability of having a forecast error greater than the system reserve level minus the power lost during the full outage of generator $i$.  

67
It can be seen from Equation 4.4 that $PLSNO_h$ monotonically decreases with increasing $R_h$. Since $PLSNO_h$ directly determines the reserve level on the system, and the maximum risk of load shedding directly after each generator outage, $PLSFO$ and $PLSPO$, depends on the reserve on the system before that outage, then $PLSNO_h$ directly determines the values of $PLSFO$ and $PLSPO$. The probability of load shedding directly after the full and partial outage of unit $k$ in hour $h$, $PLSFO_{k,h}$ and $PLSPO_{k,h}$ are shown in Equations 4.5 and 4.6. The extra term in Equation 4.6 is to account for the probability of having a full outage of the remaining output from the unit that has just previously partially tripped.

$$PLSFO_{k,h} = \left( \prod_{j=1}^{g} (1-FOP_{j,h}) \right) \left( \prod_{j=1}^{g} (1-POP_{j,h}) \right) \left( 1-\Phi \left( \frac{R_h-Pnafo_{h}}{\sigma_{nafo_h}} \right) \right)$$  \hspace{1cm} (4.5)

$$PLSPO_{k,h} = \left( \prod_{j=1}^{g} (1-FOP_{j,h}) \right) \left( \prod_{j=1}^{g} (1-POP_{j,h}) \right) \left( 1-\Phi \left( \frac{R_h-Pnafo_{h}-Pnapo_{h}}{\sigma_{nafo_h}} \right) \right)$$  \hspace{1cm} (4.6)

The average probability of load shedding in hour $h$, $PLSh$, shown in Equation 4.7 comprises of both the probability that load will be shed under normal operation of the system and that load will be shed during the period after the outage of each unit. The contribution from the later comprises a series of triangular areas, shown as Area 2 in Figure 4-1, multiplied by the probability of them occurring over the hour period.
The $PLS_h$ can be simply related back to the reliability criterion over the year as shown in Equation 4.3. Since $R_h$ cannot be explicitly expressed in terms of the other variables, for a given $PLSNO_h$, $R_h$ is solved using the MATLAB optimization toolbox. This allows a solution to be found for any LSI by searching the solution space, varying $PLSNO_h$ between its lower bound of zero and its upper bound of $LSI/8760$. Figure 4-3 shows a flows chart of this process.

\begin{equation}
PLS_h = PLSNO_h + \frac{1}{2} \left[ \left( \frac{1}{2} \right) \left( \frac{1}{2} \right) \left( \frac{1}{2} \right) \right]
\end{equation}

\begin{equation}
(4.7)
\end{equation}

\textbf{4.3 APPLICATION TO THE ALL-IRELAND ELECTRICITY SYSTEM}

The reserve quantification methodology is applied to a single bus model of the all Ireland system. The model system is based on the system as it was at the beginning of 2003. Additional quantities of wind are added to the system to examine the effects that increased wind power penetration has on the reserve levels. Wind power forecasting characteristics are key inputs into the model.
4.3.1 Wind Power Forecasting

The impact that additional wind capacity will have on the system reserve levels will depend on the increased uncertainty that it presents to the system in the form of larger wind power forecast errors. Various different factors contribute to the overall wind power forecast error such as the accuracy of the forecasts for individual wind farms, the correlation of wind power forecast errors between different wind farms, the forecast horizon, the size of the individual wind farms and their geographical dispersion around the country.

Much work has been done in assessing the performance of wind forecasting techniques in Ireland (Watson and Lanberg, 2003; Pinson and Kariniotakis, 2003; Kariniotakis and Pinson, 2003). In general the wind power forecast errors can be expressed as a function of the forecast horizon. Other factors such as the level of output of a wind farm may also have some effect on the size of the forecast error. However, this effect was shown by Watson and Lanberg (2003) to be small. Figure 4-4 shows the typical standard deviation of the wind power forecast error for an individual farm against the forecast horizon. This is based on work done by Watson and Lanberg (2003) and Kariniotakis and Pinson (2003). For small forecast horizons i.e. less than 3 hours, modern forecasting techniques can offer little improvement over the persistence technique. However, over longer forecast horizons considerable improvements can be attained by adopting more sophisticated forecasting techniques.

![Figure 4-4. Plot of typical standard deviation of wind power forecast errors per MW of installed capacity for an individual farm versus the forecast horizon.](image-url)
Correlation between individual wind farms’ forecast errors is a very important issue as it has the potential to significantly increase the overall uncertainty that the system is exposed to from wind capacity. Modern forecasting techniques utilize meteorological forecasting tools to forecast the wind speed at various points around the country. Any error in this meteorological forecast can cause the forecast errors of individual wind farms to become correlated. It should be noted that this correlation is distinct from the correlation between individual wind farms’ forecasted outputs, which do not expose the system to greater levels of uncertainty. It has been shown in Watson and Lanberg (2003), that the correlation between wind power forecast errors of individual wind farms is strongly dependent on the distance between the wind farms. It has also been shown that the forecast horizon also has an effect on the correlation. However, this has a small effect over longer forecast horizons and very little work has been done on examining these correlations for forecast horizons shorter than 6 hours. It is for these reasons that the correlation of wind power forecast errors are assumed to be solely a function of the distance between the wind farms. Based on work done by Watson and Lanberg (2003), Figure 4-5 shows the correlation coefficient between individual wind farms’ forecast errors against the distance between the wind farms.

![Figure 4-5](image)

**Figure 4-5.** Plot of correlation coefficient between individual wind farms’ forecast errors versus distance.

### 4.3.2 Wind Farm Size and Geographical Dispersion

From analysis of wind power projects still in development (CER and OFREG, 2003) it looks likely that that the west and north coasts along with other mountainous areas
further inland will be the main focus for future on-shore wind power development. Figure 4-6 illustrates the assumed installed wind capacity on the island, as a percentage, on a county by county basis. This was based on figures given by Hurley and Watson (2002) and DETI (2003).

![Figure 4-6](image)

**Figure 4-6.** Future per county distribution of installed wind power capacity as percentage of total.

It is unlikely that there will be a significant change in the size of on-shore wind farms in the near future. For this work a distribution of wind farm sizes was created based on all existing farms, and farms in the planning process (SEI, 2003; ESB NG, 2003a). When calculating the overall wind power forecast error for a specified installed capacity, wind farms of a size randomly picked from the distribution were allocated to each county until each county’s stated capacity had been met. When calculating the distance between wind farms it was assumed that wind farms within a county were randomly distributed in a circular area of 90km. The distance from the centre of one county to another was then taken from a distance matrix, part of which is shown in Table 4-1.

<table>
<thead>
<tr>
<th></th>
<th>Cork</th>
<th>Clare</th>
<th>Cavan</th>
<th>Carlow</th>
<th>Dublin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clare</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cavan</td>
<td>240</td>
<td>170</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carlow</td>
<td>150</td>
<td>150</td>
<td>150</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dublin</td>
<td>230</td>
<td>190</td>
<td>100</td>
<td>90</td>
<td></td>
</tr>
<tr>
<td>Donegal</td>
<td>320</td>
<td>230</td>
<td>120</td>
<td>260</td>
<td>210</td>
</tr>
</tbody>
</table>

**Table 4-1.** Part of matrix of county distances
From this the distance between every wind farm was approximated and the corresponding correlation coefficients found.

### 4.3.3 Total Wind Power Forecast Error

The overall wind power forecast error for hour $h$, $\sigma_{\text{wind},h}$, can then be calculated from Equation 4.8 where $F$ is the number of wind farms, $\sigma_{m,h}$ is the standard deviation of wind power forecast error for farm $m$ in hour $h$ and $\rho_{m,n}$ is the correlation coefficient of wind power forecast errors between farms $m$ and $n$.

$$
\sigma_{\text{wind},h} = \sqrt{\sum_{m=1}^{F} \sigma_{m,h}^2 + 2 \sum_{m=1}^{F} \sum_{n=m+1}^{F} \rho_{m,n} \sigma_{m,h} \sigma_{n,h}}
$$

(4.8)

Using the information shown in Figures 4-4 to 4-6 and Equation 4.8, Figure 4-7 shows the total wind power forecast error for an installed capacity of 1500 MW versus the forecast horizon.

**Figure 4-7.** Standard deviation of total wind power forecast error for an installed wind capacity of 1500 MW versus the forecast horizon.

It can be seen that the forecast horizon has a major impact on the total wind power forecast error. The characteristics of the curve are as expected and are similar to that of the individual wind farm forecast errors as shown in Figure 4-4. The correlation of the individual wind farm forecast errors contributes heavily to the overall wind power forecast error. For an installed wind capacity of 1500 MW and a forecast horizon of 6 hours the correlation in the wind forecast errors causes an increases in the total wind power forecast error of 419% over a case where there is no wind power forecast error.
correlation between farms. The use of different forecasting techniques to predict wind farm output farms may have the potential to reduce the correlation of the errors and thus the total system wind power forecast error.

### 4.3.4 Variable Wind Power Forecast Accuracy

Much analysis of wind power forecasting accuracy concentrates on the average standard deviation of the forecast errors. However, wind power forecasts, like wind power output is stochastic in nature and not all hours of the year are equally forecastable. This is due to the fact that the stability of the weather conditions and other factors may vary. Recent forecasting work by Pinson and Kariniotakis (2003) has developed a weather stability index called the “meteo-risk index” and has established a roughly linear relationship between this index and the standard deviation of the forecast errors for individual wind farms. Based on the frequency of occurrence of different weather situations as expressed by the meteo-risk index, and its effect on the standard deviation of the wind power forecast errors, “best” and “worst” case scenarios have been established which will roughly correspond to the most accurate and least accurate that the wind power forecast error is ever likely to be. Figure 4-8 shows the best and worst case scenarios along with the average case versus the installed wind capacity for a forecast horizon 6 hours ahead.

![Figure 4-8](image_url)

**Figure 4-8.** Standard deviation of average wind power forecast errors along with the best and worst case scenarios versus installed wind capacity for a forecast horizon of 6 hours.
4.3.5 Load Forecast Error and Total System Forecast Error

As shown in Equation 4.2, the total system forecast error comprises of both the wind power forecast error and the load forecast error. Here both errors are assumed to be uncorrelated. It is also assumed here, that due to the highly repetitive nature of the daily load profile, the load forecast errors within a 24-hour period are not function of the forecast horizon. From analysis of historical data, (ESB NG, 2005) the load forecast errors were, however, found to be sensitive to the load level during a day. The standard deviation of the load forecast error during a day on the all-Ireland system is taken to be 75 MW. Using this and the values for the wind power forecast errors the total system forecast error can be found using Equation 4.2.

The result illustrated in Figure 4-9, shows the percentage increase in the total forecast error with increasing wind power penetration for forecast horizons of 1 hour and 6 hours. Due to the nature of Equation 4.2, the increase is very small at low wind power penetrations and then grows more rapidly as the installed wind capacity becomes larger. The value of the total system forecast error with zero wind capacity is entirely due to the load forecast error.

![Figure 4-9](image)

\[ \text{Figure 4-9. Percentage increase in the total system forecast error versus the installed wind capacity for forecast horizons of 1 and 6 hours.} \]

4.3.6 Units, Outage Rates and Dispatches

Sixty-five individual generators and the one HVDC interconnector are considered in the system which is based on the system as it was at beginning of 2003. The largest single
unit then had a maximum capacity of 408 MW. The FOPs and POPs of the units in the Republic of Ireland system were derived from historical data provided by ESB NG. The FOPs range from 0.0062 for the most unreliable thermal plant to 0.0002 for the most reliable hydro unit. The power from the units assumed not available after a partial outage, \( P_{napo} \), is based on the average power not available following partial trips from the units during the year. The outage probabilities of the units in Northern Ireland were based on those of similar units in the Republic of Ireland. It is assumed that the time taken to restore the reliability of the system after a generator outage, \( Hr \), is 2 hours. Typical generator dispatches are used and are based on historical data available from ESB NG (2005).

### 4.3.7 Results

Results here are based on a one hour period on the 3\(^{rd} \) of December 2002 when the conventional generating units on the all Ireland system were generating 4459 MW. The largest single infeed for the hour was supplying 397 MW. Figure 4-10 shows the required reserve level for a forecast horizon of 3 hours and for different numbers of load shedding incidents per year against increasing wind power penetration.

![Reserve Level vs Wind Capacity](image)

**Figure 4-10.** System reserve level for a various number of load shedding incidents per year and a forecast horizon of 3 hours against wind power penetration.

Figure 4-10 shows that as the wind power penetration increases then the system reserve level must also increase or the system will suffer a decrease in reliability. The rate of increase of reserve needed becomes greater as the installed wind capacity increases. It
can be seen that 1500 MWs of installed wind capacity causes roughly a 20% increase in the need for reserve for a forecast horizon of 3 hours.

Figure 4-11 shows the effect that the forecast horizon has on the required reserve level for a wind power capacity of 1500 MW under different reliability criterions. As the forecast horizon increases the standard deviation of the total wind power forecast error increases causing a greater need for reserve.

![Figure 4-11. System reserve level for an installed wind capacity of 1500MW and for various load shedding incidents per year versus the forecast horizon.](image)

Usually in electricity systems, the operating decisions for any particular hour are made some time before that hour, e.g. hour ahead, day ahead, etc. The amount of reserve that is dispatched or committed for a certain hour is the amount that is deemed necessary at the time the operating decision is made. With a substantial wind power penetration, Figure 4-11 illustrates the benefits of making the dispatch decision closer to real-time when the standard deviation of the wind power forecast error is smaller causing a reduction in the amount of reserve required. However successfully operating a system closer to real time will require a reasonably flexible set of conventional plant which are able to respond to signals and instructions over short time frames. In a market situation the forecast period can be thought of as the gate closure time, where a 6 hour forecast horizon here corresponds to a five hour gate closure time before a one hour trading period, and a one hour forecast horizon corresponds to a real-time gate closure at the beginning of a one hour trading period.
Figure 4-12 shows a plot of the required system reserve level for a LSI of 3 versus the installed wind capacity for the average case along with the best and worst case scenarios, as outlined in Section 4.3.4. With an installed wind power capacity of 1500 MW the best case scenario shows a 12 % increase in the amount of reserve needed above the case with no wind, while the worst case scenario shows an increase in the need for reserve of 44 %. However, it must be stressed that that this is the very worst case scenario and would be expected to occur extremely rarely.

![Figure 4-12. System reserve level for the average, best and worst case scenarios for a forecast horizon of 3 hours versus installed wind capacity for a reliability criterion of 3 load shedding incidents per year.](image)

From Figure 4-12 it can be seen that for a reliability criterion of 3 load shedding incidents per year and a forecast horizon of 3 hours, the reserve needed on the system with no wind capacity is 470 MW. With 1000 MW of wind capacity the system requires 516 MW. This is a 10% increase. If the load forecast error were to be excluded from the calculation then the system would need to carry 468 MW of reserve to cover for just the wind power forecast error and unit outages. This shows that with a forecast horizon of 3 hours the uncertainty associated with 1000 MW of wind capacity has a similar impact in terms of reserve as the uncertainty in the load.

### 4.3.8 Conventional Reserve Categories

In general electricity systems have several categories of reserve defined over different time frames. The aim here is to examine the impacts that wind penetration will have on conventional reserve categories based on those used in Republic of Ireland system. See
Table 4-2. It should be noted that the reserve categories defined in the Republic of Ireland system are exclusive of each other and are only required to generate within the time frame shown after an event. The nature of the variation of wind power output over time periods as short of 15 seconds has not been the subject of study in Ireland. Over short periods of time the standard deviation of the total system forecast error is heavily dependent on the standard deviation of the wind power and load variations, as sophisticated forecasting techniques can offer little improvement on the persistence method over such time frames (Watson and Lanberg, 2003; Pinson and Kariniotakis, 2003). For time periods less than one hour, it is assumed that the standard deviation of the total system forecast error over \( t \) seconds, \( \sigma_{total,t} \) is related to the standard deviation of the total system forecast error for a one hour forecast horizon, \( \sigma_{total,1Hour} \) as follows:

\[
\sigma_{total,t} = \sqrt{\frac{t}{3600}} \sigma_{total,1Hour}
\]  

(4.9)

Parsons et al. (2001) presented results from a program that measured the variations in wind power output over various time frames. The relationship of the variations over different time frames were found to generally support the assumption made in Equation 4.9. Table 4-2 shows the different reserve categories used in the Republic of Ireland and the time frames they are to respond within (ESB NG, 2003b). As stated before primary reserve will not be considered here and will be dealt with in depth in Chapter 5. It can be seen that the standard deviation of the total system forecast error is very small over 15 seconds and gradually gets larger as the time frame increases.

<table>
<thead>
<tr>
<th>Category</th>
<th>Time Frame</th>
<th>( \sigma_{total} ) (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary</td>
<td>5 - 15 sec</td>
<td>6.0</td>
</tr>
<tr>
<td>Secondary</td>
<td>15 - 90 sec</td>
<td>14.8</td>
</tr>
<tr>
<td>Tertiary 1</td>
<td>90 sec - 5 min</td>
<td>27.0</td>
</tr>
<tr>
<td>Tertiary 2</td>
<td>5 - 20 min</td>
<td>54.0</td>
</tr>
<tr>
<td>One Hour</td>
<td>20 min - 1 hour</td>
<td>93.4</td>
</tr>
</tbody>
</table>

Table 4-2. Time frames of conventional reserve categories and standard deviation of total system forecast error within time frame for 1500 MW of installed wind capacity.

The current reserve requirements in Ireland do not require that the frequency be restored to nominal value within the primary and secondary time frames. Thus it is assumed that the dynamic response of the load to a frequency event reduces the need for secondary reserve by about 2% of the total system load at any given hour (O'Sullivan and
O'Malley, 1996). This amount is deducted from the secondary reserve target to give the net secondary reserve targets that must be met by conventional generation. Figure 4-13 shows how much of each category of reserve is needed at the start of a one hour period (i.e. one hour forecast horizon) to operate with a LSI of 3 per year.

![Figure 4-13. Conventional reserve categories versus installed wind capacity.](image)

Increasing wind penetration has little effect on the categories of reserve that operate over a shorter time frame, this is due to the small standard deviation of the forecast errors over such short periods. It should be noted that the reserve targets shown in Figure 4-13 are the amounts of each category of reserve that need to be in place at the start of that hour to operate in accordance with the reliability criterion. If the reserve has to be put in place some time before the start of that hour, i.e. a forecast horizon greater than one hour, then more reserve will be needed to cover for the possible total system variation between the time the operating decisions were made and the start of the hour period. This was illustrated in Figure 4-11.

### 4.4 Implications for System Operation

Much work in the past (CER and OFREG, 2003; DETI, 2003) which looked at the integration of wind power into the electricity system in Ireland assumed a fuel saver mode of operation. In this section the methodology is applied to the all-Ireland test system to show the effect that more sophisticated modes of system operation can have on the integration of significant quantities of wind power. Both modes of system operation were run for a typical day on the all-Ireland system the results illustrate the relative merits of the different operational scenarios. Attention is given to the amount of
conventional generation dispatched and the resultant emissions under both types of system operation.

4.4.1 The Test Day

In order to illustrate the relative performance of the different operation scenarios in integrating wind power, a typical 24 hour period was created on the system assuming an installed wind capacity of 1500 MW. Figure 4-14 shows the load and wind power production during the day. The average hourly wind production for the day in question is 525 MW, this gives the installed wind capacity a capacity factor of 0.35 for the day, which is what one would expect as a typical annual capacity factor.

![Figure 4-14. Load and wind power production for the 24 hour period.](image)

4.4.2 System Operation Scenarios

For the 24 hour period in question the system is subjected to different operational scenarios to illustrate the impacts that system operational modes have on the successful integration of wind energy. For each case the reserve needed during the 24 hour period is calculated using the probabilistic method outlined earlier. The system reserve requirement is set in such a way as to have a system reliability criterion of 3 load shedding incident per year. For each hour under each scenario there will be a conventional generation commitment target which consists of the amount of conventional generation in MW that needs to be available on the system to provide reserve and energy. It is assumed that wind power does not provide reserve. Wind and load forecasting inputs are the same as outlined earlier. Conventional generator
dispatches for all-Ireland system are based on historical data available from ESB National Grid (ESB NG, 2005)

Three scenarios are considered here.

**No Wind Scenario:** This scenario is used as the base case to compare the impact of the wind power capacity. It is assumed here that there is no installed wind capacity on the system. In this case the total generation and reserve targets must be met by conventional generation.

**Fuel Saver Scenario:** The fuel saver mode of operation assumes that the generation and reserve required on the system is planned with no consideration given to the forecasted wind production. The fuel saver approach plans the system to operate solely with conventional generation. When wind power production is present, it is assumed that conventional generation is backed off in accordance with a merit order to lower operating points. Conventional plant can be backed off as far as its minimum operating point but no generation plant is turned off. If wind production reaches a level such that no more conventional generation can be backed off, then any further wind production will be curtailed.

**Forecasted Scenario:** This mode of operation uses the probabilistic methodology to plan the necessary generation and reserve on the system with explicit consideration given to the forecasted wind power production and forecast errors. This approach considers the increased need for reserve on the system due to the uncertainty in the wind power forecasts and also considers the decreased need for conventional generation due to the forecasted wind power production. Using this system operation approach, the forecast horizon of the planning period becomes a significant factor as wind power forecast errors for an hour ahead are much smaller than those for a day ahead. This results in a need for larger amounts of reserve for hours planned with longer forecast horizons. Here variations on the “forecasted” scenario are examined. The first variation assumes that the system is planned at the beginning of each hour period with a forecast horizon of one hour. The second variation assumes that the system is planned once at the beginning of the 24 hour period with each hour during the day planned with an increasing forecast horizon from 1 to 24.
4.4.3 Impact on System Reserve and Conventional Generation Needed

Using the reserve definitions used in the Republic of Ireland system, Table 4-3 shows the average amount of each category of reserve on the system during the day for each of the operational scenarios. Also shown are the availability rates paid to the different categories of reserve in the Republic of Ireland system in 2003, (ESB NG, 2003b). Again it is assumed that dynamic response of the load reduces the need for the secondary reserve by about 2% of the load at any hour.

<table>
<thead>
<tr>
<th>Category</th>
<th>Rate</th>
<th>Time Scale</th>
<th>Reserve (MW)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>No Wind</td>
<td>Fuel Saver</td>
<td>Forecasted</td>
<td>Forecasted</td>
</tr>
<tr>
<td>Secondary</td>
<td>€1.57</td>
<td>90 sec</td>
<td>315</td>
<td>329</td>
<td>329</td>
<td>329</td>
</tr>
<tr>
<td>Tertiary 1</td>
<td>€1.43</td>
<td>5 min</td>
<td>401</td>
<td>417</td>
<td>417</td>
<td>417</td>
</tr>
<tr>
<td>Tertiary 2</td>
<td>€1.43</td>
<td>20 min</td>
<td>420</td>
<td>441</td>
<td>441</td>
<td>441</td>
</tr>
<tr>
<td>One Hour</td>
<td>€1.08</td>
<td>1 hour</td>
<td>455</td>
<td>978</td>
<td>491</td>
<td>626</td>
</tr>
</tbody>
</table>

Table 4-3. Average reserve needed during the day under different system operation modes.

The 1500 MW of installed wind capacity causes a slight increase in the need for secondary and tertiary reserves in the range of 4% to 5% for all operational scenarios. With the forecasted hour-ahead technique the wind capacity causes an 8% increase in the need for one hour reserve while the forecasted day-ahead approach causes a 38% increase. Some of this increase is due to the increased potential for variations within each hour as was the case for the hour ahead scenario, however, the system must also carry more generation capacity to cater for the possible unforecasted variations in the wind power production between the time the system was planned and the actual hour in question. As the forecast horizon increases, the forecast error associated with the wind production increases significantly, causing an increased need for extra generation capacity to be on-line. It is assumed here that this extra generation capacity falls into the category of one hour reserve. Adopting the fuel saver approach causes a 116% increase in the amount of one hour reserve on the system. The fuel saver approach assumes that there will be no wind production during the day and then backs off conventional generation to facilitate the wind generation. Since the fuel saver approach dictates that no conventional plant is turned off, all the generation capacity that is backed off but must remain on-line is assumed to fall into the category of one hour reserve.

Figure 4-15 shows the amount of conventional generation needed to meet the generation and reserve requirements during the day under the different operational scenarios. It
should be noted the conventional generation needed for the no wind case is the same as that for the fuel saver.

![Graph Showing Conventional Generation Capacity Needed](image)

**Figure 4-15.** Conventional generation capacity needed under the different modes of system operation.

As can be seen from the graph the fuel saver approach requires significantly more conventional generation to be committed than the day-ahead forecasted scenario, and the hour-ahead forecasted approach offers a further improvement again over the forecasted day-ahead approach.

It can be seen from the illustrations above that the mode of system operation will have a significant effect on reserve provision costs. Here an approximation is made of reserve availability payments throughout the year to illustrate the effect of system operation strategy. If it is assumed that the day represents the typical or average day on the system and that the wind production during the day represents an average day of wind production, then the cost of reserve over the year can be approximated from the cost of reserve during this day. This is a reasonable approach, as the factors that have a dominant effect on the reserve level do not vary greatly throughout the year. Using the rates shown in Table 4-3, the cost of reserve payments over the year on the all Ireland system based on the test day is given in Table 4-4.
Table 4-4. Approximations of cost of reserve availability per year.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Cost of Reserve (€m/year)</th>
<th>% Increase in Cost over No Wind Case</th>
<th>Cost Imposed per MW Installed Wind Capacity (€/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Wind Capacity</td>
<td>23.6</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Fuel Saver</td>
<td>29.4</td>
<td>24.7</td>
<td>3888</td>
</tr>
<tr>
<td>Forecasted Hour-Ahead</td>
<td>24.8</td>
<td>5.1</td>
<td>804</td>
</tr>
<tr>
<td>Forecasted Day-Ahead</td>
<td>26.1</td>
<td>10.5</td>
<td>1656</td>
</tr>
</tbody>
</table>

It can be seen that adopting the fuel saver strategy means that incorporating 1500 MW of wind capacity will cost €5.8 (i.e. 29.4 - 23.6) million extra per year in extra reserve availability payments, based on 2003 reserve payment rates. The forecasted techniques show a significant improvement on this and also highlight the benefits of planning the system over shorter time frames when the uncertainty in the wind power production is reduced. The forecasted hour-ahead approach shows that incorporating the 1500 MW of wind capacity can cost €1.2 (i.e. 24.8 - 23.6) million extra per year. The difference in the increase of the costs is significant and underlines the importance of adopting an efficient system operation policy. Table 4-4 also shows the increase cost of reserve availability per MW of installed wind capacity for a total installed wind capacity of 1500 MW for each of the different system operational scenarios. This shows that a 25 MW wind farm would be expected to impose around €20,000 per year in extra reserve availability costs under the hour-ahead forecasted scenario. Under the fuel saver scenario the wind farm would be expected to impose around €100,000 euro per year in extra reserve availability costs. Some argue that wind capacity should be made liable for the reserve costs that they impose on the system, however, if would be unfair to impose excessive costs on wind power capacity while adopting a system operation strategy which itself is serving to greatly increase these costs.

4.4.4 Impact on System Emissions

Under the Kyoto Protocol, (UNFCCC, 1997), Ireland’s target is to keep its increase in carbon dioxide to 13% above 1990 levels in the by 2012. This target is particularly demanding as Ireland has achieved recent substantial economic growth, resulting in increased emissions. The large combustion plant directive, (EU, 2001b), states emissions limits for NO\textsubscript{X} and SO\textsubscript{2} for combustion plants over 50 MW in size. The
Republic of Ireland should not have a problem meeting its national SO\textsubscript{2} targets, however, the NO\textsubscript{X} ceiling will create significant difficulties (DEHLG, 2003)

On an electricity system with a significant wind power penetration the operation strategy will determine the manner in which the conventional generators are run. Generator emissions depend on the fuel type, the combustion methods and the set points of the generators dispatched. Thus it is important to any system operation analysis to examine the likely effect increasing levels of wind generation will have on the emissions from conventional plant. In this section analysis is undertaken to gain insight into the effect of the different operation scenarios on CO\textsubscript{2}, NO\textsubscript{X} and SO\textsubscript{2} emissions. Generator and fuel characteristics were supplied by ESB, (O’Mahony, 2004), and generator dispatches are based on historic dispatches and are altered for the fuel saver scenarios using a simple merit order. This approach does not alter generation set points for the provision of extra reserve for the forecasted scenarios and therefore emissions for both forecasted methods are the same. This preliminary analysis, (Doherty et al. 2004), has been significantly expanded by Denny and O’Malley (2005), to analyse more comprehensively the impact of wind generation on system emissions.

Carbon dioxide emissions for a unit is typically a direct function of the amount of fuel burnt. Thus, carbon dioxide emissions from a generation plant burning a carbon intensive fuel will increase with increasing levels of generation. Typical values were given in the previous chapter in Table 3-1. Here the emissions in kilograms of CO\textsubscript{2} per MWh for each conventional generation plant were calculated for the existing generation using the relationship in Equation 4.10 and data from ESB NG, (2005) and O’Mahony, (2004).

\[
\text{Kg CO}_2/\text{MWh} = \left(\%\text{Carbon Content of Fuel} \times \frac{44}{12}\right) \left(\frac{\text{Energy Consumption of Generator}}{\text{Specific Calorific Value of Fuel}}\right)
\] (4.10)

For each of the system operation strategies the CO\textsubscript{2} emissions of the conventional plant were calculated. Table 4-5 shows the results under the different modes of operation for the test day.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total CO\textsubscript{2} Emissions (Tonnes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Wind Capacity</td>
<td>63,562</td>
</tr>
<tr>
<td>Fuel Saver</td>
<td>57,991</td>
</tr>
<tr>
<td>Forecasted</td>
<td>50,966</td>
</tr>
</tbody>
</table>

Table 4-5. CO\textsubscript{2} emission under each scenario for test day.
The no wind scenario has the highest level of CO₂ emissions as only combustion plants are generating to meet the load, resulting in more fuel being burnt than under the other scenarios. The fuel saver approach shows an improvement over the no wind scenario of about 9%, whereas, the forecasted scenario shows a reduction in CO₂ emissions of 20% over the no wind scenario. The reason for the difference between the fuel saver and the forecasted approach is that under the forecasted approach, certain expensive, high emitting high merit order plant were turned off causing a greater reduction in CO₂ than in the fuel saver approach where these plant had to remain on-line.

Unlike CO₂, NOₓ emissions are predominantly determined by the combustion techniques and other measures employed by the generator rather than on the composition of the fuel. Thus, it is not necessarily the case that the NOₓ emissions of a plant rise as the plant’s generation increases. For example, Figure 4-16, below shows the NOₓ emissions characteristics for a CCGT and an OCGT (O’Mahony, 2004).

![Figure 4-16. NOₓ emissions characteristics for a CCGT and an OCGT.](image)

Under the large combustion plant directive, (EU, 2001b), generation plants must limit their emissions of NOₓ, however, as evident from Figure 4-16, there is a significant difference in emissions levels depending on the output level of the generator. The NOₓ emissions for the test day were calculated from Figure 4-16 for each of the operational scenarios and the results are presented in Table 4-6.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total NOₓ Emissions (Tonnes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Wind Capacity</td>
<td>128</td>
</tr>
<tr>
<td>Fuel Saver</td>
<td>126</td>
</tr>
<tr>
<td>Forecasted</td>
<td>114</td>
</tr>
</tbody>
</table>

*Table 4-6. NOₓ emission under each scenario for test day.*
The forecasted scenario shows a decrease in NO\textsubscript{X} emission of 11% due to the 1500 MW of installed wind capacity, while the fuel saver scenario shows a decrease of just 1.5%. Under the fuel saver technique certain plants were run at lower loads to accommodate the wind generation, some of these plants were CCGTs which experience a large increase in NO\textsubscript{X} emissions per MWh at lower operating points. On the test day, which was based on the all Ireland system as it was at the beginning of 2003, CCGTs made up 22% of the installed capacity. Current indications (CER, 2004c) predict that the bulk of future investment in generation on the all Ireland system is likely to be in gas fired plant. This will decrease further any NO\textsubscript{X} benefits that the system may see from wind power penetration operating under the fuel saver approach. In fact, with high penetrations of gas powered generation, the system may actually have higher NO\textsubscript{X} emissions under the fuel saver approach when wind power capacity is added to the system. Table 4-7 shows the NO\textsubscript{X} emissions from just the CCGTs on the system for the test day. This type of behaviour may seriously diminish any potential benefits wind power may have in achieving NO\textsubscript{X} emissions targets.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total NO\textsubscript{X} emissions from CCGT plants (Tonnes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Wind Capacity</td>
<td>16.25</td>
</tr>
<tr>
<td>Fuel Saver</td>
<td>22.24</td>
</tr>
<tr>
<td>Forecasted</td>
<td>10.89</td>
</tr>
</tbody>
</table>

*Table 4-7. NO\textsubscript{X} emissions from CCGTs under each scenario for test day.*

Although not a primary concern for Ireland, sulphur dioxide, SO\textsubscript{2} emissions also come under the large combustion plant directive, (EU, 2001b). Sulphur dioxide is a function of the sulphur content of the fuel. Using a relationship similar to that in Equation 4.10, Table 4-8 give the total sulphur dioxide emissions for each of the three operating scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total SO\textsubscript{2} Emissions (Tonnes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Wind Capacity</td>
<td>272</td>
</tr>
<tr>
<td>Fuel Saver</td>
<td>269</td>
</tr>
<tr>
<td>Forecasted</td>
<td>243</td>
</tr>
</tbody>
</table>

*Table 4-8. SO\textsubscript{2} emissions under each scenario for test day.*

The difference between the fuel saver and the forecasted approach is, like the CO\textsubscript{2} case, primarily due to the fact that under the forecasted approach certain expensive plants, which were high emitters of SO\textsubscript{2} were not on.
4.5 **Adapting Methodology for Reserve Markets**

Economic factors are the main drivers in modern electricity systems and operators no longer enjoy the same redundancy in systems as they had in the past. It is generally accepted that cost reduction can be achieved if ancillary services are simultaneously considered when dispatching the system (Gibescu and Liu, 1998), and many systems now handle frequency control issues inherently within their markets to try to reduce the costs of system security (Aronnt *et al.*, 2003). Some developed electricity markets use LP dispatch algorithms to co-optimise energy and reserves as a means to ensure system reliability in a least cost manner (NEMMCO, 2004b; EMC, 2004; Transpower, 2002). Each electricity system has different characteristics and therefore, electricity markets and procedures are tailored to suit the specific needs of each system. In this short section the reserve quantification methodology developed is used to examine the nature of the demand for reserve on the all-Ireland system. This gives insight into the suitability of various reserve procedures and market types for the all-Ireland system. Some suggested modifications to the methodology are also made so that it may be used in reserve markets to properly reflect reserve demand.

### 4.5.1 Suitability of Markets for Reserve for the All-Ireland System

The methodology was used to examine the nature of the demand for reserve for a typical hour on the all-Ireland system. The largest single infeed for the hour was supplying 397 MW. Figure 4-17 shows the need for reserve expressed by the equivalent LSI plotted against the amount that may be lost for various scenarios. The scenarios shown include the reserve needed to cater for just generation deficits, the reserve needed in the various time frames with load forecast errors and no wind generation and the reserve needed 1 hour ahead with wind forecast errors from 1500 MW of wind generation.
Analysis in the primary time frame here simply considers possible megawatt deficits on the system and does not consider any system dynamic issues. The very steep nature of the reserve curve in the relevant region of LSI range of approx. 2 – 5 can be seen. This highlights the significance of the loss of the largest infeed for this reserve range. Weitzman (1974), in a discussion on trades offs between price and quantities points out the benefits of ensuring quantity when the expected damage function is steeper than the cost function under conditions of uncertainty. Given the steepness of this curve, the consequences of having insufficient primary reserve and the fact that the wind and load forecast errors have little effect in this range, it would appear that there would be little benefit from the introduction of a quantity varying market for primary reserve in the all-Ireland system. This is the conclusion reached here and Chapter 5 continues on the topic of primary reserve deriving constraints, which are essentially a more sophisticated way to ensure the correct quantity in a market for reserve given the dynamics of the power system over this time frame.

It can be seen that the reserve curves become less steep as the time frame over which the reserves are defined becomes larger. This suggests that there may be more benefit in having a quantity varying market for these categories of reserve. The introduction of wind capacity onto the system increases the amount of reserve needed and consequently the size of the market for reserve. The varying confidence of the wind power forecasts will also cause the system reserve needs to become more stochastic in nature. Both
these factors may make the introduction of a quantity varying reserve markets more attractive with large quantities of wind capacity

4.5.2 Basic Concepts for Reserve Markets

The implementation of markets for reserve categories can take various forms. One option is to fix the quantity of reserve needed and allow the price to vary as suggested for the primary reserve category. In this approach, the methodology can be used to set reserve quantity targets based on the system reliability criterion, LSI. It may also be possible to derive linear programming constraints that will set the reserve targets based on the running level of the largest units and the combined load and wind power forecast errors. This approach is often used to incorporate constraints into dispatches and in Chapter 5 this approach is used to derive constraints that encapsulate the dynamics of the system in the primary reserve time frame. However, with high levels of wind generation the fixed quantity, varying price method may have some drawbacks. Even though the system security may not be especially affected, the marginal price for reserve may become unnecessarily high if units have to be started up in order to supply the last few megawatts to meet the reserve targets.

A fixed price and varying quantity approach may not be suitable as it may lead to shortfalls of reserve. One suitable option may be to use the methodology to produce a reserve demand curve that can be used in a market along with generators reserve supply curves.

4.5.3 Reserve Demand Curves

The reserve quantification methodology effectively produces a curve that gives the probability of having a load shedding incident plotted against the corresponding amount of reserve. This is illustrated in Figure 4-17. Given a set point, if the system was to carry one more megawatt of reserve then theoretically the system would have to shed one megawatt less of load in the event of a load shedding incident. Hence the incremental value to the system of the next megawatt of reserve can be related to the Value of Lost Load (VoLL) and the probability of it being needed.

The VoLL varies from system to system, for example the England and Wales pool market set VoLL at £2,816 per MWh in 2000/2001 while the Australian electricity
market set VoLL at AUD $10000 per MWh in 2003 (Green, 2005). There is no official VoLL in the Republic of Ireland at present, however a value of €5000 per MWh is assumed here to illustrate what follows.

As can be seen from Table 4-2, the Republic of Ireland system has 5 categories of reserve that act within an hour time frame. A shortfall of reserve in any one category could lead to loss of load, however, if each category of reserve derives its price from VoLL then the system would essentially be paying a cost based on 5 times the VoLL price to ensure security for an hour period. Here it is assumed that each category of reserve is equally important in maintaining system security and that the demand curve for each category of reserve is based on VoLL/5. The incremental system reserve demand curve can then be obtained for each category by multiplying the probability of having a load-shedding incident by VoLL/5. This is essentially multiplying the probability of needing a megawatt of reserve by the cost of not having it. Figure 4-18 shows the reserve supply curve for the Tertiary 1 reserve category with no wind capacity and a notional reserve supply curve.

![Figure 4-18. Reserve supply and demand curves.](image)

It can be seen that the demand curve can reflect the reserve needs of a system in order to set both price and quantity in a market context. The facility may prove useful as increasing wind capacity in systems increases the size of the reserve markets and also introduces a more stochastic aspect to reserve demand.
4.6 SUMMARY

This chapter presents a new probabilistic approach to calculating system reserve that accounts for the uncertain nature of wind power production. The approach links the amount of reserve carried on the system in every hour with the reliability of the system over the year. The methodology is applied to a model of the all Ireland system, and it was shown that increasing wind power capacity causes a distinct but not excessive increase in the amount of reserve needed on the system. The methodology illustrates that with increasing amounts of wind capacity reserve quantification based on deterministic metrics such as the size of the largest infeed becomes less appropriate. Due to the small nature of the total wind power variations over short time frames the impact of wind power capacity on the more expensive fast acting reserve categories is minimal. Increasing amounts of wind capacity causes a greater increase in the need for categories of reserve that act over longer periods of time. It is shown that committing reserve with a large forecast horizon, i.e. several hours before the hour in question, causes an increase in the amount of reserve needed, as extra reserve must be committed to cater for possible wind power deficits between the time the operating decisions were made and the period in question.

Illustrative results are presented to gain insight into the behaviour and relative performance of the different operating strategies shown on a system with significant wind power penetration. Adopting a fuel saver mode of operation on a system with high wind power penetrations may lead to the over-commitment of conventional generation that will result in a less economic system and may mitigate potential emissions benefits from wind power. The forecasted technique, based on the methodology developed here, shows significant improvements in facilitating the wind power capacity in the system. By allowing conventional plant to be turned off, the forecasted approach leads to a more efficient integration of the wind power while still maintaining the reliability of the system by considering the need for higher levels of reserve to account for the uncertainty in the wind production. Discussion on the role of electricity markets and some modifications of the methodology have been included in order that system demand for reserve may be appropriately reflected in reserve markets.
Chapter 5 – Ensuring Short-Term Frequency Control in System Dispatch

The dynamic and inertial characteristics of electricity systems are evolving with consequences for system frequency control. In a liberalised environment this issue needs to be dealt with in a systematic way compatible with the method of market dispatch to ensure least-cost operation of the system. This chapter describes how frequency control constraints can be derived and included in a market dispatch algorithm. These constraints can account for the reserve and inertial characteristics of individual generation units and as such are suitable for system with large wind penetrations and/or HVDC interconnection. Comparisons are made with a conventional reserve target dispatch approach for the all-Ireland power system. The impact on market prices, cost and the number and size of problem contingencies is assessed. The effect of increasing amounts of wind capacity of the ability to dispatch the system securely is also examined.

5.1 Background

Controlling the system frequency at all times to avoid load shedding is a critical aspect of system security (Wood and Wollenberg, 1996), and while this is easily achieved in large heavily interconnected systems, it is much more problematic in smaller isolated systems. Electricity systems are evolving rapidly and the inertial and dynamic characteristics of many new sources of generation differ from that of conventional plant in the past (IEEE Working Group, 1994). The increasing penetration of wind generation in systems has caused concern about the availability of the turbines’ stored kinetic energy to the system (Holdsworth et al., 2004; Mullane and O'Malley, 2005). In isolated systems, which already have a relatively small inertial base, these changes may cause significant problems to operators trying to ensure system security. Typically, many power systems try to ensure short-term frequency control by the use of a simple reserve constraint in an economic dispatch algorithm (Stadlin, 1971; Bobo et al., 1994). Such constraints were generally determined heuristically and did not account specifically for the dynamic characteristics of the power system. Given the evolving characteristics of
systems it may be the case that consideration should also be given to other factors such as the alteration of the size of the largest contingency and the stored kinetic energy on the system.

Anderson and Mirheydar (1990) derive a low order system frequency response model suitable for estimating the frequency behaviour of a power system during sudden load disturbances. The simplified model is based on neglecting non-linearities, and the generation units’ inertial and reheat time constants dominate the model’s frequency response. The authors point out that a simplified model provides an understanding of the way in which important system parameters affect the frequency response that is difficult to achieve with higher order models.

Work based on the Taiwan power system (Wu and Chen, 2004), and work based on the Republic of Ireland power system (O'Sullivan and O'Malley, 1999) use system frequency models to examine the behaviour of the systems after the loss of large units. The amount of reserve carried by the systems is assessed to see if it is sufficient to meet the systems’ frequency criteria. These methodologies can help to ensure system security but are generally not compatible with modern market dispatch algorithms. Crucially they also lack the facility to alter other important factors such as the size of problematic contingencies and the amount of kinetic energy connected to the system as part of a least-cost solution.

Recent work by Lalor et al (2005a), examines the impact of increasing wind penetration on frequency control on the all-Ireland electricity system for different wind generation technologies. Results found that high penetrations of wind generation can cause system security to become compromised during the loss of the largest infeed on the system. Results showed that this problem became more acute at times of low system load such as the summer night valley. Opportunities for the introduction of supplementary control on wind turbine generators were examined and the benefits of different reserve types were assessed.

Although there is much work modelling the frequency behaviour of systems there is very little work aimed at specifically developing methods of systems dispatch that will ensure adequate frequency control of systems after contingencies. The remainder of this
chapter will present a method of system dispatch which will ensure frequency control in system and which is compatible with existing market clearing engines. A co-optimised market clearing algorithm is presented which incorporates two new frequency-based security constraints, a Rate Of Change Of Frequency (Rocof) constraint and a minimum frequency constraint. These constraints are derived in terms of the variables that have a direct impact on the frequency. These variables are also control variables in the dispatch. In this way the system can be dispatched in a least-cost manner and in accordance with frequency control criteria.

The next section presents the general co-optimised market clearing formulation necessary for the type of dispatch used here. Section 5.3 shows how the two frequency control constraints are derived and formulated in a way that is compatible with the market clearing formulation. Section 5.4 describes the system and scenarios tested using the methodology. Results and discussion are given in Section 5.5 and a summary in given in Section 5.6

### 5.2 Market Clearing Formulation

In any economic dispatch the aim is to dispatch the system in a least-cost manner subject to constraints. Here a LP market clearing formulation is used to co-optimise energy, reserve and system kinetic energy. Kinetic energy has to be considered so that the dispatch can accurately meet the frequency control criteria of the system. The control variables in the dispatch formulation are:

- $P_i$ power from each unit, and thus the size of the contingency resulting from the loss of the unit
- $R_i$ primary reserve from each unit
- $KE_i$ stored kinetic energy provided by each unit
- $L$ the system load

The two frequency based constraints will be derived in terms of these control variables, thus allowing the LP algorithm to meet the constraints in a least-cost manner. Unit operating points, reserve levels and kinetic energy are co-optimised to find a least-cost solution on an hourly basis. Units are assumed to have linear bids for energy and reserve. Units are assumed to have a zero bid for kinetic energy, as there is little or no
incremental cost associated with its provision. Price responsive load characteristics can easily be included in the formulation, but for simplicity have been excluded here.

5.2.1 Formulation

The aim is to minimise the objective function:

$$\min \left( \sum_{i=1}^{N} b_{p_i} P_i + \sum_{i=1}^{N} b_{r_i} R_i \right)$$  \hspace{1cm} (5.1)

where $b_{p_i}$ and $b_{r_i}$ are the energy and reserve bids of generator $i$ and $N$ is the number of generators. Neglecting losses, this is subject to the load balancing constraint.

$$\sum_{i=1}^{N} P_i = L$$  \hspace{1cm} (5.2)

The constraints that encapsulate the units’ reserve and kinetic energy characteristics are incorporated into the LP dispatch and are illustrated in Figure 5-1.

![Figure 5-1. Generator reserve and kinetic energy characteristics.](image)

The unit characteristics shown in Figure 5-1 are included in the LP dispatch with Equations (5.3)-(5.8).

$$0 \leq P_i \leq P_{max_i}$$  \hspace{1cm} (5.3)

$$0 \leq R_i \leq R_{max_i}$$  \hspace{1cm} (5.4)

$$0 \leq KE_i \leq KE_{max_i}$$  \hspace{1cm} (5.5)

$$P_i - \frac{1}{R_{slope_i}} R_i \leq P_{max_i}$$  \hspace{1cm} (5.6)
where $P_{min_i}$ is the minimum power that unit $i$ can be dispatchable, $K_{Emax_i}$ is the maximum stored kinetic energy for unit $i$, $P_i$ is the size of the infeed lost, $H_{system}$ is the system inertial constant, $f_0$ is the nominal system frequency and $S_b$ is the MVA rating of the system. Therefore, the rate of change of frequency on a 50 Hz system can be expressed in terms of the kinetic energy as follows:

$$\frac{df}{dt} = 25 \frac{P}{KE_{system}}$$

(5.10)

where $KE_{system}$ is the total stored kinetic energy on the system. This comprises the kinetic energy of both the generation and the load. In this formulation only the kinetic energy supplied from the units is deemed dispatchable and therefore it must be
separated from $KE_{system}$ in the constraint. For a maximum allowable Rocof of 0.25 Hz/s the constraint is formulated as follows.

$$\sum_{i=1}^{N} KE_i \geq 100P_e - KE_L \quad \forall k \in G$$  \hspace{1cm} (11)

where $G$ is the set of generators and $KE_L$ is the kinetic energy supplied from the load. It can be seen that the Rocof constraint is inherently linear and can be expressed in terms of the control variables.

### 5.3.2 Minimum Frequency Constraint

The minimum frequency constraint is also a function of the size of a single possible contingency and the kinetic energy on the system but, unlike the Rocof constraint, the minimum frequency constraint is also a function of the response of the generators providing reserve and the dynamic response of the load. In order to examine such a system a dynamic frequency model is required. A fully validated dynamic frequency model of the all-Ireland system (Lalor et al., 2005b; O'Sullivan, 1999; Thompson and Fox, 1994) developed over many years is used here to derive the minimum frequency constraint.

To be meaningfully incorporated into economic dispatch, the MW amount of primary reserve that a unit is dispatched for must be related to the response of the unit to a frequency event. Here the amount of reserve that a unit is dispatched for corresponds to the maximum amount that the unit is able to provide 5 seconds after a frequency event. Figure 5-2 illustrates the maximum response of a unit that can provide 30 MW of primary reserve to a frequency event at 5 seconds.

![Figure 5-2](image.png)

**Figure 5-2.** Maximum response of a unit which is taken to provide 30 MW of reserve.
In order to accurately derive the minimum frequency constraint a frequency model of the system needs to be run many times to create a very large database of events that have either a Rocof of 0.25 Hz/s or frequency fall to 49.3 Hz. The fully validated system frequency model is a large and complex model, which is valid for a large range of frequency events. However, the full system frequency model is computationally intensive and would require a very long time to create a large database of events. It is for this reason that a simplified model of the system was used. This is shown in Figure 5-3. The dynamic load response in the simplified system model is assumed to be 2.5% for a one hertz drop in frequency (O'Sullivan and O'Malley, 1996), and the kinetic energy of the load, \( KE_L \), is assumed to be 2.5\( L \) in MWs. All kinetic energy connected to the system is gathered into the model of the connecting system.

![Figure 5-3. Outline of simplified system frequency model.](image)

The simplified system model incorporates a black box model to simulate the generator reserve responses. The black box model was tuned using the fully validated frequency model and is only valid for frequency events that result in a minimum frequency of 49.3 Hz. This is sufficient, as the purpose here is to derive a constraint based on frequency drops to 49.3 Hz. Figure 5-4 shows the black box model where \( R \) denotes the total reserve dispatched on the system.

![Figure 5-4. Black box model of generator reserve responses.](image)
Figure 5-5 shows the response of 252 MW of primary reserve to a relatively slow frequency deviation for both the black box model and the full system model and Figure 5-6 compares black box model with the full system model for 403 MW of reserve during a faster frequency deviation. It was found that the black box model provides a good approximation to the fully validated system model’s generator responses for frequency deviations to 49.3 Hz and over the relevant range of system reserve.

The simplified system model is run many times for different sizes of contingencies, reserve levels and load levels. For each combination of inputs the kinetic energy on the system is altered through an iterative process until the resulting frequency output either
has a rate of change of frequency of 0.25 Hz/s or a minimum frequency of 49.3 Hz. A large database of over 20,000 event scenarios was produced this way. While creating the database the load values, size of contingency values and system reserve values were each varied over a wide range so that the database encapsulates all likely single event scenarios. Events that have a binding Rocof constraint need to be identified so that the minimum frequency constraint can be approximated over the relevant region.

Figure 5-7 shows the minimum amount of kinetic energy needed from the generation to meet the two constraints as a function of the size of the infeed lost and the reserve on the system. In Figure 5-7 it should be noted that the load dimension has been excluded and that the constraints are shown for a load level of 5000 MW. Event scenarios that require unfeasible amounts of kinetic energy from the generation, i.e. more than 40,000 MWs, are not considered and are shown as zero and labelled as the infeasible region.

![Figure 5-7. Illustration of the frequency-based constraints.](image)

It can be see that the minimum frequency constraint is not inherently linear in nature. However, it was found that the minimum frequency constraint remained convex over the full range of values examined and therefore can be approximated for the LP dispatch with a number of linear functions. The set of scenarios that were identified as having binding minimum frequency constraint are approximated for the relevant region with 5 separate, 4 dimensional linear functions. This was done using functions in the
MATLAB optimisation toolbox to minimise the error between the linear functions and the actual data from the database of event scenarios. The linear approximations were based on dividing the size of contingency and reserve plane into 5 pieces. It was found that the linear functions gave a very good approximation to the constraint with an absolute mean percentage error of 1.6%. The minimum frequency constraint as approximated in terms of the control variables by the linear functions is given in Equations 5.12 and 5.13, where $j$ ranges between 1 and 5 denoting each of the linear functions.

\[
\sum_{i=1}^{N} KE_i \geq C_{j,i} L + C_{j,2} P_k + C_{j,3} \sum_{i=1}^{N} R_i + C_{j,4} \quad \forall k \in G, \quad \forall j
\]  

(5.12)

\[
C = \begin{bmatrix}
-5.33 & 230.93 & -124.89 & -834.79 \\
-5.56 & 248.35 & -150.80 & -580.40 \\
-4.69 & 182.40 & -67.61 & -832.85 \\
-4.84 & 198.17 & -76.98 & -2887.29 \\
-4.48 & 175.78 & -52.08 & -4143.23
\end{bmatrix}
\]  

(5.13)

It can be seen that the minimum frequency constraint and Rocof constraint consider the load, reserve from each unit and the kinetic energy from each unit along with the energy dispatched from each unit. These constraints are added to the market clearing formulation in Equations 5.1 to 5.8. This allows system security to be controlled in the dispatch as part of a least-cost solution.

**5.4 System and Scenarios**

Frequency control has always been an important issue on the all-Ireland system, as it is an isolated system where a single unit can be providing up to 10%-15% of the generation at certain times. The prospect of increasing amounts of HVDC interconnection and wind power capacity has given rise to further concern about frequency control (Lalor *et al* 2005a) as the possible provision of reserve and stored kinetic energy from these technologies is still unclear. The system has four 73 MW pumped storage units at Turlough Hill which plays an important role in the dynamic security of the system.
5.4.1 Scenarios

Market simulations were carried out for the all-Ireland system for three test days in a 2004 and a 2010 scenario. The load levels for the 2004 scenario were based on historical data and load levels for the 2010 scenario are based on a load growth of 4% per year (ESB NG, 2003a). The three test day are:

1. July business day, this represents the summer valley, low load case.
2. May business day, this represents an average load case.
3. January business day, this represents the winter peak, high load case.

Units’ bids are assumed to be the short run cost of the provision of energy and reserve. Typical energy bids ranged between about 20 and 45 €/MWh, while typical reserve bids ranged between 0.5 and 3 €/MW per hour. The largest units in both test systems are assumed to be a CCGTs with a maximum output of 400 MW. The 2010 test system assumes several new large CCGTs and some new peaking plant. The installed wind capacity for the 2004 and 2010 test systems was assumed to be 270 MW and 2000 MW respectively. The wind production profile is the same as that used in the previous chapter in Section 4.4, and is shown in Figure 5-8. It has a capacity factor of 0.35 and is assumed to be the same for each of the test days.

![Figure 5-8](image)

Figure 5-8. Wind generation output for test days as a percentage of installed capacity.

5.4.2 Hydro and Pumped Storage

Assessing the optimum use of energy constrained and hydro units pumped storage is not the focus of the work here. For the three test days the operating points of the hydro and pumped storage units is based on their historical operation on the test days in 2003. Given the important role that pumped storage plays in frequency control it essential that
the characteristics of the pumped storage units are accurately incorporated into the dispatch.

The contribution of each of the units to the dynamic security of the system must be assessed for their given operating points. The units have generally two modes of operation, generating and pumping. The units provide their kinetic energy to the system while in both modes. While generating it is assumed that each unit can provide a maximum of 8 MW of reserve and that the station as a whole can provide a maximum of 25 MW of reserve when all 4 units are generating. While pumping the units contribute to frequency control by way of under frequency tipping of the pumps. The frequency control constraints are designed to keep the system frequency above 49.3 Hz. Only two of the Turlough Hill pumps have under frequency relays set above this level and therefore only these two units are of significance to this work in pump mode. Turlough Hill 2 and Turlough Hill 4 have under frequency relays set at 49.4 Hz and 49.6 Hz respectively.

The behaviour of the two 73 MW pumps tripping was modelled and included in the validated all-Ireland frequency model. The impact of the under frequency tripping of the pumps on frequency traces during contingencies was examined. The impact of the under frequency tripping of the pumps on frequency traces which fell to 49.3 Hz was equated in terms of megawatts of reserve as defined in Section 5.3.2. Figure 5-9 shows 3 frequency traces for the loss of a 381 MW of generation at 5 seconds. The load level and the amount of kinetic energy on the system are the same for all 3 cases.

![Frequency traces with and without different Turlough Hill pumps tripping.](image-url)

**Figure 5-9.** Frequency traces with and without different Turlough Hill pumps tripping.
In the case with no Turlough Hill pump trip, the system is carrying 316 MW of reserve. For the Turlough Hill 2 case, it was found that 73 MW of pumping load tripped out at 49.4 Hz could replace 68 MW of conventional reserve and keep the frequency nadir at 49.3 Hz. This gives the Turlough Hill 2 unit, in pump mode, a reserve coefficient of 0.93 (i.e. 68 / 73). Similarly, for the Turlough Hill 4 case it was found that 73 MW of pumping load tripped out at 49.6 Hz could replace 94 MW of conventional reserve. This gives the Turlough Hill 4 unit, in pump mode, a reserve coefficient of 1.28 (i.e. 94 / 73). The reserve coefficients were found to be accurate for different contingencies, load levels reserve levels etc. Using the reserve coefficients, the impact of the pumped storage units can be accurately incorporated into the frequency control constraints.

This approach to the incorporation of the pumped storage was adopted as it did not require the introduction of another variable into the constraints thus keeping the problem tractable. A similar approach could be taken to modelling other features of power systems such as the contribution of neighbouring systems during frequency events.

### 5.4.3 Conventional Reserve Target Method

The performance of the dispatch model with the frequency-based constraints as described by Equations 5.1 - 5.8 and 5.11 - 5.13 is compared to a conventional dispatch model with just a simple reserve target $R_T$. The conventional reserve target dispatch has no frequency-based constraints and does not consider kinetic energy. Instead there is a reserve target of 316 MW, this is similar to the amount of primary reserve held on the all-Ireland system present. This is a heuristic target based on an assumed largest infeed of 400 MW in both 2004 and 2010 and an assumed load response of 2.5% per hertz. The conventional reserve target method is fully described by Equations 5.1 - 5.4, 5.6, 5.7 and 5.14.

$$R_T = \sum_{i=1}^{N} R_i = 316$$

(5.14)

### 5.4.4 Ensuring Feasibility of Dispatch

The problem of ensuring feasibility in co-optimised LP market dispatch is well documented (CER, 2003c; CER, 2003d). The minimum operating point of generators requires that discrete decisions be made about the on or off status of the units. In the
past this problem was often dealt with by unit commitment techniques. However, in many deregulated electricity markets, central unit commitment algorithms are not being used and market participants are expected to self-commit. As this issue is not the main focus of study in this work a simple approach is adopted. The dispatch algorithms are run firstly with the set of $P_i$ allowed to vary between 0 and $P_{max}$ in Equation 5.3. This ensures optimality but does not ensure feasibility as some of the units may be dispatched below their minimum operating points. With linear bids for energy and reserve, and the nature of constraints described by 5.7 and 5.8, it is assumed that the units which the algorithms have dispatched on in the infeasible region are necessary for the dispatch. The dispatch algorithms are run a second time with all the units that were deemed necessary for the dispatch turned on by allowing their set of $P_i$ vary between $P_{min}$, the actual minimum operating points and $P_{max}$. The remainder of the units are made unavailable. The dispatch algorithms now return a feasible dispatch. Although this approach has the potential to over commit generation it was found to give good results for almost all the scenarios tested with only a very slight increase in the value of the objective function between the first and second run of the algorithm.

5.4.5 The Lagrangian and Marginal Prices

The Lagrange multipliers can be used to provide a measure of the sensitivity of an objective function to changes in a constraint (Gill and Murray, 1997). Here they are used to derive the marginal price for energy, reserve and kinetic energy. The full Lagrangian functions and the market prices for both dispatch methods are given in Appendix B.

5.5 RESULTS AND DISCUSSION

5.5.1 Performance of Conventional Reserve Target Dispatch

Figures 5-10 to 5-13 show the number of problem contingencies that would occur during some of the test days using conventional reserve target dispatch method. Shown is the number of individual units, which, if tripped during the hour in question would cause a Rocof greater than 0.25 Hz/s or cause a minimum frequency less than 49.3 Hz. It can be seen that for the May 2004 test day there are up to 6 different units that cause the Rocof and the minimum frequency security criteria to be broken. The lower level of
response and kinetic energy provided by the load during the night hours coupled with the fewer units and consequently less kinetic energy supplied from the units causes the number of problematic contingencies to increase during the night hours. For the May 2010 test day it can be seen that the number of problematic contingencies has in general reduced due to the increase in load and subsequent increase in the number of units online. However, there are up to 9 separate units that can cause the security criteria to be broken. This is due to the projections that several new large CCGT plant will be built in the coming years.

Figure 5-10. Number of problem contingencies during May 2004 test day.

Figure 5-11. Number of problem contingencies during May 2010 test day.

Figure 5-12. Number of problem contingencies during July 2004 test day.
The July 2004 test day was shown to be the day with the most problem contingencies due to its low load level while the January 2010 test days had the fewest problem contingencies. However, even the January test days showed hours where 6 separate unit contingencies that could break the frequency control criteria.

5.5.2 Performance of Dispatch with Frequency-Based Constraints

The dispatch model with the frequency based constraints as described by Equations 5.1 - 5.8 and Equations 5.11 - 5.13 was applied to the test days. Individual hours were run and dispatches obtained. Due to the frequency-based constraints all dispatches met the frequency control criteria. The dispatched operating points of the units, the reserve levels and the kinetic energy levels were then fed back into the simplified system frequency model to check dynamically the performance of the dispatch. It was found that the dispatch model produced accurate dispatches in terms of meeting the frequency-based constraints in a least-cost fashion for all the scenarios tested. This shows that the linearisation of the minimum frequency constraint has not compromised the accuracy of the constraint. This also leads to the conclusion that specific frequency control criteria can be met in a least-cost fashion with a LP dispatch algorithm provided there is an accurate system frequency control model on which to base constraints.

5.5.3 The Effect of the Frequency-Based Constraints on the Largest Infeeds

One of the main differences between the conventional reserve target method and the dispatch with frequency-based constraints is the ability of the frequency-based constraints to dispatch large problematic units at lower levels to help meet the constraints as part of a least-cost solution. Figure 5-14 shows the operating point of the largest units on the system, a 400MW CCGT, for the January 2004 test day. It can be
seen that the conventional dispatch method dispatched the system at its maximum during all hours of the day. The dispatch with the frequency-based constraints determines that the least-cost operation of the system given the constraints results in the units being dispatched at lower operating points. Figure 5-15 shows the operating point of the CCGT using both dispatch methods for the January 2010 test day. It can be seen that the conventional dispatch method dispatched the system at its maximum all day except for two hours where it is dispatched at a lower point in order to supply reserve.

![Figure 5-14. Operation of the largest unit during the January 2004 test day.](image1)

![Figure 5-15. Operation of the largest unit during the January 2010 test day.](image2)

It can be seen that the operation of the CCGT using the dispatch with frequency-based constraints results in higher operating points for the 2010 test day than for the 2004 test day. For the 2004 there are only two infeeds of 400 MW and the frequency-based constraints determine that the least-cost operation of the system results in the curtailment of these units rather than the provision of increased amounts of reserve and kinetic energy to facilitate the loss of the units at higher operating points. For the 2010
test day there are assumed to be five infeeds of a similar size to the CCGT. For this case it can be seen from Figure 5-15 that the frequency-based constraints determines that the least-cost operation of the system results in the system carrying increased amounts of reserve and kinetic energy to allow all five units to be dispatched at higher operating points.

5.5.4 Market Prices

Figure 5-16 shows the market prices for both methods of dispatch for the July test day in 2004.

![Market Prices Graph](image)

Figure 5-16. Market prices for July 2004 test day for (a) Energy, (b) Reserve and (c) Kinetic Energy.

It was found that for all test days in 2004 and 2010 the two methods of dispatch give similar marginal prices for energy. The marginal price of reserve is generally lower for
the dispatch with frequency-based constraints as it often dispatches the system with a smaller largest contingency and, as a result, a smaller amount of reserve. The marginal price of kinetic energy ranges from between 2c and 35c over all the test days and is generally higher during the lower load hours. The conventional reserve target dispatch does not produce a marginal price for kinetic energy. It should be noted that the marginal price for primary reserve here may be higher than it would be if other categories of reserve were also co-optimised in the dispatch.

Although the possible benefits of a competitive market for kinetic energy are limited, this marginal price could be paid to participants providing kinetic energy. This would provide a reflective price signal of the value of the kinetic energy to the system. Developers of sources of generation that may not provide any natural inertial response, e.g. wind capacity and HVDC interconnection can use this price signal to determine the feasibility of enabling their technology to provide an inertial response (Holdsworth et al., 2004; Fujita et al., 2003; Lalor et al., 2005a).

5.5.5 Cost and Revenue

Analysis was carried out on the cost of dispatching the system using the frequency-based constraints and comparisons were made with the cost of dispatching the system with the conventional dispatch method. Table 5-1 shows the change in cost of using the dispatch with the frequency-based constraints over the conventional dispatch method. Revenue here is defined as the total amount paid to generators based on the quantities of energy, reserve and kinetic energy multiplied by their respective marginal prices.

<table>
<thead>
<tr>
<th>Test Day</th>
<th>% Change in cost</th>
<th>% Change in revenue</th>
<th>% Revenue spent on KE</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 2004</td>
<td>1</td>
<td>2.7</td>
<td>4.5</td>
</tr>
<tr>
<td>May 2004</td>
<td>0.8</td>
<td>3</td>
<td>5</td>
</tr>
<tr>
<td>January 2004</td>
<td>-0.01</td>
<td>-0.8</td>
<td>3</td>
</tr>
<tr>
<td>July 2010</td>
<td>0.3</td>
<td>2.3</td>
<td>2.4</td>
</tr>
<tr>
<td>May 2010</td>
<td>0.3</td>
<td>-0.3</td>
<td>1.9</td>
</tr>
<tr>
<td>January 2010</td>
<td>-0.5</td>
<td>0.2</td>
<td>1.4</td>
</tr>
</tbody>
</table>

*Table 5-1. Change in cost and revenue using the dispatch with frequency-based constraints.*

It can be seen that there is only a very slight increase in the cost of dispatching the system during the test days when the dispatch with frequency constraints is adopted.
This can be seen as the cost of avoiding the numerous load shedding incidents possible with the conventional reserve target approach. The January test days even show a cost saving. The change in revenue that must be paid out of the market can also be seen to increase for most of the test days. However, it can be seen that the percentage of the revenue that is spent on kinetic energy is greater than the change in revenue. Since there is no incremental cost associated with the provision of kinetic energy, in a truly competitive market one would assume that participants would reduce their energy bids in proportion to the revenue they would expect to make from their kinetic energy. With this behaviour, it is expected that there would be no meaningful increase in the amount being paid to the participants.

5.5.6 Meeting the Security Constraints with the Conventional Reserve Target Dispatch

Analysis was carried out to determine the ability of the conventional reserve target method to satisfy the security criteria by increasing the heuristic reserve target for the test day above 316 MW. For the January 2004 test day it was found that the system needed to carry 573 MW of reserve in order to just satisfy the minimum frequency constraint in every hour. This causes a 5.5% increase in the cost of dispatching the system for the day. The January 2010 test day required 438 MW of reserve to be carried to satisfy the minimum frequency constraint. This resulted in a 1.1% increase in the cost of dispatching the system. For the May and July test days the dispatch algorithm experienced significant difficulty in solving due to the large amount of reserve needed to satisfy the minimum frequency constraint. However, if feasible solutions do exist for these days it is expected that these test days would experience a greater increase in cost than the January test day in the same year. It was found that the conventional reserve target method could not satisfy the Rocof constraint for any of the test days.

5.5.7 Effect of Increasing Wind Capacity and Benefits of Curtailment

In future years the all-Ireland system is likely to experience a large increase in the amount of wind generation. There is also concern about the impact wind capacity will have on small systems if its stored kinetic energy is not available to the system. The variable nature of the wind production and its subsequent replacement of generation that does provide kinetic energy to the system makes the effective application of heuristic reserve constraints more difficult.
In (ESB NG, 2004c) it is suggested that at high wind capacities significant curtailment of wind generation may be necessary for various reasons to ensure security of the system. The three test days were run on the 2010 system using the dispatch with frequency-based constraints considering increasing amounts of wind generation. Each test day was run with a constant megawatt amount of wind production available throughout the day. This was done for range of wind production levels up to 2000 MW. It was again assumed that the wind generation’s stored kinetic energy was not available to the system. Results found that the January 2010 and May 2010 test days did not require any curtailment of wind production to ensure short-term frequency control of the system, even with 2000 MW of wind generation production. The July 2010 test day did however require very slight curtailment during some hours with very high available wind production. The dispatch algorithm generally found that the least-cost system dispatch with high levels of wind penetration involved significantly reducing the size of the largest contingency rather than curtailing the wind generation.

5.6 Summary

This chapter presents a new approach to ensuring adequate frequency control when dispatching the system. The work has shown that Rocof and minimum frequency constraints can be derived accurately and successfully incorporated into a LP dispatch algorithm. It has been shown that this approach provides a least-cost solution to meeting the frequency control criteria. This method produces marginal prices of energy reserve and kinetic energy. Payments for kinetic energy may induce participants to supply increased amount of kinetic energy to the system.

It was found that a conventional reserve target dispatch method resulted in the violation of the frequency control criteria for numerous single generation contingences for all of the days tested. It was found that modification of the reserve target dispatch method is not sufficient to meet the frequency control criteria for the all-Ireland system. The dispatch with frequency-based constraints has shown that for the all-Ireland system, reducing the size of contingencies that the system is exposed to plays an important role in securely dispatching the system in a least-cost way. It was found that curtailment of wind generation, even at times of high wind production and low load, was generally not necessary to meet the frequency-based security constraints in a least-cost manner.
Chapter 6 – Conclusion and Recommendations for Future Research

6.1 Conclusion

With rising fuel prices and greater realisation about the threat of global warming, wind power looks set to play an important role in the future of many electricity systems. The characteristics of wind generation differ greatly from that of thermal generation presenting challenges to system operators and planners. This thesis presents three new methodologies for planning and operating electricity systems with significant installed wind capacities. The methodologies treat fairly and equitably wind generation and are not biased by previous analytical or operational procedures, many of which have developed to suit traditional thermal generation.

The generation portfolio planning methodology, presented in Chapter 3, specifically considered the characteristics of wind generation to establish the role that it, and other technologies, play in least-cost generation portfolios for the all-Ireland system in 2020. It was found that wind generation has a significant role to play in the future and an increase in gas prices, and the cost of emitting carbon dioxide along with the need to diversify energy sources serves to increase the amount of wind generation in future generation portfolios. It was found that due to a decreasing capacity credit and other characteristics, the incremental benefit of wind generation to the system decreased as installed wind capacity increased. Despite this behaviour, for a large range of future scenarios, the issue is not determining whether wind generation is part of a least-cost portfolios, but rather it appears to be finding exactly how much wind generation can be accommodated economically in such portfolios. A full unit commitment algorithm that incorporates the characteristics of wind generation is needed to examine this issue further.

A new methodology for quantifying the reserve needs of the system is presented in Chapter 4. Results showed that wind generation causes a distinct but not excessive
increase in the amount of reserve needed. The forecast horizon was also found to be a
significant factor for the amount of reserve required. This has implications for systems
that use central unit commitment algorithms. Adopting a fuel saver approach to system
operation was shown to be considerably less favourable when compared to a mode of
operation which explicitly quantifies reserve needs, both in terms of emissions and the
amount of conventional generation which must be dispatched. The results illustrate that
relating the characteristics of wind generation in a fundamental way to the needs of the
system is necessary to ensure the most efficient operation of the system.

In Chapter 5 a conceptually new approach is taken to ensuring short-term system
frequency control after the loss of generation. Frequency based constraints are derived
in terms of dispatchable variables that also directly affect the system frequency. This
new approach is compatible with modern market clearing algorithms, suitable for
systems with changing dynamic characteristics such as systems with significant
quantities of wind generation, and also produces marginal prices for energy, reserve and
kinetic energy. Again, the approach of relating the characteristics of the generation
directly to the security needs of the system resulted in the security objectives being met
in the most efficient manner. In systems with high wind penetrations the approach
illustrated that frequency control problems arise mainly due to the size of the largest
units rather than the characteristics of the wind generation.

In the future, wind generation may play a central role in the provision of electricity in
many systems. Given its unique characteristics, the successful integration of wind
generation requires innovation and conceptually new perspectives to be taken.
Methodologies developed for system planning or operation must be based on the
principle of relating the characteristics of the various system components to the
fundamental objective of supplying economical and reliable electricity. Wind generation
may be the forerunner to a host of generation sources, such as tidal, wave and
photovoltaic generation, whose integration will require a similar fundamental approach.
6.2 **Recommendations for Future Research**

The aim of the work presented in Chapter 3 was to find least-cost generation portfolios for a single year, 2020, assuming almost no existing generation present. Further insight into desirable generation portfolios could be gained by applying the methodology developed to a series of years preceding 2020. This approach could consider the existing plant and practical options could be considered such as the closure or refitting of existing plant. As plants retire and load grows the evolution of the generation portfolio could be analysed and compared with the least-cost generation portfolio for 2020 to gain insight as to the effect and extent of the transitional process undergone by the portfolio.

Further work based on the methodologies presented in this thesis could prove useful for methods for system dispatch and scheduling with significant wind power. For any particular system, the reserve quantification methodology presented in Chapter 4 could be approximated for inclusion into a linear co-optimised dispatch formulation. This could be done by either approximating the reserve demand curves in the objective function or deriving linear constraints in terms of the most significant control variables. This, along with the constraints obtained from Chapter 5 would give a complete linear economic dispatch formulation which would fully incorporate the characteristics of wind generation. This would be extremely useful and is needed for the task of analysing the best unit commitment approach to adopt with significant wind generation.

Incorporating wind generation fully and efficiently into a unit commitment algorithm is one of the most challenging issues surrounding wind generation integration. The uncertainty that wind generation introduces to the problem means that desirable commitment schedules are not necessarily those possible of resulting in the least-cost dispatches but rather those that are the most robust given the level of uncertainty involved. The work presented in Chapter 4 highlighted the increased uncertainty and subsequent need for reserve as the forecast horizon increased. An interesting aspect of the unit commitment problem with wind generation is determining the length of the scheduling period to consider. The scheduling period will equate to the forecast horizon used for the wind power forecasts. Analysis will involve weighing the benefits of using a short period to reduce the level of uncertainty against the inefficiencies introduced by...
considering an overly short scheduling period. The optimal scheduling period to use will depend on the flexibility of the dispatchable generation. This again highlights the issue of desirable generation portfolios.

With a full unit commitment methodology that incorporates wind generation correctly further work can be done on analysing least-cost generation portfolios. Results in Chapter 3 found that the incremental benefit of wind generation to the system decreased as installed wind capacity increased. This behaviour can be examined further with the inclusion of inter-temporal and start-up issues. This would allow the type of upper limit on wind generation used in the analysis in Chapter 3 to be removed and the maximum amount of wind generation that it is desirable to have in generation portfolios could then fully examined for all scenarios.
References and Bibliography


Rourke, S, 2005, Personal Communication.


Appendix A – Number of Unit Outages to Consider in Reserve Calculations

The binomial coefficient, \( \binom{n}{k} \), is the number of ways of picking \( k \) unordered outcomes from \( n \) possibilities. It is also known as a combination or combinatorial number. This is used here to examine the relative magnitudes of the probabilities of losing 1, 2 or 3 units in a short period of time.

\[
\binom{n}{k} = \frac{n!}{(n-k)!k!}
\]  \hspace{1cm} (A. 1)

Taking an average full outage probability, \( FOP \), of 0.0012, a typical value on the all-Ireland system in 2002, Table A.A-1 shows the probability of having 1, 2 and 3 unit outages in the same hour for different amounts of generators on-line.

<table>
<thead>
<tr>
<th>Number of Outages (( n ))</th>
<th>Set of On-Line Units (( k ))</th>
<th>Binomial Coefficient (( \binom{n}{k} ))</th>
<th>Probability of Having ( n ) Units Trip in Same Hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>30</td>
<td>30</td>
<td>0.036</td>
</tr>
<tr>
<td>2</td>
<td>30</td>
<td>435</td>
<td>0.0006264</td>
</tr>
<tr>
<td>3</td>
<td>30</td>
<td>4060</td>
<td>0.0000070157</td>
</tr>
<tr>
<td>1</td>
<td>80</td>
<td>80</td>
<td>0.096</td>
</tr>
<tr>
<td>2</td>
<td>80</td>
<td>3160</td>
<td>0.0045504</td>
</tr>
<tr>
<td>3</td>
<td>80</td>
<td>82160</td>
<td>0.0001419725</td>
</tr>
<tr>
<td>1</td>
<td>170</td>
<td>170</td>
<td>0.204</td>
</tr>
<tr>
<td>2</td>
<td>170</td>
<td>14365</td>
<td>0.0206856</td>
</tr>
<tr>
<td>3</td>
<td>170</td>
<td>804440</td>
<td>0.0013900723</td>
</tr>
</tbody>
</table>

It can be seen that the hourly n-3 events are significantly less probable than n-1 and n-2 events. It can be seen that magnitude of the difference in the probabilities decreases as the number of units increase, although still remains notable. The methodology in Chapter 4 includes more complicated features, like system reliability being above normal for more than one hour, however the illustration here backs up the assumption that it is sufficient to ignore n-3 contingencies and upwards. It may be the case for an extremely large system that n-3 contingencies should be included, however this not the case in the all-Ireland system as well as many others.
Appendix B – Lagrangian Functions and Marginal Prices for Energy, Reserve and Kinetic Energy

The Lagrangian function for the conventional reserve target dispatch as described by Equations 5.1 – 5.4, 5.6, 5.7 and 5.14 is as follows:

$$\Gamma \left( (P, R), \lambda, \gamma \right) = \sum_{i=1}^{N} b_{pi} P_i + \sum_{i=1}^{N} b_{ri} R_i + \lambda_{p} \left( L - \sum_{i=1}^{N} P_i \right) + \lambda_{r} \left( R_i - \sum_{i=1}^{N} R_i \right) + \sum_{i=1}^{N} \gamma_{Pmin,i} (P_{min,i} - P_i) + \sum_{i=1}^{N} \gamma_{Pmax,i} (P_i - P_{max,i}) + \sum_{i=1}^{N} \gamma_{Rmin,i} (-R_i) + \sum_{i=1}^{N} \gamma_{Rmax,i} (R_i - R_{max,i}) + \sum_{i=1}^{N} \gamma_{Rchar,i1} \left( P_i - \frac{1}{R_{slope,i}} R_i - P_{max,i} \right) + \sum_{i=1}^{N} \gamma_{Rchar,i2} \left( \frac{-R_{max,i}}{P_{min,i}} P_i + R_i \right)$$

(B.1)

The Lagrangian function for the dispatch model with the frequency based constraints as described by Equations 5.1 – 5.8 and Equations 5.11 – 5.13 is as follows:

$$\Gamma \left( (P, R, KE), \lambda, \gamma \right) = \sum_{i=1}^{N} b_{pi} P_i + \sum_{i=1}^{N} b_{ri} R_i + \lambda_{p} \left( L - \sum_{i=1}^{N} P_i \right) + \lambda_{r} \left( R_i - \sum_{i=1}^{N} R_i \right) + \sum_{i=1}^{N} \gamma_{Pmin,i} (P_{min,i} - P_i) + \sum_{i=1}^{N} \gamma_{Pmax,i} (P_i - P_{max,i}) + \sum_{i=1}^{N} \gamma_{Rmin,i} (-R_i) + \sum_{i=1}^{N} \gamma_{Rmax,i} (R_i - R_{max,i}) + \sum_{i=1}^{N} \gamma_{Rchar,i1} \left( P_i - \frac{1}{R_{slope,i}} R_i - P_{max,i} \right) + \sum_{i=1}^{N} \gamma_{Rchar,i2} \left( \frac{-R_{max,i}}{P_{min,i}} P_i + R_i \right) + \sum_{i=1}^{N} \gamma_{Kmin,i} (KE_{i} - KE_{min,i}) + \sum_{i=1}^{N} \gamma_{Kmax,i} (KE_{i} - KE_{max,i}) + \sum_{i=1}^{N} \gamma_{Kchar,i1} \left( P_i - \frac{1}{R_{slope,i}} R_i - P_{max,i} \right) + \sum_{i=1}^{N} \gamma_{Kchar,i2} \left( \frac{-KE_{max,i}}{P_{min,i}} P_i + KE_{i} \right)$$

(B.2)
Using the standard Kuhn-Tucker optimality conditions the marginal cost of energy, \( C_E \) and the marginal cost of reserve \( MC_R \) for the conventional reserve target dispatch is shown in Equations B.3 and B.4.

\[
MC_E = \lambda_p \quad \text{(B.3)}
\]

\[
MC_R = \lambda_R \quad \text{(B.4)}
\]

For the dispatch with the frequency-based constraints the marginal cost of energy can be again given by Equation B.3. The marginal cost of reserve, \( MC_R \) and the marginal cost of kinetic energy \( MC_{KE} \) are shown in Equations B.5 and B.6.

\[
MC_R = \sum_{j=1}^{5} \sum_{k=1}^{N} \gamma_{\text{minfreq},j,k} C_{j,3} \quad \text{(B.5)}
\]

\[
MC_{KE} = -\sum_{k=1}^{N} \gamma_{\text{rocof},k} - \sum_{j=1}^{5} \sum_{k=1}^{N} \gamma_{\text{minfreq},j,k} \quad \text{(B.6)}
\]