Investigation of factors driving the costs of operating the 2020 Irish power system with large-scale wind generation.

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I, Edward V. Mc Garrigle, certify that this thesis is my own work and I have not obtained a degree in this university or elsewhere on the basis of the work submitted in this thesis.

Edward V. Mc Garrigle

Abstract

The main goal of this work is to determine the true cost incurred by the Republic of Ireland and Northern Ireland in order to meet their EU renewable electricity targets. The primary all-island of Ireland policy goal is that 40% of electricity will come from renewable sources in 2020. From this it is expected that wind generation on the Irish electricity system will be in the region of 32-37% of total generation. This leads to issues resulting from wind energy being a non-synchronous, unpredictable and variable source of energy use on a scale never seen before for a single synchronous system. If changes are not made to traditional operational practices, the efficient running of the electricity system will be directly affected by these issues in the coming years.

Using models of the electricity system for the all-island grid of Ireland, the effects of high wind energy penetration expected to be present in 2020 are examined. These models were developed using a unit commitment, economic dispatch tool called PLEXOS® which allows for a detailed representation of the electricity system to be achieved down to individual generator level. These models replicate the true running of the electricity system through use of day-ahead scheduling and semi-relaxed use of these schedules that reflects the Transmission System Operator's of real time decision making on dispatch. In addition, it carefully considers other non-wind priority dispatch generation technologies that have an effect on the overall system.

In the models developed, three main issues associated with wind energy integration were selected to be examined in detail to determine the sensitivity of assumptions presented in other studies. These three issues include wind energy's non-synchronous nature, its variability and spatial correlation, and its unpredictability. This leads to an examination of the effects in three areas: the need for system operation constraints required for system security; different onshore to offshore ratios of installed wind energy; and the degrees of accuracy in wind energy forecasting. Each of these areas directly impact the way in which the electricity system is run as they address each of the three issues associated with wind energy stated above, respectively.

It is shown that assumptions in these three areas have a large effect on the results in terms of total generation costs, wind curtailment and generator technology type dispatch. In particular accounting for these issues has resulted in wind curtailment being predicted in much larger quantities than had been previously reported. This would have a large effect on wind energy companies because it is already a very low profit margin industry.

Results from this work have shown that the relaxation of system operation constraints is crucial to the economic running of the electricity system with large improvements shown in the reduction of wind curtailment and system generation costs. There are clear benefits in having a proportion of the wind installed offshore in Ireland which would help to reduce variability of wind energy generation on the system and therefore reduce wind curtailment. With envisaged future improvements in day-ahead wind forecasting from 8% to 4% mean absolute error, there are potential reductions in wind curtailment system costs and open cycle gas turbine usage.

This work illustrates the consequences of assumptions in the areas of system operation constraints, onshore/offshore installed wind capacities and accuracy in wind forecasting to better inform the true costs associated with running Ireland's changing electricity system as it continues to decarbonise into the near future.

This work also proposes to illustrate, through the use of Ireland as a case study, the effects that will become ever more prevalent in other synchronous systems as they pursue a path of increasing renewable energy generation.

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Chapters 6, 7 and 8 of this thesis are either in review or have been accepted for publication in peer review journals. The chapters are presented as the text submitted for review with minor modification and formatting changes.

List of Acronyms

AIGCS All island grid capacity statement

AIGS All-island Grid Study

AC Alternating current

AGU Aggregated generation unit

AI All-island of Ireland, consisting of Northern Ireland (UK) and the Republic of Ireland

ARMA Average regressive moving average

BETTA British Electricity Trading and Transmission Arrangements

CAES Compressed air gas storage

CCGT Combined cycle gas turbine

CHP Combined heat and power

DA Day ahead

DA UC Day ahead unit commitment

DC Direct current

DFIG Double feed induction generator

DS3 Delivering a Secure Sustainable Electricity System

DSO Distribution system operator

DSU Demand side unit

ENTSOE European network of transmission system operators for electricity

ERCOT Electric Reliability Council of Texas

EU European Union

EWIC East West interconnector

GB the island of Britain

GDP Gross domestic product

GW Gigawatt

GWh Gigawatt hour

HVDC High voltage direct current

HVAC High voltage alternation current

IC Interconnector

I-SEM Integrated Single Electricity Market

LCC Line Commutated Converter

LOLE Loss of load expectancy

MAE Mean absolute error

MIP Mixed integer programming

MSL Minimum stable level of generation

MSQ Market schedule quantities

MW Megawatt

MWh Megawatt hour

NCC National control centre

NI Northern Ireland

NREAP National Renewable Energy Action Plan

OCGT Open cycle gas turbine

PASA Projected Assessment of System Adequacy

PHES Pump hydro energy storage

PSO Public Service Obligation

PUCR Post unit commitment relaxation

RCUC Reserved constrained unit commitment

REFIT Renewable energy feed-in tariffs

RES Renewable energy sources

RES-E Electricity generated from renewable energy sources

RMSE Root mean squared error

RoCoF Rate of Change of Frequency

ROI Ireland, Republic of

RT Real time

SEM Single Electricity Market

SEMO Single Electricity System Operator

SMP System marginal price

SNSP System non-synchronous perpetration

SOC System operational constraint previously known as TCG

SONI System operator of Northern Ireland

ST Steam turbine

STATCOMs Static synchronous compensator

TER Total energy requirement

TLAF Transmission Loss Adjustment Factors

TSO Transmission system operator

UC Unit commitment

UC ED Unit commitment economic dispatch

UCTE Union for the Coordination of the Transmission of Electricity

UK United Kingdom of Great Britain and Northern Ireland

USA United States of America

VOM Variable operation and maintenance costs

VSC Voltage source converter

WILMAR Wind Power Integration in Liberalised Electricity Markets

Highlighted Findings

- Wind capacity requirements to meet the 2020 renewable electricity targets vary considerable. Estimates from this work have shown that the required installed wind capacity could be between 5064MW and 6890MW
- Increasing the proportion of offshore wind reduces the total installed wind capacity necessary to meet the 2020 renewable targets by as much as 397MW
- The contribution of renewable energy from bioenergy sources also effects the total installed wind capacity. There is a potential requirement of an extra 847MW of wind energy if bioenergy plants do not build
- The potential wind curtailment that could occur in 2020 has been estimated to be between 4-14%
- It is shown that wind curtailment drops from an average of 14 to 8% with the relaxation of the non-synchronous generation limits (a system operational constraint) from 60-70%
- And future wind curtailment reductions of 8 to 4% is possible with the relaxation of localised system operational constraints
- Having a proportion wind capacity installed offshore also reduces wind curtailment by a possible 1-1.5 percentage points
- Relaxing of local system operational constraints results in large generation costs savings
- However non-synchronous generation limits being relaxed above 65-70% have little effect if applied prior to relaxing other more influential local system operational constraints
- System operational constraints are shown to have effects the dispatch of conventional generation technology type on the system
- This work shows the cost savings achievable by increasing wind forecast accuracy with system cost reductions possible of 1.6% with realistic improvements in wind forecasting
- Improved forecasting leads to reductions in amount of wind curtailment with on average of 0.2 percentage point reduction in wind curtailment for every percentage point increase in MAE accuracy
- There is also clear benefit in the improved wind forecast in reducing open cycle gas turbine plant usage
- However switching to stochastic scheduling leads to greater savings in cost than any realistic improvement in wind forecasting

Chapter 1

Introduction

The overall objective of the work presented in this thesis is to determine the effects on the power system and the costs of those effects for the Republic of Ireland (ROI) and Northern Ireland (NI) to meet their renewable electricity generation (RES-E) targets.

To increase renewable generation on the All-island of Ireland (AI) [1], there has been a rapid development in wind energy over the last ten years. This is expected to continue as the installed wind energy capacity is forecasted to increase into the future to meet these RES-E targets.

Wind energy generation issues investigated in this thesis result from two sources. The first source is the nature of wind itself in terms of its variability, spatial correlation and unpredictability which leads to inefficient running of the electricity system. The second main source of issues is associated with the non-synchronous nature of the majority of wind energy generation technologies, which can result in system stability issues if generation from wind makes up a significant proportion of the total generation at any instantaneous point in time. Electricity system stability is compromised by large amounts of non-synchronous generation as this affects frequency response and voltage control which is crucial in maintaining a stable system.

The work looks at the effects of issues such as wind variability, spatial correlation, unpredictability and non-synchronous generation with the objective to quantify and highlight their effects on the AI system. It is anticipated in this investigation that further investment in areas of research

[1] All-island of Ireland (AI), consisting of Northern Ireland (UK) and the Republic of Ireland

and technology related to minimising the effects of wind energy integration issues will be justified. Furthermore, it is intended that the AI will be viewed as a case study to illustrate the incumbent need to deal with these same issues that will also arise in other larger synchronous systems that propose to integrate large amounts of wind energy in the future.

There are considerable variations in the installed wind capacity estimates required for AI to meet its 2020 RES-E targets. It is expected that investigations in this thesis will determine the required wind capacities under different scenario in order to achieve the RES-E targets. Taking account of the issues that cause wind curtailment on the AI system will dramatically increase the amount of installed wind capacity required to meet the renewable targets in comparison to that estimated in previous studies. This adds a considerable, albeit indirect, expense to the electricity consumer.

This thesis illustrate the effects of different mixes of offshore/onshore wind capacities to identify the most feasible onshore/offshore wind energy portfolio to meet the 2020 RES-E 40% target. In doing so, it will also show the benefits of increasing offshore wind installation through reductions in wind curtailment due to the decreased spatial correlation of wind energy across the wider onshore and offshore area and the increased offshore wind capacity factor.

This thesis also aims to quantify the benefits of improvements in the accuracy of wind forecasting to the overall running of the electrical system in AI and in doing so, it will assist in justifying further investment for improving wind forecasting techniques. This work hopes to highlight the potential effects exerted on generators, power system operators and other participants in the Single Electricity Market (SEM). A more accurate forecast reduces the uncertainty associated with wind generation and therefore reduces the overall requirement to balance the electrical system in the event of wind forecast errors. This work shall also strongly highlight the benefit of creating the day-ahead unit commitment (DA UC) schedule from wind forecasts through stochastic scheduling rather than deterministic scheduling. This allows the known uncertainty associated with wind forecasts to be accounted for in the DA UC process.

A special emphasis shall be placed on the effects of wind energy's non-synchronous generation to the AI system. It is anticipated that, through showing the effects of different system non-synchronous penetration (SNSP) limits placed on the system, in terms of installed wind capacity required to meet the RES-E targets and wind curtailment, further investment in new technologies allowing for larger wind penetrations to be placed on the system safely will be justified.

In addition, this work shall underline the effects of relaxing the, currently necessary system operational constraints (SOCs) for the 2020 AI system. This is to be achieved by quantifying the effects on total generation costs, wind curtailment and generator dispatch by relaxing the SOCs currently necessary to maintain a safe, stable and reliable electricity system. This is expected to emphasise the need for further investment into mitigating the problems associated with reduced inertia requirements in order to allow the relaxation of these constraints (such as the SNSP limit). Investigations carried out in this thesis will illustrate the overall potential benefits to the AI system of allowing the relaxation of the voltage control SOCs through the installation of dedicated reactive power support. Importantly, this work hopes to illustrate the need to lower the required minimum number of conventional generators on-line, together with the relaxing of the SNSP limit as the issues of voltage control and frequency response are stemming from the same source, namely wind energy generation.

While important for Ireland in the next five years, the issue associated with large scale wind generation to be examined here will become important for larger synchronous systems in the future. If present trends in the installation of non-synchronous sources of generation such as wind, HVDC interconnection or photovoltaic technologies continue, then the Great Britain (GB) synchronous system may find similar issues becoming apparent in the next 10-15 years. Furthermore, the synchronous system of Continental Europe may experience similar difficulties in the next 30-40 years. Therefore AI should be viewed as an important case study for the future trends of these larger synchronous systems.

Thesis structure

The thesis structure is made up of four sets of Chapters. The first set of Chapters 1 to 3 provide information to explain and highlight issues that will develop on the electricity system in the near future. These issues result directly from the growing installed wind capacity on the island of Ireland and the electricity systems need to change in order to meet this. These issues included the effects from spatial correlation of wind, the inaccuracy in the predictability of wind and the current reliance of electricity system services from conventional generation as highlighted in Fig. 1.1.

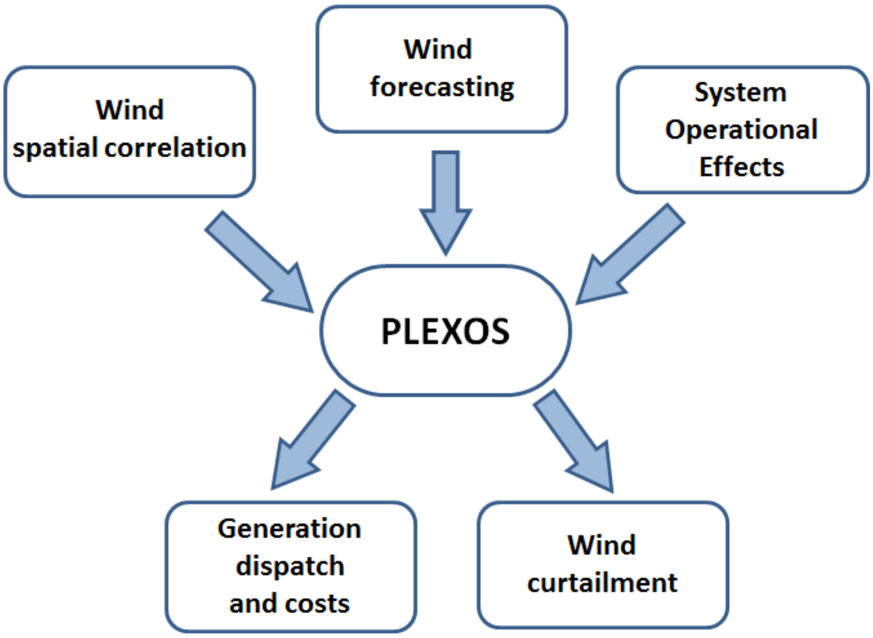


Figure 1.1: Diagram representing the basic thesis structure with areas of research on top and effects on results examined underneath

The second set of Chapters 4 to 5 explain in detail the methodology and gathering of data to allow the issues highlighted in Chapter 3 to be examined. In Chapter 4 a detailed methodology of the use of PLEXOS and other processes are set out showing how these issue were thoroughly and systematically evaluated. Chapter 5 details the acquirement of all data necessary to carry out the evaluation in Chapter 4.

The third set of Chapters 6-8 are each individually representative of the three peer-reviewed journal papers outputs from this thesis. These chapters represent the results sections detailing the findings from the examination of the issues performed in Chapter 4. Common areas of results were examined for all issues raised in Chapter 3 these being the effects on conventional generator dispatch, total system generation costs as well as wind curtailment as highlighted in Fig. 1.1.

The fourth and final set of Chapters, 9-10, discuss the receptivity of the results obtained in terms of reflectiveness of reality in light of the assumptions made and make recommendations from these results to other organisations and academia in general.

Chapter 2

Context

2.1 2020 Renewable Electricity Target and Policy Perspective

The EU renewable energy targets have two main policy objectives driving their implementation, these being energy security and the reduction in carbon dioxide emissions. It is seen as crucial for the future of EU member states to reduce dependency on imported fossil fuels from current levels [1]. It is viewed that it is not in the EU's best interest to allow, in the short term, exposure of EU economies to uncontrollable energy price volatility and in the long term, to continue with unsustainable practices for their energy needs [2]. The link between global warming and man-made emissions is becoming more evident with time [3]. This leads to the inescapable conclusion that global CO_2 emissions most be reduced to minimise the cost of climate change in the future and it is developed countries' moral obligation to lead the way on this issue. From this reasoning the EU has set ambitious renewable energy targets that are designed to achieve 20% of its overall energy from renewable sources by 2020 [4]. These targets are to be implemented by all EU member states individually through their respective National Renewable Energy Action Plans (NREAP). Resulting from this, as a member of the EU, the Republic of Ireland's (ROI) government has set a target of 40% renewable electricity generation (RES-E) by 2020 [5]. Northern Ireland (NI), while not separately dealt with under the United Kingdom of Great Britain and Northern Ireland's (UK) NREAP [6], has through its own devolved government, the NI Executive, has also set a target of 40% RES-E by 2020 [7].

This creates a renewable electricity target of 40% in both jurisdictions making up the All-island of Ireland (AI) [1] which is covered by the Single Electricity Market (SEM).

What is considered a renewable energy source is defined in [4]. These are energy from renewable non-fossil sources, namely wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases. These forms of generation are give priority dispatch on the electricity systems and are outlined in the market rules [8].

In AI the RES-E targets are to be met by ROI's already existing large scale hydro-electric generation and by the construction of the "new" renewable generation sources which will contribute approximately 37% of AI electricity generation. These "new" renewable sources for AI include small amounts of biomass, tidal, small scale hydro and waste to energy plants but most importantly large scale wind energy which will make up by far the majority of renewable generation in AI [9]. Large scale hydro in ROI refers to all conventional hydro-electricity stations situated on four rivers of the Erne, Lee, Liffey and Shannon and range in size from 4MW to 22MW.

2.2 The Irish Single Electricity Market

The Single Electricity Market (SEM) is a gross mandatory pool electricity market for the island of Ireland consisting of the two separate jurisdictions of ROI and NI and using two different currencies, both Euro and Pounds Sterling. It was the first market of its kind in the world, beginning operation on November 1st 2007 [10].

There are two main types of electricity markets these being bilateral markets and pool based markets. Bilateral markets are based on the majority of trade being arranged by contract between generators and suppliers. The British Electricity Trading and Transmission Arrangements (BETTA), the GB market, is considered a bilateral market. The other type of market, being more common, is a pool or spot market. Into this market pool all electricity generation and imports are sold and all electricity consumed is purchased.

[1] All-island of Ireland (AI), consisting of Northern Ireland (UK) and the Republic of Ireland

The Nordpool for Scandinavia and the Baltic states was the first of this style of market [11].

The SEM is a gross mandatory pool market for AI which accounts for the wholesale energy cost of the electricity system. It consists of day-ahead complex bidding where the final system wide electricity price is settled on ex post market run which is based on a completely unconstrained system for each trading period [12] [2]. The SEM is governed by the Trading and Settlement code [8]. In November 2016 the SEM is scheduled to be superseded by the Integrated Single Electricity Market (I-SEM) which will compatible with the European target model. The I-SEM will retain certain elements of the pool based market but will be much more in-line with a bilateral market with a non-mandatory day ahead market followed by a intra day balancing market [13]. Market participants will be responsible for self dispatch of generation and demand due to a more relaxed biding structure than that of the SEM.

The Market dispatch schedule is formulated based on an ex-ante unconstrained model of the electricity system where supply is balanced with demand and market scheduling is based on order of merit and solved using a Linear Relaxation method. This order of merit is the scheduling of the cheapest form of generation first followed by the next most expensive until the system demand is met. The exception to this is priority dispatch generation plant. The reason for this is that the TSO, under the EU directive [4], is obligated to minimise the amount of wind curtailment that can take place. This is done through the priority dispatch of wind generation outlined in the market rules [8] which are designed to minimise wind curtailment in the Market schedules through the pricing of wind energy at zero and therefore treating wind as a negative load.

The actual dispatch schedule gives wind energy priority dispatch over conventional forms of generation within the limits of the safe running of the electricity system. System services must also be provided in the dispatch schedule, this includes reserves, voltage control and frequency response, and are discussed in detail in Section 3.2.

The market model is idealised with simplified assumptions made in relation to synchronising times and the ramp rate profiles of generators [14]. Also the market model being unconstrained does not account for the transmission

[2]Note: The Helicopter Guide [12] is a high level summary of the SEM's Trading and Settlement code [8] and is referred to frequently in this document.

system, frequency response requirements, voltage control requirements or reserve. This results in market schedules that may not be technically feasible.

The determination of the electricity price for each trading period, the System Marginal Price (SMP), is formulated in an ex post model, where the actual wind and system demand profiles are used. This allows the ex post market model to have perfect foresight. However the actual scheduling of generation, carried out by the reserved constrained unit commitment (RCUC) scheduling tool by the TSO, must be based on forecasts. Therefore differences will arise between the ex post market model and the actual dispatch schedule [14].

Constraint costs occur due to the differences in the dispatch of generation that arise between the market schedule and the actual dispatch schedule. This is to account for the costs of system services provided by generators. For example, if a generator is scheduled to run in the market schedule but is not run in the actual real time dispatch due to SOCs, that generator will receive the market payment but must pay a constraints payment as it did not incur any operating costs. Since generation was removed from the schedule it must be replaced and dispatched elsewhere, therefore generation is scheduled in the actual dispatch that would not have been scheduled in the market schedule, this generator will receive a constraint payment that covers its operating costs. Since constraint payments to re-dispatch generators are always higher than constraint payments paid by generation not dispatched, this results in constraint payments always being a net cost to the SEM [14].

There are different roles and obligations for the different parties involved in the SEM. The Market Operator is the Single Electricity Market Operator (SEMO). Chief among them is the administration and operation of the Trading and Settlement code [8].

2.3 Global perspective of AI

The effects of large penetrations of wind energy on individual electricity systems have been extensively studied in recent years [15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 20, 26, 27, 28, 29, 30, 31, 32]. There are a number of electricity systems worldwide where wind curtailment is expected to take place in the future, most notable Germany, Denmark, Portugal, Spain and different US TSOs such as New York ISO [33], however these electricity systems are part of a much larger single synchronised systems such as in continental Europe the "Continental Synchronous Area" and the Eastern Interconnect (USA).

A review of the provisions of system services was carried out by [34] for GB, New Zealand, Tasmania, Singapore, Spain and Cyprus. This compared system services provision such as frequency regulation and reactive power provision. It is however viewed that the market's wholesale energy component is still the largest cost relative to system services costs which range between 1.5-10.8% of the total electricity market costs. But with time the system service component will grow in relation to the wholesale energy component of the market as more zero fuel costed renewable power is installed.

It would not be a correct view to equate these individual systems of high wind penetration with each other. This due to system stability issues discussed in Section 3.2.1. For example comparisons should be drawn between synchronised electrical systems such as AI, Hawaii, New Zealand, GB, ERCOT interconnect (Texas) and the Continental Synchronous Area as a whole.

Therefore from this methodology systems such as AI and Hawaii with installed wind capacities predicted to be much greater than other synchronous systems should be viewed as test cases for larger synchronous systems that will not reach these wind penetration levels until a later time.

Chapter 3

Transmission System Challenges of Large Scale Wind Energy Penetration

3.1 All-Island Electricity System

3.1.1 Wind energy

Currently the majority of wind turbines use a double fed induction generator (DFIG) technology as the conversion mechanism from mechanical power into electrical power. The DFIG technology utilises at its core an induction generator for the primary reason that it is capable of producing electrical energy at variable speeds as well as being a simple robust device that does not require brushes that are prone to wear over time. However the disadvantage to this technology is that electrical energy must be converted to DC before being converted back to a 50Hz AC current. This results in DFIG wind turbines being a non-synchronous source of electricity resulting in system stability issues if used on a large scale in a synchronous system, this is discussed in depth in Section 3.2.1.

The determination of the required amount of wind capacity to be installed in ROI and NI to meet the 2020 RES-E targets, discussed in Section 2.1, varies depending on reports. It is assumed that wind energy will have to contribute between 32% and 37% [9, 35, 36] of total generation depending on assumptions made. These variations are in the hundreds of MW and represent hundreds of millions of Euro in additional installation costs [37]. The variation in the required installed wind capacity is a considerable extra cost when it is assumed for starting in 2013 that onshore wind capital costs are €1.5 million per megawatt [38].

It is estimated in [39] the required wind capacity will be approximately 5300MW for AI, with between 3500MW and 4000MW in ROI while NI will have 1278MW (978MW onshore and 300MW offshore) however it is assumed that renewable generation will come from other non-wind sources. These figures make up the main contribution to the 40% RES-E target in both jurisdictions. For ROI it has been reported that 36.5% of total generation will come from 4649MW of wind capacity [5]. A comparison cannot be drawn with the UK NREDP [6] as it does not separate NI capacity from the rest of the United Kingdom. It has been shown that with 6000MW of installed wind capacity, which is almost entirely onshore, AI can produce 34% of demand [23]. However these figures are based on a higher prediction of system demand growth which has since been revised downwards due to the economic recession and also wind curtailment not being taken into account.

Simulations by the ROI and NI Transmission System Operators (TSO), EirGrid and the System Operator for Northern Ireland (SONI), using the Siemens PTI power system simulation package PSS®E showed that for 6000MW of installed wind the 40% renewable electricity target is not met unless a 80% SNSP is allowed [21]. For the issue of grid stability a SNSP of 80 % is not feasible in the 2020 time frame. In the same report a 7550MW wind scenario is determined to meet the targets with a 60% SNSP [21]. This indicates the strong effect wind curtailment has on the wind capacity required to meet the RES-E targets, discussed further in Section 3.4.

There are currently five developments equating to approximately 2400MW of offshore wind capacity under consideration in ROI waters. These developments all have either a grid connection or foreshore licenses approved, this is shown in Table 3.1. Also strong interest is being shown in the potential development of 600MW of offshore wind capacity off the coastline of county Down. This is part of the Crown estate licensing rounds in NI [40].

There is a projection from the NREAP of ROI that 555MW is needed in offshore wind just to help meet the targets for 2020 [5]. This recommendation comes from concern that the 2020 renewable targets will not be met from solely onshore wind developments as many onshore wind developments are

Table 3.1: Offshore Wind Farms

Name	Capacity (MW)
Dublin Array (ROI)	364
Oriel (ROI)	320
Doolick (ROI)	100
Codling wind park (ROI)	1100
Arklow Bank Phase 1 (ROI)	25.2
Arklow Bank Phase 2 (ROI)	493
Crown Estate round (NI)	600

[40, 43, 44, 45, 46, 47]

encountering difficulties in the planning process. For this recommendation to be met it would result in one to two of the five Irish offshore wind developments being constructed.

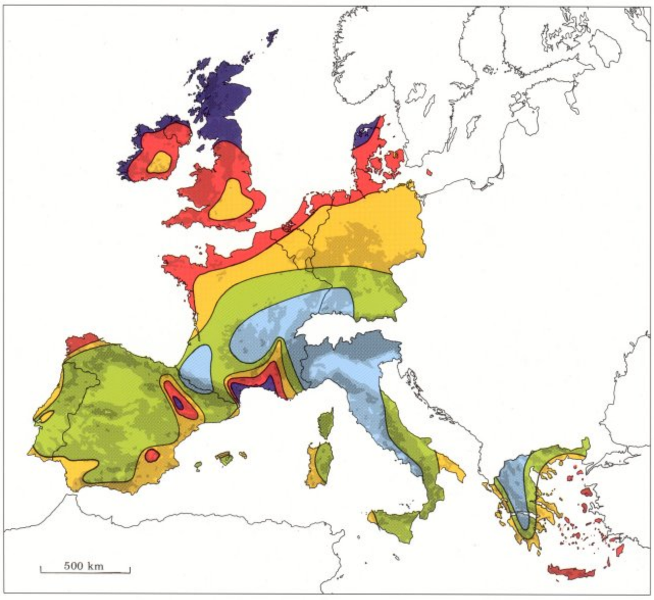
The All Island Grid Study (AIGS) assumed an installed offshore wind capacity of 245MW in its portfolio 5, which is closest to the 40% renewable target for AI in terms of installed wind capacity [41]. While it is unlikely that all of the possible 3000MW of offshore wind capacity under consideration in ROI and NI will be constructed, it will only take less than 10% of what has been proposed to exceed the AIGS Portfolio 5 estimate.

In 2009 the Department of Communications, Energy, and Natural Resources announced details of the Renewable Energy Feed in Tariff - Additional Categories (REFIT II) specific to offshore wind at 140€/MWh [42]. It was due to be introduced by early 2012, but was cancelled following a change of government. This has removed a considerable incentive for offshore wind development in the ROI. The considerable cost of installing offshore wind should be noted. It is considered conservative to assume for starting in 2013 that offshore wind will cost €3.5 million per megawatt capital cost [38].

The suggestion from EirGrid is that the system will only be able to cater for 600-700MW of offshore wind due to such issues such as reserve provision and system stability in the event of the loss of large infeeds.

Ireland has an abundant natural resource in wind energy and it is often commented that Ireland has some of the highest average wind speeds in Europe as shown in Figs. 3.1 and 3.2. The long term average onshore wind capacity factors are taken to be 31.7% and 31.4% for ROI and NI respectively [9]. It can also be noted however that there are interannual fluctuations in annual wind capacity factors [9]. This is evident on comparison of the wind data based on 2008 from the SEM forecast model [48] with actual EirGrid wind generation data [49] which showed that 2010 was a particularly calm year for wind speeds.

In Denmark offshore wind capacity factors for the country averaged 42.7% in 2013 with the best performing offshore windfarm have a capacity factor of 49.1% [50]. The offshore wind capacity factor for AI is assumed in this thesis at 40% [51] as most wind farms are located in the Irish Sea where wind speeds are shown to be high as shown in Fig 3.3. However large scale offshore wind capacity factors are assumed to be 35% in [9].



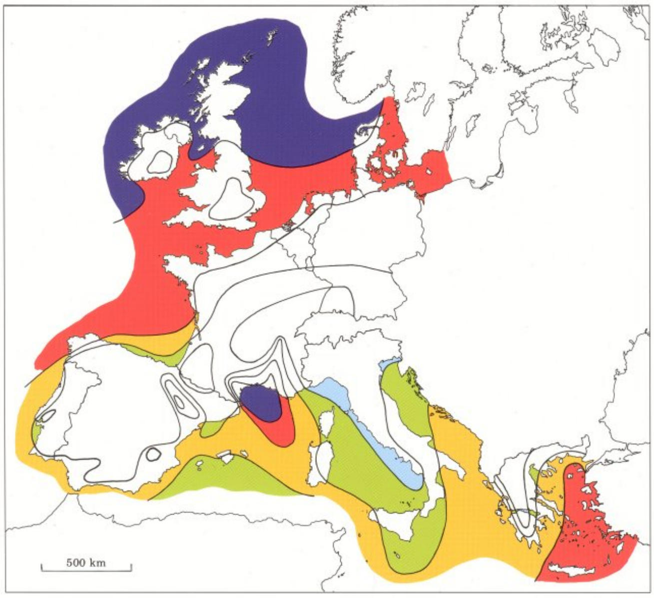
Wind resources[1] at 50 metres above ground level for five different topographic conditions										
	Sheltered terrain[2]		Open plain[3]		At a sea coast[4]		Open sea[5]		Hills and ridges[6]	
	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}
	> 6.0	> 250	> 7.5	> 500	> 8.5	> 700	> 9.0	> 800	> 11.5	> 1800
	5.0-6.0	150-250	6.5-7.5	300-500	7.0-8.5	400-700	8.0-9.0	600-800	10.0-11.5	1200-1800
	4.5-5.0	100-150	5.5-6.5	200-300	6.0-7.0	250-400	7.0-8.0	400-600	8.5-10.0	700-1200
	3.5-4.5	50-100	4.5-5.5	100-200	5.0-6.0	150-250	5.5-7.0	200-400	7.0- 8.5	400- 700
	< 3.5	< 50	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 7.0	< 400

[52]

Figure 3.1: Mean onshore wind speeds for Europe

Wind generation, unlike conventional forms of generation, has no controllable variability in its generation output, with the exception of wind curtailment. Due to the large amount of wind capacity being constructed on the system this results in a large proportion (in excess of 30%) of AI electricity generation coming from a single source that is completely dependent on local instantaneous weather conditions.

The spatial correlation of wind energy is also important. This helps reduce the variability of wind energy on an electricity system if the wind generation is spread over a wider area. Is also important in considering export of power to neighbouring systems with high wind penetrations as wind generation peaks tend to correlate in areas under a 1000 km scale length [55]. Using



Wind resources over open sea (more than 10 km offshore) for five standard heights										
	10 m		25 m		50 m		100 m		200 m	
	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}
	> 8.0	> 600	> 8.5	> 700	> 9.0	> 800	> 10.0	> 1100	> 11.0	> 1500
	7.0-8.0	350-600	7.5-8.5	450-700	8.0-9.0	600-800	8.5-10.0	650-1100	9.5-11.0	900-1500
	6.0-7.0	250-300	6.5-7.5	300-450	7.0-8.0	400-600	7.5- 8.5	450- 650	8.0- 9.5	600- 900
	4.5-6.0	100-250	5.0-6.5	150-300	5.5-7.0	200-400	6.0- 7.5	250- 450	6.5- 8.0	300- 600
	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 6.0	< 250	< 6.5	< 300

[53]

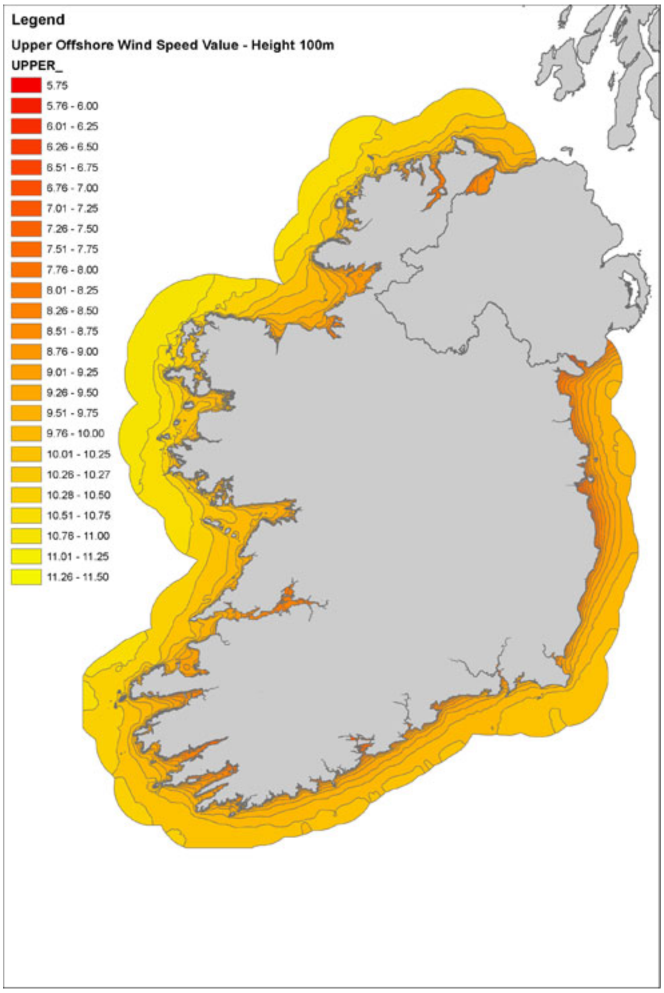
Figure 3.2: Mean offshore wind speeds for Europe

cross-correlation analysis it was found that GB wind lagged ROI wind by 2-3 hours [56]. Wind correlation between ROI and GB was also examined in [57] and shown to closely correlated.

3.1.2 Interconnectors

Due to Ireland's position as an island, high voltage direct current (HVDC) interconnection is used to connected to the neighbouring island of Great Britain (GB) as it is not practical to have a high voltage alternating current (HVAC) interconnection. It is considered that for distances greater that 80km for underwater cables that HVDC is more economical than HVAC [58], this is mainly due to the consumption of reactive power over long distances in an AC cable. There are also additional benefits of HVDC over HVAC such as better controllability of power flows [58].

Interconnection between AI and GB in 2020 is expected to consist of the existing Moyle interconnector with a maximum capacity of 500MW in both directions but currently limited to importing 450MW in the winter and 410MW in the summer [9, 59] and the East-West interconnector (EWIC)



[54]

Figure 3.3: Mean offshore wind speeds for the ROI

having a maximum capacity of 500MW in each direction. There are two general types of converter stations that change the electricity from AC to DC and back to AC again. These are Line Commutated Conversion (LCC) and Voltage Source Conversion (VSC). Moyle utilises the LCC technology which is considered to be well proven, however EWIC utilizes the new technology VSC that allows reactive support and blackstart capability [58]. It should also be noted in the context of the electricity system, interconnectors are a considerable infrastructural investment as the projected cost of the EWIC interconnector between ROI and GB was €596 million [60].

HVDC interconnection is not a synchronous source of generation as power is converted from a DC source to an AC as it enters the electricity system. From the SNSP Eqn. 4.6, which is discussed in detail in Section 4.5.1, it is evident that increasing exports to a maximum during times of high wind power penetration on the All-island system will be essential to reducing the amount of wind curtailment that will necessary with a fixed SNSP. This raises an issue over the use of the interconnectors. A major influence on Ireland's ability to export electrical energy to the GB market will be GB's targets for an installed wind capacity of 27GW in a system with 113GW installed generation capacity by 2018 [61] as the times of peak wind power on the AI system and time difference, leading or lagging, relative to wind power peaks in GB will be important [56]. Previous work assumed that most of Britain's installed wind would be built onshore in Scotland but with recent developments in offshore wind, the largest proportion of the installed wind capacity will be in the North Sea with lesser amounts in the Irish Sea.

There is a view that the commissioning of the EWIC will result in an increase in the price for the use of the interconnectors with the GB [62]. This may not affect the average system marginal price SMP over a year but it may have a large effect on how the model uses the interconnectors between the two markets, SEM and BETTA. It is also noted that imports on the interconnectors are recommended to be limited to 500-1350MW depending on the wind generation due to SNSP, assuming there is a third interconnector by 2020 [21].

From a dispatch point a view an issue arises over whether the interconnectors are dispatched on a day-ahead schedule which is fixed or flexible to change on an intra-day schedule as up-to-date wind data becomes available. This has been shown to have an effect on interconnector usage and wind curtailment [15]. Currently interconnectors are also dealt with under priority dispatch rules [8].

3.1.3 Electricity prices

It is recognised that fuel pricing can be very unpredictable due to its strong link with socio-economic events such as the influences that the Arab Spring had on oil prices [63]. For the EU where the gas price is still coupled to the oil price this also affects electricity prices. It is also difficult to predict the increased usage of existing technologies that become financially viable or the development of new technologies in fossil fuel extraction such as what occurred in the USA due to increased shale gas extraction [64] which dramatically affect price trends of natural gas in North America and therefore created a large increase in the proportion of electricity being produced from natural gas.

The Public Service Obligation (PSO) levy supports all peat plants in ROI as well as wind energy, small-scale hydropower, combined heat and power (CHP), biomass-landfill gas, biomass-CHP, biomass-anaerobic digestion and offshore wind. However this is due to change by 2020 where peat will no longer be supported. The CHP plant at Aughinish Alumina and the CCGT at Tynagh also receive support through the PSO levy [65]. This was needed to secure additional capacity to meet a predicted generator capacity shortfall in 2005. This support is due to end in 2016 with support not expected to continue beyond this time.

In the 2010 ROI for the first time introduced a carbon tax which was levied at €15 per tonne of CO_2 emissions. However the carbon tax is not currently applied to fuels used in the generation of electricity. Assumptions for the carbon price in 2020 vary dramatically from the €41.60 per tonne [58] down to €25.00 per tonne [66]. Also it should be noted that a recorded low in market carbon price was €2.81 per tonne occurring on the 24^{th} January 2013 in the EU Emissions Trading System [67]. Conventional generators subject to the PSO levy are exempted from the carbon levy as they do not earn any carbon credit windfall profits [68].

3.2 Transmission System Operations

The electricity system must remain in balance at all times. Electricity system balancing in its simplest form is matching of generation with system demand in real time. To ensure this is met, one of the primary functions of the Transmission System Operator (TSO) is to maintain the system frequency, local voltages and system reserve levels within defined limits set out in the Grid code [69]. In the SEM the balancing procurement scheme is done through mandatory provision, which differs to the rest of Europe.

The TSO for ROI is EirGrid and for NI is System Operator of Northern Ireland (SONI). EirGrid and SONI are jointly responsible for the coordination of the running of the transmission system in AI while both schedule generation in their respective jurisdictions. The role of the TSOs is to provide services in relation to connection to the grid, transmission of high voltage electricity and the electricity market for the users of the high voltage electricity transmission system. These users include electricity generators, suppliers and customers. The TSOs are also responsible for the development of grid infrastructure as well as incorporating the AI electricity system into the European system through further interconnection.

3.2.1 Electricity system stability issues

The electricity system has developed with large synchronous generators which are electrically locked into one coherent phase. This means that all electrical generators rotate at the same relative speed, which creates the same frequency throughout the synchronous system. The electricity system operates at an average frequency of 50Hz which is to be maintained within predefined limits set out in the EirGird and SONI Grid Codes [69, 70]. The frequency is constantly changing as supply in the form of generation alters in response to system demand. If the system demand exceeds generation the frequency will fall and if the system demand falls below generation the frequency will rise. The frequency must also be maintained within certain limits event in the event of a loss of generation source(s). Therefore this creates the need to have system reserve, which is extra dispatchable generation on standby ready to be utilised or shedable load in the event that a source of generation is lost. This is described in detail in Section 4.5.4.

There a need to prevent a rapid change in frequency occurring during times where a loss of generation has just occurred, therefore the frequency response of the system is important and is measured in the "rate of change of frequency" (RoCoF). Therefore to maintain frequency response within limits there is a requirement to keep sufficient amounts of inertia on a electricity system. Inertia is traditionally maintained on the system through the use of conventional (synchronous) generation machines being kept on-line and synchronised to the grid. Inertia is provided by the rotating mass of a conventional generator such as the rotating turbine, generator and drive chain. The faster the rated rotational speed of the generator and larger the spinning mass, the larger the inertia provided from the generator to the system. With the loss of a generation source a large system will react more slowly, as in the RoCoF will be lower, than that of a small system with the same loss of generation. This is due to the potential RoCoF that may occur is inversely proportional to the amount of inertia on the system [71].

Table 3.2: Cost estimates of installation of frequency response support devices.

Device name	Capacity (MW)	Storage (MWh)	Total cost per device (€m)
Flywheels	20	5	15.33
Batteries (Li-ion)	40	10	33.17

[73]

To ensure that RoCoF does not exceed its limits (currently 0.5Hz/s) [69, 70], a sufficient amount of inertia must be kept on the system at all times. Currently when inertia falls below 25000MWs a warning is sounded in the EirGrid national control centre (NCC) and it is prevented from falling below 20000MWs on the AI system, as this is the minimum amount of inertia required on the system to maintain a RoCoF of less than 0.5 Hz/s in the event of the loss of the largest in-feed, which is EWIC at 500MW.

Issues surrounding the need to maintain a minimum amount of inertia on the system lead to the need for system-wide operational constraints. This is achieved in AI by the use of a system non-synchronous penetration (SNSP) limit. The SNSP is the instantaneous portion of generation that comes from non-synchronous sources such as wind energy and high voltage direct current imports on interconnectors [21]. This is discussed in detail in Section 4.5.1. The technical reasons to why limitations are placed on the proportion of wind energy and HVDC generation that can occur on the electricity system is explained in Sections 3.1.1 and 3.1.2.

There is no one solution to the issue of frequency response. It is highlighted in [72] that resolving issues such as the loss of the largest infeed that other generators should with stand a RoCoF of 2Hz/s. It is however possible also to provide inertia on the system from sources other than conventional generators. Devices such as flywheels and batteries are available, however not commercially tested, and those most likely to be used are listed with costs in Table 3.2 [73]. Flywheels can provide fast frequency response and low speed flywheels linked through a synchronous generator/motor can provide inertia support. It is viewed in the future that high speed flywheels through the use of power electronics will also be capable of providing inertia support [73]. Batteries can be used for frequency response, particularly suited to this are Lithium-ion (Li-ion) batteries due to their small power to energy ratio and almost instantaneous ramp rates [73].

With in an alternating current (AC) system a portion of the energy being transferred maintains electric and magnetic fields of AC equipment, this is known as reactive power. Therefore reactive power moves within an AC system due to the creation of electric or magnetic fields in different parts of the system. It is also known as apparent energy as it does not contribute to the overall energy in or out of system however does contribute to the amount of energy transferred, as energy is in a sense being circulated within the system. Reactive power is usually measured in megavars (Mvar). Devices that create magnetic fields, i.e. induction motors/generators, are considered to be reactive power consumers and devices that create electric fields, i.e. synchronous generators and capacitors, are considered to be reactive power producers. The control of reactive power on the system is crucial to maintaining voltage control by maintaining the voltages in the transmission network with 10% above or below the rated voltages of the lines [69, 70].

The voltage control on an electricity system is important as it affects the efficiency of the transportation of the electricity as well as the stability of the system itself. Voltage stability is maintained by the balancing of the quantity reactive power on all nodes on the system with conventional generation sources [74]. In the event of a fault, an increase in load or an increase in non-synchronous generation, voltage stability can be affected negativity if the system is not capable of providing sufficient reactive power to meet the reactive power demand of the node where the event took place [21].

The fault ride-through capability of wind turbines is also very important in relation to maintaining limits on voltage control, as wind farms can trip out in a cascade in the event of a large voltage drop occurring [75, 76]. This could result in a very large loss of generation that the electricity system may not be able to remain stable through, resulting in load shedding or blackout.

Unlike frequency response, which is constant across the system, voltage levels are required to be managed locally as the transmission system varies based on location and reactive power consumption alters from node to node. As a result, reactive power cannot be transported over long distances and requires injections of reactive power at nodes where voltages begin to drop [21]. The reactive power capabilities of generators are important for maintaining voltage stability on the system. To maintain voltage stability the TSO controls the amount of reactive power entering nodes by the controls for generator terminal voltages [21]. It has been traditional practice to assume that each transmission node would be able to provide a sufficient amount of reactive power to maintain its voltage. The distribution system operators (DSOs) then use transformer tap-changers and voltage boosters to maintain certain voltages tolerance on the distribution network [77].

Generation capacity has been traditionally located close to areas of high demand typically urban areas. However with the large increase in wind energy this is no longer the case. If urban areas have to substitute their local generation for that of generation imported from an external area there is a decrease in their reactive power support that must be compensated for locally. With the large increase in wind energy planned for AI, there will be times where the total system demand of the island could be met by wind energy alone. The majority of wind energy in Ireland is located in rural areas on the west, located far from urban areas. This issue of voltage stability in urban areas [77] leads directly to the need of specific SOCs [78] to maintain a minimum numbers of conventional generators on-line in certain areas such as in Dublin and the North West of NI, as shown in Table 4.4. The locations of these areas are shown in Figure 3.4.

It is predicted that the amount of synchronous reactive power capacity will fall by 25% by 2020 [21]. This is due to wind energy replacing synchronous generators as wind farms continue to be built. It is stated in [77] that this will reduce the amount of leading reactive power capability of the system resulting in reduced capability of the generators to absorb reactive power. This will have effects on urban areas such as Dublin during times of low system demand as Dublin has extensive cabling of the transmission system producing reactive power [77]. Cables naturally generate reactive power leading to voltage rises.

There is a clear incentive in the future to not have conventional generators operating at their minimum stable levels in order to maintain voltage stability if wind energy is being curtailed. Reactive power support can be provided separately to active power. This can be done simply through the use of capacitor banks [79] however this is not a dynamic source of reactive power as mechanically switched capacitors provide only a constant reactive power support. There is however a range of dynamic reactive power supporting devices, with the most suitable being Static synchronous compensator (STATCOMs) and Synchronous condensers. STATCOMs are capable of providing fast acting reactive power support as well as supplying variable amounts of reactive power depending on local network demand. Synchronous condensers mimic a flywheel synchronised to the electricity

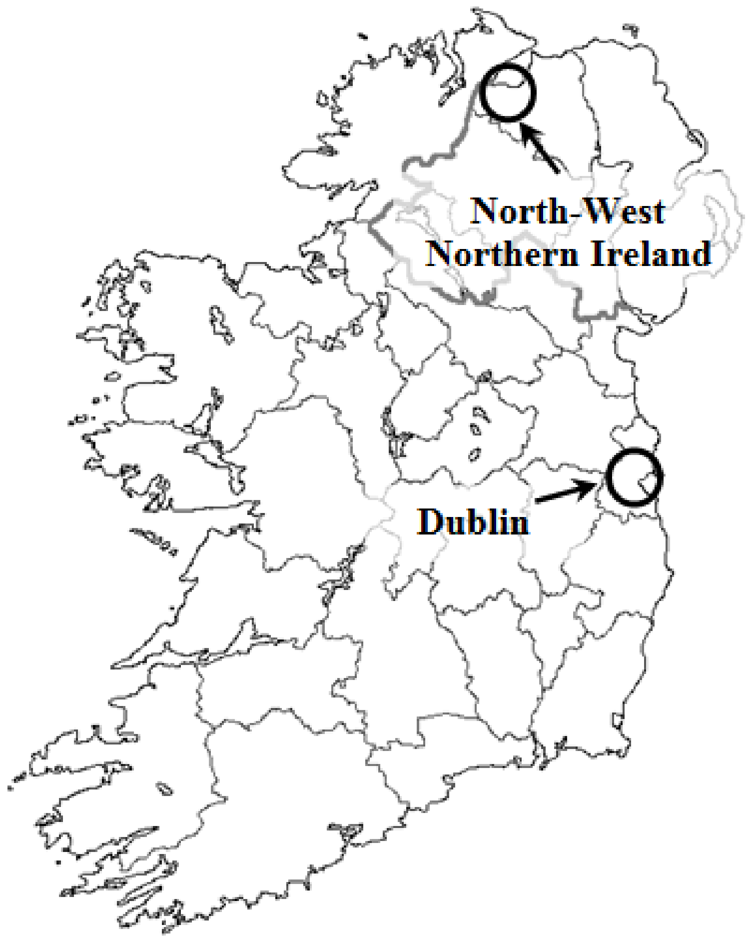


Figure 3.4: A map of the island of Ireland indicating the Dublin and North-West of Northern Ireland areas.

Table 3.3: Cost estimates of installation of reactive power support devices.

Device name	Capacity (VARs)	Total cost per device (€m)
STATCOM	50	5.43
Synchronous Condenser	75	4.73

[73]

system and are capable of consuming and generating reactive power [73]. Estimates of installation costs of these reactive power support devices are shown in Table 3.3. Changes to how reactive power is provided on the AI system is seen as an important part of allowing AI meet its RES-E targets [73].

3.2.2 Ireland AC isolation

The AI electricity system has only two HVDC interconnectors to GB, Moyle and EWIC [9, 59], with a combined capacity of approximately 950 MW. HVDC connection does not provide reactive power or inertia support and with no AC link to GB this results in a situation where there is no reactive power or inertia support from neighbouring electricity systems [80]. Therefore it must be noted that Ireland is considered to be “AC isolated” as a separated synchronised grid and therefore only comparable to GB, Scandinavia and UCTE, and not individual countries which are part of a larger AC synchronised grid. For example, care should be taken to directly compare the SOC assumptions of AI [78] to that of Western Denmark [19] due to Denmark’s has strong AC connection to its neighbours, providing stability to the Western Denmark system.

3.2.3 System operational constraints (SOCs)

The AC electricity system in its current form needs some amount of conventional (synchronous) generation to be on-line at all times. Wind energy and other non-synchronous sources of electricity would not be able to provide 100% of instantaneous power at any point in time without endangering the stability of the electricity system, for reasons discussed in Section 3.1.1.

The TSOs’ primary function is to ensure the constant supply energy and the security of the system in real time. This means that to the TSOs the issues such as frequency response and voltage control, discussed in Section 3.2.1, are of great importance. Therefore the TSOs, EirGrid and SONI, have created and implemented system operational constraints (SOCs) [78] in order to maintain acceptable levels of system stability both system-wide and locally. Accounting for the SOCs in the model allows for a more realistic power system simulation. It would also be reasonable to assume that there will be relaxations of the SOCs in the future as this is being work on by the TSOs EirGrid and SONI in the Delivering a Secure Sustainable Electricity System (DS3) program [81]. The main function of the DS3 program is to manage the integration of high levels of RES penetration in AI and to over come the significant technologically challenging work required to do this. These SOCs are discussed in detail in Sections 4.5.1 and 4.5.2

3.2.4 Effects of constraints

A large proportion of AI electricity is projected to be coming from non-synchronous sources by 2020, as discussed in Section 3.1.1 this is in the region of 32-37%. There is no precedent for a system of this size to have such a level of non-synchronous generation without AC links to neighbouring systems. Ireland's AC isolation is discussed in Section 3.2.2. However it is necessary for a AC system to require some amount of conventional synchronous generation on-line at all times in order to maintain overall frequency stability as well as local voltage stability as discussed in Section 3.2.3. The majority of wind turbines being double-fed induction generators (DFIG's) or full-converter generators which are non-synchronous are not capable of providing sufficient inertia [82] to the system. However it is recognised that a number of TSOs of high wind penetration systems view that inertial response from wind turbines will become a grid code requirement in the future [83]. Modern wind turbines do also produce reactive power but at a lower quality than conventional generators [84], though it is assumed that in the future wind turbines will be capable of providing more reactive power [85].

As wind energy penetration begins to reach the technical limits of what is possible on present-day electricity systems it is becoming evident that more research is needed in relation to allowing higher levels of non-synchronous sources of electricity on to the system.

Previous studies have included SOCs in the form of a minimum conventional generation requirement [15, 16, 18, 19, 22] and studies that have not included these constraints have recognised their potential impacts on results [17, 20, 23, 24, 25, 30, 86]. So far, the only study that has assessed the impact of relaxing these constraints in terms of wind curtailment and costs is [16], which looked at such effects on the NI system. It has also been shown in [22] that SOCs in the AI system will have a dramatic effect in terms of wind curtailment and generator dispatch in the future.

It was shown in [16] that relaxing the NI constraint requiring three large generators to be on-line at all times to two generators on-line results in wind curtailment dropping from 7.5% to the region of 1.5-5% and also indicates possible increases in OCGT generation. An unspecified minimum number of large base load generators were required to be on-line at all times in the AI model of [15] in order to maintain sufficient inertia and reactive power on the system. For NI, an examination of the effects of variable generation on conventional generators is shown in [25] and there is also a recommendation made for further research into the effects of the requirement for three large generators to be on-line at all times. While a constraint for a minimum number of on-line generators was not included in [23, 24], it is stated in [24] that such constraints would increase wind curtailment. In [23] it was stated that the exact minimum required number of on-line generators was not obvious and therefore was neglected but recognised that its inclusion would increase wind curtailment.

From a wider international perspective, in [18] it was assumed that a minimum of 400MW of conventional generation was required on the Western Denmark system, but by 2025 it was assumed that 300MW would be sufficient due to stronger interconnection with neighbouring regions. This assumption was taken from [19] where the year 2008 was examined to find the lowest instantaneous level of conventional generation during periods of excess wind energy generation, which was estimated to be 415MW. This was then assumed as a minimum technical feasible state of system operation. However, in 2012 wind generation in Western Denmark has been allowed to exceed demand through the use of interconnectors to export surplus generation [20]. It should be noted that due to AI's AC isolation as discussed in Section 3.2.2, care should be taken when comparisons are made between countries that are part of a larger synchronous system, i.e. Western Denmark [19] due to the system's use of synchronous compensators as well as its strong AC interconnection to its neighbours, thus providing stability support. Systems with high percentages of installed capacities of CHP's and wind mimic the same problem as SOCs in the form of must-run units. In [87] wind curtailment is shown to increase from a minimum generation requirement made up of the CHP plants on the system. In Spain it is recognised that a minimum amount of conventional generation to be kept synchronised to the system will have to calculated and this will increase wind curtailment estimates [30]. In studies of the GB system it is recognised that a minimum amount of conventional plant running at all times will be necessary to provide frequency response and also due to inflexible must-run units such as nuclear plants which will result in wind curtailment [17]. The modelling of the AI Single Electricity Market (SEM) includes a inertia constraint requiring a minimum number of conventional generators to be on-line at all times [26], however such a constraint on the GB system is not included in the same study. The Hawaiian electricity system has similar wind targets to that of AI, albeit on a small system. Problems related to system stability have recognised as important issues in the coming years [28, 29].

In an European-wide context it is recognised in [86] that wind curtailment may become necessary in central and northern Europe when a minimum number of on-line conventional generators is reached during high wind and low demand periods, in order to provide adequate response and reserve on the system. A review of several countries carried out by [20] recommended that further research be performed into issues associated with wind curtailment and states that wind curtailment resulting from the minimum stable generation limits of conventional generators will be an issue in the future as inertia requirements and frequency response of systems may suffer as wind penetrations increase.

It is viewed by EirGrid that as wind penetration increases and the network and SEM designs are not changed, that problems will emerge such as escalating constraints payments, discussed in Section 2.2, due to a divergence between the unconstrained market model and the constrained dispatch model [88]. Having to maintain the frequency, voltage and reserve on the electricity system creates a different dispatch schedule to that that is created by the market, refer to Section 2.2. However with the payment for wind curtailment set to be phased out in 2016 [89] this may help prevent escalating constraints payments in the future.

3.3 Wind forecasting

Wind forecasting is important for the efficient running of the AI electricity system as the scheduling of large generators takes place one day in advance of dispatch [12]. For example, with the assumption that a perfect wind forecast was available, the day-ahead unit commitment (DA UC) schedule for the electricity system would be able to correctly schedule the correct amount of generators to be on line to accommodate the system demand minus the wind generation. However in the event of the wind forecast being inaccurate, the DA UC schedule will mistakenly commit too little or too much capacity from cheaper large generators, resulting in additional costs due to such generators being run at reduced efficiency levels or by bringing on additional, more expensive, open cycle gas turbines (OCGTs) to make up the system demand requirement.

Wind power is given priority dispatch over the conventional, non-renewable sources of generation in most electricity markets [8]. For this reason TSOs may view wind generation as a negative load. Forecasts of wind generation and system demand are required for scheduling generator dispatch, therefore wind power forecast inaccuracy can be viewed as a component of the net system load forecast inaccuracy. In systems with high wind penetrations, load forecasts are more accurate than wind power forecasts [90], therefore it is wind power forecasts that are the largest source of uncertainty in terms of net system demand requirements. Furthermore, wind generation has little controllable variability in its output and to compound the issue, this variability has a low degree of predictability with very large instantaneous errors in forecasts occurring frequently. There is, therefore, a considerable uncertainly associated with wind generation forecasting, with root mean squared errors of up to 20% for 24-hour ahead predictions reported [91].

It is viewed that the improvement of the accuracy of wind forecasts has a potential value for several parties: TSOs; wind farm operators in competitive, deregulated electricity markets; non-wind generation operators in the same markets; and electricity traders [91]. It is recognised by TSOs that improving the accuracy of wind power forecasts, particularly the 48 hour ahead forecast used in optimising the DA UC schedule, is worth investing in [92] and it has been stated that increasing the penetration of wind in the AI system may be achieved by improvements in the accuracy of wind power forecasting [93].

In the context of Ireland's small size in comparison to other electricity systems, it is also worth noting that it has been shown that large areas help in the reducing the aggregate wind variability and forecast errors as well as allowing more cost effective balancing [55, 94].

There are several sources of information that allow for analysis of wind forecast data for AI. EirGrid published an on-line up to date wind generation and wind forecast profiles allowing the wind forecast error time-series to be analysed [49]. EirGrid also have published the annual mean absolute error (MAE) of 0-48hr lead time forecast for the years 2008-2010 [80] showing the accuracy of a lead time forecast over time and for 2006 data it was shown that Ireland had a MAE to be 8% for day ahead wind forecasts [93]. SEMO also publishes a the 2-day forecast for NI and ROI [95].

3.3.1 Auto-regressive moving average (ARMA)

Use of auto-regressive moving averages (ARMA) in the simulation of wind forecasts was first documented by [96]. The method used in [97] formed the basis of the ARMA model created in this paper. Previous works have used different methods to simulate wind forecasts for use in UC and economic dispatch studies of electricity systems. For example, ARMA methods were used in [98] to create 12-36 hour ahead wind generation forecast time-series with a mean absolute error (MAE) of 7.8%, and in [24, 23, 99] where the Wilmar planning tool was used to develop wind forecast scenarios. It has been used in representing wind forecasts in Ireland in [23] and used by [98] for the creation of wind forecasts. For stochastic modelling of wind forecasts error quantiles have been created in [100, 101] to better describe wind forecasts and their associated errors.

3.3.2 Wind forecasting, deterministic vs. stochastic scheduling

It has been shown in previous work that, in the presence of wind forecast errors, stochastic scheduling approaches perform better than deterministic approaches [99, 101, 102]. Stochastic methods have been used in a number of other studies to determine the effects of wind forecast uncertainty on electricity systems [24, 103, 104] .

The benefits of using probabilistic methods of forecasting wind over deterministic single value forecasts for system operational decision making are discussed in [101]. A comparison is made between point predictions and predictive marginal densities. A point prediction means a single value result of the forecast which results in a smaller model problem size as the model is deterministic and traditionally used by most TSOs. A predictive marginal densities forecast or a stochastic quantile forecast includes a probabilistic description of forecast uncertainty which can be used to create more general optimality for the expected range of system wind generation. It has been shown in [105] that using different types and different levels of detail of wind power information, be it the MAE of the forecast or a probability density function of errors, can effect both the system costs and wind curtailment on an autonomous electricity system.

3.3.3 Wind forecasting error effects on systems

On examination of the literature, no work has attempted to estimate the effects of realistic, incremental improvements of wind forecast accuracy on electricity system scheduling. A number of studies have estimated the effects of wind forecasts on electricity systems containing significant penetrations of wind energy [24, 23, 55, 94, 99, 102, 103, 106], but most do not quantify the wind forecast error and only compare a single forecast scenario against the 'perfect foresight' scenario, while the mean forecast error is not even quantified in some cases. While it is noted that these works focus on several different electricity systems with varying penetrations of wind energy, they all share a common conclusion, that negligible wind curtailment occurs. On comparison of the works above there are differences reported in the savings of total system costs ranging from 0.02% to 1.2% when accounting for the difference between actual wind forecast errors and perfect foresight.

Rogers et al. [107] acknowledged that one of the largest challenges with the integration of wind generation will be formulating the dispatch schedule. This is a result of the limited accuracy of wind forecasts. They state that errors in wind forecasts must be taken into account when the dispatch schedule is made in advance. It raises the question of how much wind forecast error should be accounted for in light of the costs associated with provision of extra reserve compared to the risk of endangering the system if not provided.

In [98] there is shown to be little benefit from wind forecasting as the perfect foresight assumption leads only to savings of 0.02% of total system cost and no significant reductions in the wind curtailment taking place, though the amount of wind curtailment taking place is at highest 0.6% for a system of 22% annual wind energy penetration.

The work presented in [102, 104] assumes that the day ahead unit commitment (DA UC) schedules are fixed as in the unit commitment (UC) of large generators are not relaxed. These studies did not simulate over a full year. In [104] a stochastic unit commitment model is used with a decomposition algorithm producing weighted wind scenarios and wind curtailment is shown to be negligible for all scenarios when transmission constraints and contingencies are not considered. While a full year is not simulated in [102], rather a 91 day period, the wind forecast does come from observed data and the MAE is reported. The MAE varies from 8.4-12.4% for different hours of the day.

Tuohy et al. [99] uses stochastic UC scheduling of the AI electricity system to look at the effects of updating rolling UC on the system for different time intervals while taking account of updated wind forecasts. However the actual MAE of the wind forecasts are not stated. Due to the rolling UC method there is a re-scheduling of the UC schedule in the intra-day time period and therefore the DA UC is not fully fixed. However it was assumed that the interconnectors are fully fixed a day ahead.

It is shown in [24] that there is a change of 1.2% of system cost between the assumption of perfect foresight compared to the inclusion of wind forecasting for installed wind capacity at 6000MW on the AI system and the authors report negligible wind curtailment occurring on the system. As part of the work the model was validated against a deterministic, perfect foresight model developed in PLEXOS®.

It has also been shown in [108] that using shorter time steps in the scheduling simulation results in higher system costs, due to the higher accuracy of modelling, although this work assumed perfect foresight for wind forecasts.

Ultimately wind forecasting inaccuracy does not only lead to costs associated with an inaccurate DA UC schedule but also leads to differences between the market ex ante and ex post model runs [14]. This due to the ex ante market run receiving a wind forecast while the ex post receives the actual wind generation that occurred. This is discussed further in Section 2.2.

3.3.4 Reserves and forecasting

Reserve is necessary for the safe running of the electricity grid. With operating reserve represented in the model changes become apparent compared to models without reserve, which is a result of generators not being utilised to 100%. This is discussed in detail in Section 4.5.4. It is found that the reserve requirement increases as the forecast horizon for wind power becomes longer [24, 109, 107, 23]. If there is a large installed wind capacity on the system the reserve used to compensate for forecast error will dominate other requirements for reserve [55] but this forecast error reserve will not exceed the reserve requirement to back up all wind generation [109].

In [24] replacement reserve requirement is showed to have a significant variation, linked to the installed capacity of wind generation and the forecast horizon used. Using the AIGS Scenario P5 (6000MW of wind) [23] an average replacement reserve requirement of approximately 550MW is shown at one hour forecast horizon, at three hours it is approx. 800MW and at 12 hours it is approximately 1000MW. This shows the large increase in the required replacement reserve as the forecast horizon is extended. Taking account of forecasting errors can have a large effect on replacement reserve required in the hours leading up to dispatch however there is little change in the replacement reserve requirement between the forecast horizon range of 16-24 hours [24].

For windfarms dispersed over a 250km radius it is estimated that the wind will need 10% spinning reserve and 20% spinning reserve, as a proportion of the installed wind capacity. However as the area reduces the reserve requirement dramatically increases [55]. It is also shown in [94] that dispersal over large areas helps in reducing wind variability and forecast errors as well as allowing more cost effective balancing.

The study of [94] only accounts for up to 20% RES-E targets, however at 20% RES-E system operational costs increase by €1-4 /MWh due to wind variability and uncertainty. In [98] for a system of 22% wind energy penetration the value of wind forecasting is very small at only 0.02% of system cost. It states the limited predictability of wind power results in additional reserves requirements for the larger forecast horizons. However, in the Dutch system CHP units have larger reserve requirement, resulting in no changes with increased wind penetration.

3.4 Wind constraint and curtailment

Wind curtailment is an intentional reduction in overall wind power output ordered by a TSO in response to the risk of instability to the electricity system from non-synchronous generation among other reasons such as managing frequency response, voltage control and reserve requirements, as discussed in Section 3.2. Wind curtailment will also result from the increased variability of generation from renewable sources through the re-dispatch of conventional plant for ramping requirements during high instantaneous wind penetrations, resulting in a temporary decrease in wind generation [21].

Curtailment of wind power is dependent on a number of factors such as the instantaneous system demand and the system's capacity to safely produce a certain percentage of its generation from non-synchronous sources such as wind energy or HVDC interconnections [21, 110].

In [111] it states the current reasons for curtailment on the AI systems are: System inertia requirements; reserve requirements; Voltage control requirements; Morning load rise requirements; and the SNSP limit. With the projected increase in installed capacity of wind generation on the electrical system, discussed in Section 3.1.1, it will result in an increase in the frequency and magnitude of wind curtailment events [98, 112, 113]. However the priority dispatch of wind generation outlined in the market rules [8] is designed to minimise wind curtailment in both the Dispatch and Market schedules.

In AI wind curtailment is implemented on a pro-rata basis and under current rules available wind energy from windfarm owners is paid for regardless of wind curtailment through Dispatch Balancing Costs [89]. However this is to be phased out starting in 2016 so that by 2020 wind curtailed will not be compensated. The estimated saving by 2020 would be approximately €13 million per year [89].

3.4.1 Curtailment and constraint

The definitions of wind constraint and wind curtailment are set out by EirGrid and SONI in [114] and are as follows: If there is a security issue present on the AI system and only a portion of the wind farms of the AI system can be reduced in output to resolve the issue then this is referred to as a constraint. If all of the wind farms of the AI system can be reduced in output to resolve the issue then this is referred to as curtailment. The TSOs are obliged to deal with constraint decisions first before dealing with wind curtailment decisions. However it should be noted that there are very different approaches used worldwide with regard to how wind curtailment is operated by TSOs and compensated by markets [115].

While wind constraints on the system are expected due to network congestion, it is a separate issue to wind curtailment that would occur for example due to the imposition of a fixed, system-wide percentage limit on generation from non-synchronous machines. It is however not possible to determine how much the two separate issues will cause wind curtailment/constraints simultaneously without detailed modelling of a transmission grid. For this reason wind constraints are not considered here as modelling with the assumption of no transmission system leaves only the possibility of wind curtailment as wind constraints cannot be captured by the model. Wind constraints can be largely resolved by the building of an adequate electricity transmission system which is the main goal behind the Grid 25 project [116] in Ireland. This project informs the assumption that wind constraints in the AI system will be small in the future.

However it should be noted that one study estimates that wind constraints of 6.8% would occur due to network constraints with 7000MW of installed wind capacity on the system [117]. Therefore not including the effects of wind constraints could lead to overestimates of the total wind generation output in wind energy that may occur in the future.

3.4.2 Wind curtailment with high wind penetration

To date the majority of studies show that the amount of wind curtailment will be minimal at installed wind capacities of less than 7000MW on the AI system [15, 117, 118, 119]. In Tuohy et al. [118] it is demonstrated that significant wind curtailment would only begin to occur when installed wind capacity exceeded 7000MW on the AI system, however the authors acknowledged that taking account of inertia issues or voltage stability on the system might change this estimate. Also, it must be noted that these figures were based on pre-recession projections of system demand growth which are now unlikely to be met. It has been shown that using 5000MW of installed wind capacity on the island that negligible wind curtailment would take place if a SNSP limit of 66.6% were imposed [120]. When the installed wind capacity is increased to 9500MW wind curtailment was estimated at 14.4% of the available energy. This does not however include the non-synchronous properties of interconnection imports and assumes a much higher system demand as it contains pre-recession demand projections. It has also been shown in [24] that wind curtailment is negligible for a generator portfolio based on the portfolio P5 from [120] which best represented the 2020 case of Ireland meeting its RES-E targets.

However the results of the studies just discussed have already been called into question as wind curtailment has already been shown to take place in AI, with 2.2% recorded in 2011 [111]. Estimates for the required installed wind capacity for AI have been mainly based on the wind capacity factor for an area. The exclusion of SOCs, discussed in Section 3.2.3 on the system leads to an underestimation of the required installed wind capacity for AI to meet its 2020 targets. This is a result of the over-estimating the annual energy yield per MW unit of installed wind capacity due to an underestimate in wind curtailment. While constraints such as a minimum number of on-line generators were not included in [23, 24], it is stated in both studies that such constraints would increase wind curtailment.

It is discussed in [121] that in a future AI system scenario incorporating high wind power and HVDC interconnection to GB, in order to avoid risks to system stability, wind curtailment may have to be employed. The effects of HVDC interconnection are examined further in [15] with an assumed high interconnection capacity of 2000MW with GB resulting in negligible changes in wind curtailment compared with a baseline scenario of 1000MW interconnection. However, overall curtailment was in the order of 0.12% to 0.15%. This takes account of issues such as a minimum number of large base-load units to be online at all times in order to maintain grid stability.

The investigation of [117], which included a minimum inertia constraint showed wind curtailment to be almost negligible. However it is shown in [16] that including the NI constraint requiring three large generators to be on-line at all times results in wind curtailment of at 7.5% for the NI system. In [71] it has been shown that using constraints associated with maintaining lower bound limits on the amount of inertia on the AI system that 2.5-4% wind curtailment would be expected in 2020. The ROI TSO EirGrid has published work in [89] where they assume in 2020 that wind curtailment will be at a level of 4% for the AI system under a SNSP limit of 70%. Wind curtailment could have a considerable effect on estimates of required installed capacity in order for ROI and NI to meet their 2020 RES-E targets.

In a wider international perspective it is not just in AI that it will become necessary to curtail wind for system wide reasons. In GB it has been shown that wind curtailment could be as high as 4% for a 40% penetration of wind however this is without the inclusion of a minimum amount of conventional generation requirement or a SNSP limit [31]. As GB is an isolated AC electricity system, similar to AI, these issues will have to be considered and could dramatically increase wind curtailment estimates. It has been shown in [27] that Portugal will experience wind curtailment of up to 8.5% for wind penetrations of 23%, this being due to the presence of run of river hydro and does not account for SOCs.

Chapter 4

Methodology: PLEXOS implementation

4.1 Unit Commitment and Economic Dispatch

The terms unit commitment and economic dispatch (UC ED) can be explained in two parts. The UC is an integer decision of whether or not to commit a generation unit, meaning a choice to start up and synchronise to the electricity grid or not. This is necessary as the majority of generators have a minimum stable generation level and a start cost. Therefore they cannot operate from the zero generation to their maximum generation capacity. ED is the minimisation of costs of a problem, for example the solution to the problem is lowest costs scheduling of generators to produce electricity for a specific time period with the constraints of generator UC applied.

4.1.1 Optimisation method

Optimisation is simply the minimisation or maximisation of a function by adjusting variables until a minimum or maximum value to the function is found. This done through computational techniques explained in the following Sections.

Constrained linear optimisation problems are widely used in research and industry. Constrained optimisation problems generally consist of: variables that need to be solved; the objective function that needs to minimised;

constraints that apply limits to certain objects when solving the objective function and variable bounds that impose boundary limits on the variables to be solved.

The Simplex method is used to solve the majority of Linear programs today [122]. It is vastly more efficient approach to solving for the optimum than that of enumeration. The Simplex method in linear programming has key properties assumed.

- the optimal point is always in a cornerpoint of the feasible region.
- the cornerpoint that is feasible and a value better or equal to all other adjacent feasible cornerpoints is the optimal solution
- there is a finite number of feasible solutions.

The proportionality property, meaning a real, non integer value been used instead of a integer value, occurs in linear optimisation. For example a fraction of a single generating unit maybe scheduled and this results in start-up cost not being accounted for in totality. Therefore using real-value results for integer variables is not realistic when it comes to UC. It is also considered not an expectable assumption to solve the problem linearly and round to the nearest integer in order to achieve integer unit commitment [123].

To solve integer restricted variables, such as the number of generators that need to be scheduled to be on-line, it is not sufficient to use linear relaxation as it is not possible to schedule a fraction of one generator. It is not possible to use linear programming methods to solve integer problems and solving a integer problem through enumeration is only possible for small problems.

The most common method of solving integer problems is through the branch and bound method [124]. The branch and bound technique, first proposed by [125], is for structuring the solution in order to slow down the combinatorial explosion, meaning the limiting of the exponential increase in calculations that need to be performed if all possible outcomes are computed. This is done through the growing of the solution tree in stages as shown in Figure 4.1. With the root node at the top (level 1), for each of these stages branching from the root node (levels 2 & 3) is performed to give new bud nodes (level 4). The bounding function is then used to estimate the bud nodes to determine the best value and from that which to grow further. The closer the bud node's value (found by the bounding function) is to the same leaf node's value (found by the objective function) the more efficiently the solution will be formed. However the bounding function most obtain a value on the optimistic side of the objective function. Pruning is used to remove all nodes that are shown not to be feasible or optimal for it or any of the nodes that may branch from it, this is represented in Figure 4.1 by the red "X" terminating branches from these nodes. This is done to dramatically reduce the size of the tree. A set of policies, which are problem specific, are applied for the purposes of the bounding function. These usually relate to decisions of which node is chosen next and when pruning should take place [123].

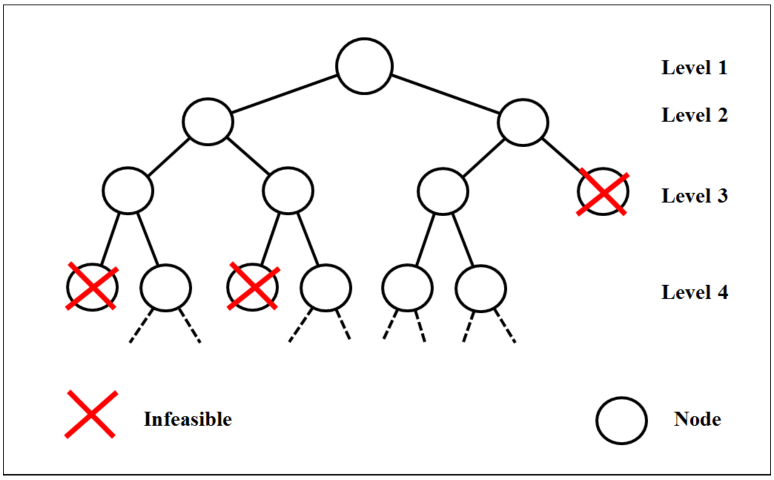


Figure 4.1: Branch and Bound Enumeration tree

Mixed Integer Programming (MIP) or mixed integer linear programming is a specialised version of the branch and bound technique [126]. A MIP resembles a linear program however not all the variables are fractional values; some of the variables are integer values. The first recorded conversion of LP to MIP code appears to be by [127] which called on work by [125] and [128].

The branch and bound technique used in MIP uses real value variables in place of the integer variables in the problem, creating a value from the bound function very close to the value from the objective function. In the branching new variable bounds are created in the child nodes and from the variables originally intended to be integer values, one is selected and branching is performed on it. The variables intended to be integer values have integers placed on them and the best is determined by further branching of the node. The branch and bound method works by finding better adjacent integer solutions and also bounding the linear relaxation as it moves through the tree of integer combinations.

4.1.2 Electricity system dispatch tools

Extensive reviews of electricity system modelling tools have been carried out by [129] and [130]. Some of these other electricity system modelling tools are discussed briefly here. AURORAxmp was developed by EPIS Inc. and uses chronological dispatch and includes transmission constraints [131]. Argonne National Laboratory developed the Electricity Market Complex Adaptive System (EMCAS) which is electricity market orientated with the capability of modelling individuals business and bidding strategies [132]. Also developed by the Argonne National Laboratory, the Generation and Transmission Maximization (GTMax) Model an internationally recognised as the preferred tool for interconnected electricity market analysis [133]. Wien Automatic System Planner (WASP) was created by the Tennessee Valley Authority and Oakridge National Laboratory [134]. WASP is international recognised for use in generation capacity expansion analysis for medium to long term time scales. Artificial Neural Networks (ANN) have also be used in the simulation of accounting for contingencies and other complex system operation problems.

Some of the energy tools that cover technologies such as fluctuating renewable and storage on the electricity system are now described. Wind Power Integration in Liberalised Electricity Markets (WILMAR) was developed by RISO National Laboratory and was created for analysing wind energy and hydro planning in liberalised markets [135]. ProdRisk and EMPS optimise the operation of hydro power [136, 137]. ProdRisk is mainly used for medium and long-term hydro scheduling. ProdRisk models thermal power-plants, wind power, hydro power, and energy storage. EMPS models all thermal-generation technologies, wind power, and energy storage. AEO-LIUS tool analyses the effects of fluctuating renewable-energy on conventional generation and focuses on the impact of higher penetration rates of fluctuating energy carriers such as wind and PV, in conventional power-plants systems [138].

While PLEXOS® was decided on as the most suitable for the purposes of work carried out in this thesis there are many other computer tools designed for generator dispatch on electricity systems. PLEXOS® was also chosen as it is considered to be the industry standard in Ireland due to the realise of the Regulatory Authorities of ROI and NI validated SEM PLEXOS® forecast models updated each year [139].

4.1.3 PLEXOS

The power systems simulation tool PLEXOS® [140] was used in this study. This software is widely used for the simulation of mixed integer unit commitment/economic dispatch problems of power systems [139, 22, 108]. PLEXOS® was primarily designed as a market simulation tool. PLEXOS also has the capability of modelling the actual power system. This achieved by the modelling of the transmission system, coupled with an ability to enter specific constraints this makes a very capable tool for modelling the actual dispatch of power systems and mimic the dispatch derisions of the SEM DA dispatch scheduling tool RCUC.

In PLEXOS® there are three methods of optimisation. These are Linear Relaxation, Rounded Relaxation and Mixed Integer Programming. In Linear Relaxation unit commitment decisions are real values resulting in unit start up variables taking non-integer values for the optimal solution. There are quick simulation times associated with this method however it comes at a cost in accuracy of system price simulation. The Rounded Relaxation method takes the Linear Relaxation to the unit commitment problem and applies unit commitment decisions in a finite number of passes of optimisation and results in an integer solution. The Rounded Relaxation method can be faster than a full integer optimal solution but is not as accurate. There is also an issue of not being able to report the associated error of the problem solution. The Integer Optimal method the use of a mixed-integer program (MIP) based on the branch and bound technique explain above. A MIP Relative Gap is set in the model. This is the gap between the objective function values and the best known bounding linear solution and therefore gives a minimum accuracy achieved. However PLEXOS® relies on a third party solver. The Solver used is Xpress-MP [141] developed by FICO based in the USA, with the newest release, FICO Xpress 7 used in the work presented here.

The simplified mixed integer linear programming formulation for dispatchable units is:

$$min \left\{ \sum_{t=1}^{48} \left\{ \sum_{i=1}^{N} d_i \, C_i(P_i) \right\} + C_{uplift} \right\}, \; d_i \in \{0, 1\}$$

subject to the constraints:

$$\sum_{i=1}^{N} P_i = P_d$$

$$P_i^{min} \leq P_i \leq P_i^{max}$$

where d_i is a binary quantity indicating whether a unit has been scheduled (1) or not (0), C_i is the unit generation cost of unit i, P_i is the unit power generation, P_d the system demand, N the number of dispatchable generation units, P_i^{max} and P_i^{min} the unit power output limits, i the index of generation units, and C_{uplift} is the uplift cost which is determined from start-up, no-load and other fixed costs. Additional constraints on unit ramp-up and ramp-down rates, minimum on and off times are not shown here.

4.2 Post unit commitment relaxation (PUCR) with interleaving

4.2.1 Interleaved model simulation

The interleaving tool's main function is to account for the assumption of perfect foresight in the day-ahead (DA) scheduling of generation. The models in Chapter 7 and Chapter 8 were developed with both a DA and a real-time (RT) model interleaved with each other.

The interleaved model is based on the running of the SEM, which is scheduled on a DA basis for the next day with the assumptions shown in Table 4.3 and the optimisation of each day is divided into intra-day trading periods [12], as shown in Table 4.1. To account for the effects of wind energy forecasting errors and unforeseen forced outages, the simulations use two models running interleaved with each other. The first is a DA model which is followed by a RT model. Having the models running linked to each other helps to achieve accurate results for the simulation of dispatch of generators on the AI electricity system. The DA and RT models pass information back and forth between each other at the end of every simulation day as illustrated in Fig. 4.2.1. This information sent from the DA model to the RT model at the end of the DA model's simulation day includes the DA UC, generation, and interconnector flow schedules. At the end of the RT model simulation day the RT model sends the generators' initial conditions back to the DA model to start the simulation of the next simulation day. The DA and RT models are represented in Eqn. 4.1.

Accounting for the forecast error in the day-ahead unit commitment (DA UC) schedule leads to differences in generation cost as well as differences in generation dispatch due to varying degrees of accuracy of the DA schedules being sent to the RT model.

Table 4.1: SEM optimisation time-line

Time	Event
06.00hr D	Schedule commences
48 (30 minute)	48 (30 minute) interval optimisation
05.30hr D+1	Schedule ends
06.00hr D+1	Lookahead period for model optimisation begins
6 (1 hour)	6 (1 hour) interval optimisation
11.30hr D+1	Lookahead period for model optimisation ends

The DA model optimises on a short term schedule as shown in Table 4.1. The function of the DA model is the creation of DA UC schedules for all large generators in the AI system, which are listed in Table 4.2. The DA model also creates the DA interconnector flow schedules and fixed generation schedules. The DA model is optimised based on the DA wind forecast data. Scheduling of the DA model is carried out stochastically to account for the known wind forecast uncertainty, this is described in Section 4.3. The DA model includes maintenance in the simulation as the maintenance schedule is known in advance of the DA UC schedule. The DA model however does not include forced outages as these in reality will occur randomly and without advance knowledge.

The RT model re-optimises the final schedule using the DA schedules. However, these are subject to constraints and post unit commitment relaxation (PUCR) which are discussed in depth in Section 4.2.2. The RT model optimises on the same schedule as the DA model as described in Table 4.1. The RT model includes forced outages and the same maintenance schedule as the DA model. The same maintenance and forced outage file is used across all scenarios and is developed from the base-case scenario of the particular simulation.

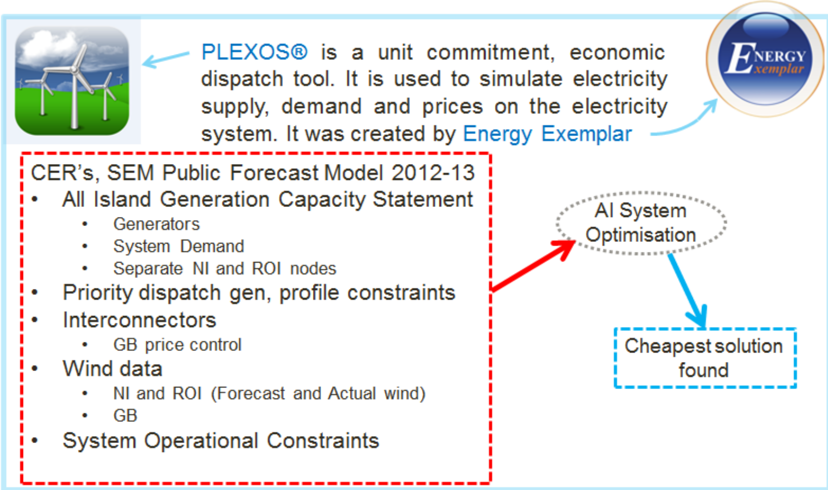


Figure 4.2: The PLEXOS optimisation process showing information used in the process represented by "AI system optimisation"

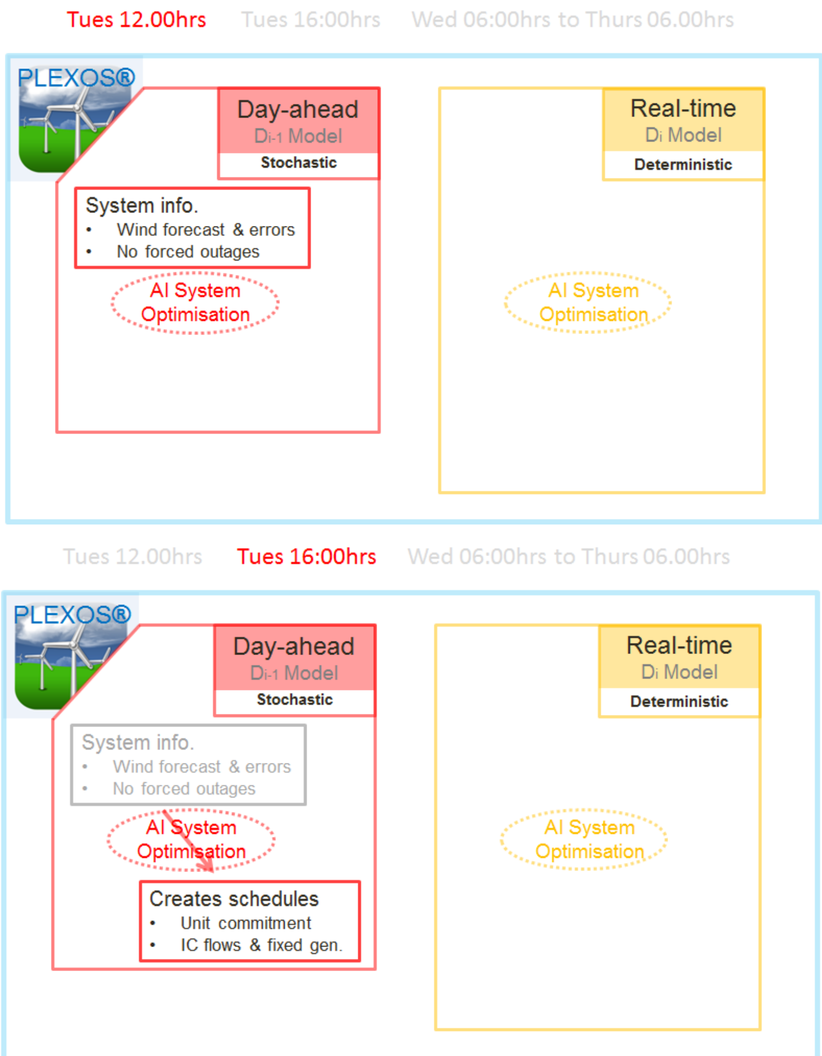


Figure 4.3: Flowcart representing the simulation steps of the DA and RT models' interleaved process

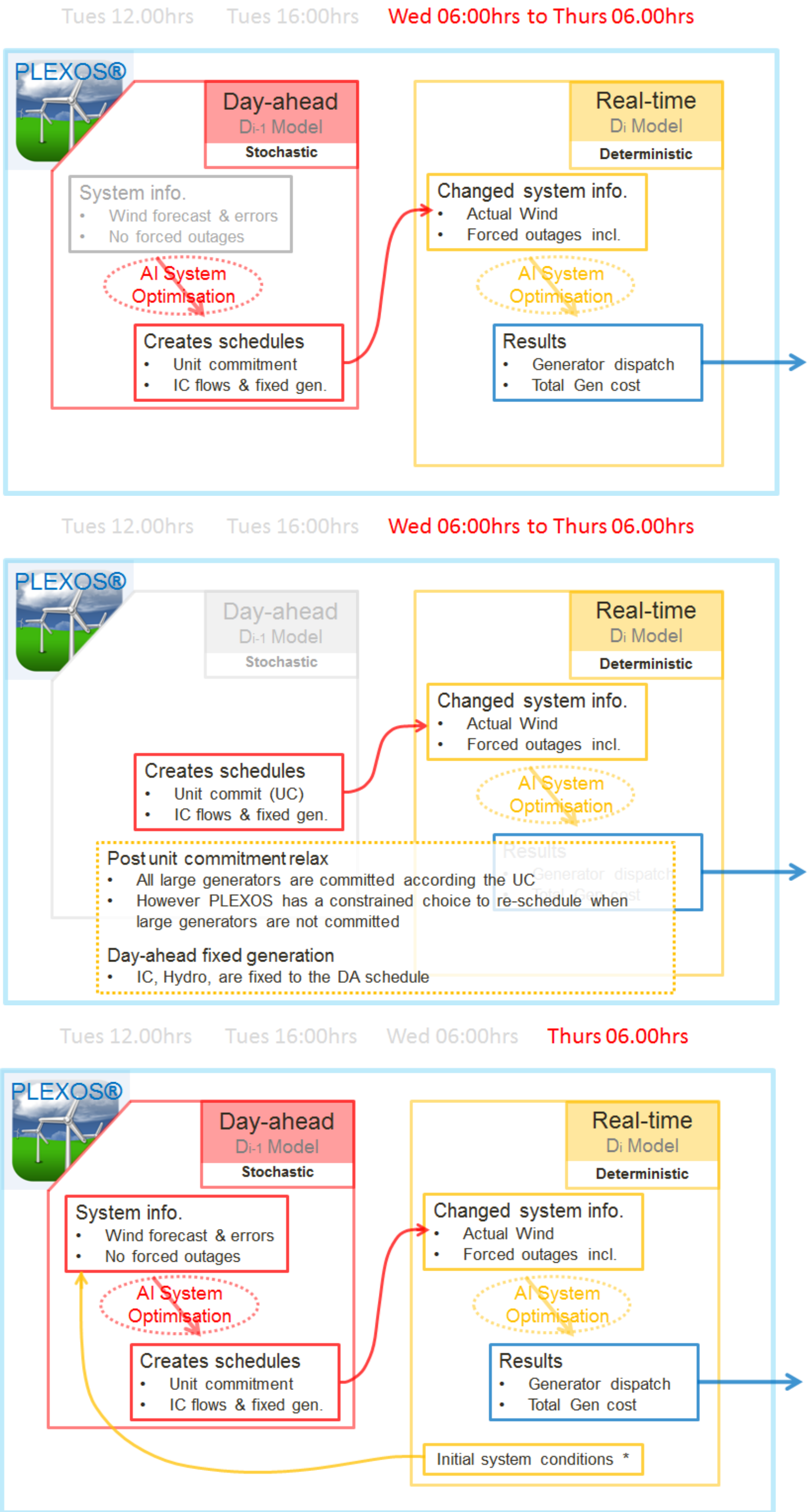


Figure 4.4: Flowcart representing the simulation steps of the DA and RT models' interleaved process

Table 4.2: List of DA UC generators in ROI and NI

Generator name	Generator ID
ROI	
Aghada Unit 1	AD1
Aghada Unit 2	ADC
Dublin Bay Power	DB1
Great Island	GI CCGT (new)
Huntstown Phase 2,	HN2
Huntstown Phase 1	HNC
Moneypoint Unit 1	MP1
Moneypoint Unit 2	MP2
Moneypoint Unit 3	MP3
Northwall Unit 4	NW4
Poolbeg	PBC
Tynagh	TY
Whitegate	WG
NI	
Ballylumford Unit 10	B10
Ballylumford Unit 31	B31
Ballylumford Unit 32	B32
Kilroot Unit 1	K1
Kilroot Unit 2	K2

The daily solutions of the DA and RT models may be described by the following Equations:

$$\begin{aligned} DA(d-1|d) &= f(WF(d),\ IC_{info},\ Model_{s,info}(d)) \\ &\quad where\ d = 1 \\ DA(d-1|d) &= f(WF(d),\ IC_{info},\ RT.End_{syst,con}(d-1), \\ &\quad Model_{s,info}(d)) \\ &\quad where\ d = 2, 3, 4, \ldots, n \end{aligned} \tag{4.1}$$

$$\begin{aligned} RT(d|d) &= f(WA(d),\ DA.UC_{pucr}(d),\ DA.IC_{fix}(d), \\ &\quad DA.Gen_{fix}(d),\ FO(d),\ Model_{s,info}(d)) \\ &\quad where\ d = 1, 2, 3, \ldots, n \end{aligned} \tag{4.2}$$

$$\begin{aligned} Model_{s,info}(d) &= Sys_{demand}(d),\ F_{cost}, \\ &\quad OP_{const},\ Gen_{const},\ GB_{sytem,info}(d), \\ &\quad Maint(d) \end{aligned} \tag{4.3}$$

where: $Model_{s,info}(d)$ = system information given to both DA and RT models; $Maint(d)$ = maintenance schedule set for both DA and RT models; $DA(d-1|d)$ = DA model solution for day d on $d-1$; $RT(d|d)$ = RT model solution for day d on d; $f(WF(d))$ = DA wind energy forecast and uncertainty quantiles time-series; $f(WA(d))$ = realised actual wind energy time-series; IC_{info} = interconnector characteristics; $RT.End_{syst,con}$ = end system conditions from the RT model for the DA initial conditions; $DA.UC_{pucr}(d)$ = DA UC schedule with post unit commitment relax; $DA.IC_{fix}(d)$ = fixed interconnector flow schedule from DA model; $DA.Gen_{fix}(d)$ = fixed generator flows schedule on day d from DA model (hydro, waste, biomass and CHP units); $FO(d)$ = forced outages; $Sys_{demand}(d)$ = system demand; OP_{const} = operational constraints; Gen_{const} = generator profile constraints, ensuring minimum capacity factors and reducing ramp cycling (Hydro, Waste, Biomass, Peat and CHP units); F_{cost} = Fuel costs; $GB_{system\,info}$ = Great Britain wind generation, system demand and price settings; d = day interval in 2020; n = 366 days in 2020.

4.2.2 Post unit commitment relaxation (PUCR)

Separate from the interleaved method described above this work is completely original and developed solely by the author. In the RT model the DA UC schedule locks all the large generators on the SEM (Table 4.2) into a constraint that they must be on-line at the times in which the DA UC schedule commits them but are free to be rescheduled within their operational limits during this time. The DA UC schedule is only broken in the event of an unforeseen forced outage occurring. While the DA UC schedule may not be violated when the generators are committed, there is a facility built into the RT model called "post unit commitment relaxation (PUCR)", which is shown in Fig. 4.2.1, which allows for the large generators to be kept on-line or to be brought on-line outside the DA UC schedule. The model's use of PUCR is restricted as an additional cost to the generation is incurred in the form of a start cost penalty and a penalty running cost. It is important to note that these penalty costs influence PLEXOS® decision making but are not explicitly reported in the results.

The main purpose of incorporating PUCR into the RT models is that it mimics more realistic running of the SEM. From studying the Dispatch Quantities in comparison to the Market Schedule Quantities of generators on the SEM, retrieved from the SEMO [142], it is evident that the large generators do not abide strictly to the DA UC which is reflective of the Market Schedule Quantity.

It can be viewed that the quantity of OCGT usage is an indicator of how accurate the DA UC schedule is in a system. The more accurate the DA UC schedule the less requirement there will be for forms of generation other than the large DA committed generators, i.e. OCGTs, to fill the generation gap left by the inaccurate DA UC schedule. From the study of the Dispatch Quantities published by SEMO [142], it shows OCGT usage for 2011 was 195.5GWh for the ROI and 6.5GWh for NI and this with an AI system demand of 35700GWh [9] which results in less than 0.6% of total generation on AI in 2011 coming from OCGTs.

From the development of the models used in Chapter 7 and Chapter 8 it was noted that OCGT usage was unrealistically high when the model of the AI system is placed under the constraint of following the DA UC schedule, regardless of such generators being committed either on or off. This is also shown in early work done using an interleaved model in [143] where OCGT usage exceeds 1.8% of AI total generation in the base-case perfect foresight scenario. It was assumed that wind forecast inaccuracies did not affect OCGT usage in 2011 due to the AI installed wind capacity not exceeding 2000MW and therefore that 2011 is comparable to the 2020 Base scenario with perfect wind foresight. Therefore it was assumed that for 2020 OCGT generation would be at 200GWh in the perfect foresight base-case scenario. This assumption was necessary as there was no source to base 2020 OCGT generation on. It is also viewed as a conservative assumption due to the much larger conventional generation peaks and ramp rates that will be present in the 2020 AI system which would also result in increased OCGT usage by that year.

A manually adjusted variable was used to control the degree of relaxation for the use of the PUCR technique and therefore OCGT usage in the base scenario. The variable is a multiplier for the addition of the cold start penalty cost for each large generator if the generator is started outside DA UC schedule. The variable is used again as a multiplier for an addition of the average running penalty costs of each large generator. The a value of 0.6 was arrived at as it best achieved, in a base case DA perfect foresight scenario, the desired OCGT generation of 200GWh. This variable was applied to all scenarios unchanged. This simple approach was used to avoid bias in the RT rescheduling of individual large generators.

There are restrictions in the interleaving process of PLEXOS® on the transfer of information from one model to another. An example of this is the generator UC status in the DA model, whether on or off, which is represented by a Boolean vaiue 1 or 0 in a .csv file, which can only be passed to the "commit" property in the RT model. This results in the RT model failing if you wish to allow the generator to break its unit commitment through the use of a constraint as the constraint in the RT model cannot receive the UC file from the DA model.

Therefore to allow the committed generator in the RT model to violate its own UC with an associated penalty cost it became necessary to use a "dummy generator". This dummy generator is a separate zero cost "free" generator in a different region separated from the AI or GB regions. The dummy generator is linked by a constraint in the DA model to be committed whenever the DA UC generator is generating. The unit commitment of the dummy generator is then passed to the RT model through the interleaving process. The dummy generator in the RT model is, in a sense, a switch which allows a condition to be activated which removes the fixed unit commitment status during non-committed times and applies an additional start cost and run cost in the form of a penalty to the unit commitment generator. This allows PLEXOS® to efficiently evaluate between the UC decision of taking the UC generator off line as per the DA UC or keeping it on-line at an additional cost.

4.3 Deterministic vs. stochastic scheduling

4.3.1 Scheduling time line

It was assumed that the scheduling times are as shown in Table 4.3 which are taken from [12, 144, 145, 146].

Table 4.3: Scheduling time-line.

Time	Event
12.00hr D-1	Wind forecasts are submitted to System Operator
16.00hr D-1	DA UC schedule is created and submitted to generators
06.00hr D	DA UC schedule commences
05.30hr D+1	DA UC schedule ends
06.00hr D+1	Lookahead period for model optimisation begins
11.30hr D+1	Lookahead period for model optimisation ends

4.3.2 Deterministic scheduling

For deterministic optimisation all inputs are assumed to be known and fixed, meaning there is no probability of error attached to the input data. Deterministic scheduling is always used in the real-time (RT) model simulation whose main purpose is to reschedule the AI system within the constraints imposed by the DA UC schedule, based on realised actual wind generation and forced outages. For RT simulation all inputs are known as they occur in real time.

For deterministic optimisation of the system DA UC schedule, the DA model receives only the median wind forecast. Therefore, in the deterministic case, the DA model has no capability to evaluate the associated wind forecast uncertainty. The advantage of deterministic modelling over stochastic modelling is that it is a much smaller model problem size to solve. For example, in Chapter 8 stochastic models took 16 hours on average to run while the deterministic model run times were only 2 hours on average.

4.3.3 Stochastic scheduling

In the DA models, stochastic scheduling which accounts for the known probability of error associated with wind forecasting was used in the models presented in Chapters 7 & 8 instead of the deterministic scheduling used in the RT model. This was developed to allow for the evaluation of effects on the AI electricity system from different levels of wind power forecast error together with their associated probability of occurrence. The DA model uses a scenario-wise decomposition method for the stochastic optimisation from wind forecasts and their probability of error.

For example due to probabilities of occurrence being attached to different wind power forecasts this allows for evaluation of the benefits of keeping large generators on-line versus the risk of more expensive generation being required, depending on the risk associated with the wind power forecast. Therefore this is a cost minimisation problem dependent on the probability of expected results.

The model receives a wind power forecast file containing the median forecast (corresponding to 50% probability of exceedence) and upper and lower quantiles of wind power forecast error with associated cumulative exceedance probabilities (5.0, 27.4, 72.6 and 95.0%), described in detail in Section 4.4. A single set of DA UC decisions is optimised for each simulation day. The reader is referred to Table 4.3 for details.

Each of the five wind forecast quantiles is used to create five separate "model samples". From the five model samples a single set of DA UC decisions is optimised for each simulation day. The DA UC schedule is created from the economic dispatch minimisation from the likelihood of occurrences of the five separate "model samples". This is done through the use of UC non-anticipativity penalty costs associated with all the scheduled large generators and interconnectors, making the UC schedule of these selected generators and interconnectors match across all five "model samples".

The UC non-anticipativity penalty costs were decided through an iterative process to achieve matching UC decisions across all five model samples to within a single hour difference over the course of a year. This was necessary for the reduction of model simulation times as explained in Section 4.8. An optimum UC non-anticipativity penalty cost was found in order to allow for an acceptable degree of accuracy as well as a acceptable model simulation time. The UC non-anticipativity penalty cost decided on was €100,000 for violating non-anticipativity constraints in the scenario-wise decomposition mode.

The single set of DA UC decisions provides the lowest-cost solution in the DA model for the expected inputs of the RT model and therefore realistically reflects the probability of wind forecast errors occurring between the DA and RT scheduling.

Due to the way PLEXOS® is implemented it was not possible to model each optimisation and look-ahead period independently of the next. This resulted in the optimisation period's look-ahead receiving the improved wind power forecast starting at 06.00hrs in the next simulation day. An attempt to minimise the effects of this was made by setting unit commitment non-anticipativity to 24 hours.

For the passing of UC status between the UC generator and its dummy generator in the DA model, as discussed in Section 4.2.2, it is necessary to use a constraint instead of a condition in the DA model as conditions interfere with the simulation times of the stochastic scheduling of wind forecasts as their status differs across the “model samples”.

4.4 ARMA and wind forecasts

The Irish TSO, EirGrid, publishes up-to-date wind generation data and wind forecast accuracy statistics online allowing wind forecast error time-series to be calculated in order to analyse the growth of the forecast error with forecast lead time [49]. EirGrid also has published the annual MAE of forecast of 0-48hr lead times for the years 2008-2010 [80] showing the decrease in accuracy of a point forecast with increasing lead time. A 2-day forecast is regularly published for NI and ROI by SEMO [95] but this is frequently updated overwriting existing information so “pure” point forecasts are not available. From 2006 data it was shown that ROI had a mean absolute error (MAE) of 8% for day ahead wind forecasts [93].

For this study it was necessary to synthesise wind power forecasts at specified accuracy levels that realistically replicate actual wind power forecast data. For this reason and from studying the literature it was decided that the use of autoregressive moving average (ARMA) models would best replicate wind power forecast errors. Using an ARMA model it is possible to issue synthetic wind power point forecasts that are statistically similar to actual point wind forecasts. An additional benefit from using ARMA models, which is demonstrated here, is the ability to generate the error and associated probability of occurrence of the generated wind power point forecasts. This gives much more detailed information for use in the DA UC economic dispatch decisions.

As shown in Section 4.3.1 it was assumed that the scheduling times for the AI electricity system are as shown in Table 4.3. It was determined from this that the assumption of an 18-42hr point wind forecast would best represent the forecast upon which the Irish TSOs [1] base the DA UC schedule. Therefore in this work, for the creation of point wind forecasts the "18-42 hour-ahead time window of interest" will be focused on.

A code was developed in Matlab R2010b (Mathworks, USA) consisting of three processes in order to realistically replicate the wind forecasts and associated errors, illustrated in Fig. 4.5. The first step was to determine the control parameters of the ARMA model α, β and σ_z.

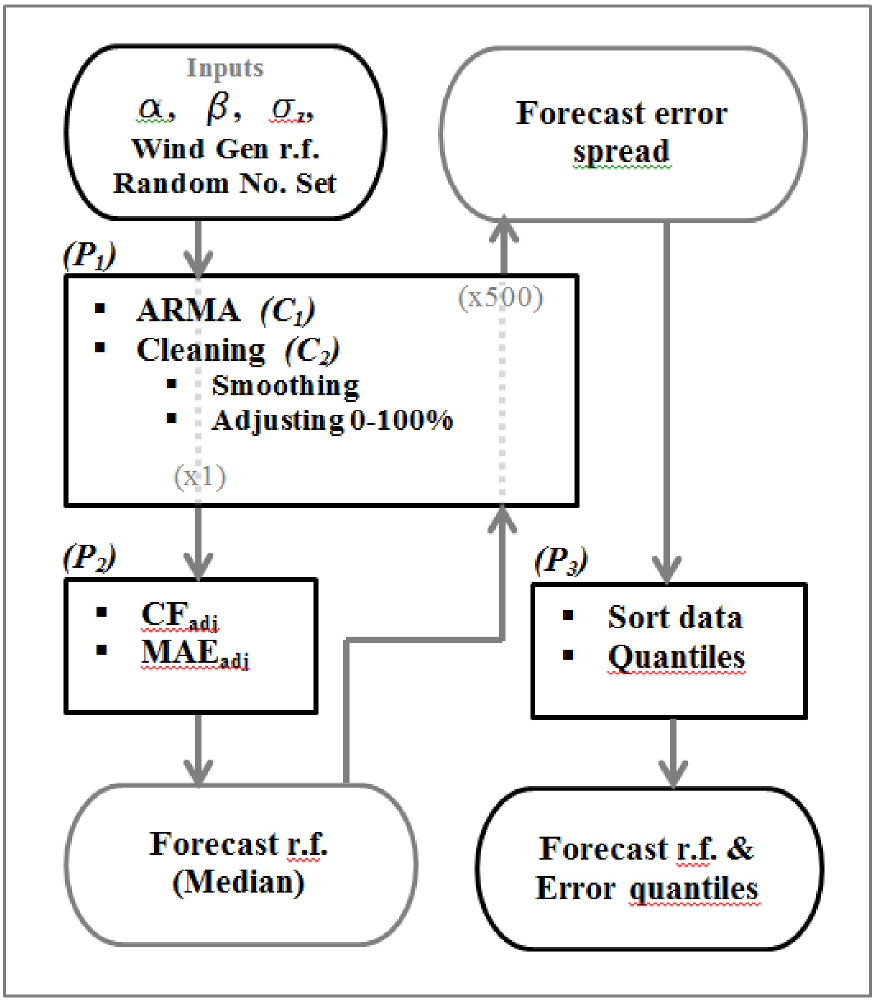


Figure 4.5: Flow chart describing the process of generating the wind forecast and associated error profiles

The parameter β was chosen first, this was determined from EirGrid's wind forecast error time-series [49]. The parameter β controls the degree of variation from positive to negative errors that occurs over the duration of the individual 0-48 hour point forecast. It was determined that β = -0.1 best

[1] The SEM contains two TSOs, EirGrid in the Republic of Ireland and the System Operator for Northern Ireland (SONI)

replicated the actual error growth with forecast lead time when the ARMA model was run at a 30 minute time resolution.

The annual MAE over wind forecast lead times within the range 0-48 hours for point forecasts for Ireland is given in [80] and this was used to create the target mean annual MAE growth profiles over lead time, shown in Fig. 4.6, which the generated wind forecasts would mimic by means of C_1 of P_1 in Fig. 4.5. The target mean annual MAE growth profiles shown in Fig. 4.6 were developed by linear extrapolation of the actual MAE profiles in [80].

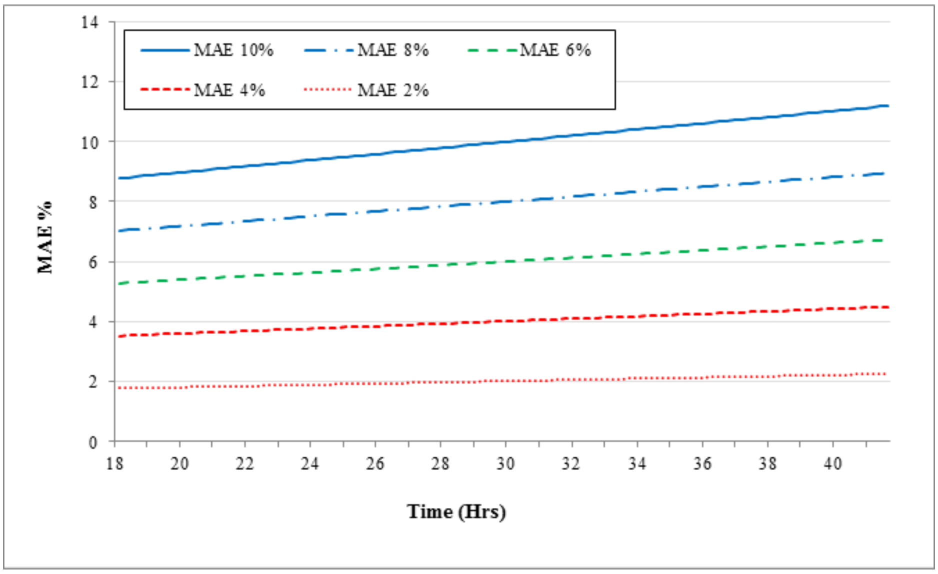


Figure 4.6: Average MAE over lead times of 18-42hrs

The parameters α and σ_z, assuming β = -0.1, were determined through least-squares fitting using the first process, P_1, from the method illustrated in Fig. 4.5. The least-squares fitting technique was based on the 48 intervals (of 30 minutes each) for 367 days for 20 years, meaning the creation of 352,320 random numbers with a near-constant statistical spread between separate runs of P_1. The parameter α at a value of 0.99 was a determined as a best fit for the time period 18-42hrs as this creates the near linear deterioration in accuracy of wind forecast with time shown in Fig. 4.6. The last parameter σ_z (0.390, 0.980, 1.550, 2.120, 2.695) varies depending on the scenario of MAE 2, 4, 6, 8, 10% respectively and reflects the overall accuracy of the wind forecast for the time period 18-42hrs.

The following is an explanation the code represented in Fig. 4.5 and how it is used. The first process, P_1 in Fig. 4.5, consists of two main components, C_1 and C_2. This process is run twice, firstly to create the median wind forecast and then secondly to create the forecast error spread. The forecast error spread is created from the median wind forecast which is used as the base forecast from which a spread of 500 randomised forecast time-series are generated, shown in Fig 4.9.

It should be noted that P_1 uses the same ARMA parameters used in the creation of the median wind forecast however with one exception, the 2% MAE scenario has a multiple of 1.27 attached to the parameter σ_z as the original σ_z is too small to produce a matching annual MAE of 2% on the wind forecast spread. This multiple attached to σ_z for the 2% MAE scenario was iteratively found and use in the creation of all ten 2% MAE scenario.

A scenario set is a set of single MAE 2, 4, 6, 8, 10% scenarios all created from the same random numbers set, which is used in C_1. There are ten separate scenario sets used in work presented in Chapter 8. In a scenario set, as shown in Fig. 4.7, the different individual scenarios, MAE 2, 4, 6, 8, 10%, retain generally the same forecast profile shape with changes only occurring in the magnitude of each error interval which is a direct result of using the same random numbers set.

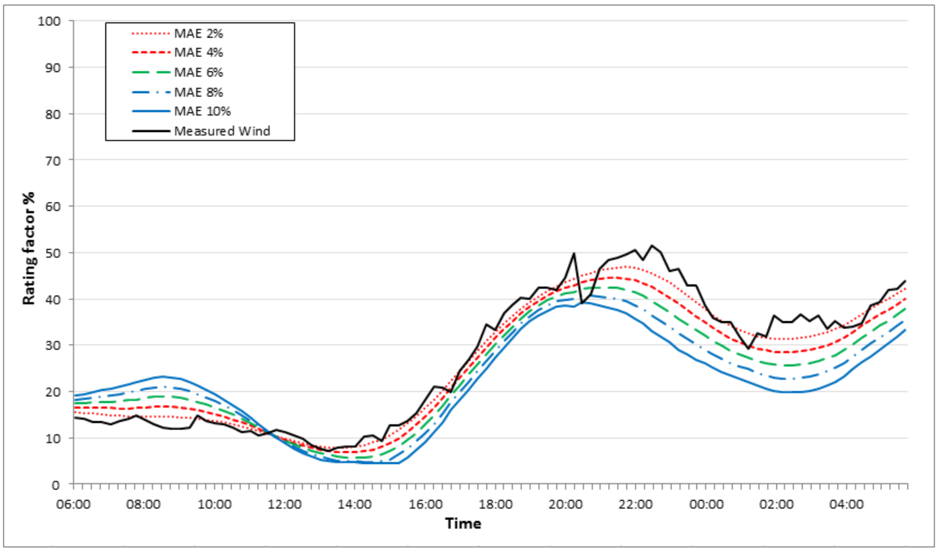


Figure 4.7: Wind forecast profile comparison 2-10%MAE

The reason for the creation of the scenario sets is due to the variability that occurs between the wind forecast profiles created from different random number sets. From simulations using the PLEXOS® model described in Chapter 8 it was shown that two forecasts of the same MAE% error created from different sets of random numbers can frequently have a larger total generation cost differences than two forecasts of different MAE% from the same sets of random numbers. It is recognised that the approach of scenario sets used here is a simplification, however the computational capacity to carry out a large number of simulations with multiple randomised forecasts of the same MAE scenario, in order to find the true average, was not available. It also should be noted that the averaging of all results across ten separate scenario sets is to help remove bias due to the assumption described above.

The first component, C_1 in Fig. 4.5, of P_1 is an ARMA model described in Eqn. 4.4. The ARMA model has three controlling parameters (α, β & σ_z) which creates 96 half hour intervals representing 0-48 hour point forecasts for 366+1 days needed to simulate the year 2020. This ARMA model was developed from that of [97], and is represented by Eqn. 4.4.

$$\begin{aligned}
Z(0) &= 0 \\
Z(t) &= random\ numbers\ of\ standard\ deviation\ of\ \sigma_z\ and\ mean\ zero \\
X(0) &= Z(0) \\
X(t) &= \alpha X(t-1) + Z(t) + \beta Z(t-1)
\end{aligned} \tag{4.4}$$

(t=1,2,3,. . . ,N)

where: $\alpha,\ \beta$ & σ_z are control parameters; t = time step (intervals of 30 minute for 2 days); $Z(t)$ = a random number for interval "t" with a standard deviation of σ_z; $X(t)$ = the wind energy forecast error for interval "t"; N = number of intervals in data.

In C_1 there is an option in the code to generate different random numbers for each individual run or to take the random numbers from a predetermined file which is necessary for the creation of the scenario sets. The random numbers produced have a mean of zero and a standard deviation of σ_z and are normally distributed.

The creating/choosing of the random number set upon which the scenario set will be based was necessary as only 17616 (48 intervals for 367 days) are being generated for a forecast error profile per year which is not a sufficient amount have an even statistical spread with lead time. A predicted wind forecast profile (random number set) was chosen to mimic the desired annual MAE with lead time as shown in Fig. 4.6. The chosen random number set is then used to create the scenario set of individual wind forecasts scenarios, MAE 2, 4, 6, 8, 10%, as shown in Fig 4.7.

The second, larger component, C_2, of the first process P_1, in Fig. 4.5, allows for the adjustment of the ARMA wind forecast error into a more statistically representative wind forecast time-series. This takes the 96 half hour intervals representing 0-48 hour point forecast error for 367 days created by C_1. The forecast error is assessed to a 18-42 hour-ahead time window of interest, plus five intervals either side. The extra intervals retained on both sides of the window are due to the need to mitigate the adverse edge effects of the smoothing that is performed later in the code, which are discussed in detail below.

The time resolution of the forecast error matrix is changed from 30 minutes to 15 minutes by duplication of consecutive values. The forecast error is added to the 2011 ROI wind time-series [49] described in Section 5.4.2, overlapping each simulation day (which is 6am to 5.45am the next) by 10 intervals either side. This now gives 367 point wind forecasts which represent the 18-42 hour area of interest, plus 10 intervals either side.

A smoothing technique is then applied to individual days within the wind forecast error time-series. The extra interval on either side of the area of interest is to prevent the smoothing component distorting the data statistically as the first and last five intervals have notable increased MAE errors due to the smoothing technique's method of local regression using weighted linear least squares and a 2nd degree polynomial model. With the use of the extra intervals on either side of the 18-42 hour ahead time window of interest there are negligible effects on the annual statistical values of the data. This is done to replicate the wind forecast profiles produced by the TSO. After smoothing, the individual wind forecast profiles are cut down to the 18-42 hour ahead time window of interest. The 367 "18-42 hour-ahead time windows of interest" are placed sequentially one after another making a complete wind forecast error time-series.

The wind forecast must then be adjusted as the rating factor on the wind forecast error time-series may sometimes fall outside the limits of 0-100% of installed wind capacity. Therefore, using Eqn. 4.5 the assumption was made that all wind forecast error rating factors under the percentage of (p) would be adjusted upwards to avoid negative generation. This was achieved by a linearly varying scaling factor with a value of 0 at the minimum value of the wind forecast generation profile and a value of 1 at p, the results of which are shown in Fig. 4.8 where p was taken as 5%. Several variations of adjustment of low and negative values in the wind forecast profile were tested, and the results were considered carefully for potential changes to the output statistics. Even though a Gaussian distribution is used in the creation of the random number set, this is altered in the final wind forecast error due to the adjustments to the data in the 5-0% wind rating factor range. It is noted on examination of the TSO's wind forecast errors [49], that they were also not of a exact Gaussian distribution but skewed positive (i.e. over-prediction particularly in the low wind generation periods) which the use of Eqn. 4.5 replicated. Values greater than 100%, due to their seldom occurrence of only a few times a year on average, are simply set to 100% rating factor.

The adjustments is described by:

$$WF_{ad}(t) = |WF_{min}| \left(\frac{p - WF(t)}{p + |WF_{min}|} \right) * \tag{4.5}$$

(t=1,2,3,. . . ,N)

where: t = intervals of 15 minute for 367 days; $WF(t)$ = The wind forecast profile at interval "t"; WF_{min} = The minimum value of the wind forecast profile WF; $WF_{ad}(t)$ = The adjusted wind forecast profile at interval "t" ; N = number of intervals in data; p = the percentage r.f. below which "Eqn. 4.5" is applied.

In the creation of the predicted (median, 50%) wind forecast, an extra adjustment (P_2 in Fig. 4.5) is added, where the data is uniformly adjusted by a multiplier to achieve the exact MAE% required. This is followed by an adjustment to achieve the same annual capacity factor as the actual wind generation. This is necessary as the limited number (367) of random forecast series within a year does not always guarantee convergence precisely at the desired value of the MAE. This also helps to reduce variations in the results between the scenario sets for runs in one MAE% scenario.

The resulting (median, 50%) wind power forecast profile statistically, both in terms of annual properties and the step to step properties of the time-series, replicates the actual wind power forecast presented by EirGrid's publicly available wind generation files [49] as well as remaining inside the actual generation boundaries.

The third and final process, P_3 in Fig. 4.5, creates the error quantiles. The empirical error quantiles are then taken from the sorted spread of profiles

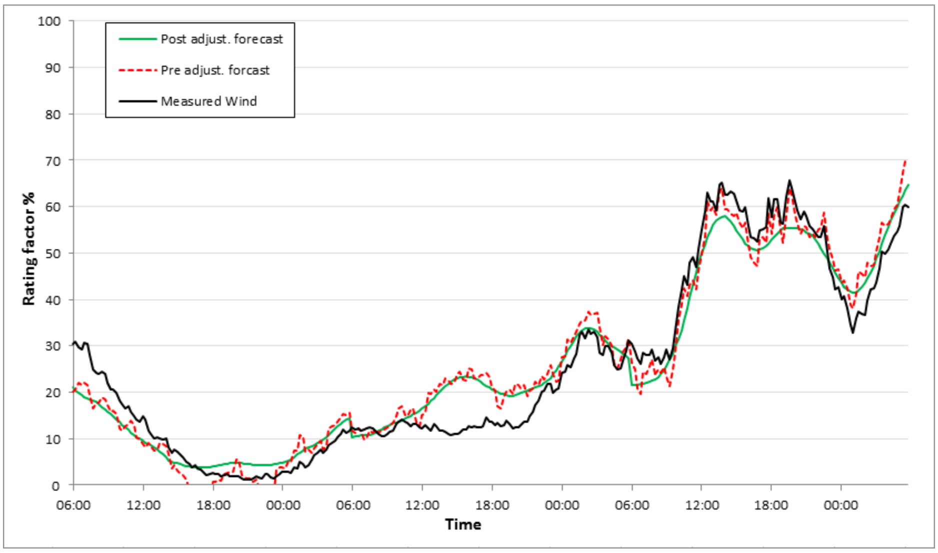


Figure 4.8: Wind forecast adjustment for the 6% MAE scenario and measured wind profile for the 21^{st} to 23^{rd} February of the test year.

created shown in Fig 4.9. The error quantiles were chosen at 5.0, 27.4, 50.0, 72.6 and 95.0% probabilities of occurrence, shown in Fig 4.10, to best reflect the statistical spread of the wind forecast errors. The final wind forecast error quantiles that are passed to PLEXOS is shown in Fig. 4.11

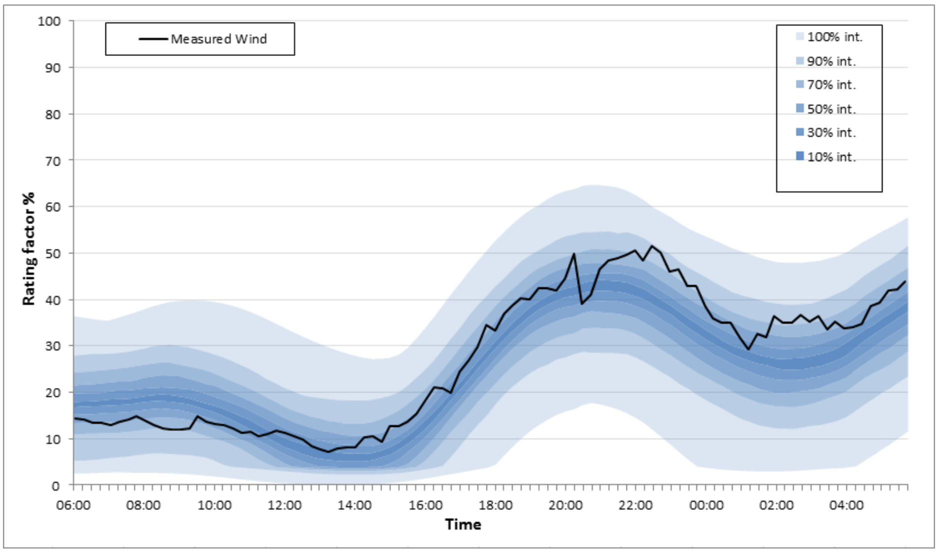


Figure 4.9: ARMA generated DA interval wind forecast profile for the 6% MAE scenario and measured wind profile for the 2^{nd} April of the test year.

It should be noted that the empirical quantiles method was chosen over distribution fitting as the error distribution is not normal at rating factors less than 7% and greater than 93%. Furthermore, it is stated in [147] that it is a simplification to assume that wind power forecast error is of a near normal distribution.

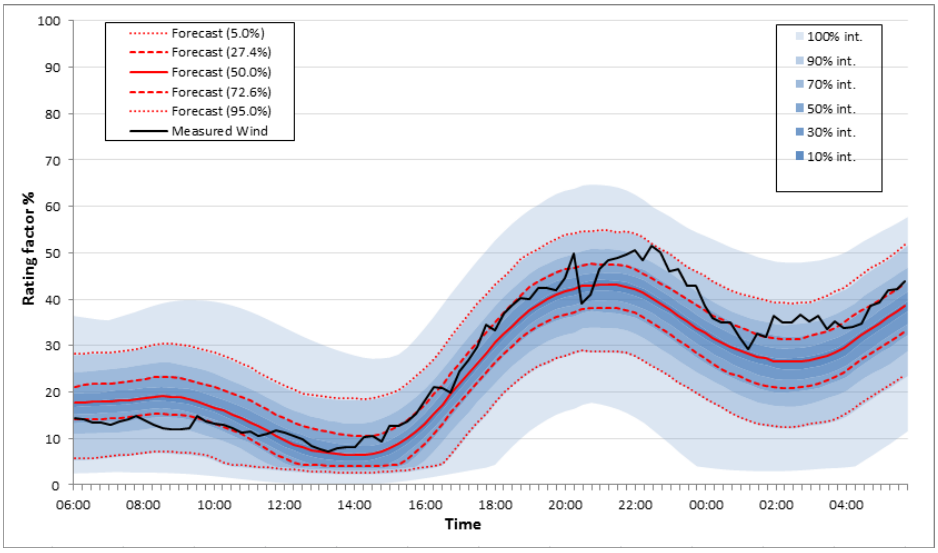


Figure 4.10: ARMA generated DA interval wind forecast profile and the five cumulative probability levels of DA wind forecast profile quantiles given to PLEXOS for the 6% MAE scenario and measured wind profile for the 2nd April of the test year.

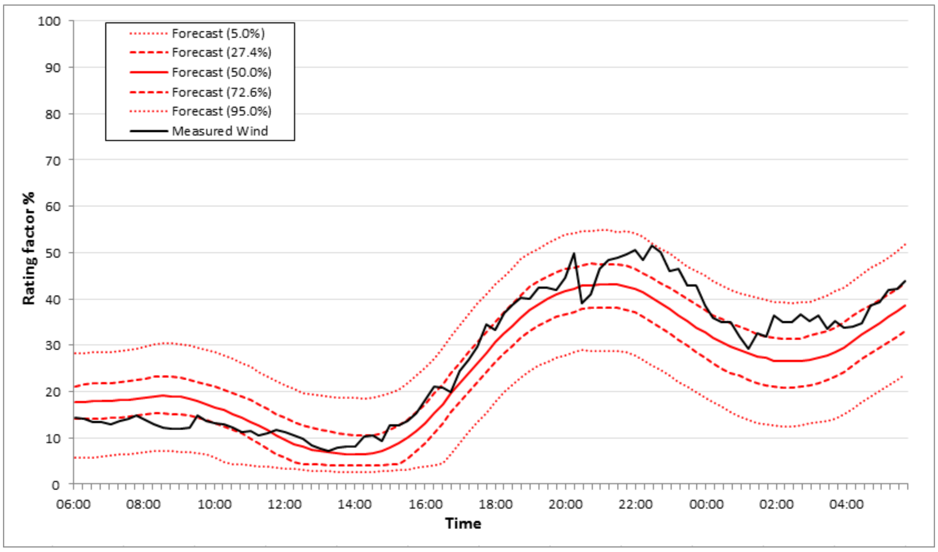


Figure 4.11: The five cumulative probability levels of DA wind forecast profile quantiles given to PLEXOS for the 6% MAE scenario and measured wind profile for the 2nd April of the test year.

4.5 Modelling of system operational constraints

The modelling of system operational constraints (SOCs) is important in replicating the dispatch of the AI electricity system in future as discussed in Section 3.2.3. All system operational constraints (SOCs) listed in this Section are modelled separately using the constraints objects in PLEXOS®.

It must be noted that running the model with the inclusion of SOCs is not reflective of the true market pool model, as it optimises on a purely economic means on an unconstrained grid. This work is only an attempt to replicate the dispatch of the electricity system in the real world by the TSO.

4.5.1 System non-synchronous penetration (SNSP)

The SOC system non-synchronous penetration (SNSP) limit, shown in Eqn. 4.6 was developed in response to the issue of frequency response and to a lesser extent voltage control [21] which is discussed in Section 3.2.1. The SNSP is approximately the percentage non-synchronous generation of total generation on the system at any instantaneous time. The SNSP limit is described by Eqn. 4.7, and may be imposed by the TSO to prevent an exceedance of a certain percentage of total generation by non-synchronous sources at any one point time. This can result in generation from non-synchronous sources being curtailed in keeping with Eqn. 4.7. The SNSP constraint applies, system-wide, to the entire AI electricity system, however its effects are not applied evenly due to assumptions made on wind curtailment scheduling, discussed further in Section 4.5.3

$$SNSP = \frac{wind\ generation + HVDC\ imports}{system\ demand + HVDC\ exports} \tag{4.6}$$

$$SNSP_{Limit} \geq \frac{wind\ generation + HVDC\ imports}{system\ demand + HVDC\ exports} \tag{4.7}$$

where: SNSP is the system non-synchronous penetration; and HVDC refers to flows on high voltage direct current interconnectors.

Currently the SNSP is limited to 50% with one of the main reasons for this being the need to maintain a certain amount of conventional generation online as inertia is not allowed to fall below 20,000MWs on the AI system [80]. It has been predicted that the permitted limit of SNSP on the AI system will be raised to a value between 60-80% by 2020, with recommendations that a SNSP limit of 75% could be technically achieved [21]. DS3 have presented timeliness to indicate increases in the SNSP limit however it is predicted that no increase in SNSP limits will occur prior to 2017.

The system demand used in PLEXOS® is equal to the AIGCS demand modified profile described in Section 5.4.3. However the SNSP equation, Eqn. 4.7, uses the system demand profile minus the embedded generation, described in Section 5.4.3. The decision not to include the embedded generation was made as embedded generation is not dispatchable by the TSO. This may not be considered a conservative decision as currently the majority of the embedded generation is most likely synchronous. However, if embedded generation does increase in the future, the increase will most likely come from non-synchronous, non-dispatchable, micro, renewable generation. The pump load from Turlough Hill was not included in the SNSP equation as an additional demand, however it is now included as system demand for SNSP calculations in [78].

4.5.2 Local Constraint Groups

The issues of voltage control and jurisdictional frequency response discussed in Section 3.2.1 lead directly to the need to maintain minimum numbers of conventional generators on-line in different parts of the AI system [78]. These are local constraints on generation from certain groups of generators and are shown in Table 4.4. As part of the same SOC document [78] there are also SOCs that limit maximum export capabilities from certain areas however these are due to constraints on the transmission system in relation to congestion and not issues related to grid stability, and therefore will not be discussed further.

It should be noted from Table 4.4, that the "ROI-System Stability, min no. on" and "NI-System Stability, min no. on" could become a single-system wide constraint after the completion of the second North-South interconnector [116]. This is due to the two jurisdictional electricity systems of ROI and NI effectively becoming fully integrated and frequency response then being a system-wide issue.

Local SOCs are important in capturing the effects of maintaining certain levels of voltage control and jurisdictional frequency response as discussed in Section 4.5.2. Certain local SOCs also account for transmission grid limits, but are not examined here in detail. The local SOCs are presented in [78] and are shown in Table 4.4. From this a base-case scenario was developed from [78] in which likely changes to SOCs between the present day and 2020. The base case of SOCs developed is as follows:

Table 4.4: System operational constraints required for grid stability

Constraint	Currently	Issue(s)
ROI-System Stability, min no. on	5	Frequency response
Replacement reserve, max OCGT	504MW	Reserve
Dublin Generation, min no. on	2/3 (day/night)	Voltage control
ROI-SW Generation, min no. on	3/2 (day/night)	Voltage control
Moneypoint, min no. on	1	Frequency/Voltage
NI-System Stability, min no. on	3	Frequency response
Replacement reserve, max OCGT	211MW	Reserve
NI-NW Generation, min no. on	0/1 (if load>1.0GW)	Voltage control
Kilroot Generation, min no. on	1 (if load>1.4GW)	Voltage control
Kilroot Generation, min no. on	2 (if load>1.55GW)	Voltage control

[78]

All island of Ireland system operational constraints

- Non-synchronous generation, is discussed in detail in Section 4.5.1.
- Inter-Area flow, in a limit on maximum transfer from ROI to NI and vice versa, is assumed to be 2000MW both ways due to the North-South interconnector being in place [9].

Northern Ireland system operational constraints

- System Stability, this constraint is modelled assuming that three of the following generators with SEM id codes C30, B31, B32, B10, K1, K2 must be on at all times.
- Replacement Reserve, this constraint is modelled assuming the combined generation output of NI OCGTs must be less than 211MW leaving a 100MW of spare capacity for replacement reserve at all times.
- North West Generation, this constraint is modelled assuming that Coolkeeragh (SEM id code CPS) must be generating when NI system demand exceeds 1000 MW. This is for voltage control issues in the north-west of NI.
- Kilroot Generation, this constraint is modelled assuming that for Kilroot's two units that there must be at least one unit generating if NI system demand exceeds 1400 MW and both units are required to be on-line if NI system demand exceeds 1550 MW. This is for voltage control issues in the Belfast area.
- Ballylumford generation, this constraint is ignored due to assumptions that transmission grid restrictions that cause these constraints will be upgraded by 2020.

- Moyle Interconnector, this constraint is ignored due to assumptions that transmission grid restrictions in Scotland that cause this maximum export capacity constraint will be upgraded by 2020.

Republic of Ireland system operational constraints

- System Stability, this constraint is modelled assuming that five out of the following generators SEM id coded: AD1, ADC, DB1, HNC, HN2, MP1, MP2, MP3, PBC, TYC, WG1 and new unit GI4 (CCGT) must be on at all times.
- Replacement Reserve, this constraint is modelled assuming an increased allowing maximum OCGT generation of 1034MW which still keeps 300MW for replacement reserve provison due to the additional OCGT generation added by 2020. The following generators SEM id coded: AT1, AT2, AT4, ED3, ED5, MRC, NW5, RP1, RP2, TP1, TP3, and new units Cahir or Culleen (OCGT), NO1, Caulstown (OCGT) are controlled by this constraint.
- Dublin Generation, this constraint is modelled assuming that at least three genertors by night and two by day must be on-line in the Dublin area, This is out the group of the following generators, SEM id coded: DB1, HNC, HN2, PBC. This is for voltage control issues in the Dublin region.
- South West Generation, this constraint is modelled assuming that at least three generators by day and two by night must be on-line in the South West area, This is out the group of the following generators, SEM id coded: AD1, AD2, AT1, AT2, AT4, SK3, SK4, WG1, MRC and new unit GI4 (CCGT). This is for voltage control issues in the South West region.
- Cork Generation, this constraint is modelled assuming that the maxium generation in the Cork area can not exceed 880MW due to transmission system restrictions. The proposed Grid Link Project [148] is assumed not to be completed by 2020. The following generators SEM id coded: AD1, AD2, AT1, AT2, AT4, WG1, MRC are controlled by this constraint.
- Moneypoint, this constraint is modelled assuming that for Moneypoint's three units (SEM id coed MP1, MP2 and MP3) that there must be at least one unit generating at all times, in order to support the 400kV network.

- The Hydro Smolt Protocol constraint is not included due to lack of data.

4.5.3 Wind curtailment modelling

An issue arose over how PLEXOS® would allocate wind curtailment on the SEM system consisting of 2 nodes (ROI and NI) with no constraints placed between them. PLEXOS® would randomly choose a node, either ROI or NOI, to schedule wind curtailment on and curtail as much wind as possible on this node before curtailing wind on the other node. This resulted in a bias favouring the ROI over NI as wind curtailment would predominate in NI as a result of ROI generating more than its own demand requirements for a large proportion of the time.

Two methods of resolving this issue were tested. Firstly, by a constraint was used such that wind curtailment percentages would be equal on both jurisdictions, and secondly by a charge on the energy flow between ROI and NI of 0.01 €/MWh which has the effect of lightly encouraging that each jurisdiction to accommodate its own wind curtailment within its economic and operational limits. It was assumed that the second light constraint would best reflect the TSO's decision making in the future.

Analyses carried out on both methods results showed a slight increase of wind curtailment in NI over ROI when the constraints are used. For both methods there is almost no effect on generator dispatch, costs, CO_2 emissions and overall AI wind curtailment. This is due to the assumption that north-south interconnection is 2000MW both ways and at no point is the transfer capacity utilised to the full, resulting in the equivalent of an unconstrained system. It should be noted however that if the new North-South interconnector is not constructed by 2020 these assumptions on wind curtailment will have a large effect on dispatch in both ROI and NI.

4.5.4 System Reserve

Ancillary services are necessary for the safe running of the electricity grid. Modelling ancillary services creates a more realistic image of the operation of the electricity grid. In the SEM ancillary services are made up of Reserve, Reactive Power and Black Start capability. Reserve in the SEM is made up of five different components as shown in Table 4.5. Reserve is generally

Table 4.5: Reserve categories on the SEM

Name	ID	Time after Event
Primary Operating Reserve	POR	5 - 15 sec
Secondary Operating Reserve	SOR	15 - 90 sec
Tertiary Operating Reserve 1	TOR1	90 sec - 5 min
Tertiary Operating Reserve 2	TOR2	5 - 20 min
Replacement Reserve	RR	20 min - 4 hr

[69, 70]

categorised in two types, spinning and non-spinning/replacement reserve, which is discussed in the following Sections.

When including operational reserve in the model changes become apparent compared to models without reserve. This is a result of generators not being utilised to 100%. The TSO instructed certain generators to run below their maximum rated capacity to allow for spare generation capacity to be available at short notice in the event of a loss of generation. The modelling of reserve also gives a truer evaluation of the benefit of large scale energy storage such as pump-hydro energy storage (PHES) and compressed air energy storage (CAES). Both PHES and CAES are viewed as having potential development in Ireland [149, 150, 151].

Reserve provision comes from two sources, dynamic and static reserves. Dynamic reserve comes from synchronised generators on the AI system. Static reserve comes from the IC's and the PHES plants when in pump mode. Generators in the SEM have limits on the maximum provision of reserve and their effectiveness at providing that reserve. This information is commercially sensitive and is not publicly available. Therefore assumptions must be made in the model. The interconnectors Moyle and EWIC have voltage source converters which allow for 1s fluctuations, therefore they can contribute to all reserve types. The maximum static reserve provision of Moyle and EWIC respectively is 75 and 50 MW. Reserve for the AI system should be modelled in keeping with the loss of load expectation (LOLE) requirements in the ROI which is 8 hours/year (NI is 5 hours/year) [39]. Costs for these reserves are €0.88/MWh and €0.20/MWh for TOR2 and RR respectively [152]. An additional cost to maintaining reserve is due to the differences that occur between real time dispatch and the market schedule, discussed in Section 2.2, where some generators will be constrained down while others will be constrained up and even brought on-line in order to keep the power balance in the system. This leads to costs in the form of constraint payments [14] and also results in generators generating at lower efficiencies.

Table 4.6: Details of reserve categories provision on the SEM

ID	AI, % Largest In feed	ROI (MW)[3]	NI (MW)
POR[4]	75%	120/75	50
SOR	75%	120/75	50
TOR1	100%	120/75	50
TOR2	100%	120/75	50

[153]

There is a large amount of work done on estimating the necessary reserve requirement of electricity systems with large amount of installed wind power [103, 99, 102, 24, 23, 55, 94, 106]. PLEXOS® is capable of modelling the all the reserves required by the SEM however there is a dramatic increase in problem size when reserve is include in simulations.

Spinning reserve is dependent on the largest in feed on generation to the system. From this it is recommended that in order to avoid risk to system stability during critical times, that there is a reduction of power output of the largest unit on the system in order to reduce the size of reserve required in the event of a fault [121]. This is most likely to be EWIC in 2020, which has an import rating of 500MW. Spinning reserve is reserve that is synchronised to the system, meaning a generator that is not generating at its maximum output can be quickly scheduled to increase its output up to its maximum rated capacity. The four spinning reserve categories in AI are shown in Table 4.5.

The Codling Bank offshore wind farm that has been proposed in the Irish Sea [44] have, if built, an 1100MW installed capacity and with one point of connection to the grid this creates a considerable need for reserve if the wind farm is operating at full capacity. There is also a limit on the size of the loss of the largest unit on the system due to it been linked to SNSP [21]. This raises questions regarding the practicality of an offshore wind farm the size of Codling Bank.

Replacement reserve is mainly provided by off-line OCGTs, which can be brought on-line and increase generation to their scheduled output in less than the 20 minutes as stated in Table 4.5.

Wind turbines may require additional reserves due to the higher risk of tripping off-line, than conventional generators. This is a result of technical characteristics, such as fault ride-through capability and reactive power requirements, of the generators used in the majority of wind turbine plant in

[3]ROI lower values apply from 22:30-08:30 inclusive

[4]Minimum values of POR in each jurisdiction must be supplied by dynamic sources

AI [69, 70].

Previous works have looked at the effect of wind forecasting on system reserve provision [24, 55, 94, 98, 99, 109]. It has been shown that increasing installed wind capacity increases replacement reserve requirements [24, 94, 106].

In [24] it is shown that there are only small changes in spinning reserve requirements for different installed wind capacities and therefore changes in wind forecast accuracy should have a negligible effect on spinning reserve capacities overall. However, the latter study does show large increases in the requirement for replacement reserve as the forecast horizon is extended and this could also be interpreted as an increase in replacement reserve necessary with decreasing wind forecast accuracy. From this is can be assumed that wind forecast accuracy will have small effects in terms of spinning reserve and therefore spinning reserve will not be considered for the studies presented here.

It is recognised however that wind forecast accuracy will have an effect on the provision of replacement reserve. Replacement reserve is provided over the time frame of 20 minutes to four hours [69, 70] as shown in Table 4.5. This results in replacement reserve mainly being provided by off-line OCGTs. To help mitigate the effects of not explicitly considering replacement reserve provision in the models, the models will include the SOC from the published System Operational Constraints (SOC) document [78] that includes a constraint that 400MW of OCGT capacity must not be scheduled at any one time in order for it to mimic replacement reserve.

4.6 Modelling of priority dispatch (non-wind)

Priority dispatch generators are generators that enter the market with zero generation costs and therefore have priority over conventional generation which is in keeping with [154]. However there is an order of priority within the priority dispatched generators outlined in [155]. This states that in the event of re-dispatch the order in which re-dispatch should take place is as follows: Peat; High Efficiency CHP/Biomass/Hydro; Wind energy; Interconnectors.

Therefore to account for this in the model it is assumed that wind energy, hydro and tidal energy are free and therefore have zero generation costs. The majority of the non-wind priority dispatch generators, made up of the peat plants, Sealrock CHP units (Aughinish) and bioenergy plants are modelled as almost free, near zero generation cost (fuel cost of 0.01€/GJ). The three Contour Global CHPs and the three waste-to-energy Plants are included as priority dispatch generators in Section 4.7.1 but their generation costs are included. The interconnectors are fixed DA and cannot be rescheduled in the RT model, therefore the interconnectors have priority over wind energy. This creates in the model the priority order within the priority dispatched generators group, as stated in [155], and helps mimic the reality of the RT dispatch.

4.7 Generator capacity factors and profile constraints

In the development of the models presented in Chapters 7 and 8 it was observed that certain generator groups were not being dispatch in a manner that would reflect reality. This was mainly due to the high penetrations of wind energy creating a very constrained electricity system to model. Therefore it was decided to place certain constraints on the following generator groups: all non-wind priority dispatch units; the PHES unit; and coal units. These constraints help to reflect the reality of how TSO's dispatch generators on the system and mitigate problems occurring in the simulation due to a very constrained model which is discussed further in Section 4.8.

4.7.1 Biomass, CHP, waste-to-energy and peat

The modelling of non-wind priority dispatch generators were considered carefully, as these types of generators together make up on average 13-15% of total AI generation in the 2020 models presented in Chapters 7 and 8. This was viewed as important as the capacity factors and the generation profiles of this group of generators do directly affect OCGT usage and wind curtailment and have effects on the overall running of the electricity system.

It was found during the development of the models used in Chapters 7 and 8 that certain priority dispatch plants, namely peat and CHP plants, were not being dispatched at sufficiently high capacity factors. It was also noted that excessive ramping and cycling of non wind priority dispatch plants was taking place due to them being modelled as free generation sources. This is illustrated in Fig. 4.12 which shows the low dispatch quantities and excessive ramping and cycling of plant in relation to when the priority dispatch constraints listed below are imposed, shown Fig. 4.12.

The resulting low capacity factors of the non-wind priority dispatch generators were mostly due to the conflict of SOCs placed on the system and high levels of wind generation resulting in these generators, which should mimic base load generators, not being dispatched at sufficient levels. The target capacity factors for the priority dispatch plants are shown in Table 4.7 which are based on current capacity factors taken from [154]. It was assumed that the Contour CHP plants in NI would have a target capacity factor of 80%.

Table 4.7: Target capacity factors for priority dispatched generation type

Non-wind priority generators	Installed capacity	Target capacity factor
Peat	345.6 MW	75.0 %
CHP	161 MW	89.5 %
Waste to Energy	94 MW	80.0 %
Biomass	195 MW	80.0 %
Hydro	216 MW	n/a

Due to these issues constraints were developed to more closely mimic the reality of how these set of generators are dispatched while keeping the optimised scheduling of these generators. The constraints encourage the priority dispatch generators to: have high annual generation capacity factors; be continuously committed; have a more inflexible generation profile without excessive cycling and ramping; have a lower priority of dispatch than that of wind energy but higher priority than that of conventional generators.

To impose more realistic running of the non-wind priority dispatch generators, four constraints listed in Table 4.8 were placed on this group of generators individually, which are described in detail as follows.

The first constraint is a near-fixed constraint that commits the non-wind priority dispatch generator to be continuously dispatched while the plant is operational and does not relax in the event of wind curtailment which is in keeping with [155]. This constraint will only relax in the event of an model infeasibility which indicates a possible system stability risk.

The second constraint is a fixed constraint and imposes a maximum energy usage per month on a non-wind priority dispatch generator. This is necessary to create a upper limit on monthly capacity factors for the individual generators during months of low wind energy output. During months of low wind energy output the model is less constrained and freer to abide by all the constraints imposed on it, as the majority of constraints conflict directly with high levels of wind generation.

The third constraint is a chosen penalty imposed if the non-wind priority dispatch generator is not run at its maximum capacity. This prevents the plant remaining at its minimum stable level and helps to give it more priority over large conventional plants that are dispatched due to the SOCs. However an exception to this is that the constraint is relaxed in the event of wind curtailment, which is necessary to retain the priority of dispatch outlined in Section 4.6. Effects of this are also illustrated in Fig. 4.13 with the majority of priority dispatch plant ramping down to minimum stable generation limits in the event of wind curtailment. It should also be noted that the reductions in wind curtailment occurring between Fig. 4.13 and Fig. 4.12 are due to the constraints. The chosen penalty, which is €500 per MW of the maximum installed capacity of the generator, is uniformly applied to all non-wind priority dispatch generators. This simplistic approach of uniformly applying the penalty to all of the generators was chosen to help remove bias between the generators in terms of priority of dispatch. The penalty was chosen through an iterative process to achieve the desired capacity factors of the generators in question.

The fourth constraint is a penalty attached to ramping of non-wind priority dispatch generators up or down. This prevents excessive ramping the reasons for which are discussed in detail in 4.7.4. Similar to the third constraint, this is removed during the first and last hour of wind curtailment taking place. This is necessary to allow the non wind priority dispatch generator to ramp down from their high generation levels to their minimum stable generation levels as it is not always economically optimal to reduce their output, due its near zero cost, if the ramp rate penalty is still imposed. The chosen penalty, €50 per MW of change in generation level of the generator, is also uniformly applied in order to remove bias to all non-wind priority dispatch generators and its value also was chosen through an iterative process.

Table 4.8: The list of constraints placed on non-wind priory dispatch generator

No.	Reason	Solution
1	Constant unit commit	If available commit
2	Prevent high capacity factors	Maximum month energy usage
3	Prevent low capacity factors	Penalty cost for MW short of max. capacity
4	Present excessive ramping	Penalty cost per MW change generation

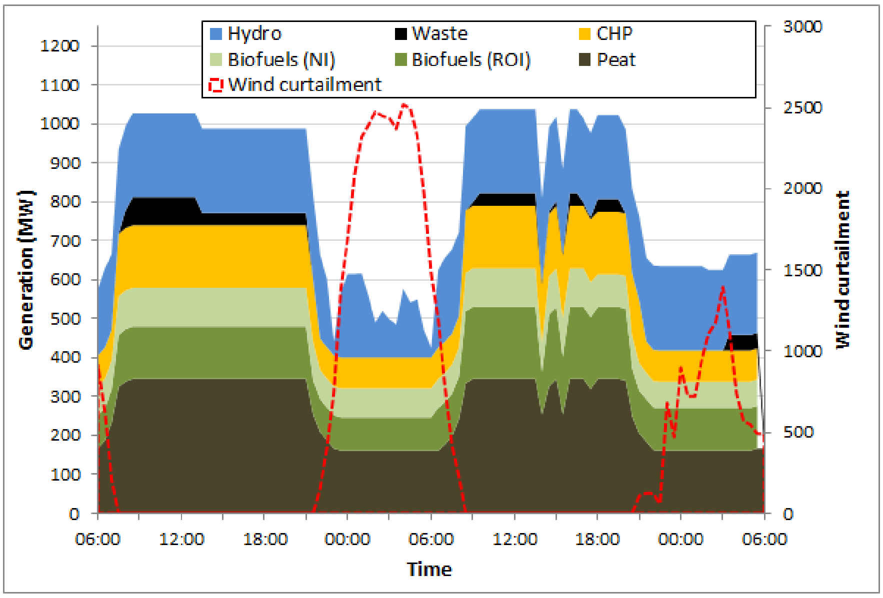


Figure 4.12: Dispatch of priority dispatch generators without constraints imposed and the occurrences of wind curtailment from the 8^{th} to 10^{th} March

4.7.2 Coal and Hydro

A constraint consisting of a penalty attached to ramping generators up or down is attached to the individual coal and hydro units. This is for same reasons outlined in the description of the fourth constraint in Section 4.7.1, namely to prevent excessive cycling and ramping during times of wind curtailment. These constraints are applied continuously and are not relaxed in the event of wind curtailment. The chosen penalty per MW of change in generation level of the generator, is also uniformly applied across the generation types to remove bias and also was chosen through an iterative process. Values of €15/MW change for coal and €20/MW for hydro were chosen.

It should be noted that for hydro, due to the limit daily energy usage constants placed on it from [139] it is viewed that it does not interfere with the priority of dispatch within the priority dispatch generators, as set out in [155] as the model optimises usage of hydro units around wind curtailment regardless of hydro generation being set to zero or near zero. This is due to

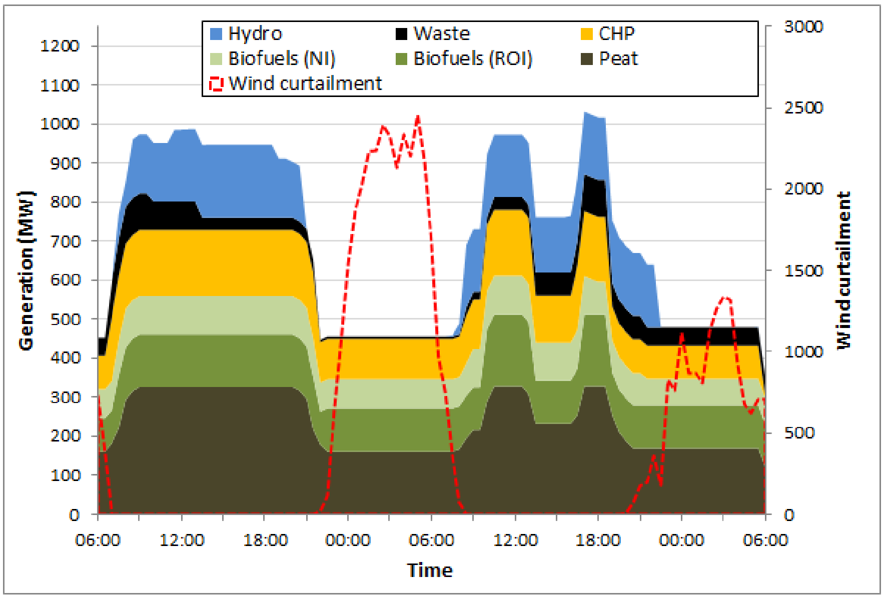


Figure 4.13: Dispatch of priority dispatch generators with constraints imposed and the occurrences of wind curtailment from the 8th to 10th March

the hydro units not having sufficient potential energy (storage/run of water) per day to run at the maximum capacity continuously. There was also a small penalty start cost added to the individual units to prevent excessive cycling during times of wind curtailment, the reasons for this are discussed in more detail in Section 4.7.4.

4.7.3 Pump Hydro Energy Storage

The PHES plant at Turlough Hill contains four separate turbine/pump units and one penstock. This results in the situation where all four units must be either off or in the same type of mode, be it pumping or generating. Therefore constraints where added to Turlough Hill, not present in [139], so that the facility is only allowed be in pump mode or generation mode at any one time, as shown in Fig. 4.14. If these constraints are not imposed, PLEXOS® can find optimality where generation and pumping modes can occur simultaneously in the PHES station, which is not possible due to the single penstock, and is shown in Fig. 4.14 and was highlighted by [156]. Changes were also made to the unit's generation specifications such as the adding of a minimum stable generation of 5MW per unit and the pump mode is set to only 71.5MW or off which helps to reflect the observed dispatch behaviour of Turlough Hill, shown in Fig. 4.15. There was also a small penalty start cost (€20) added to the individual units to prevent excessive cycling during times of wind curtailment, this is discussed in more detail in Section 4.7.4.

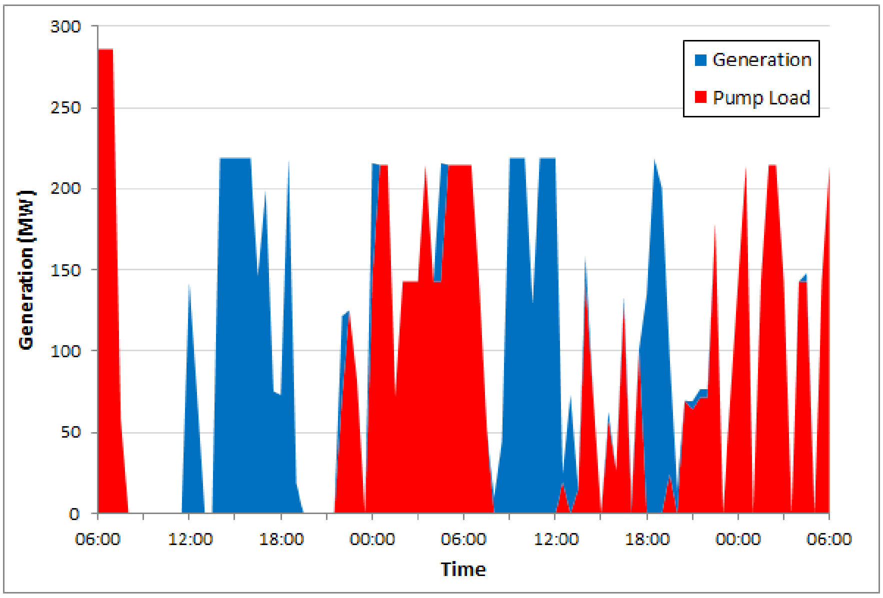


Figure 4.14: Dispatch of PHES generation and pumping without start penalty, ramping constraints and pump/generation constraints imposed from the 8^{th} to 10^{th} March

4.7.4 Mitigation of excessive cycling of plant

While developing the models for Chapters 7 and 8 it was found that during times of wind curtailment on the AI system excessive cycling and/or ramping would take place between different generation units on the system which is shown occurring 9^{th} March 12.00 - 18.00 hrs in Fig. 4.12 and 4.14. During these wind curtailment events the wind curtailment itself would also oscillate up and down from one simulation step to the next, every 30 minutes.

These events occurred due to a complex interaction taking place between wind curtailment, IC usage, Turlough Hill (PHES plant) and non wind priority dispatch plant. The cause of this problem was a combination of wind curtailment occurring while SOCs were forcing a number of generators to remain committed and operating at their minimum stable levels, forcing the model simulation to become very constrained. During these model times where the simulation becomes very constrained, optimality is not always converging fluidly from one simulation time step to the next, as discussed in Section 4.8, and oscillation would occur between the different generators stated above and actual wind curtailment taking place.

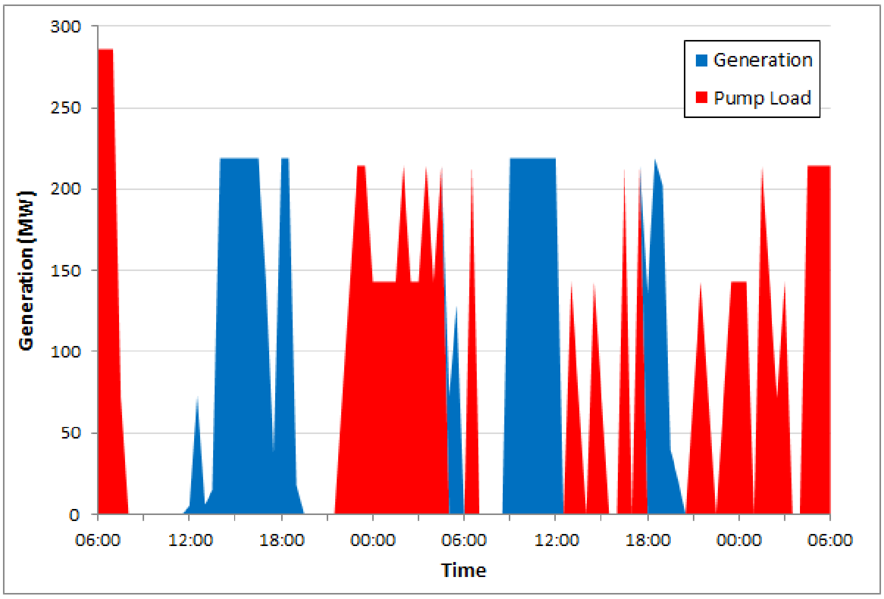


Figure 4.15: Dispatch of PHES generation and pumping with start penalty, ramping constraints and pump/generation constraints imposed from the 8^{th} to 10^{th} March

To mitigate the oscillations in generation and to better reflect the reality of RT dispatch, two main constraints were imposed on the generators affected by the problem. These constraints include ramping penalty charges and penalty start costs, details of which are outlined in Sections 4.7.1, 4.7.2, 4.7.3 and 5.5.2. It should be noted that penalty costs don't affect total generation cost reporting and are only a tool to influence PLEXOS® economic optimisation decision making.

It is also possible that the relative gap of 0.5 in the DA model is leading to unit commitment decisions that are not optimal and not converging fluidly from one simulation time step to the next. The problem was also compounded at times by the time out feature for optimisation periods in PLEXOS® as this was set to 900 seconds to help reduce simulation time. This could distort results in the RT model where the relative gap is 0.05 and should converge much more fluidly between simulation time steps. This unfortunately was a necessary measure that had to be accepted while attempting to mitigate the problems caused by it which are discussed further in Section 4.8.

4.8 Model problem size reduction

In the models presented in Chapters 7 and 8 effort was spent in reducing the overall problem size of the model with only negligible effects on results. This was important due to the large run times associated with the stochastic models developed and the multiple scenarios in each. Several techniques were used to reduce the size of the model.

In Chapter 8 generation schedules for hydro, waste, biomass and CHP units were created in the DA model to pass on to the RT model. This assumption of DA fixed generation profiles was appropriate for the work being done in Chapter 8 but was also a model problem size reduction technique as the generators with fixed generation profiles in the RT model no longer have unit commitment decisions to be made for them. There was minimal effect on the results from this decision and it was considered acceptable for the reduction in simulation time achieved. Also there is an argument that these types of generation are not frequently dispatched on a RT basis.

In Chapters 7 and 8 all but four OCGT's were omitted from the DA model. As there is minimal OCGT usage this has almost no effect on results. The four OCGT's that are kept reflect generally the SMP in the rare event they are used. These include one gas OCGT as well as one distillate OCGT in both ROI and NI. This is necessary as the IC flows are dependent on the electricity price of the SEM in the DA model.

It was decided, in order to help reduce simulation times in Chapter 7 and 8, that ROI hydro would be fixed from a single run of the model and made the same for all scenarios. This, while not perfect, had minimal effects on results.

During the development of the model in Chapter 7 a condition was originally placed on the model to indicate wind curtailment taking place and to allow the model to react by relaxing constraints associated with priority dispatch generators, discussed further in Section 4.7.1. However, due to the complexity of modelling a condition whose effects affect the status of the condition itself, simulation times in the DA model became unacceptably long. This was also due to the stochastic scheduling of the DA model, running five model samples simultaneously. As a result of the long simulation times it was decided to instead create a file for both NI and ROI jurisdictions indicating when wind curtailment was occurring. These files were created from the base-case scenario and used for all sequence scenarios after.

In Chapters 6, 7 and 8, the Xpress MP solver [141] is used for the simulation of the models. While the relative gap used in the SEM Forecast Model [139] is set to 0.025%, it was initially considered sufficient in the models presented here that for RT simulation the solver be set to a relative gap of 0.05%. However due to the stochastic scheduling of the DA model and the long simulation times resulting it was necessary to reduce the relative gap of the solver to 0.5% and have a time out feature for optimisation periods in PLEXOS® as this was set to 900 second in DA model. This is considered to have an effect but only minimally as the DA model's only purpose is the creation of schedules for the RT model but it was considered necessary to help reduce simulation time.

From work done in Section 4.3.3 for stochastic scheduling accounting for wind forecast errors it was necessary to find an optimum UC non-anticipativity penalty cost to allow for an acceptable degree of accuracy as well as an acceptable model simulation time. This is necessary as unit commitment decisions, for accuracy of modelling purposes, must match across all model samples, however changing the UC non-anticipativity penalty costs to infinity, therefore making a it hard constraint, result in a very lengthy simulation time for the models.

4.9 Optimisation periods

4.9.1 Examining simulation time reduction

For the purpose of overall simulation time reduction the simulation optimisation periods were reduced in length based on recommendations from [156]. The 24hrs plus 6hrs lookahead optimisation period used in Chapters 6, 7 and 8 was reduced to an optimisation period of 6hrs plus 24hrs lookahead and an optimisation period of 4hrs plus 26hrs. The more frequent but shorter optimisation period can lead to reductions in overall simulation time of large problem sized models. However from a comparison study of the three optimisation periods described above notable differences do occur in generator dispatch and costs. This is due to the effect of rolling periods being solved with the same lookahead period creating a better overall optimisation of the system than single days been optimised individually. An issue also arose when using the interleave process from varying the optimisation periods between the DA and RT models as UC decisions would not be available for RT model simulation when using long lookahead periods. For these reasons the assumption was made to retain the SEM 24hrs plus 6hrs lookahead optimisation period.

4.9.2 Examining simulation accuracy improvements

For the purpose of increased RT simulation accuracy the simulation optimisation time steps were reduced based on recommendations from [108]. The simulation time step of 30 minutes was retained in the DA model to mimic the SEM however the simulation time step was reduced in the RT model to 15 and then 5 minutes. This was to better capture OCGT usage and ramp rate restrictions. However due to an issue in the interleaved process a lookahead period in the DA model had to be a multiple of that of the RT model and was dependent of the difference of the simulation time step of the two models interleaved. Therefore a longer lookahead period was required in the DA model than the 6 hours normally considered which changed the model solution. Due to this issue this line of work was not pursued. It has also been shown in [108] that using shorter time steps in the scheduling simulation results in higher system costs, due to the higher accuracy of modelling.

Also examined in [143] from recommendations in [156] were the effects of unforeseen forced outages in the simulation until the actual simulation step in which they occur. This done by only allowing the RT model to simulate using a optimisation period of one simulation step and using a lookahead period of 30 hours where the forced outages are unforeseen. This method allowed for a more accurate simulation of actual dispatch, but dramatically increased overall simulation time.

Chapter 5

Model Inputs

5.1 Generator portfolio 2020

The generation portfolios in Chapters 7 and 8 are based as accurately as possible on the generators predicted to be present on the AI electricity system for 2020 as stated by [9]. However the assumptions made for the generation portfolio in Chapter 6 do differ from Chapters 7 and 8. This is due to the generation portfolio being based on [39] and assumptions made in relation to the capacity of biomass plants were ignored in [39], details of which are discussed in the following Section 5.1.3.

5.1.1 Generator portfolio in Chapters 7 and 8

For the models developed in Chapters 7 and 8, the installed generation capacity and technology type are taken from the All-Island Generation Capacity Statement (AIGCS) 2013-2022 [9]. The model attempted to replicate as close as possible the 2020 generator portfolio described by [9]. The current 2012 generator portfolio and specifications for generators are taken from [139], from which the 2020 generator portfolio was developed. All additions to the 2012 generator portfolio in [139] are listed in Table 5.1. Other changes on [139] included the removal of all oil-fired power stations in ROI along with the units B4-6 in NI, in keeping with [9]. This results in a 2020 installed dispatchable generation [1] capacity for ROI and NI of 7025 and 1965 MW respectively. Details of the individual generator type additions to the 2020

[1] includes all forms of generation capacity excluding wind energy and tidal energy

generation portfolio shown in Table 5.1 that are not present in [139] are described in detail in this Section.

Table 5.1: Additions to the generation portfolio in the SEM 2012 Forecast model for 2020

Generator name	Capacity (MW)
ROI	
Cahir or Culleen (OCGT)	98
NO1 (OCGT)	98
Caulstown (OCGT)	55
AE1 (DSU)	12
DAE (DSU)	29
Dublin waste to energy	62
Wind	3786
Small scale hydro	21
Biogas from landfill	43
Three biomass plants (CHP)	50 (x3)
NI	
Aggregated generation unit (AGU)	47
NI waste to energy	17
Wind	1278
Small scale hydro	4
Tidal	154
Biogas from landfill	23
Small scale biogas	30
Three biomass plants	15 (x3)
Small scale biomass	14

[139, 9]

In ROI it is assumed that three of the four OCGTs in planning will be built by 2020. Therefore it was assumed that only one of the OCGTs at either Cahir, Co. Tipperary or Culleen, Athlone, Co. Westmeath would be included in the model, these two OCGTs were assumed to be identical. Two more OCGTs were also included, an OCGT plant called Nore Power (NO1) at Kilkenny and and OCGT plant at Caulstown, Co. Louth. These three OCGTs were modelled using the generator specifications based on the most modern OCGT on the AI electricity system. The most modern OCGT currently on the system is KGT3 commissioned in March 2009 at Kilroot power station, Carrickfergus, Co. Antrim. The specifications of the KGT3 plant were used generally unchanged with just a few exceptions. These exceptions were changes made to the maximum capacity of the plant and linearly scaled adjustments, in relation to the maximum capacity, to start costs and minimum stable levels of the plant. With similar characteristics as OCGTs in manner of their dispatch, the two demand side units (DSU) AE1 and DAE in ROI were also modelled with the scaled down generator specifications of the KGT3 OCGT as above. The assumption was also made to include the same scale generation specifications of the KGT3 OCGT for the aggregated generation unit (AGU) in NI.

It is predicted that three waste to energy plants will exist in 2020, these plants are also considered to be priority dispatch generation sources and therefore require specific modelling techniques as described in Section 4.6. The Dublin waste to energy plant generator specifications were modelled based on the scaled generator specification of the waste to energy (IW1) plant in Duleek, Co. Meath with the same method used in Section 5.1.1. A comparison was also made to the generator specification of the peat plants to ensure assumptions were conservative due to the similar nature of low calorific value fuel types consumed in these generation technology types. Due to its very similar size the NI waste to energy plant was a copy of the Meath waste to energy (IW1) with the exception of its maximum installed capacity.

It was assumed that small scale hydro in both NI and ROI would have a fixed generation profile based on a forecast wind profile time lagged by 2 hours and modified linearly to a 27.4% capacity factor in response to the predicted energy output stated in [9]. This assumption allows for loose correlation of wind and rain while not assuming an exact correlation. Small scale hydro generation is also consider a priority dispatch generation source and requires specific modelling techniques as described in Section 4.6.

For the models presented in Chapters 7 and 8 it is assumed that Bioenergy plants are included in the generation portfolio, however this not the case in Chapter 6, details of which are given in Section 5.1.3. Bioenergy plants are a priority dispatch generation source and require specific modelling techniques as described in Section 4.6. In ROI it is assumed that three dispatchable biomass CHP plants of installed capacity of 50 MW each will be present in 2020 and there is assumed that for NI there will be three dispatchable biomass plants of installed capacities of 15MW each. These plants are based on the generator specification of the Meath waste to energy plant (IW1). However while the dispatch of these generators is optimised in the model run, they do have constraints placed on them that effect their dispatch, this is discussed in detail in Section 4.7. It was assumed as a result of lack of data that biogas from landfill in ROI would have a fixed and constant generation profile at 80% of maximum installed capacity, creating the 80% capacity factor stated in [9]. This was justified as plant of this size would most likely not be centrally dispatched. The same principle was applied to biogas from landfill, small scale biogas and small scale biomass in NI.

Tidal generation was simulated by a periodic oscillation of period 12 hours and 25 minutes in Eqn. 5.1. The signal wave was “squeezed” to represent the pulsating effect of tidal energy, due to the non-linear correlation between fluid velocity and power extraction. Eqn. 5.1 was used to produce a signal wave at a period of 12 hours 25 minutes at a height from 0 to 1. Then, through three iterations using $a = 0.75$, the pulsating effect of tidal energy developed. The tidal rating factor was created in a 15 minute resolution time-series matching the wind data (PLEXOS® interpolates the 30 minute data). This is recognised to be a simplistic approach due to the monthly cycles of tides not being represented, but due to the small installed capacity of tidal turbines (154MW) on the system it is considered to have minimal impact on overall results. It was selected that a 20% capacity factor was associated with tidal energy [9] however this is very dependent on the power curves of tidal turbines to be utilised in the future. It should be noted however while the available capacity factor is 20% the actual capacity factor is reduced to approximately 17-18% due to operational constraints as tidal is a non-synchronous generation source. Tidal generation is also consider a priority dispatch generation source and requires specific modelling techniques as described in Section 4.6.

$$RF_{T(1)} = 0.5\left(1 + \sin\left(8\pi tn\right)\right) \tag{5.1}$$

(n=1,2,3,. . . ,N)

$$\begin{gathered} RF_{T(i+1)} = RF_{T(i)} - a\left(\sqrt{\left(RF_{Ti} - A\right)^2}\right) \\ A = 1\; if\; \left\{RF_{T(i)} > 0.5\right\}, \\ A = 0\; if\; \left\{RF_{T(i)} < 0.5\right\} \end{gathered}$$

(i=1,2 and 3)

where: RF_T = rating factor (tidal); sin angle in radians; t = 24.83333 which is the number of 30 minute intervals in 12 hours 25 minutes; N = number of intervals in data; a = adjustment factor, value was chosen to achieve a 20% capacity factor.;

5.1.2 Assumptions on renewable energy sources

The EU directive on the promotion of the use of energy from renewable sources [4] outlines what energies are considered to be from renewable sources. In relation to Ireland specifically [9] outline which energy sources contribute to the 2020 RES-E targets. For the models presented in Chapters 7 and 8 these renewable sources are outlined in Table 5.2 with contribution to total AI generation from the base-case scenario in Chapter 7. This results in a total annual electrical energy contribution from renewable sources meeting the 40% 2020 RES-E targets.

Table 5.2: The AI renewable generation sources

Generator type	Capacity	Considered Ren.	Contribution to AI gen.
Wind	5064 MW	100%	32.0%
Hydro	218 MW	100%	1.82%
Tidal	154 MW	100%	0.57%
Small scale hydro	25 MW	100%	0.15%
Waste to energy	94 MW	50%	0.75%
Edenderry peat plant	118 MW	30%	0.46%
Dispatchable biomass	195 MW	100%	3.11%
Biogas from landfill	66 MW	100%	1.15%
Small scale biofuels	44 MW	100%	0.77%

5.1.3 Generation portfolio in Chapter 6

For the study carried out initial by in Chapter 6 the assumption was taken to exclude biomass plants from the generation portfolio. This was due to a lack of information present in relation to planing permission being sought or information on possible developments being published. However more recently there has been an increase in new projects been proposed for development in the Biomass sector [157].

The decision whether to exclude or include biomass plants is important as it affects the installed capacity of wind energy that will be needed to meet RES-E targets, assuming wind would be needed to fill the renewable generation gap. This in turn effects wind curtailment as well as the overall running of the electricity system. For example, in the work presented in Chapter 6 where biomass is not included, this results in a total annual electrical energy contribution from non-wind renewable sources of 2.9%. This then leaves 37% of generation to come from wind energy. However if biomass plants were included this would result in approximately an extra 5% electrical energy contribution from non-wind renewable sources, meaning only 32% of total generation would have to come from wind energy. This has a direct effect on wind curtailment results. The biomass renewable energy contribution of approximately 5% stated above from [39] is as follows: biomass CHP in ROI (2.4% of total AI generation); biomass in NI (1.5%); bio-fuel in NI and ROI (1.0%).

Marine (wave) energy in ROI (which would contribute 0.3% of total AI generation) was not included in any of the studies presented here due to the present lack of development or planning permission activity in this area.

5.2 Installed wind energy capacities

Installed capacity predictions vary dramatically due to the estimates of the TER of electricity consumption changing for AI discussed in Section 5.4.3. This is due to AI's renewable targets being set as a percentage of electricity generation.

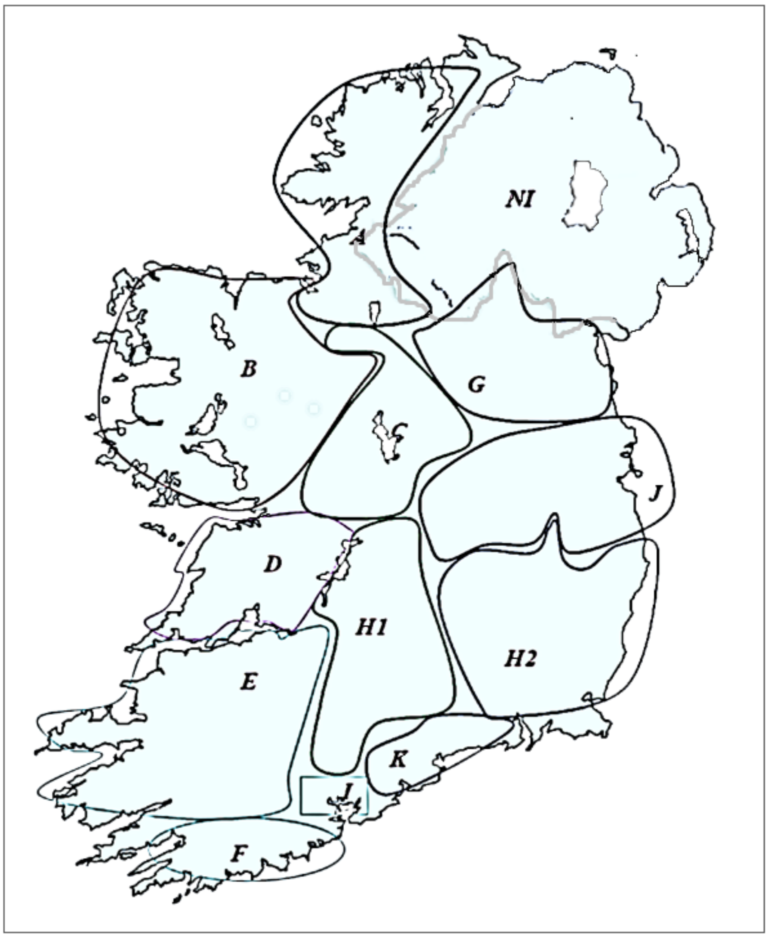
5.2.1 EirGrid wind regions

For a realistic simulation of the variable nature of wind generation, it is important to capture the spatial and temporal variability of the resource. Therefore in Chapter 6 wind generation data aggregated on a regional basis was used in the simulations as shown in Fig. 5.1, reproduced from EirGrid.

The AI onshore wind capacity in Chapter 6 consisted of 1991MW of installed wind farms and 1875MW of planned wind farms [39]. This comes to a total installed capacity of 3866MW. With knowledge of wind farm locations this allowed for the percentage of installed wind capacity of each wind region to be calculated using the wind capacity presently connected and future planned wind installations.

Form the installed wind capacity percentage per area calculated above, each wind region was therefore linearly scaled up in order to meet the target amount, with the exception of Region E (Kerry/West Cork). Region E has a total existing and planned installed wind capacity of 1036MW which is reaching its export limit due to transmission constraints (assuming eight 110kV lines at an average rating of 120MW). The final total wind capacity was determined by an iterative process in order to obtain the required capacity to achieve 37% of total generation for AI from wind.

The assumption was then made that 37% of electricity generation must come from AI wind for all scenarios [35, 36]. This results in the onshore wind being adjusted in proportion to Table 6.2 to achieve the 37% figure. A further requirement was imposed that 37% of generation must come from wind for both jurisdictions NI and ROI independently. This results in the onshore wind capacities being adjusted. The relationship between the installed wind capacity and the balancing of generation in the two jurisdictions is almost linear in nature, this resulted in the scaling of the data to reflect the annual proportion of the total system demand requirement by NI and ROI from AI. For a base case assumption of no additional offshore wind additions to AI the percentage of installed onshore wind in each wind region is shown in Table 5.3.



[158]

Figure 5.1: Eirgrid wind regions

Table 5.3: The regional breakdown of wind capacities across the onshore wind regions.

Wind region	%
A	12.3
B	8.7
C	0.7
D	8.0
E	16.5
F	2.7
G	3.5
H1	9.9
H2	8.9
J	2.0
K	0.5
NI	26.2

5.2.2 Offshore Wind Energy

For the model presented in Chapter 6 there were three assumed offshore wind scenarios represent low, medium, and high offshore wind penetration levels with installed capacities of 25.2MW, 850MW and 1300MW respectively with the remainder of wind installed capacity onshore to meet the 2020 renewable targets. These were based on proposed offshore wind farms around the island of Ireland as shown in Table 5.4.

The low offshore scenario is essentially a “baseline scenario” consisting only of the 25.2MW of installed offshore wind capacity that currently exists. This is from a single windfarm at Arklow Bank. For this scenario it is assumed that no more offshore wind will be developed in AI prior to 2020 and the 2020 RES-E targets will be met almost entirely by onshore wind developments.

The medium offshore scenario consists of 850MW offshore wind capacity. This is an amalgamation of the NREDP recommendations and half of the offshore wind proportion of the Crown Estate’s NI round, consisting of 550MW and 300MW respectively. Dublin Array and Oriel offshore wind farms are reduced proportionally in capacity, by 278MW and 245MW respectively, to make up the ROI contribution. The NI contribution will consist of a single proposed offshore wind farm off the Co. Down coast.

The high scenario consists of 1300MW offshore wind capacity. This is an amalgamation of the upper limit recommended by Eirgrid for installed offshore wind in the ROI and the full offshore wind proportion of the Crown Estate Northern Ireland licencing round, or 684MW and 600MW respectively. The Dublin Array and Oriel offshore wind farms make up the ROI

Table 5.4: Existing and proposed offshore wind farms.

Name	Capacity (MW)
Existing	
Arklow Bank Phase 1 (ROI)	25.2
Proposed	
Dublin Array (ROI)	364
Oriel (ROI)	320
Doolick (ROI)	100
Codling wind park (ROI)	1100
Arklow Bank Phase 2 (ROI)	493
Crown Estate round (NI)	600

Sources: [40, 43, 44, 45, 46, 47].

contribution and two 300MW proposed offshore wind farms off the Co. Down coast fulfil the NI contribution.

5.2.3 Wind regions for Chapter 7 and 8

For the models presented in Chapter 7 and 8 only three wind regions were used. These three wind regions represented the different jurisdictions of ROI, NI and GB. This was considered an appropriate simplification as only the differences in wind generation between the three jurisdictions were required in the results.

The total installed wind capacity for ROI and NI was assumed to be 3786MW and 1278MW respectively [9]. These levels of installed wind capacity allow for AI to meet its renewable targets in work presented in Chapter 7 and 8. The installed wind capacity of GB is discussed in Section 5.5.

5.3 Data sources

5.3.1 Fuel prices, taxes and levies

It was decided for the purposes of this work that fuel prices would be based on the 2020 predictions by EirGrid in [58]. The most important relationship in the fuel price is the ratio of price between coal and gas. It is taken that coal is 2.12 €/GJ and gas is 7.03 €/GJ. The ratio of prices of these fuels in relation to each other can have a large effect on the dispatch of generation types.

The carbon price was assumed to be €25 per tonne for work done in Chapters

6 however this was assumed to be €30 per tonne for work done in Chapters 7 and 8. No additional taxes or duty were assumed. These assumption where made in-line with previous work done [22, 159, 160].

5.3.2 Generator start cost and start fuel off-take

The start costs were taken from averaging the individually daily issued start cost for 2011 for each generator given in [161]. These are also presented in three bands allowing for different start costs to be taken depending on how cold/warm/hot the generator may be. The times associated with the heat bands of the individual generators were taken from [161].

However these start costs represent the total cost including start off-take fuels and this had to accounted for. Start fuel off-takes also given in three heat bands were taken from [139] and the fuel cost was subtracted from the total start cost. This leaves both the total start cost being accounted for accurately, as well as the carbon dioxide emissions contribution of the start fuels having being accounted for.

5.4 Time-series data sources and processing

5.4.1 Wind energy times-series; Regional

The wind data used in Chapter 6 is based on 12 separate wind regions as shown in Fig. 5.1, reproduced from EirGrid. The regional wind data is based on hourly resolution time-series for multiple wind regions across the island developed by EirGrid and used in the SEM forecast model of 2010-2011 [158]. The regional wind data used is developed from actual data from the mean wind speed year of 2008.

New time-series to represent additional offshore regions were added to the model so that it consisted of 14 onshore wind regions and six offshore wind regions. With only a single, small operational offshore windfarm on the AI system, Arklow Bank, there is a lack of representative data for offshore wind generation. The three new offshore wind regions which are based on adjacent onshore regions B, G and H2 taken form [158] and were chosen to reflect the locations of the proposed offshore wind sites in the future. These sites are discussed in more detail in Section 5.2.2.

A general offshore capacity factor of 40% was assumed, this is based on a conservative assumption obtained from Denmark as described in Section 3.1.1. It was decided for the purpose of the model that the best solution would be the adjustment of the power duration curve to reflect a 40% capacity factor with emphasis on increasing the lower capacity values. This is a simple method based on a straightforward adjustment of existing data. The offshore wind region profiles are developed from the respective neighbouring onshore wind regions. The onshore regions' wind time-series data was first converted into a power duration curve. Then the power duration curve was scaled to achieve a representative 40% capacity factor for offshore wind by manipulated power duration curves as is shown in Eqn. 5.2 before being converted back to time-series.

Due to Ireland's predominantly westerly wind, offshore data would be time lagged or led by one hour with respect to the neighbouring onshore region to reflect this [56]. This resulted in the offshore wind regions data on the east coast of AI being time-lagged by one hour relative to their respective onshore wind regions, and the single offshore wind region of the west coast of AI being time-led by one hour. It may be however a more true representation of offshore wind data to increase the values in the form of a normally distributed random increase in generation about the average generation value.

The capacity factor adjustment is described by:

$$CF_{off,n} = CF_{on,n}\left(\left(\frac{a}{1-N}\right)n + a + 1\right) \tag{5.2}$$

Where CF_{off} and CF_{on} are capacity factors offshore and onshore respectively, a is a scaling factor, chosen to achieve a 40% capacity factor, n is the interval number and N is the number of interval points.

The Pearson product-moment correlation coefficient, R, was used to determine the spatial correlation of the regional wind time-series with respect to each other, this is shown in Table 5.5. Correlation coefficients between pairs of onshore wind regions were in the range 0.51 - 0.90. The correlation coefficients between the manipulated offshore wind regions ($G_{off},\ J_{off},\ NI_{off}$ and their respective neighbouring onshore wind regions

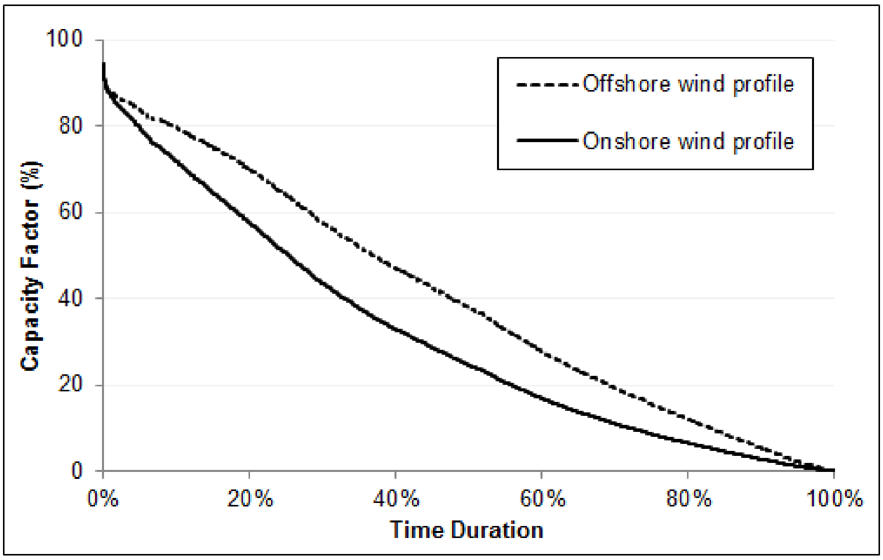


Figure 5.2: Wind power duration curves for the onshore Region and the adjusted offshore Region

$G,\ J,\ NI$ were in the range 0.94 - 0.97. Note in Table 5.5, highlighted in yellow, the spatial correlation of the manipulated offshore wind regions $(G_{off},\ J_{off},\ NI_{off}$ to the original wind region they were based on. Offshore data is on a one hour time lag from the respective neighbouring onshore wind regions.

The lowest correlation (R = 0.51) occurred between two onshore regions, A and E, both of which have large installed capacity and are separated by a large north-south distance. From this it is clear that the adjustments made to create the offshore wind data can be viewed as conservative in terms of the likely effects on wind curtailment.

There is a clear indication from aggregated onshore and offshore duration curves as shown in Fig. 5.3 that offshore wind suffers less curtailment during periods of high wind generation than onshore wind. This is a result of the greater overall spatial dispersion of wind capacity when more wind capacity is located offshore.

Also of note and highlighted in yellow in Table 5.5 is the correlation of the GB wind region data which has a two hour time lag from the J wind region's data.

Table 5.5: The spatial correlation the EirGrid wind regions in relation to each other, as defined by the Pearson correlation coefficient

	A	B	C	D	E	F	G	H1
A	1.00	0.86	0.77	0.74	0.51	0.51	0.86	0.77
B	0.86	1.00	0.83	0.81	0.56	0.56	0.82	0.83
C	0.77	0.83	1.00	0.98	0.62	0.62	0.80	1.00
D	0.74	0.81	0.98	1.00	0.64	0.64	0.77	0.98
E	0.51	0.56	0.62	0.64	1.00	1.00	0.56	0.62
F	0.51	0.56	0.62	0.64	1.00	1.00	0.56	0.62
G	0.86	0.82	0.80	0.77	0.56	0.56	1.00	0.80
H1	0.77	0.83	1.00	0.98	0.62	0.62	0.80	1.00
H2	0.65	0.65	0.74	0.74	0.61	0.61	0.73	0.74
J	0.86	0.82	0.80	0.77	0.56	0.56	1.00	0.80
K	0.65	0.65	0.74	0.74	0.61	0.61	0.73	0.74
NI	0.95	0.83	0.77	0.75	0.52	0.52	0.88	0.77
G_{off}	0.85	0.78	0.77	0.74	0.55	0.55	0.94	0.77
J_{off}	0.85	0.78	0.77	0.74	0.55	0.55	0.94	0.77
NI_{off}	0.92	0.79	0.74	0.72	0.51	0.51	0.86	0.74
GB	0.84	0.78	0.78	0.76	0.55	0.55	0.95	0.78

	H2	J	K	NI	G_{off}	J_{off}	NI_{off}	GB
A	0.65	0.86	0.65	0.95	0.85	0.85	0.92	0.84
B	0.65	0.82	0.65	0.83	0.78	0.78	0.79	0.78
C	0.74	0.80	0.74	0.77	0.77	0.77	0.74	0.78
D	0.74	0.77	0.74	0.75	0.74	0.74	0.72	0.76
E	0.61	0.56	0.61	0.52	0.55	0.55	0.51	0.55
F	0.61	0.56	0.61	0.52	0.55	0.55	0.51	0.55
G	0.73	1.00	0.73	0.88	0.94	0.94	0.86	0.95
H1	0.74	0.80	0.74	0.77	0.77	0.77	0.74	0.78
H2	1.00	0.73	1.00	0.67	0.72	0.72	0.65	0.73
J	0.73	1.00	0.73	0.88	0.94	0.94	0.86	0.95
K	1.00	0.73	1.00	0.67	0.72	0.72	0.65	0.73
NI	0.67	0.88	0.67	1.00	0.88	0.88	0.97	0.87
G_{off}	0.72	0.94	0.72	0.88	1.00	1.00	0.90	0.99
J_{off}	0.72	0.94	0.72	0.88	1.00	1.00	0.90	0.99
NI_{off}	0.65	0.86	0.65	0.97	0.90	0.90	1.00	0.87
GB	0.73	0.95	0.73	0.87	0.99	0.99	0.87	1.00

5.4.2 Wind energy time-series; Countries-level

Without the need to study the variability of wind within the geographical area of ROI it was considered acceptable to retain just a single wind time-series per jurisdiction (ROI, NI and GB). This was necessary for wind energy forecast development as described in Section 4.4.

AI wind time-series are developed from 2011 ROI and NI wind time-series data. The ROI wind data was downloaded from EirGrid's publicly available website [49]. The NI wind data was given by SONI on request. The wind generation data was divided by the installed capacities of NI and ROI per month for the year of 2011. This important particularly for ROI as the

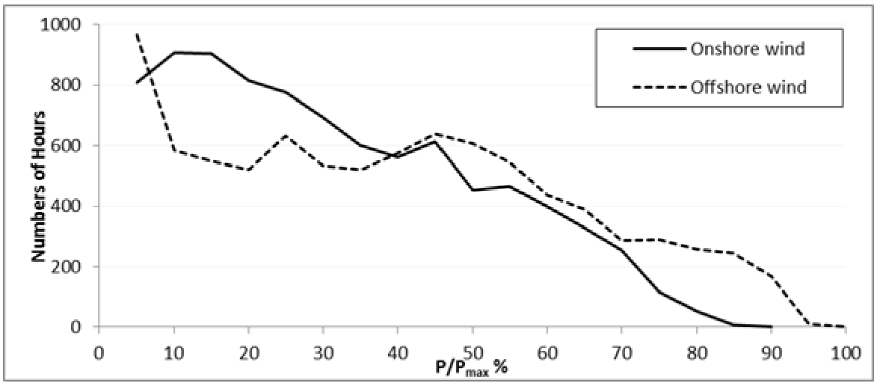


Figure 5.3: Wind generation duration curves for aggregated onshore and offshore power, net of curtailment, with a SNSP limit of 70%.

installed wind capacity grew throughout the year and would distorted the wind energy times series over the course of the year if not accounted for. The resulting wind rating factor time-series was then cleaned to remove missing values. The ROI and NI in 2011 had wind capacity factors of 32.5% and 30.7% respectively [9] however it is stated that long term respective average capacity factors are assumed to be 31.7% and 31.4%. This was accounted for by applying a multiplier to the time-series to achieve the desired average capacity factors for the year.

The total installed wind capacity of GB is expected to be 34.5GW in 2020 [61] and 18.0GW of this will be installed offshore [162]. The 2011 30min GB wind generation time-series was taken from the National Grid Data at the ELEXON Portal [2]. This data was scaled using the installed capacity of 3.48-5.06GW [61] of the course of 2011, giving a wind capacity factor for GB of 25.5% which is low compared to the wind year of 2011 [163]. It is assumed that not all wind generation is reported in the National Grid Data at the ELEXON Portal. The assumption is made that the capacity factor for the total GB wind generation in 2020 will be 32.0% which is half way between the onshore and offshore wind capacity factor for 2011 of 27.5 and 37% respectively [163]. This was achieved by a simple scaling of the data by a multiplier.

The Pearson's correlation coefficient was calculated between the wind generation time-series of ROI-NI 0.851, ROI-GB 0.715, NI-GB 0.673 which is similar to findings in [56, 57]. Also using the Pearson's correlation coefficient it was found that GB wind generation is at a maximum correlation at a 5-6hr time lag of the ROI wind data.

[2]https://www.elexonportal.co.uk/

5.4.3 System demand data

The system demand predictions of a country are usually limited link to its expected gross domestic product (GDP) growth. Therefore due to the recession that has occurred in ROI and NI, system demand predictions have changed from 2011 to 2013.

System demand 2011 prediction

The model developed in Chapter 6 assumed an increase of 17% in system demand for the time frame of 2010-2020. The increase in total energy requirement (TER) was taken from a median projection scenario [39]. This was applied by means of a linear scaling to the AI system demand time-series for the year 2010 from [158]. The system demand of both jurisdictions NI and ROI is modelled as 25.8% and 74.2% respectively from the AI system demand time-series data, allowing for each jurisdiction in order to be viewed separately to ensure compliance with the RES-E targets and a more accurate model representation.

System demand 2013 prediction

The models developed in Chapter 7 and 8 assumed an AI system demand of peak demand 7317MW and TER of 39.85TWh/yr in 2020 [9]. The AI system demand was developed from 2012 AI data given in [139]. The 2012 30 minute AI system demand time-series having a peak demand of 6496MW and annual total energy requirement (TER) of 36.56TWh/yr was manipulated to achieve a peak demand of 7317MW and TER of 39.85TWh/yr. The data was first had a multiplier evenly applied to the time-series to achieve the desired TER of 39.85TWh/yr creating $SD_{TER,add}$ in Equ. 5.3. This was then followed by the application of Equ. 5.3 to the time-series to achieve the desired peak demand without distorting the TER/yr:

$$SD_{peak,add} = SD_{TER,add} + a\left(SD_{TER,add} - SD_{TER,add,avg}\right) \tag{5.3}$$

where: $SD_{peak,add}$ = peak demand adjusted system demand time-series (MW); $SD_{TER,add}$ = TER adjusted system demand time-series (MW); $SD_{TER,add,avg}$ = the average value of the TER adjusted system demand time-series (MW); a is a scaling factor, chosen to achieve the desired peak demand.

The AI system demand is split between the two nodes of NI and ROI at 25.2%

and 74.8% respectively [9]. This takes account for the latest projections in demand growth due to the effect of recession in the NI and ROI economies. The Transmission Loss Adjustment Factors (TLAFs) have been removed due to large transmission grid changes [116] rendering them obsolete by 2020.

Embedded generation is small scale generation that is connected to the electricity system. Sources of embedded generation include CHP generation attached to commercial properties and small scale renewables. This area of generation is expected to increase in installed capacity out to 2020 due to incentives in place [42]. I was assumed in this work that the 2020 embedded generation would not change from current estimates. Currently the embedded generation assumed in [139] fluctuates between 112 and 211 MW dependent on the time of the week and in total makes up approximately 3.1% of system demand in 2020.

5.4.4 Maintenance schedules

Maintenance schedules are created separated from the forced outages schedule to reflect the knowledge in the DA model of only maintenances outages and not forced outages. The same maintenances profile is used in both the RT and DA models. Due to a lack of publicly available data for generator maintenances scheduling. The percentage of time generators spent in maintenance was assumed to be 3.5% for ROI Hydro plants and 4.0% for all other plants. Maintenance schedules are created in PLEXOS® from the Projected Assessment of System Adequacy (PASA) tool. The maintenances schedules are also manipulated to reflect their summer/winter patterns.

5.5 British System data

5.5.1 Interconnectors and British system

Interconnection between the SEM and GB is represented by East West (EWIC) at 500MW for ROI to GB and Moyle at 450MW in winter and 410MW in summer for NI to GB. In Chapters 7 and 8 the interconnector flows are fully fixed on a DA schedule, with the exception of forced outages occurring on the lines. The interconnector flows match the export and import energy from AI to GB of 2200GWh and 1500GWh [58] through modification of the GB shadow price. This was considered carefully as interconnector usage has an effect on OCGT usage in the model and was viewed as important to adjust to receive realistic OCGT usage.

The interconnector usage is based on the difference in the price between the AI and GB systems. Therefore adjustment of the interconnector flows is achieved by adjustment of the single GB generator running costs. These adjustments are a more simplified version of what was carried out to achieve the GB generator running costs as shown in [62]. It should be noted that due to the GB shadow price rising at night and lowering during the day the GB generation cost data from [139] was not used and the GB generation cost data from [158] was used instead. This GB generation cost data is made up of heat rates, variable operation and maintenance (VOM) charges and a GB gas fuel price.

Adjustment of the interconnector flows was manually achieved by two adjustable variables and was carried across all scenarios unchanged. First, the variations that occur over the year were separated from the summer and winter average year running costs. The variations in the costs over the year control the quantity of net flow on the interconnectors, therefore the larger the variations of the GB price, the larger, the net flows on the interconnectors. Secondly, the average winter and summer running costs to the year are adjusted proportionally to achieve the correct import-export ratio but this also has an effect on net flow over the interconnecter. The higher the average GB price the more frequently GB will import from AI. The "wheeling charges back" that are present in [158] are ignored as it is assumed by 2020 that interconnector flow will transfer with equal ease in both directions. In place of this a flat wheeling charge of €2/MWh is introduced in both directions. Therefore the end result of the modifications to GB price is an adjustment of the variability of the price and summer/winter average prices however keeping the six intervals per day and summer/winter variations of the original data in proportion to each other as in [158].

The GB system demand for 2020 was developed from 2011 GB data taken from the National Grid website [3]. The 2011 30 minute GB system demand time-series, from a peak demand of 55.11GW and total energy requirement (TER) of 308.3TWh was manipulated to achieve a peak demand of 61.00GW

[3] http://www.nationalgrid.com/uk/Electricity/Data/Demand+Data/

and TER of 314.5TWh in 2020 [61].

5.5.2 British system non-synchronous penetration limit

A constraint was placed on the GB region consisting of an SNSP limit of 70%. This limit was assumed as no reference has been found on this particular issue for GB. However due to GB's large nuclear fleet it is assumed that there must be a limit on instantaneous renewable energy penetration on the GB system [17]. This was to more realistically deter or even prevent imports to GB from the SEM in times of GB high wind generation on the GB system. This results in times where the interconnectors cannot be used preventing exports from SEM and resulting in additional wind curtailment in SEM.

A step change that could occur between the GB SNSP limit of 70% being reached or not, which could result in oscillation on the interconnectors occurring where full interconnector export would be available during one simulation step followed by no availability on the next and again available following this. This resulted in 950MW of exports oscillation on or off during the certain times. This was mitigated by averaging the availability of the interconnector over four hours and the removal of any point values of on or off. This issue also contributed to the generator oscillation problems discussed in Section 4.7.4 due to the correlation of wind energy output that exists between AI and GB as shown in Section 5.4.2.

Chapter 6

How much wind energy will be curtailed on the 2020 Irish power system?

NB: it should be noted that there has been a terminology change from the publication of this paper and submission of this thesis. The term Transmission Constraints Groups (TCGs) used in this Chapter is the same as the System Operational Constraints (SOCs) used in the rest of the document.

6.1 Abstract

This paper describes a model of the 2020 Irish electricity system which was developed and solved in a mixed integer programming, unit commitment and economic dispatch tool called PLEXOS®. The model includes all generators on the island of Ireland, a simplified representation of the neighbouring British system including proposed wind capacity and interconnectors between the two systems. The level of wind curtailment is determined under varying levels of three influencing factors. The first factor is the amount of offshore wind, the second is the allowed limit of system non-synchronous penetration (SNSP) and the third is inclusion or exclusion of transmission constraints. A binding constraint, resulting from the 2020 EU renewable energy targets, is that 37% of generation comes from wind. When the SNSP limit was increased from 60% to 75% there was a reduction in wind curtailment from 14% to 7%, with a further reduction if the proportion of

wind capacity installed offshore is increased. Wind curtailment in the range of SNSP limit of 70-100% is influenced primarily by the inclusion of transmission constraints. Large changes in the dispatch of conventional generators were also evident due to the imposition of SNSP limits and transmission constraints.

6.2 Introduction

Ireland has an abundant natural resource in wind energy, with some of the highest average wind speeds in Europe [52]. There is currently 1955MW of installed wind capacity and a total conventional generation capacity of 9356MW on the island of Ireland [39]. In the Republic of Ireland (ROI) the government has set a target of 40% for renewable electricity generation (RES-E) by 2020 [5]. In Northern Ireland (NI) the Executive has also set a target of 40% RES-E by 2020 [7]. As wind is the most mature of the renewable technologies it is expected to be the biggest contributor to fulfilling the RES-E targets. This will be achieved through the planned installation of up to 5300MW of wind generation capacity on the island of Ireland (AI)[1] [39]. This means that wind turbines will be expected to produce 37% of AI electrical energy needs in 2020 assuming that existing hydroelectric plant and other forms of renewable electricity generation will only make up 3% of total generation.

6.2.1 Installed wind capacity

Estimates of the wind capacity required to be installed in ROI and NI to meet the 2020 RES-E targets vary according to reports. These variations are in the order of hundreds of MW and represent hundreds of millions of Euro in additional installation costs [37].

The most current estimate of the required wind capacity is of up to 5300MW for AI, with between 3500MW and 4000MW in ROI while NI will have 1278MW (978MW onshore and 300MW offshore). These figures make up the main contribution to the 40% RES-E target in both jurisdictions [39]. For ROI

[1] All-island of Ireland (AI), consisting of Northern Ireland (United Kingdom) and the Republic of Ireland.

it has been reported that 36.5% of total generation will come from 4649MW of wind capacity [5]. A comparison cannot be drawn with the UK NREDP as it does not separate NI capacity from the rest of the United Kingdom. With a total AI installed wind capacity of 6000MW in 2020, almost entirely onshore, wind has been predicted to produce 34% of total generation [23]. However these figures are based on predictions of system demand growth which have since been revised downwards due to the ongoing recession and wind curtailment has not been taken into account.

6.2.2 Offshore Wind

There are currently five developments equating to approximately 2400MW of offshore wind capacity under consideration in ROI waters. These developments all have either grid connection offers or foreshore licenses approved (Table 6.1). Strong interest is also being shown in the potential development of 600MW of offshore wind capacity off the coastline of county Down. This is part of the Crown estate licensing rounds in NI [40].

The National Renewable Energy Action Plan (NREAP) for ROI suggests that 555MW of offshore wind is needed to ensure ROI meets its RES-E targets for 2020 [5]. This recommendation comes from concern that onshore wind developments may not be sufficient to meet the RES-S targets as many onshore wind developments are encountering difficulties in the planning process. This would result in at least one and possibly two of the five ROI offshore wind developments being constructed.

While it is unlikely that all of the possible 3000MW of offshore wind capacity under consideration in ROI and NI will be constructed, it will only take less than 10% of what has been proposed to exceed the estimate proposed in the All-Island Grid Study (AIGS) Portfolio 5 [41]. The suggestion from the transmission system operator (TSO)[2] of ROI is that the system will only be able to cater for 600-700MW of offshore wind due to issues such as reserve provision and system stability.

Currently all proposed offshore wind farms in AI waters are located on sand banks or rock shelves in less than 30 metres of water depth, in what would generally be considered shallow waters. There is an argument for installing

[2]The TSOs are Eirgrid for ROI and the System Operator for Northern Ireland (SONI)

Table 6.1: Existing and proposed offshore wind farms.

Name	Capacity (MW)
Dublin Array (ROI)	364
Oriel (ROI)	320
Doolick (ROI)	100
Codling wind park (ROI)	1100
Arklow Bank Phase 1 (ROI)	25.2
Arklow Bank Phase 2 (ROI)	493
Crown Estate round (NI)	600

Sources: [40, 43, 44, 45, 46, 47].

wind turbines in deeper water to avail of the greater capacity factors generally present at locations further offshore. The greater geographical spread would also contribute to reducing wind curtailment. However there is an increase in cost as wind turbines are placed further offshore [164] and this is likely to rise further if floating wind turbines are required in deeper waters.

6.2.3 Wind Curtailment and Constraint

Wind curtailment is an intentional reduction in overall wind power output ordered by a TSO due to the risk of instability on the electricity grid from non-synchronous generation as well as other reasons such as managing grid stability and reserve requirements. As installed wind turbine capacity on the power system increases, this will result in an increased frequency and magnitude of wind curtailment events becoming necessary [112, 113, 98]. Wind curtailment could have a considerable effect on estimates of required installed capacity in order for ROI and NI to meet their 2020 RES-E targets. Wind curtailment will also result from the increased variability of generation from renewable sources and the re-dispatch of conventional plant for reserve and ramping requirements during periods of high instantaneous wind penetration, resulting in a temporary decrease in wind generation [21].

To date, most studies have shown that wind curtailment will have minimal effects at installed wind capacities of less than 7000MW on the AI system [117, 15, 118, 119]. Tuohy et al. [118] demonstrated that significant wind curtailment would only begin to occur when installed wind capacity exceeded 7000MW on the AI system, however the authors acknowledged that taking account of inertia issues or voltage stability on the system might change this estimate. Also, it must be noted that these figures were based on pre-recession projections of system demand growth which are now unlikely to be met. Doherty et al. [121] discussed that wind curtailment may be used in a future AI system with a scenario of high wind power and HVDC interconnection to Great Britain[3] (GB), in order to avoid risks to system stability. An assumed high interconnection capacity of 2000MW with GB resulted in negligible changes in wind curtailment compared with a baseline scenario of 1000MW interconnection. However, overall curtailment was in the order of 0.12% to 0.15% [15].

It has been shown that wind output will sometimes have to be constrained on the All-Island system as a result of network congestion. One study estimated 6.8% reduction in wind output due to network constraints with 7000MW of installed wind capacity on the system, however in the same study for a minimum inertial constraint showed wind curtailment to be almost negligible [117]. While wind constraint taking place on the system due to network congestion is a separate issue to wind curtailment that would occur due to the imposition of a fixed, system-wide percentage limit on generation from non-synchronous machines, it is however not possible to determine how much the two separate issues will cause wind curtailment simultaneously without detailed modelling of a transmission grid. For this reason these issues are not considered in this paper.

6.2.3.1 System non-synchronous penetration (SNSP)

Curtailment of wind power is dependent on a number of factors such as the instantaneous system demand and the system's capacity to safely produce a certain percentage of its generation from non-synchronous sources such as wind turbines based on double-fed induction generators or high voltage direct current interconnections [21, 110]. The penetration of non-synchronous generation is described by Eqn. 6.1, and an SNSP limit may be imposed by the TSO to prevent exceedance of a certain percentage of total generation by non-synchronous sources at any one time. This constraint on non-synchronous generation is called the system non-synchronous penetration (SNSP) limit [21].

$$SNSP = \frac{wind\ generation + HVDC\ imports}{system\ demand + HVDC\ exports} \tag{6.1}$$

[3] Great Britain (GB) refers to the mainland island of Britain

Estimates for the required installed wind capacity for AI have been mainly based on the wind capacity factor for an area and also include allowances for a minimum number of large conventional generators to be on-line at all times. Excluding SNSP limits leads to an under-estimation of the required installed wind capacity for AI to meet its 2020 targets. This is a result of over-estimating the annual energy yield per MW of installed wind capacity due an under-estimate of wind curtailment.

It has been estimated that the SNSP limit will be between 60-75% in 2020, with recommendations that a SNSP of 75% could be technically achieved [21]. The issues resulting in the 75% ceiling for SNSP are associated with frequency response to disturbances and transient stability on the power system. It has been suggested that the possible curtailment of wind power or HVDC interconnector imports may be most economic solution to stability issues at certain times [121] .

It has been shown that with 5000MW of installed wind capacity on the island, negligible wind curtailment would take place if a SNSP limit of 66.6% were imposed [120]. When the installed wind capacity is increased to 9500MW wind curtailment was estimated at 14.4% of the available energy. This does not however include the non-synchronous properties of interconnection imports and assumes a much high system demand as it contains pre-recession demand projections.

Simulations run by the TSOs have shown that AI would not meet its 2020 RES-E targets with 6000MW of installed wind capacity under a 60% SNSP limit. It was found that the 2020 RES-E targets could be achieved using 6000MW of installed wind capacity with a 80% SNSP constraint, however due to grid stability reasons, the TSOs did not consider an 80 % limit to be feasible by 2020 [21]. In the same report a 7550MW wind scenario is determined to meet the targets with a 60% SNSP limit. Taking these results into account, considerable uncertainty remains over whether or not AI can achieve its 2020 RES-S targets with 5300MW of installed wind capacity when SNSP limits are taken into account. This poses the question of how much wind capacity will actually be required.

6.2.3.2 Transmission Constraint Groups (TCGs)

Another contributor to wind curtailment is the requirement that certain generators or certain numbers of a generator group to be online at certain times, embodied in the TSOs' Transmission Constraint Groups [153]. There are also constraints on generation from certain groups of generators and maximum export capacities from certain areas. Accounting for these constraints in the model allows for a more realistic power system simulation.

6.2.4 Interconnection

From Eqn. 6.1 it is evident that increasing exports to a maximum during times of high wind power penetration on the AI system will be essential in order to reduce the amount of wind curtailment necessary with a fixed SNSP limit. This raises an issue over the use of the interconnectors[4]. A major influence on Ireland's ability to export electrical energy to the British market will be Britain's targets for installed wind capacity of 27GW in a system with 113GW installed generation capacity by 2018 [61].

In addition to this the times of peak wind power on the All-island system and time difference, leading or lagging, relative to wind power peaks in Britain will also be important [56]. Previous work assumed that most of Britain's installed wind would be built onshore in Scotland but with recent developments in offshore wind, the largest proportion of the installed wind capacity will be in the North Sea with lesser amounts in the Irish Sea.

6.3 Aims

The aims of this study are: (1) to estimate the level of wind curtailment on the 2020 AI system under three different mixes of offshore/onshore wind capacities while accounting for the effects of inclusion of five different system non-synchronous penetration limits and transmission system constraints; (2) to determine the required total wind capacities under each scenario in order

[4]Interconnection between Ireland and Britain in 2020 is expected to consist of: the existing Moyle interconnector with a maximum capacity of 500MW in both directions (currently limited to importing 450MW in the winter and 410MW in the summer) [39, 59] and the East-West interconnector (EWIC) with a maximum capacity of 500MW in each direction, which was first energised in 2012.

to achieve the 2020 renewable generation targets; (3) to analyse changes in dispatch of the conventional generation portfolio due to the inclusion of SNSP and TCGs; (4) to identify the most feasible onshore/offshore wind energy portfolio to meet the 2020 RES-E target under realistic assumptions of power system operation.

6.4 The Model

The model simulates the 2020 AI electricity system and a simplified version of the GB electricity system. It includes offshore wind scenarios, SNSP constraints, predicted generation capacity on the All-island system, an aggregate form of GB generation, and incorporates wind generation time-series data.

PLEXOS® for Power Systems (Energy Exemplar Pty., Adelaide, Australia), a mixed integer unit commitment/economic dispatch modelling tool, is used to build and simulate the models. PLEXOS® determines the most economic means of production of electricity on the system within the constraints applied to the model. From this it will simulate supply, demand and prices on the electricity system. Version 6.203 (R02) of PLEXOS® was used on a Dell OptiPlex 380 Desktop with an Intel® CoreTH2 Duo Processor. The Express MP solver was used using Mixed integer programming at a relative gap 0.05%. Single runs of all scenarios took approximately 20 hours to solve. PLEXOS® has been used in other studies examining the impacts of energy storage, high wind penetration and wave power on electricity systems and markets [37, 165, 166].

The model consists of a short-term schedule that optimises each of the 366 days in 2020 on the 30 minute intra-day trading period. It has a six-hour look-ahead period where forced outages and wind variability are known. The scheduling method replicates the Single Electricity Market (SEM) dispatch scheduling, helping to give accurate results for the dispatch of generators on the AI power system [12]. Maintenance outage rates were also applied to all generators.

6.4.1 Model description

The simplified mixed integer linear programming formulation for dispatchable units is:

$$min \left\{ \sum_{t=1}^{48} \left\{ \sum_{i=1}^{N} d_i \, C_i(P_i) \right\} + C_{uplift} \right\}, \; d_i \in \{0,1\}$$

subject to the constraints:

$$\sum_{i=1}^{N} P_i = P_d$$

$$P_i^{min} \leq P_i \leq P_i^{max}$$

where d_i is a binary quantity indicating whether a unit has been scheduled (1) or not (0), C_i is the unit generation cost of unit i, P_i is the unit power generation, P_d the system demand, N the number of dispatchable generation units, P_i^{max} and P_i^{min} the unit power output limits, i the index of generation units, and C_{uplift} is the uplift cost which is determined from start-up, no-load and other fixed costs. Additional constraints on unit ramp-up and ramp-down rates, minimum on and off times are not shown here.

6.4.2 Scenario Descriptions

The AI system's three assumed offshore wind scenarios represent low, medium, and high offshore wind penetration levels with installed capacities of 25.2MW, 850MW and 1300MW respectively with the remainder of the installed wind capacity onshore to meet the 2020 renewable targets. Within each of the three offshore wind scenarios there will be five thresholds applied for SNSP limits on the AI system. These are limits of 60%, 65%, 70%, 75% and 100% of total generation from non-synchronous machines on the system at any time (Eqn. 6.1). The SNSP limit of a 100% is only included as a comparison case. In addition to the 15 offshore wind and SNSP sub-scenarios described above there will be five more sub-scenarios consisting of the medium offshore wind scenario on all the SNSP limits where the TCGs will be excluded from the model in order to allow for the contribution to wind curtailment from SNSP limits to be quantified separately. The conventional generation capacity and all non-wind renewable generation capacity remains unchanged for all scenarios.

The low offshore scenario is essentially a "baseline scenario" consisting only of the 25.2MW of installed offshore wind capacity that currently exists. This is from a single windfarm at Arklow Bank. For this scenario it is assumed that no more offshore wind will be developed in AI prior to 2020 and the 2020 RES-E targets will be met almost entirely by onshore wind developments.

The medium offshore scenario consists of 850MW installed offshore wind capacity. This is an amalgamation of the NREDP recommendations and half of the offshore wind portion of the Crown Estate's NI round, consisting of 550MW and 300MW respectively. Dublin Array and Oriel offshore wind farms are reduced proportionally in capacity, by 278MW and 245MW respectively, to make up the ROI contribution. The NI contribution will consisted of a single proposed offshore wind farm off the Co. Down coast in NI.

The high scenario consists of 1300MW installed offshore wind capacity. This is a amalgamation of the upper limit recommended by Eirgrid for installed offshore wind in the ROI and the full offshore wind portion of the Crown Estate Northern Ireland licencing round, or 684MW and 600MW respectively. The Dublin Array and Oriel offshore wind farms make up the ROI contribution and two 300MW proposed offshore wind farms off the Co. Down coast fulfil the NI contribution.

6.4.3 All-island generation

The generation portfolio reflects the predicted development of the AI generation mix by 2020 which is based on [39], with some minor changes due to the exclusion of a small proportion of non-wind renewable generation. The conventional generation portfolio has been developed from the Single Electricity Market Operator (SEMO) forecast model of 2011-2012, created by Redpoint Energy Ltd [158]. Generator synchronisation time, "must-run" units and modified start-up costs with additional off-take fuel[5] based on recent market data have been added as additional constraints to the models.

[5]The quantity of fuel required for the generator to go from cold to synchronous to the grid, allowing for addition of the carbon tax to start-up costs

6.4.4 Non-wind renewable sources of electricity

The four existing conventional large hydroelectric power stations in ROI with a total capacity of 218MW are expected to produce on average 1.5% of AI 2020 system demand [66]. Under [39] generation from waste is considered to be 50% renewable and with 77MW installed by 2020 this will produce 0.6% of total generation in AI. The 118 MW peat-fired power station at Edenderry in ROI will be 30% co-fired with biomass, equating to about 0.6% of 2020 AI total generation. Tidal sources are predicted to contribute 0.2% of total generation for AI. Tidal generation was simulated by a periodic oscillation of period 12 hours and 25 minutes, modified to represent the non-linear correlation between fluid velocity and power extraction, and to achieve an overall 20% capacity factor associated with tidal energy [39].

This results in a total mean annual electrical energy contribution from non-wind renewable sources of 2.9%. This then leaves 37% of generation to come from wind energy in order for AI to meet the 2020 targets.

The other renewable sources that are highlighted in [39] but excluded from the model, are as follows: biomass CHP in ROI (2.4%); biomass in NI (1.5%); bio-fuel in NI and ROI (1.0%); marine (wave) in ROI (0.3%). These generator types were excluded due to the present lack of development or planning permission activity in these categories.

6.4.5 Wind generation

For a realistic simulation of wind generation, it is important to capture the spatial and temporal variability of the resource. Therefore, wind generation was aggregated on a regional basis (Fig. 6.1), based on hourly resolution time-series for multiple wind regions across the island developed by Eirgrid for use in [158]. These data were based on the year 2008 as it was determined to be a mean wind speed year. New time-series to represent additional offshore regions which were added to the model so that it consisted of 14 onshore wind regions and six offshore wind regions.

6.4.5.1 Onshore wind

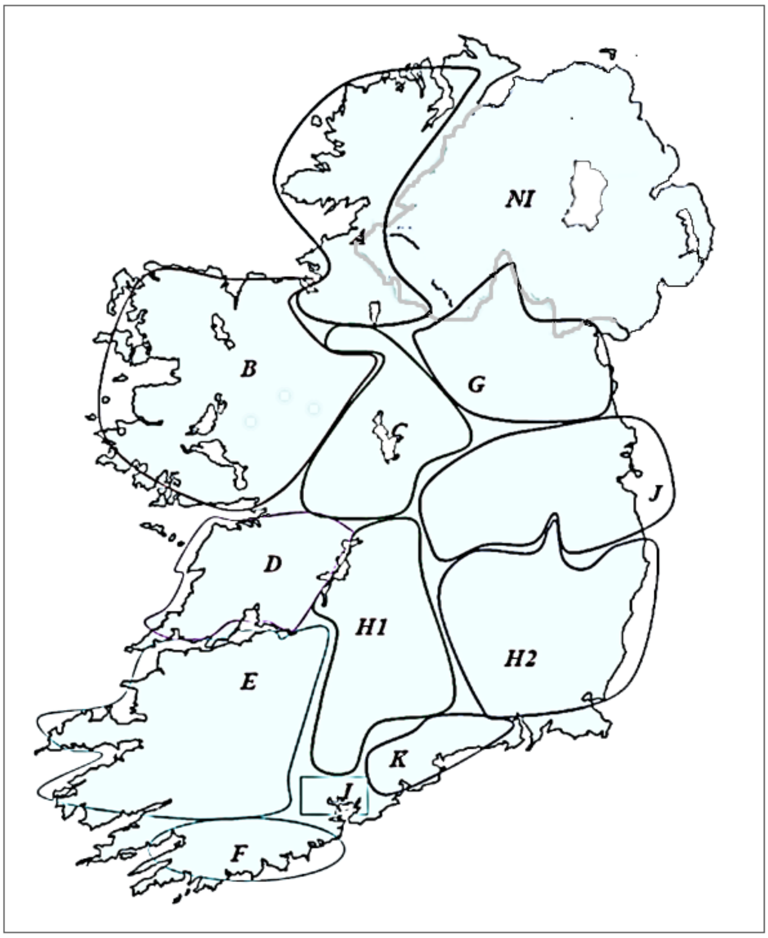
The AI onshore wind capacity consisted as of October 2011 of 1991MW of installed wind farms and 1875MW of planned wind farms [39]. Knowledge of wind farm locations allowed for the installed capacity of each wind region profile to be calculated at present and for the future planned installations. However this only comes to a total installed capacity of 3866MW, which is not sufficient for meeting the 2020 renewable generation targets.

The installed capacity of each wind region was therefore linearly scaled up in order to meet the target amount, with the exception of Region E (Kerry/West Cork). Region E has a total existing and planned installed wind capacity of 1036MW which is reaching its export limit due to transmission constraints (assuming eight 110kV lines at an average rating of 120MW). The final total wind capacity was determined by an iterative process in order to obtain the required capacity to achieve 37% of total generation for AI from wind.

A further requirement was imposed that 37% of generation must come from wind for both jurisdictions NI and ROI independently. This results in the onshore wind capacities being adjusted to take account of the varying amounts of offshore wind installed in each jurisdiction under each of the three offshore wind scenarios. The relationship between the installed wind capacity and the balancing of generation in the two jurisdictions is almost linear in nature, this resulted in a simple manipulation of the data to reflect the annual proportion of the total system demand requirement by NI and ROI from AI. The percentage of installed onshore wind in each wind region is shown in Table 6.2.

6.4.5.2 Offshore Wind

With only a single, small operational offshore windfarm on the AI system, there is a lack of representative data for offshore wind generation. Therefore, time-series for the offshore wind regions presented in this model were modified from those of neighbouring onshore wind regions. The onshore regions' wind time-series data were converted into a power duration curve and scaled to achieve a representative 40% capacity factor for offshore, (Fig. 6.2), using Eqn. 6.2 before being converted back to time-series. Due to Ireland's predominantly westerly wind, offshore data was time lagged or led



Reproduced from [158]

Figure 6.1: Eirgrid wind regions

by one hour with respect to the neighbouring onshore region to reflect this (cf. [56]). This resulted in the offshore wind regions data on the east coast of AI being time-lagged by one hour relative to their respective onshore wind regions, and the single offshore wind region off the west coast of AI being time-led by one hour.

$$CF_{OF,n} = CF_{ON,n}\left(\left(\frac{a}{1-N}\right)n + a + 1\right) \tag{6.2}$$

Where CF_{OF} and CF_{ON} are the capacity factors offshore and onshore respectively, a is a scaling factor, chosen to achieve a 40% capacity factor, n is the interval number and N is the number of interval points.

Table 6.2: The regional breakdown of wind capacities across onshore wind regions for the three wind scenarios.

	Offshore scenario		
Wind region	**Low** (%)	**Medium** (%)	**High** (%)
A	12.3	12.7	13.4
B	8.7	9.0	9.5
C	0.7	0.7	0.8
D	8.0	8.3	8.7
E	16.5	17.1	18.0
F	2.7	2.8	3.0
G	3.5	3.6	3.8
H1	9.9	10.3	10.9
H2	8.9	9.2	9.7
J	2.0	2.1	2.2
K	0.5	0.5	0.6
NI	26.2	23.6	19.4

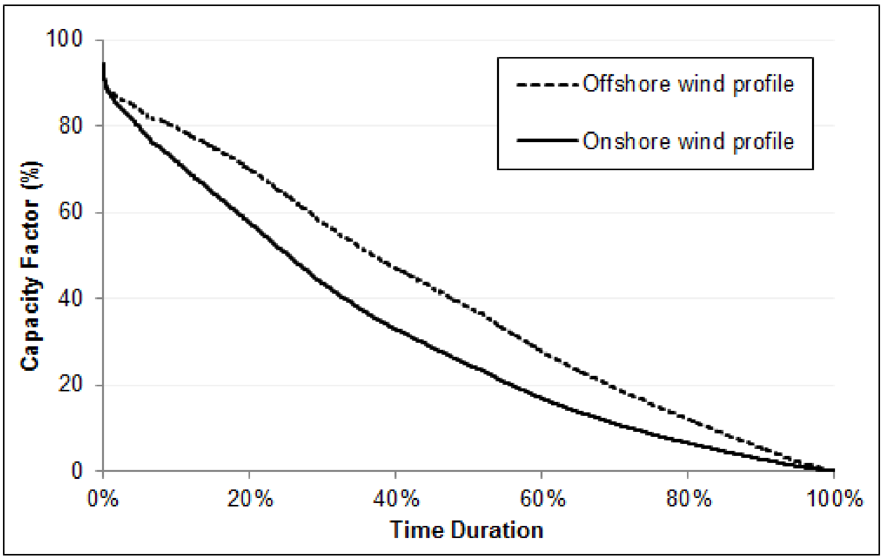


Figure 6.2: Wind power duration curves for one onshore region and the corresponding adjusted offshore region.

6.4.5.3 Spatial correlation of wind regions

The Pearson product-moment correlation coefficient, R, was used to determine the spatial correlation of the regional wind time-series with respect to each other. Correlation coefficients between pairs of onshore wind regions were in the range 0.51-0.90. The correlation coefficients between the manipulated offshore wind regions (G_{OF}, J_{OF}, NI_{OF} and their respective neighbouring onshore wind regions (G, J, NI) were in the range 0.94-0.97. The lowest correlation (R = 0.51) occurred between two onshore regions, A and E, both of which have considerable installed capacity and are separated by a

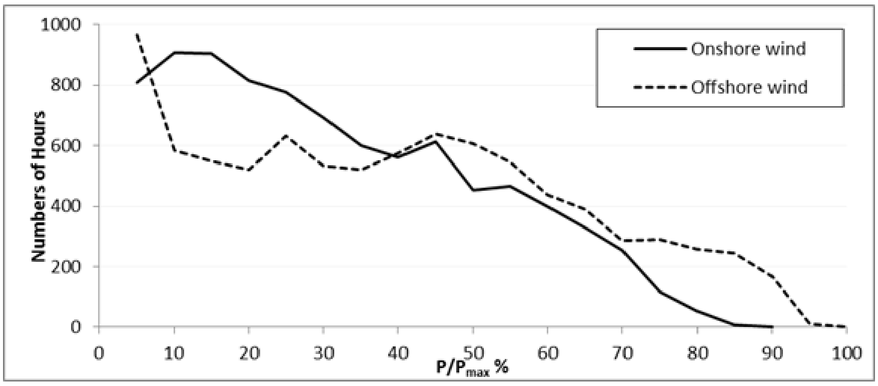


Figure 6.3: Wind generation duration curves for aggregated onshore and offshore power, net of curtailment, for the high offshore wind scenario with a SNSP limit of 70%.

large north-south distance. From this it is clear that the adjustments made to create the offshore wind data can be viewed as conservative in terms of the likely effects on wind curtailment.

There is a clear indication from aggregated onshore and offshore duration curves (Fig. 6.3) that offshore wind suffers less curtailment during periods of high wind generation than onshore wind. This is a result of the greater overall spatial dispersion of wind capacity when more wind capacity is located offshore.

6.4.6 Great Britain generation

Due to the approximately 950MW of interconnection capacity between AI and GB expected to be in place by 2020, it is necessary to simulate a simplified GB system in order to replicate the power flows on the two interconnectors. This was achieved by creating a GB generation system large enough to export to AI and, in doing so, creating a price differential across the interconnectors. The GB replica generator is increased in capacity from that of [158] in order to meet the import requirements of the AI system. To simulate the fluctuations that will result from the large amount of proposed GB wind capacity, a single, large wind generator is added. The GB wind generator takes account of the planned installation of GB wind capacity in 2020 by being the same size proportion to that of the conventional generation plant [61]. The GB wind generator is based on data taken from the wind region J and is time lagged by 2 hours, consistent with the findings of [56]. This gives a truer reflection of the interconnector usage when there is excess wind power available for export.

6.4.7 Transmission Constraints

The AI model consists of two separate nodes representing the NI and ROI systems, which results in the NI and ROI systems being effectively unconstrained. To take account of constraints between and within the two electricity systems, limitations were imposed on generators due to transmission constraints and system stability requirements which are embodied in the TCGs implemented by the TSOs [153].

The assumption was taken to retain all the TCGs unchanged in the 2020 system with one exception. The decision not to modify the majority of the TCGs was due to the difficulty in predicting which TCGs will be relaxed, assuming that the current plans to strengthen the transmission grid will take place [116]. The TCG that was considered likely to change was the restriction of flow between NI and ROI as it is planned to have the North-South interconnetor in place by 2020. Currently flow is restricted to 450MW in the NI-ROI direction and 400MW ROI-NI due to system security issues, however the full rating of transmission lines joining the NI and ROI grids in 2020 could equate to at least 3768MW [167]. The model accommodates this by allowing flows of 2000MW both ways between the NI and ROI grids.

All TCGs in the model are represented by soft constraints which incur a penalty price if violated. The penalty prices were set in order to only allow violation of the constraints for a maximum of a 100 hours of the year. As a check, TCGs were also modelled as hard constraints in order to determine if any infeasible solutions would occur. All resulting changes were negligible and therefore ignored. The model also includes modified Transmission Loss Adjustment Factors (TLAF) to account for transmission losses within the system [168]. This is not ideal as they do not reflect the 2020 grid entirely accurately, but does allow a representation of likely grid losses within the model.

6.4.8 System demand

We assumed an increase of 17% in system demand over the time frame of 2010-2020. This was applied by means of a linear scaling to the AI system demand time-series for the year 2010 from [158]. The system demand of both jurisdictions, NI and ROI, are modelled as percentages (25.8% and 74.2%

respectively) of the AI system demand time-series data in order to allow for each jurisdiction to be treated separately to ensure compliances with the RES-E targets and a more accurate model representation. The increase in total electricity requirement was taken from a median growth projection scenario [39]. This takes account for the latest reduced projections in demand growth due to the recession in the NI and ROI economies.

6.4.9 Costs Information

Fuel prices are based on predictions for of 2020 from [58]. This also correlates with the 2020 base case in [169]. This has a direct influence on the annual mean system marginal price (SMP), however more crucially it also has a direct influence on the dispatch of the different types of generation plant technologies. This is particularly acute in the relationship of the price of coal and gas. A carbon tax of €25/tonne CO_2 was applied to fossil fuel burning plant [66]. Generator start costs, including fuel take-off were included, allowing for the total carbon tax to be applied and the uplift cost to be calculated.

6.5 Results

The level of wind curtailment is evaluated for all 20 sub-scenarios, these consisting of three offshore wind scenarios all with TCGs imposed, and an extra case of a medium offshore wind scenario without TCGs. The four scenarios of offshore wind and TCGs then have five SNSP limits imposed on them (60%, 65%, 70%, 75% and 100%). There is a binding constraint in all scenarios that the 2020 RES-E target must be met, meaning wind generation will equal 37% of total generation, within a tolerance of 0.1%. The installed onshore wind portfolio is scaled to achieve this in each case. This enables a clear results comparison between the different sub-scenarios and ensures the elimination of bias. The installed wind capacities are shown in Table 6.3, and the wind curtailment resulting from the installed wind capacities chosen is shown in (Fig. 6.4).

Total non-renewable generation duration curves are shown in Figs. 6.5 to illustrate the variations in the sub-scenarios of the use of generator plant type

Table 6.3: The AI onshore wind capacities of the offshore wind scenarios, including and excluding TCGs under the different SNSP limits.

	Offshore scenario			
	Incl. TCGs			Excl. TCGs
SNSP	**Low** (MW)	**Med** (MW)	**High** (MW)	**Med** (MW)
All-island				
60%	6865	5760	5199	5388
65%	6512	5747	4878	5040
70%	6324	5248	4643	4833
75%	6262	5193	4602	4710
100%	6273	5212	4614	4545
Republic of Ireland				
60%	5069	4351	4155	4085
65%	4815	4382	3945	3871
70%	4673	3974	3748	3728
75%	4630	3927	3714	3638
100%	4609	3907	3686	3502
Northern Ireland				
60%	1796	1408	1044	1303
65%	1697	1365	933	1169
70%	1651	1274	895	1105
75%	1632	1266	888	1072
100%	1664	1305	929	1043

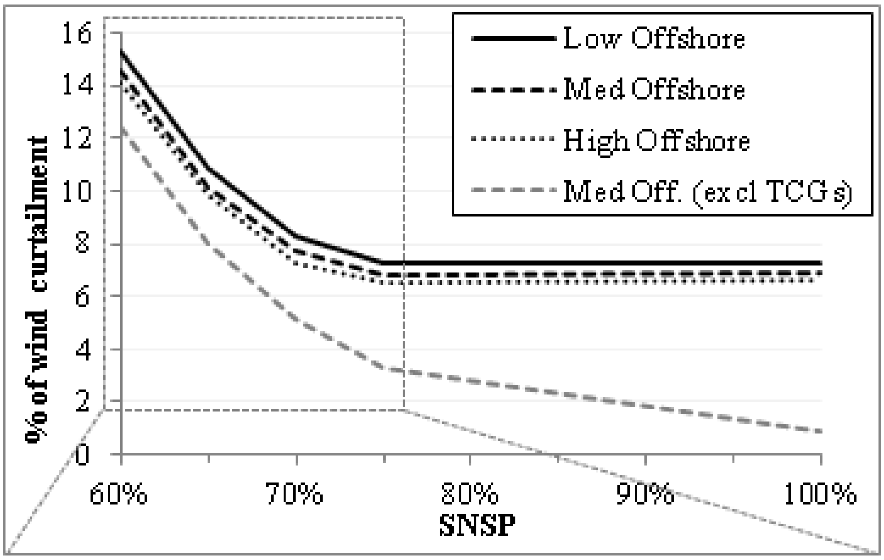
Table 6.4: The assumed AI, ROI and NI offshore wind scenarios installed capacities

	Offshore scenario			
	Incl. TCGs			Excl. TCGs
Region	**Low** (MW)	**Med** (MW)	**High** (MW)	**Med** (MW)
AI	25.2	848.2	1309.2	848.2
ROI	25.2	548.2	709.2	548.2
NI	0	300	600	300

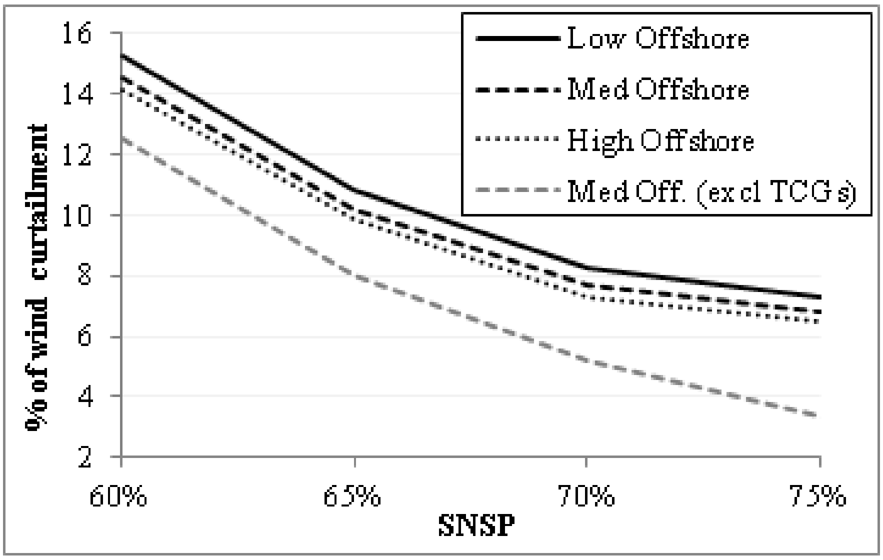
(Base plant, Mid-merit, Peaker plant). Base plant comprises all coal generation, the remaining oil plant, all peat generation, all conventional hydro generation, waste to energy generation, the gas fuelled steam turbine and CHPs. Mid-merit generation consists of all existing CCGT and a new CCGT to be constructed at Great Island. Peaker plant is a collection of all gas and distillate fuel OCGTs, both existing and planned, as well as the one pumped-hydro energy storage plant.

Table 6.5: The percentage of wind curtailment on the AI system for the offshore wind scenarios, including and excluding TCGs, under various SNSP limits.

	Offshore scenario			
	Incl. TCGs			**Excl. TCGs**
SNSP	**Low** (%)	**Med** (%)	**High** (%)	**Med** (%)
60%	15.3	14.5	14.1	12.5
65%	10.9	10.2	9.9	8.0
70%	8.3	7.7	7.3	5.2
75%	7.3	6.8	6.5	3.3
100%	7.2	6.9	6.6	0.9



(a)



(b)

Figure 6.4: Wind curtailment for offshore wind scenarios, including and excluding TCGs: (a) versus SNSP limits of 60-100%; (b) versus SNSP limits of 60-75% ("b" is a detail of "a"). Installed wind capacity satisfying 37% of system generation for all scenarios.

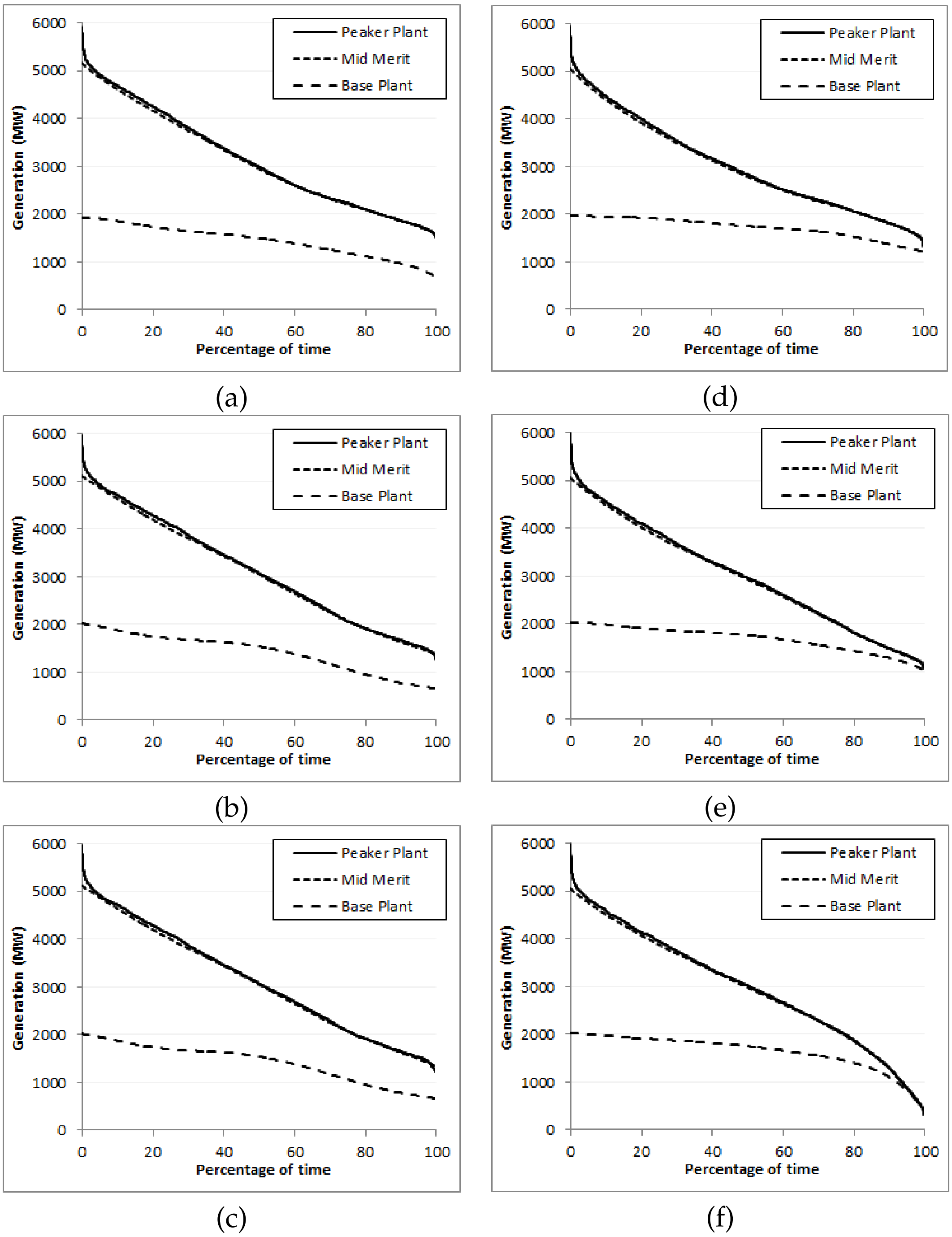


Figure 6.5: On the left the load duration curves showing use of different conventional plant type for the medium offshore wind scenario including TCGs. (a) at SNSP of 60%, (b) at SNSP of 70% & (c) at SNSP of 100%. On yhe right the load duration curves showing use of different conventional plant type for the medium offshore wind scenario excluding TCGs: (d) with an SNSP limit of 60%; (e) SNSP limit of 70%; & (f) SNSP limit of 100%.

6.6 Discussion

The primary result from this work is an estimate of the required installed wind capacities for both NI and ROI to meet their 2020 RES-E targets. It is evident that this varies greatly due to the large differences in wind curtailment that will occur based on the assumptions made. The required capacity estimates range from 5911MW to 6890MW which results in extra cost of €459 million between what is considered to be the lowest technically feasible wind curtailment scenario (high offshore wind at SNSP limit of 75%, including TCGs) to that of the highest (low offshore wind at SNSP limit of 60%, including TCGS)[6]. In the context of the electricity system this is a considerable extra expense similar in magnitude to the cost of two of the proposed North-South interconnector between NI and ROI [171]. This illustrates the importance of increasing the SNSP limit as high as technically and economically feasible.

Assuming the medium offshore wind scenario is the closest reflection of the future generation portfolio identified in [39], the required wind capacity differs between the latter and this study. For ROI there is an assumed wind capacity requirement for 2020 of 3500-4000MW, which is short of the highest assumed feasible SNSP limit requiring 4475MW. When considering NI there is an assumed wind capacity requirement for 2020 of 1278MW, which is short of the 1566 MW required under the highest assumed feasible SNSP limit. The required wind capacity figures identified in [39] do account for other renewable sources not included in our model which do bring the results closer together, however with the present lack of activity around the non-wind renewable sources it has to be assumed that wind energy will have to replace the shortfall in other renewable electricity generation in order to meet the 2020 RES-E targets.

6.6.1 Wind curtailment

Assuming again that the medium offshore wind scenario represents the most likely outcome of the wind scenarios in 2020. There is a dramatic reduction in wind curtailment, from an average of 14.5% to 6.8%, with an increase in the

[6]The assumed cost of an installed MW of wind is 1.23 million €/MW for onshore wind (2006 prices) and 1.81 million €/MW for offshore wind (2015 prices) from [170].

SNSP limit from to 60% up to 75%. This reduction in wind curtailment allows for an average reduction in installed wind capacity of 567MW.

The inclusion of the TCGs, which in their present form prevented a further reduction in wind curtailment beyond the 75% SNSP limit, is a notable result. This is a result of a minimum number of generators being forced to remain on-line generating at their minimum stable capacities. This result differs from those of other studies in the area [117, 15, 118, 119]. The inclusion of TCGs in the model resulted in a minimum wind curtailment occurring of at least 6.5% irrespective of the SNSP limit imposed.

Comparing wind curtailment for the medium offshore wind scenario with and without TCGs the SNSP limit imposed contributes to the majority of wind curtailment between the SNSP limits of 60-70%. However the TCGs contribute to the majority of wind curtailment between the SNSP limits of 70-100%. This was an unexpected result and indicates that both the TCGs as well as the SNSP limit are of equal importance in affecting wind curtailment.

There is a further clear reduction of 1-1.5 percentage points in wind curtailment if the proportion of offshore wind is increased. This is largely a result of the wider geographical spread of installed wind capacity, and the assumed 40% offshore wind capacity factor, which is higher than that of the onshore regions.

6.6.2 Conventional generator dispatch

It must be noted that running the model with inclusion of TCGs is not reflective of the true operation of the market, as it is optimised on a purely economic means assuming an unconstrained grid. The main changes to the dispatch of the conventional generators result from the inclusion or exclusion of the TCGs in the model scenarios. These changes occur at the times of the lowest point of allowable conventional generation and a change in the portions of generation from mid-merit and base load plant with respect to each other.

There is notable difference in the minimum amount of conventional generation occurring in the extreme SNSP limit of 100% with and without TCGs in Figs. 6.5(c) & (f). It is a large assumption to make to allow all conventional generation to be off line at certain times but it is useful as a comparison case. The other large difference in conventional generator dispatch is the relative proportion of generation from mid-merit and base load plant in (Figs. 6.5 a-c & d-f). This is a result of the TCGs controlling the use of the CCGTs for system stability issues in the 80%-100% time range.

6.6.3 Problems in over-estimation of wind curtailment

The times of peak wind power on the AI system relative to the time difference, leading or lagging, of wind power peaks in GB will also be important. The assumption for GB wind data that it is at a constant time lag of two hours to that of a AI wind region may result in an over-estimate of wind curtailment. This is due to the usage of the interconnections being restricted in times of peak wind generation in Ireland when in fact peak wind generation in GB may have occurred slightly earlier.

It would be reasonable to assume that there will be relaxations of the TCGs in the future. This could be justified by the transmission grid reinforcement plans in place, use of the East-West interconnector, and more control and monitoring by the TSOs of the transmission and distribution grids. The exclusion from the model of some of the non-wind renewable sources in [39], leads to a higher percentage of total generation coming from wind energy and therefore higher amounts of wind curtailment occurring in order to fulfil the 2020 RES-E targets.

6.6.4 Problems in underestimation of wind curtailment

Incorporation of the AI transmission grid into the model may also have added to curtailment as the grid is weak in western parts of ROI, where the largest proportion of wind will be installed. In this model, it assumes perfect foresight on wind generation but in reality this is not the case. As a result there will be an increase in the reserve requirements of the system in-order to maintain the required loss of load probability (LOLP). The creation of the day ahead dispatch schedule by the System Operator uses forecast wind generation to estimated the required conventional generation plant to be informed of there dispatch in advance. Due to the increased requirement for system reserve the AI system may require more generators operating at their minimum stable level at times of high wind power penetrations resulting in additional wind curtailment. With the increasing complexity of the transmission system, new TCGs will become necessary in the future.

6.7 Conclusion

Taking account of issues causing wind curtailment on the 2020 Irish electricity system dramatically increases the amount of installed wind capacity required to meet the renewable targets. There is also large variation (5911MW to 6890MW) in the amount of installed wind capacity required which depends on the assumed system non-synchronous penetration (SNSP) limits that maybe imposed and the proportion of wind that is installed offshore in the future.

Wind curtailment is shown to drop from an average of 14% to 7%, as the SNSP limit is raised from to 60% to 75%. The contribution of offshore wind also is shown to help in the reduction of wind curtailment, removing at least one percentage point of curtailment in going from the low to high offshore scenarios. The wider spatial spread of wind turbines and higher overall capacity factors due to increased offshore wind installation are the main contributors to reducing the wind curtailment occurring on the system as a whole.

A more detailed study on the technically and economically achievable limits of non-synchronous generation on the Irish electricity system is crucial to minimise the associated costs of wind curtailment by means of increasing the SNSP and maximising wind integration.

Chapter 7

Cost savings from relaxation of operational constraints on a power system with high wind penetration

7.1 Abstract

Wind energy is predominantly a non-synchronous generation source. Large-scale integration of wind generation with existing electricity systems therefore presents challenges in maintaining system frequency stability and local voltage stability. Transmission system operators have implemented system operational constraints (SOCs) in order to maintain stability with high wind generation, but imposition of these constraints results in higher operating costs. A mixed integer programming tool PLEXOS was used to simulate generator dispatch in order to assess the impact of various SOCs on generation costs. Interleaved day-ahead scheduling and real-time dispatch models were developed to allow accurate representation of forced outages and wind forecast errors, and were applied to the proposed Irish power system of 2020 with a wind penetration of 32%. Savings of at least 7.8% in generation costs and reductions in wind curtailment of 50% were identified when the most influential SOCs were relaxed. The results also illustrate the need to relax local SOCs together with the system-wide non-synchronous penetration limit SOC, as savings from increasing the non-synchronous limit beyond 70% were restricted without relaxation of local SOCs. The methodology and results allow for quantification of the costs of SOCs,

allowing the optimal upgrade path for generation and transmission infrastructure to be determined.

7.2 Introduction

The link between global warming and man-made emissions is becoming more evident with time [3]. The dependence of EU member states on imported energy in the form of fossil fuels has given rise to EU policies to reduce the overall carbon intensity of energy usage, such as [4]. As part of this policy, the Republic of Ireland (ROI) and Northern Ireland (NI) have agreed to generate 40% of their electricity demand from renewable sources by 2020 [5, 7]. The generator technology type that will be used to deliver the majority of this target will be wind power [9]. This will result in a very large proportion, in the region of 30-37%, of all-island of Ireland (AI)[1] electricity coming from non-synchronous sources by 2020. There is no precedent for a system of this size to have such a level of non-synchronous generation without AC links to neighbouring systems. This has led to a situation where the ROI and NI transmission system operators (TSOs), EirGrid and SONI respectively, have implemented system operational constraints (SOCs) [78] in order to maintain acceptable levels of system stability.

7.2.1 System operational constraints

The effects of large penetrations of wind energy in electricity systems have been extensively studied in recent years [15, 16, 17, 86, 18, 19, 20, 21, 22]. As wind energy penetration begins to reach the technical limits of what is possible on present-day electricity systems it is becoming evident that more research is needed in relation to allowing higher levels of non-synchronous sources of electricity on to the system. This is necessary as AC systems require some amount of conventional synchronous generation on-line at all times in order to maintain overall frequency stability as well as local voltage stability.

It is shown in [21, 80] that issues such as frequency response and voltage control result in the requirement for incorporating SOCs [78] in dispatch

[1] All-island of Ireland (AI), consisting of Northern Ireland (United Kingdom) and the Republic of Ireland

modelling. The system frequency must be maintained within certain limits in the event of a loss of generation. This is achieved by maintaining synchronous generation machines online to provide inertia to the system. The majority of wind turbines, being non-synchronous double-fed induction machines (DFIGs) or full-converter machines, are not capable of providing inertia to the system [82]. Voltage control is important as it affects the efficiency of the transportation of the electricity. Voltage stability is maintained by the balancing of reactive power, mainly through the use of synchronous generation sources. Modern wind turbines may also produce reactive power but with less flexibility than conventional generators [84]. These problems lead directly to the need to maintain minimum numbers of conventional generators on-line in different parts of the AI system as well as system-wide limits on the relative proportion of non-synchronous sources of generation at any point in time as stated in [78]. It has been predicted that the permitted limit of system non-synchronous penetration (SNSP) on the AI system (Eqn. 7.1) will be raised to a value between 60-80% by 2020, with recommendations that a SNSP limit of 75% could be technically achieved [21]. The factors contributing to the SNSP limit are associated with frequency response and voltage control in the presence of disturbances to the system.

It is viewed by EirGrid that as wind penetration increases, and if the network and market designs are not changed, that problems such as escalating constraints payments due to divergences between the unconstrained market model and the constrained dispatch model will emerge [88]. Previous studies have included SOCs in the form of a minimum conventional generation requirement [15, 16, 18, 19, 22] and studies that have not included these constraints have recognised their potential impacts on results [17, 86, 20, 23, 25, 24]. So far, the only study that has assessed the impact of relaxing these constraints in terms of wind curtailment and costs is [16], which looked at such effects on the NI system. It has also been shown in [22] that SOCs in the AI system will have a dramatic effect in terms of wind curtailment and generator dispatch in the future.

$$\text{SNSP} = \frac{wind\ generation + HVDC\ imports}{system\ demand + HVDC\ exports} \tag{7.1}$$

where: SNSP is the system non-synchronous penetration, the instantaneous percentage of non-synchronous generation on the system; and HVDC refers to flows on high voltage direct current interconnectors.

It is shown in [16] that relaxing the NI constraint requiring three large generators to be on-line at all times to two generators on-line results in wind curtailment dropping from 7.5% to the region of 1.5-5% and also indicates possible increases in OCGT generation. In [18] it was assumed that a minimum of 400MW of conventional generation is presently required on the Western Denmark system, but by 2025 it was assumed that 300MW would be sufficient due to stronger interconnection with neighbouring regions. This assumption was taken from [19] where the year 2008 was examined to find the lowest instantaneous level of conventional generation during periods of excess wind energy generation, which resulted to be 415MW. This was then assumed as a minimum technical feasible state of system operation. However, in 2012 wind generation in Western Denmark has been allowed to exceed demand through the use of interconnectors to export surplus generation [20]. The AI system has only two high voltage direct current (HVDC) interconnectors to the neighbouring Great Britain (GB) system with a combined capacity of approximately 950MW. This results in a situation where there is no reactive power or inertia support from neighbouring electricity systems [80]. Therefore care should be taken when comparing the SOCs assumptions of AI [78] to those of Western Denmark [19] due to the latter system's use of synchronous compensators as well as its strong AC interconnection to its neighbours, thus providing stability support.

An unspecified minimum number of large base load generators were required to be on-line at all times in the AI model of [15] in order to maintain sufficient inertia and reactive power. For NI, an examination of the effects of variable generation on conventional generators is shown in [25] and there is also a recommendation made for further research into the effects of the requirement for three large generators to be on-line at all times. While a "minimum on" constraint was not included in [23, 24], it is stated in [24] that such constraints would increase wind curtailment. In [23] the exact minimum required number of on-line generators was not obvious and therefore was neglected but recognised that its inclusion would increase wind curtailment. In studies of the GB system it is recognised that a minimum amount of conventional plant running at all times will be necessary to provide frequency response and also due to inflexible must-run units such as the nuclear plants which will result in wind curtailment [17]. The modelling of the AI Single Electricity Market (SEM) includes a "minimum on" inertia constraint [26], however such a constraint on the GB system is not included in the same study.

In a European-wide context it is recognised in [86] that wind curtailment may become necessary in central and northern Europe when a minimum number of on-line conventional generators is reached during high wind and low demand periods, in order to provide adequate response and reserve on the system. A review of several countries carried out by [20] recommended that further research be performed into issues associated with wind curtailment and states that wind curtailment resulting from the minimum stable generation limits of conventional generators will be a issue in the future as inertia requirements and frequency response of systems may suffer as wind penetrations increase.

7.3 The Model

7.3.1 System Operational Constraints (SOC) Relaxation Scenarios

The objective of this scenario selection was to illustrate the effects of the relaxation of the five most influential SOCs listed in [78] which are shown in Table 7.1 in descending order of influence. The reader is referred to [78] for detailed descriptions of the individual SOCs. The five most influential SOCs were determined by quantifying the time each SOC spent in a binding position in the simulation of the base case model. The degrees to which the SOCs were relaxed are shown in Table 7.1. The four SOCs, shown together in Table 7.1, are constraints requiring minimum numbers of certain groups of conventional generators to be on-line at all times. These are "Dublin Generation" and "NI-North West Generation", for voltage control in their respective areas, followed by "NI-System Stability" and "ROI-System Stability" to ensure a sufficient amount of inertia is maintained on their respective systems. In contrast to the SOCs described above is the "Non-Synchronous Generation" constraint, applied for frequency stability reasons. This is a AI system-wide restriction on the percentage of non-synchronous generation, and was progressively relaxed from the base-case value of 60% to 80% [21] in steps of 5%, resulting in five SNSP scenarios.

A base-case scenario was developed from [78] in which likely changes

Table 7.1: Base case and relaxed system operational constraints scenarios

Constraint	Code	Base-case	Relaxed
Dublin Generation, min-on	Dub(2/3)	2/3 (day/night)	1/2
NI-NW Generation, min-on	CPS(1)	1	0
NI-System Stability, min-on	NI-s(3)	3	2
ROI-System Stability, min-on	ROI-s(5)	5	4
Non-Synchronous Generation	SNSP	60%	65-80%

between the present day and 2020 were made to the SOCs. The changes are as follows: for AI constraints the “Inter-Area flow” is assumed to be at 2000MW both ways due to the proposed North-South interconnector being in place [9]; for the NI constraints the “Ballylumford Generation” and “Moyle Interconnector” constraints are ignored due to assumptions that transmission grid restrictions that give rise these constraints will be mitigated through upgrades by 2020. The ROI “Replacement Reserve” constraint is increased to allow a maximum OCGT generation of 1034MW, this still keeps 300MW in reserve due to new OCGT generation to be added by 2020.

It was first necessary to determine the influences each of the five chosen SOCs have in isolation on the AI system. This was achieved by individually relaxing the four “minimum number of conventional generators on-line” constraints for all five SNSP values, the results of which are shown in Figs. 7.2 and 7.3.

The large number of combinations of constraint relaxation scenarios possible with five individual SOCs to be relaxed and five SNSP limits necessitated reducing the number of scenarios examined. Therefore due to limitations on computational power available, a SOC relaxation path was identified, based on relaxing the SOC with the highest associated cost saving first, followed by relaxation of the SOC with the second highest associated cost, etc. The path continued to the relaxation of the final constraint where all four “minimum number of conventional generators on-line” SOCs are relaxed. This scenario path was applied for each of the five “SNSP” constraint limits from 60-80% [21] in steps of 5%. For each SNSP scenario the other four SOCs are relaxed in order of influence on system operating costs (Dub(1/2), CPS(0), NI-s(2) and ROI(4)), as shown in Table 7.1. This gives a full set of 20 scenarios showing the combined effects of relaxing the SOCs.

7.3.2 Scheduling

To simulate the effects of wind forecast errors and forced outages an interleaved simulation was created where two models run in step with each other. A day-ahead (DA) model and a real-time (RT) model pass information back and forth to each other in PLEXOS and allow for detailed simulation of the real running of the AI electricity system. Both models optimise on a short-term schedule of 366 single-day steps with each day divided into 48 half-hour intervals plus six 1-hour look ahead intervals. This method of simulation replicates the inter-day trading of the Single Electricity Market (SEM) [12].

Due to prior knowledge, the maintenance schedules for the generators are included in the DA run, however the forced outages are not. The same maintenance profile with the addition of forced outage profiles is used in the RT model. Both the maintenance and forced outage profiles are created in the base case scenario and then fixed for all scenarios. This is necessary to avoid differences occurring between the simulations that may distorted results.

7.3.2.1 Day Ahead, Real time model interactions

The function of the DA model is the creation of the DA UC schedule and IC generation schedules. The DA model receives only the maintenance outage schedule (no forced outages applied) and a wind forecast with an annual mean absolute error of 6%. Scheduling of the DA model is carried out stochastically to account for the uncertainty in wind forecasts as shown in Fig. 7.1 and described in [172].

The DA UC schedule locks all the large generators on the SEM into a constraint that they must be on-line at the times in which the DA UC schedule commits them and are free to be dispatched upwards or downwards within their operational limits during this time. The DA UC schedule is only broken in the event of a unforeseen forced outage occurring. While the DA UC schedule may not be violated when the generators are committed, there is a "post unit commitment relaxation (PUCR)" feature in the RT model that allows for large generators to be kept on-line or brought on-line outside the DA UC schedule. The model's use of PUCR is restricted as an additional cost of generation is incurred in the form of a start cost penalty and a penalty

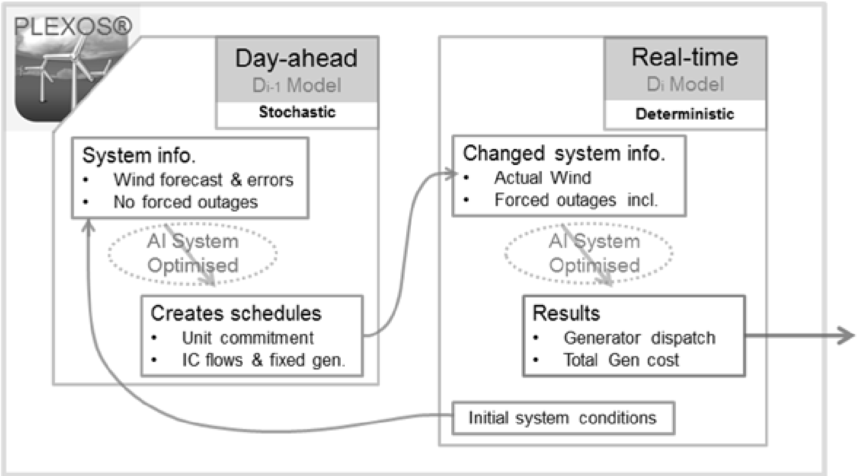


Figure 7.1: Flowchart describing the simulation of day-ahead and real-time scheduling and dispatch in PLEXOS®

running cost. These penalty costs just influence PLEXOS® decision making in the scheduling process but are not reported in the results.

The main purpose of incorporating PUCR into the RT models is that it achieves a more realistic simulation of actual generator dispatch on the SEM. From studying the actual dispatch quantities versus the market schedule quantities of generators on the SEM it is evident that the large generators do not adhere strictly to the DA UC schedule [142]. The OCGT usage is also unrealistically high when the model of the AI system is placed under the constraint of following the DA UC schedule in terms of committing generators both on and off-line. The dispatch quantities from SEMO report OCGT usage for 2011 at 195.5 GWh and 6.5 GWh for ROI and NI respectively, this in a region with a system demand of 35,700 GWh [9]. Therefore it was assumed that for 2020 OCGT generation would be at 200 GWh for the perfect foresight base scenario. It is assumed that wind forecast inaccuracies do not significantly affect OCGT usage in 2011 and therefore this is comparable to the base case scenario with perfect wind foresight.

The variable a was used to control the degree of relaxation for the use of the PUCR technique and therefore OCGT usage in the base scenario. The variable is a multiplier for the addition of the cold start penalty cost for each large generator (Eqn. 7.2) if the generator is started outside DA UC schedule. The variable is used again as a multiplier for an addition of the average running penalty costs of each large generator (Eqn. 7.3) if the generator is committed outside DA UC schedule. A value of $a = 0.6$ was determined to result in a realistic level of OCGT generation of 200 GWh in the base case DA perfect foresight scenario, and was then carried across all scenarios unchanged. This approach was used to avoid bias in the rescheduled running of individual large generators over others. The PUCR modifications can be described by:

$$GEN_{PUCR,S,C} = a\left(GEN_{Cold,S,C}\right) + GEN_{Cold,S,C} \tag{7.2}$$

$$GEN_{PUCR,R,C} = a\left(GEN_{Avg,R,C}\right) + GEN_{Avg,R,C} \tag{7.3}$$

where a = relaxation level variable; $GEN_{PUCR,S,C}$ = PUCR cold start penalty cost; $GEN_{Cold,S,C}$ = cold start cost of the generator; $GEN_{PUCR,R,C}$ = PUCR average run penalty cost; $GEN_{Avg,R,C}$ = average run cost of the generator (fuel cost by average heat rate).

7.3.3 AI system

The system demand was modified from 2012 data to reflect the predicted total energy requirement and peak demand for 2020, details of which are stated in [172]. The start costs were taken from averaging the individual daily issued start costs for 2011 for each generator given in [161]. These are also presented in three bands allowing for different start costs to be taken depending on whether the generator is cold, warm or hot. This study used the modelling tool PLEXOS® (Energy Exemplar Pty., Adelaide, Australia) to simulate the mixed integer unit commitment/economic dispatch problem. PLEXOS® version 6.208 (R08) of was run on a Dell Precision T7500 with an Intel® Xeon® CPU of six X5650 cores running at 2.67GHz. The XpressMP solver was used at a relative gap of 0.5 for the DA model and 0.05 for the RT model with the average model run taking 18 hours. There were 35 separate scenario runs for the results presented here taking 630 hours of simulation time.

7.3.4 Generation sources modified from present day to provide the 2020 base case

The predicted generation portfolio for the AI electricity system in 2020 is taken from [9] and changes from [139] are outlined in [172].

7.3.4.1 Wind data

The AI wind time-series are modified from 2011 ROI and NI wind time-series. ROI wind data was taken from [49] and NI wind data was given by SONI on request. Total installed capacity and capacity factors are shown in Table 7.2. The wind generation time-series were adjusted by a multiplier to match the long term average capacity factors of each TSO region. Wind forecasts are also included in the DA model. An annual wind forecast error of 6% MAE was assumed based on work presented in [172] and the wind forecast time-series were created with an ARMA model as detailed in [172].

An assumption was made that wind curtailment will take place within the jurisdiction of its origin unless it is more economical for the AI system as a whole for it to take place in the other jurisdiction. This assumption was carefully considered as it does effect overall results in the event that there is requirement in the future for ROI and NI to share proportionally share wind curtailment.

7.3.4.2 Tidal

Tidal generation is a priority dispatch generation source and is represented by a sine wave of period 12 hours and 25 minutes which is manipulated to obtain the desired capacity factor associated with tidal energy in [9] and is also curtailable due to it being a non-synchronous source.

7.3.4.3 Non-wind priority dispatch generating units

The modelling of non-wind priority dispatch generators was considered carefully as these make up on average 14% of generation and have direct effects on OCGT usage and wind curtailment results. Priority dispatch plant shown in Table 7.2 are modelled with an almost free, near zero generation cost in order to create a lower priority than wind energy which is modelled with zero cost, in keeping with [154, 155]. It was found that due to SOCs and high levels of wind generation the non-wind priority dispatch generators were not being dispatched at sufficiently high capacity factors, shown in Table 7.2, taken from [154]. There is also an order within the priority dispatch generators outlined in [155]. Therefore constraints were developed to reflect how these generators are actually dispatched. These constraints are: to

Table 7.2: Specification of added and modified generation sources

Generation type			
Non-synchronous	**Installed capacity**		**Capacity factor**
ROI Wind	3786 MW		31.7 %
NI Wind	1278 MW		31.4 %
NI Tidal	154 MW		20.0 %
Storage (PHES)	**Operational range**		
Generating	4x(5-71.5) MW		n/a
Pumping	4x(0 or 73) MW		n/a
Non-wind priority	**Installed capacity**		**Target capacity factor**
Peat	345.6 MW		75.0 %
CHP	161 MW		89.5 %
Waste to Energy	94 MW		80.0 %
Biomass	195 MW		80.0 %
Hydro	216 MW		n/a
Interconnection	**Installed capacity**		**Target usage**
	Summer	**Winter**	
AI (export)	950 MW	910 MW	2200 GWh
AI (import)	950 MW	910 MW	1500 GWh
Conventional	**Installed capacity**		
ROI (total)	7024.7 MW		n/a
NI (total)	1965 MW		n/a

commit the plant whenever available; a maximum energy usage per month which imposes a capacity factor; a chosen penalty imposed if the plant is not run at its maximum capacity; and a penalty attached to ramping up and down. The constraints are applied continuously with the exception that the "run at maximum capacity" constraint is lifted during times of wind curtailment as well as the ramp rate charge being removed during the first and last hour of wind curtailment taking place. These four constraints were placed on all of the priority dispatch generators individually.

7.3.4.4 Pumped Hydro

The pumped hydropower energy storage plant at Turlough Hill contains four separate turbine/pump units and one penstock. Additions to the constraints in [139] were made to only allow the facility to be in either pumping mode or generation mode at any one time. Additional changes are shown in Table 7.2.

7.3.5 Interconnection and Great Britain

It is assumed that in 2020 installed interconnector capacity between AI and GB will remain unchanged from the present, with the two HVDC interconnectors [9] shown in Table 7.2. Interconnector flows have been manipulated to reflect the reality of fluctuating GB prices on a sub daily and seasonal time frame as well as reflecting the spatial correlation between AI and GB wind energy generation [56, 57]. Overall annual interconnection flow rates, shown in Table 7.2, reflect the predicted AI exports and imports for 2020 [58].

7.4 Results

7.4.1 Effects of individual system operational constraints

Simulating the effects of relaxing individual SOCs allows for the SOCs to be ranked in order of influence on costs, which was necessary for ordering scenarios in the combined SOC effects investigation. Fig. 7.2 shows clearly that, for all SNSP values, relaxing Dub(2/3) is the most influential SOC followed by CPS(1), NI-s(3) and finally ROI-s(5). It is interesting to note however that in terms of reducing wind curtailment, relaxing the SOC CPS(1) is the most beneficial, as shown in Fig. 7.3.

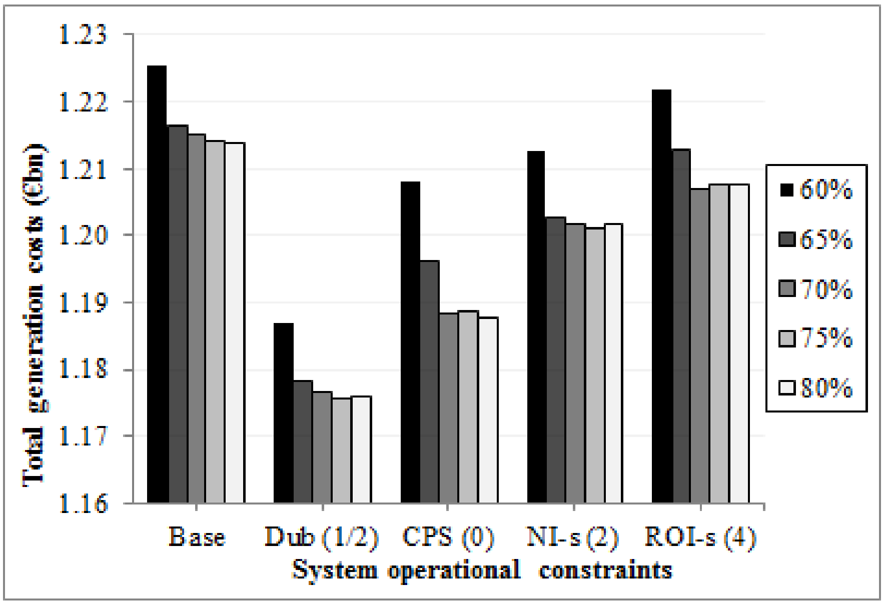


Figure 7.2: The AI total generation costs (€m) for AI at different SNSP percentage limits and minimum number of large conventional generator on-line constraints individually relaxed

It should be noted that total generation costs do not include the cost of renewable tariffs. It also should be noted that due to varying usage of interconnectors and the PHES, total generation varies from scenario to scenario. This results in the total generation cost being distorted and therefore it was necessary to scale the total generation costs of all scenarios against the base-case total AI generation in order to maintain consistency across different modelling scenarios. The total generation for all scenarios is shown in Table 7.3.

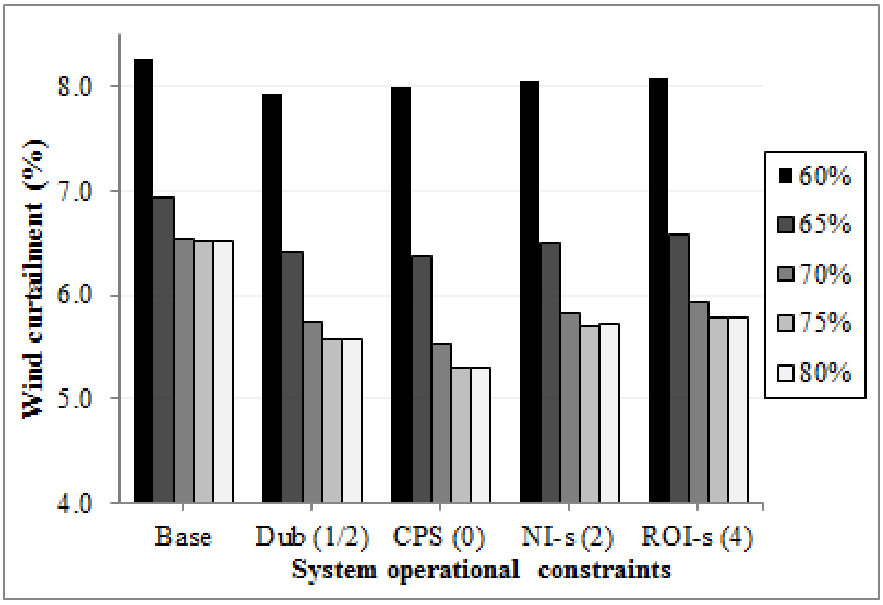


Figure 7.3: The percentage of AI wind curtailment at different SNSP percentage limits and minimum number of large conventional generator on-line constraints individually relaxed

7.4.2 Combined system operational constraints effects

The results of combined SOC relaxations are presented in order of the greatest influence, with the most influential SOCs relaxed first and relaxed SOC(s) carried forward to subsequent scenarios. Large decreases in both total generation costs and wind curtailment are evident in Figs. 7.4 and 7.5 as the constraints are progressively relaxed.

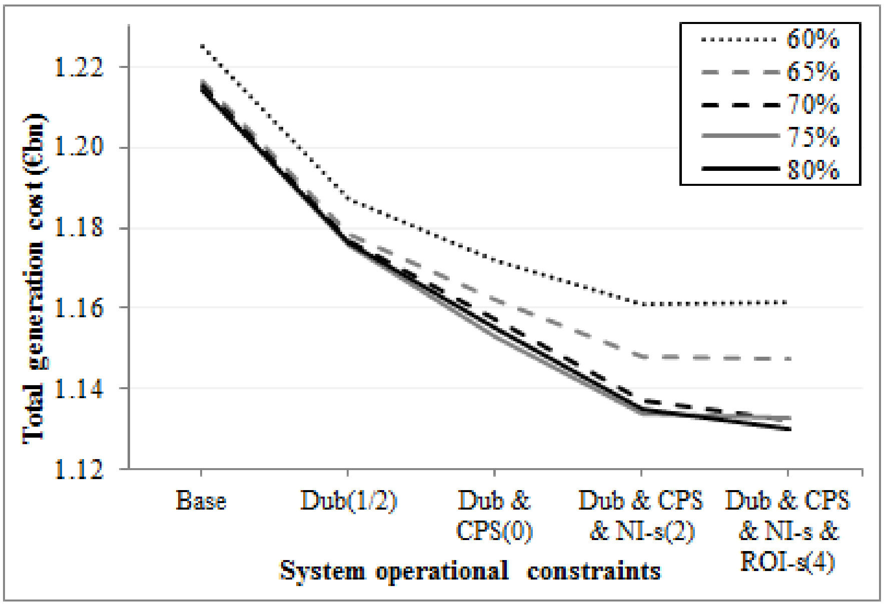


Figure 7.4: Total AI generation costs (€m) at different SNSP percentage limits and minimum number of large conventional generator on-line constraints relaxed in cumulative combination from left to right

7.5 Discussion

The results presented here show the strong effects that relaxation of SOCs has on the future AI system in terms of total generation costs, wind curtailment and generator dispatch by technology type.

Table 7.3: Total AI generation (TWh/yr) at different SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

	System operational constraints scenarios				
SNSP	**Base**	**Dub(1/2)**	**CPS(0)**	**Ni-s(2)**	**ROI-s(4)**
60%	40.34	39.97	39.40	39.18	38.84
65%	40.37	40.07	39.41	38.98	38.72
70%	40.40	40.13	39.44	39.04	38.59
75%	40.43	40.10	39.42	38.97	38.65
80%	40.39	40.13	39.51	39.09	38.63

7.5.1 Costs

It is evident in Fig. 7.2 that the two SOCs associated with voltage stability, Dub(2/3) and CPS(1), are the most costly constraints on the AI system. This result was not expected as initially it was assumed that ROI and NI system stability SOCs would be the most influential along with the system-wide

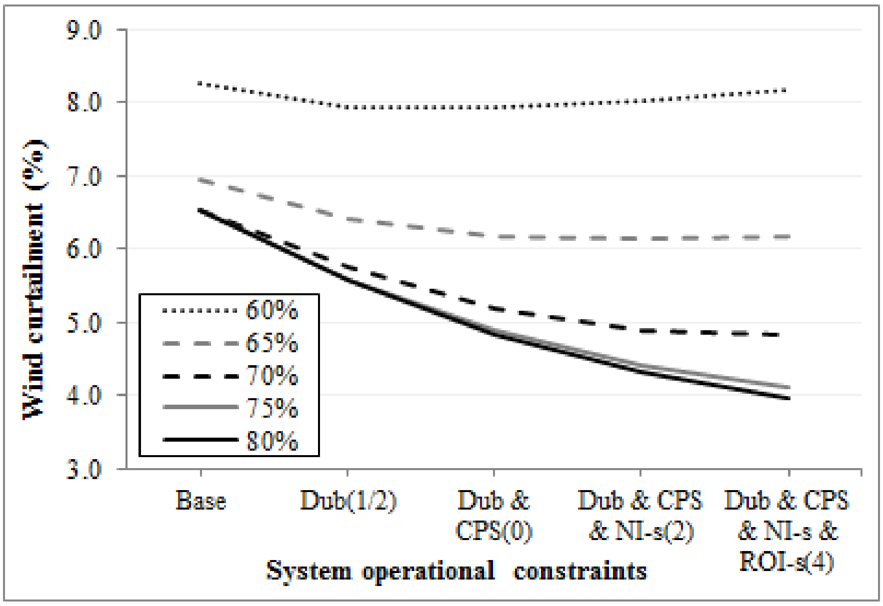


Figure 7.5: The percentage of wind curtailment for AI at different SNSP percentage limits and minimum number of large conventional generator on-line constraints relaxed in cumulative combination from left to right

SNSP limit. It is shown that relaxing the constraint Dub(2/3) has the biggest impact in terms of generation cost savings and regardless of the SNSP the limit imposed, this yields an almost constant saving of €38 million per year (3.1% of total system costs). Therefore the Dub(2/3) should be considered as a priority to be relaxed first, subject to the cost and feasibility of the required grid upgrades.

On examination of the combined effects of relaxing the five most influential SOCs there are potential savings of €95 million per year or 7.8% of total generation costs. This illustrates the need for investment in the AI electricity system to help mitigate the issues associated with reactive power and inertia that will be present in the future electricity system highlighted in [80, 21].

The most striking result from this work, shown in Fig 7.4, is the lack of reduction in total generation costs when the SNSP limit is raised above 65% unless both of the two most influential constraints, Dub(2/3) and CPS(1), are relaxed first. This strongly indicates that tackling system-wide problems requiring a SNSP limit of 65% is a secondary concern to that of "minimum on" SOC's requiried for local voltage and reactive power control. It is also interesting that savings are limited when the SNSP limit is relaxed past 70%, even if all the other SOCs are also relaxed. This would indicate that further relaxation of the Dub(1/2) or the NI-s(2) constraints may be necessary in

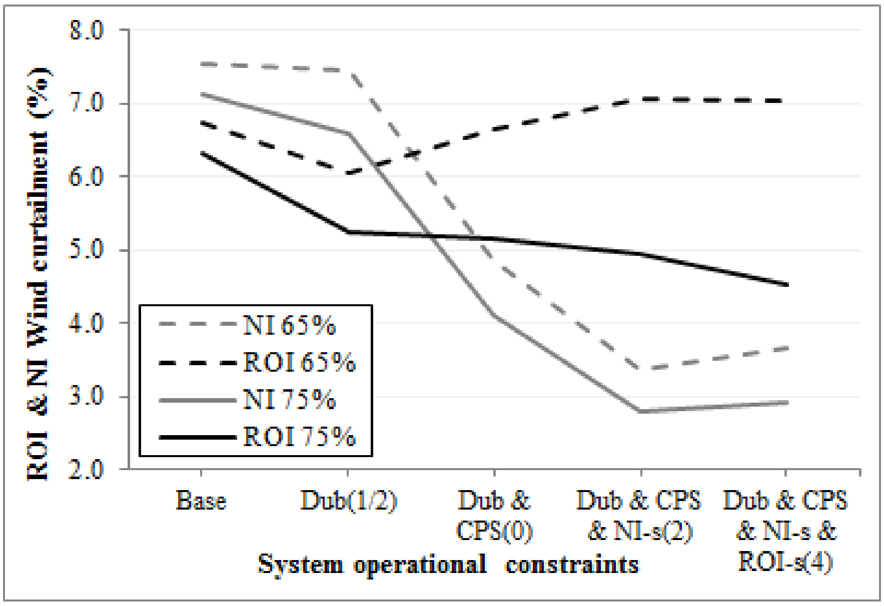


Figure 7.6: The percentage of wind curtailment in NI and ROI at 65% and 75% SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

order to deliver further reductions in total system cost.

7.5.2 Wind curtailment

A low level of wind curtailment is very desireable to help meet the 2020 renewable energy targets and in general to ensure maximum use of generation assets. In Fig. 7.5 it is shown that wind curtailment is strongly influenced by changes to SOCs. There is the potential to reduce wind curtailment to 4.0% if the five most influential SOCs are relaxed, this is in comparison to the base-case scenario prediction that wind curtailment will be 8.3% if the SOCs are not relaxed from present-day values. With today's prices this equates to €42 million extra a year worth of wind energy not being utilised [42].

Unlike total generation costs, wind curtailment is influenced more strongly by the reductions in the SNSP SOC than the four other "minimum-on" SOCs. Increasing SNSP beyond 70% offers little gain, in terms of wind curtailment, unless the other SOCs are relaxed first. It is also shown that with an increase in the SNSP limit beyond 75% there is little benefit in terms of wind curtailment if all other four SOCs are relaxed. This aspect, similar to total generation costs, would indicate that further relaxation of the Dub(1/2) or the

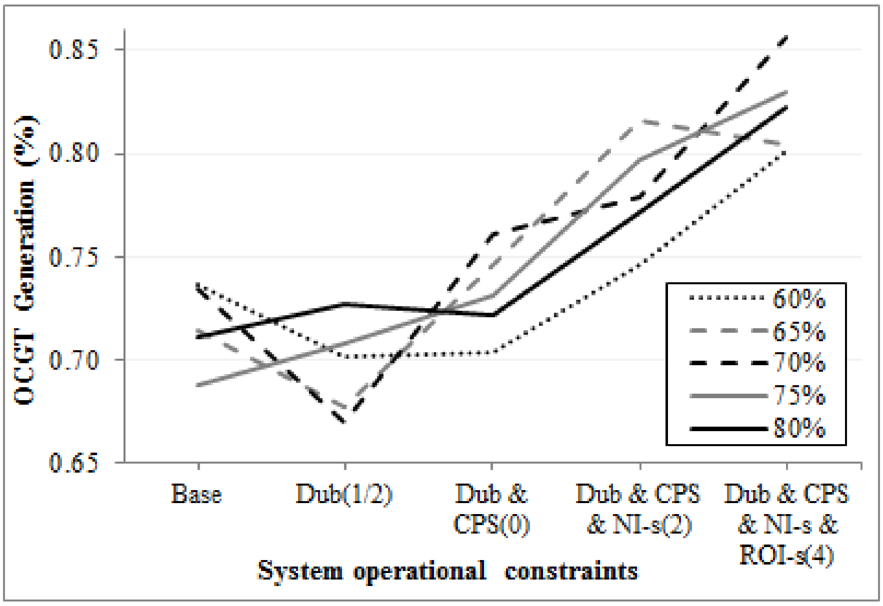


Figure 7.7: OCGT generation as a percentage of total generation for AI at different SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

NI-s(2) constraints may be necessary before wind curtailment can be reduced further.

Following from the assumption made on how wind curtailment is managed in the AI system, prioritising optimisation of the system as a whole, it is interesting to note how relaxation of the SOCs causes a regional imbalance in wind curtailment. It is shown in Fig. 7.6 that NI stands to gain in terms of reduced wind curtailment, corresponding with [16], however this is at ROI's expense. This may lead to possible issues in the future regarding ROI wind farms being penalised with greater curtailment than NI wind farms, or may lead to a need for a new constraint to equalise wind curtailment between the two jurisdictions.

7.5.3 Conventional generator dispatch

While the trends of OCGT usage in relation to changes in SNSP are not clear, there is evidence of a small increase in OCGT usage with continued relaxation of the SOCs. On average for all SNSP scenarios there is an increase of an extra 0.11% (44 GWh/yr) of total generation coming from OCGT from relaxing the four "minimum-on" SOCs. This is due to a higher frequency of extreme peaks

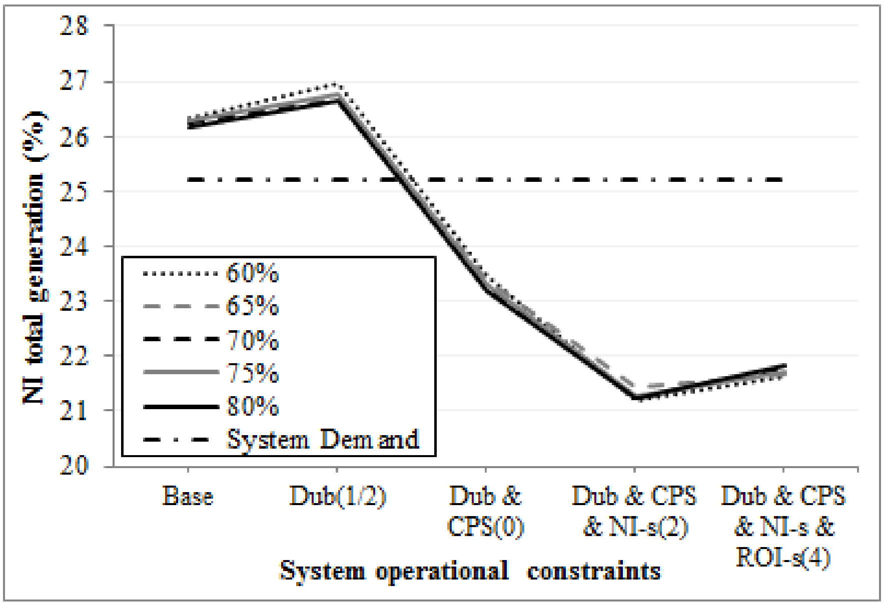


Figure 7.8: Total NI generation as a percentage of total AI generation for at different SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

and troughs in the conventional generation profile to accommodate the added wind energy resulting from relaxing the SOCs.

With the relaxation of the NI SOCs there is a dramatic shift in generation away from NI, shown in Fig. 7.8, leading to NI being supported by ROI and GB through the Moyle interconnector. Remarkably, the system-wide SNSP limit SOC has almost no effect on this result. This shift in the relative proportions of total generation between the jurisdictions is a result of the NI local SOCs artificially keeping NI generation higher than would be the case in an unconstrained AI market model. This generation shift towards ROI also contributes to it being more efficient to curtail wind in ROI rather than NI, shown in Fig. 7.6, as ROI already has a generation surplus. This result emphasises the effects that SOCs have on the AI system on a jurisdictional basis.

7.6 Conclusion

This work quantifies the effects on total generation costs, wind curtailment and generator dispatch of relaxing the SOCs currently imposed in order to maintain a safe, stable and reliable electricity system. In doing so, it illustrates the need for further investment to mitigate problems associated with voltage stability and inertia requirements to allow for the relaxation of the SOCs.

There are potential savings in total generation costs of 7.8% when the five most influential SOCs are relaxed. There are also large savings to be made with SOCs being individually relaxed. Most notably, if the Dub(2/3) SOC constraint requiring two large generators in the Dublin area to be constantly on-line by day and three by night is relaxed to Dub(1/2), one by day and two by night, there is a saving of 3.1% of total system costs regardless of the SNSP limit.

Wind curtailment is greatly affected by SOCs. There is the potential to reduce wind curtailment from 8.3% to 4% when the five most influential SOCs are relaxed. In the future, an issue may arise between the two jurisdictions, ROI and NI, over where best to curtail wind energy for the benefit of the system as a whole. It has also been shown that relaxing the SOCs affects the dispatch of conventional generators such as OCGTs, with increased usage of OCGTs as SOCs are relaxed. There is also a big effect on the relative contribution to total generation from the two jurisdictions when the NI SOCs are relaxed, with NI needing to be supported from ROI and GB in this case.

The issue of relaxing SOCs, while important for Ireland in the next 5-10 years, will probably also become important for larger systems in the future if present trends in the installation of non-synchronous sources such as wind, HVDC or photovoltaics continue. The GB synchronous system may find similar issues becoming apparent in the next 10-15 years as well as in the synchronous systems of Continental Europe in the next 30-40 years.

Grid reinforcement and technical improvements to wind and conventional generators such as synthetic inertia will allow for an increase in the permitted limit of non-synchronous generation on the system. However, this will only deliver cost savings in conjunction with measures to relax other SOCs primarily associated with local voltage control, such as introduction of non-synchronous generators with greater reactive power control. It has been demonstrated that increasing the SNSP limit beyond 65-70% has limited value without prior relaxation of the other SOCs and it is also shown that there is limited value in increasing the SNSP limit beyond 70-75% even if all other influential SOCs are relaxed.

In this study a rigorous framework has been developed for comparing system cost savings associated with grid reinforcements and generator upgrades. This has been applied to clearly demonstrate the case for investment in transmission and generator upgrades in order to allow for more flexible system operation with lower generation costs and reduced wind curtailment.

Chapter 8

Quantifying the value of improved wind energy forecasts in a pool-based electricity market

8.1 Abstract

This work illustrates the influence of wind forecast errors and choice of scheduling method, stochastic or deterministic, on system costs, wind curtailment and generator dispatch. Wind forecasts of different accuracies are created using an auto-regressive moving average model and these are then used in the creation of day-ahead unit commitment schedules which are generated using both stochastic and deterministic scheduling. The results, based on a model of the 2020 Irish electricity system with 33% wind penetration, clearly show the benefits of stochastic over deterministic scheduling. Improvements in wind forecast accuracy are demonstrated to deliver: (i) clear savings in total system costs for deterministic and, to a lesser extent, stochastic scheduling; (ii) a decrease in the level of wind curtailment, with close agreement between stochastic and deterministic scheduling; and (iii) a decrease in the dispatch of open cycle gas turbine generation, evident with deterministic, and to a lesser extent, stochastic scheduling.

8.2 Introduction

Wind power is given priority dispatch over the conventional, non-renewable sources of generation in most electricity markets. For this reason Transmission System Operators (TSOs) may view wind generation as a negative load. As forecasts of wind generation and system demand are required for scheduling generator dispatch, wind power forecast inaccuracy can be viewed as a component of the net system load forecast inaccuracy. In systems with high wind penetrations, load forecasts are more accurate than wind power forecasts [90], therefore it is wind power forecasts that are the largest source of uncertainty in terms of net system demand requirements. Furthermore, wind generation, unlike conventional forms of generation, has little controllable variability in its output, with the exception of wind curtailment, and to compound the issue, this variability has a low degree of predictability with very large instantaneous errors in forecasts occurring frequently. There is, therefore, a considerable uncertainly associated with wind generation forecasting, with root mean squared errors of up to 20% for 24-hour ahead predictions reported [91].

The Republic of Ireland (ROI) and Northern Ireland (NI) have agreed to generate 40% of electricity from renewable sources byu 2020 in response to the ambitious renewable energy targets set by the European Union for its member states [5, 7, 4]. Due to this, a large amount of wind capacity will be added to the system which will result in a large proportion (in excess of 30%) of All-island of Ireland (AI)[1] electricity generation coming from a single source that is dependent on instantaneous weather conditions across the region.

8.2.1 Forecasting

Wind forecasting is important for the efficient running of the AI electricity system as the scheduling of large generators takes place one day in advance of dispatch[12]. In the event of the wind forecast being inaccurate, the day-ahead unit commitment (DA UC) schedule will mistakenly commit too little or too much capacity from cheaper large generators, resulting in

[1] All-island of Ireland (AI), consisting of Northern Ireland (United Kingdom) and the Republic of Ireland.

additional costs due to such generators being run at reduced efficiency levels or by bringing on additional, more expensive, open cycle gas turbines (OCGTs) to make up the system demand requirement. It is viewed that the improvement of wind forecasts has potential benefits for TSOs, wind farm operators in deregulated electricity markets, non-wind generation operators in the same markets and electricity traders [91]. It is recognised by the TSO's that improving the accuracy of wind power forecasts, particularly the 48 hour ahead forecast used in optimising the DA UC schedule, is worth investing in [92] and it has been stated that increasing the penetration of wind in the AI system may be achieved by improvements in the accuracy of wind power forecasting [93].

Previous works have used different methods to simulate wind forecasts for use in UC and economic dispatch studies of electricity systems. For example, auto-regressive moving average (ARMA) methods were used in [98] to create 12-36 hour ahead wind generation forecast time-series with a mean absolute error (MAE) of 7.8%, and in [99, 24, 23] where the Wilmar planning tool was used to develop wind forecast scenarios for the AI system. The use of ARMA in the simulation of wind forecasts was first documented by [96]. The method used in [97] forms the basis of the ARMA component of the wind power forecast error model used in this paper.

It has been shown in previous work that, in the presence of wind forecast errors, stochastic scheduling approaches perform better than deterministic approaches [99, 102, 101]. Stochastic methods have been used in a number of other studies to determine the effects of wind forecast uncertainty on electricity systems [24, 103, 104] .

8.2.2 Wind forecasting effects on systems

Rogers et al. [107] acknowledged that one of the greatest challenges associated with the integration of wind generation will be formulating the DA UC schedule, due to the limited accuracy of wind forecasts. The authors of that study stated that errors in wind forecasts must be taken into account when the DA UC schedule is created in advance.

On examination of the literature, to the authors knowledge no work has attempted to estimate the effects of realistic, incremental improvements of wind forecast accuracy on electricity system scheduling. A number of studies have estimated the effects of wind forecasts on electricity systems containing significant penetrations of wind energy [99, 24, 23, 102, 103, 94, 55, 106], but most do not quantify the wind forecast error and only compare a single forecast scenario against the ’perfect foresight’ scenario, and the error is not even quantified in some cases. While it is noted that these works focus on several different electricity systems with varying penetrations of wind energy, they all share some common conclusions, such as negligible wind curtailment. On comparison of the works above there are differences reported in the savings of total system costs ranging from 0.02% to 1.2% when accounting for the difference between actual wind forecast errors and perfect foresight.

The work presented in this paper differs from the aforementioned studies in comparing how the DA UC schedules are used, as large generators were not relaxed in [102, 104] and these studies did not simulate over a full year. It has also been shown in [108] that using shorter time steps in the scheduling simulation results in higher system costs, due to the higher accuracy of modelling, although this work assumed perfect foresight for wind forecasts.

8.2.3 Reserve provision

Previous works have looked at the effect of wind forecasting on system reserve provision [98, 99, 24, 94, 55, 109]. It has been shown that increasing installed wind capacity increases replacement reserve requirements [24, 94, 106]. In [24] it is shown that there are only small changes in spinning reserve requirements for different installed wind capacities and therefore changes in wind forecast accuracy should have a negligible effect on spinning reserve capacities overall. However, the latter study does show large increases in the requirement for replacement reserve as the forecast horizon is extended and this could also be interpreted as an increase in replacement reserve necessary with decreasing wind forecast accuracy. From this is can be assumed that wind forecast accuracy will have small effects in terms of spinning reserve and therefore spinning reserve will not be considered for the purpose of this study. It is recognised however that wind forecast accuracy will have an effect on the provision of replacement reserve. Replacement reserve is provided over the time frame of 20 minutes to four hours [69, 70]. This results in replacement reserve mainly being provided by off-line OCGTs. To help mitigate the effects of not explicitly considering replacement reserve provision the published AI operational constraints [78] include a constraint that 400MW of OCGT capacity must not be scheduled any one time in order to act as replacement reserve.

8.3 The Model

The model implemented here attempts to replicate the running of the Irish Single Electricity Market (SEM) [2]. Six wind forecast accuracy scenarios are used to illustrate the effects of wind forecast errors on the system. The first scenario has a 0 MAE% forecast error i.e. the assumption of perfect foresight. The other five wind forecast accuracy scenarios have reducing wind forecast accuracy of 2, 4, 6, 8 and 10% MAE. The system is modelled using both stochastic and deterministic approaches under all of these accuracy scenarios. There are ten model runs of each of the five 2-10% MAE wind forecast accuracy scenarios and a single run of the perfect foresight scenario. This results in 51 model runs each for both the stochastic and deterministic scheduling methods. The results to be presented within each non-zero MAE scenario will be averages based on forecasts from the ten wind forecast runs.

The power systems simulation tool PLEXOS® [140] was used in this study. This software is widely used for the simulation of mixed integer unit commitment/economic dispatch problems (e.g. [22, 173]). Version 6.208 (R08) of PLEXOS® was run on a Dell Precision T7500 with a Intel® Xeon® CPU of six X5650 cores. The XpressMP solver was used at a relative gap of 0.5 for the DA model and 0.05 for the RT model with each stochastic and deterministic model run taking an average of 16 and 2 hours respectively.

Table 8.1: Scheduling time-line.

Time	Event
12.00hr d-1	Wind forecasts are submitted to System Operator
16.00hr d-1	DA UC schedule is created and submitted to generators
06.00hr d	DA UC schedule commences
05.30hr d+1	DA UC schedule ends
06.00hr d+1	Lookahead period for model optimisation begins
11.30hr d+1	Lookahead period for model optimisation ends

[2] The SEM area consists of Northern Ireland (part of the UK) and the Republic of Ireland.

8.3.1 Scheduling

The model is run on the forecast simulation year of 2020. To accurately take account of the forecast errors and forced outages that occur on the system and to help replicate the running of the SEM [12], two separate models run in step with each other using an interleaved optimisation tool which is described in more detail in [143]. It was assumed that the scheduling times are as shown in Table 8.1 which are taken from [12, 144, 145, 146]. From this, the assumption was made that an 18-42hr point wind forecast would best represent the forecast on which the Irish TSOs[3] base the DA UC schedule.

8.3.1.1 Day-ahead model

The day-ahead (DA) model's only function is to create the DA UC schedule for generators and interconnectors. These schedules are created based on the data available on the day prior to dispatch. This necessitates the use of wind forecasts and also means that forced outages cannot be taken into account. The DA UC schedule fixes large generators to be on-line with specified start times and lengths of generation. At the end of the DA simulation day d_1 the DA UC, interconnector and generation schedules are passed forward to the real-time (RT) model to be included in the RT run of the same simulation day d_1. For the deterministic optimisation of the system schedule, the DA model receives only the median wind forecast. Therefore, in the deterministic case, the DA model has no capability to evaluate the associated wind forecast uncertainty.

The DA model for the stochastic optimisation of wind forecasts uses a scenario-wise decomposition method instead of the deterministic scheduling used in the RT model. This allows the DA model to evaluate different degrees of wind power forecast error together with their associated probability of occurrence. Therefore it is a cost minimisation problem dependent on the probability of expected results. The model receives a wind power forecast file containing the median forecast (corresponding to 50% probability of exceedence) and upper and lower quantiles of wind power forecast error with associated cumulative exceedance probabilities (5.0, 27.4, 72.6 and 95.0%), described in detail in Section 8.3.2. Each of the five wind forecast quantiles is

[3]The SEM contains two TSOs, EirGrid in the Republic of Ireland and the System Operator for Northern Ireland (SONI)

used to create five separate “model samples”. From the five model samples a single set of DA UC decisions is optimised for each simulation day. The DA UC schedule is created from the economic dispatch minimisation from the likelihood of occurrences of the five separate “model samples”. This is done through the use of UC non-anticipativity penalty costs associated with all the scheduled large generators and interconnectors, making the UC schedule of these selected generators and interconnectors match across all five “model samples”. This set of DA UC decisions provides the lowest-cost solution in the DA model as the expected inputs of the RT model and therefore realistically reflects the probability of actual wind generation diverging from the forecast value between the DA and RT scheduling.

8.3.1.2 Real-time model

The purpose of the real-time (RT) model, which uses deterministic scheduling, is to reschedule the AI system within the constraints imposed by the DA UC schedule, in response to realised actual wind generation and forced outages. The RT model permits restricted rescheduling of generators committed in the DA UC schedule, as well as allowing all committed generators to alter their generation output within their operational limits. Partial rescheduling of large generators outside the UC schedule allows for more realistic simulation of open cycle gas turbine usage on the system where it was assumed that 200GWh of OCGT generation per annum would occur in the base case scenario of perfect wind foresight. This method of post unit-commitment relaxation (PUCR) is described in detail in [174]. At the end of the RT model run of the simulation day d_1, the initial conditions of all generators are sent back to the DA model to be included in the start of the DA run of the next simulation day d_2. The schedules of the interconnectors and some generators (hydro, waste, biomass and CHP) are created directly from the DA model and are fully fixed, with no possibility of relaxation by the RT model.

8.3.1.3 Formal description of the RT and DA models

The DA and RT models may be described by the following Equations:

$$
\begin{aligned}
DA(d-1|d) &= f(WF(d),\ IC_{info},\ Model_{s,info}(d)) \\
&\quad where\ d = 1 \\
DA(d-1|d) &= f(WF(d),\ IC_{info},\ RT.End_{syst,con}(d-1), \\
&\quad Model_{s,info}(d)) \\
&\quad where\ d = 2, 3, 4, \ldots, n
\end{aligned}
\tag{8.1}
$$

$$
\begin{aligned}
RT(d|d) &= f(WA(d),\ DA.UC_{pucr}(d),\ DA.IC_{fix}(d), \\
&\quad DA.Gen_{fix}(d),\ FO(d),\ Model_{s,info}(d)) \\
&\quad where\ d = 1, 2, 3, \ldots, n
\end{aligned}
\tag{8.2}
$$

$$
\begin{aligned}
Model_{s,info}(d) &= Sys_{demand}(d),\ F_{cost}, \\
&\quad OP_{const},\ Gen_{const},\ GB_{sytem,info}(d), \\
&\quad Maint(d)
\end{aligned}
\tag{8.3}
$$

where: $DA(d-1|d)$ refers to the DA model solved for day d on day $d-1$; $Model_{s,info}(d)$ is the system information given to both DA and RT models; $Maint(d)$ is the maintenance schedule set for both DA and RT models; $RT(d|d)$ refers to the RT model solved for day d on day d; $f(WF(d))$ is the DA wind energy forecast and uncertainty quantiles time-series; $f(WA(d))$ is the realised actual wind energy time-series on day d; IC_{info} is the interconnector characteristics; $RT.End_{syst,con}$ is the end system conditions from the RT model, used for setting subsequent DA initial conditions; $DA.UC_{pucr}(d)$ is the DA UC schedule with post unit commitment relaxation; $DA.IC_{fix}(d)$ is the fixed interconnector flow schedule from DA model; $DA.Gen_{fix}(d)$ is the fixed generator flows schedule on day d from DA model (hydro, waste, biomass and CHP units); $FO(d)$ indicates forced outages; $Sys_{demand}(d)$ is the system demand; OP_{const} represents the operational constraints; Gen_{const} is the generator profile constraints, ensuring minimum capacity factors and reducing ramp cycling (Hydro, Waste, Biomass, Peat and CHP units); F_{cost} is the fuel costs; $GB_{system\,info}$ is the Great Britain wind generation, system demand and price settings; d is the day number in 2020; and n is the number of simulation days (366 days in 2020).

8.3.2 Generating wind forecast data

The Irish TSO, EirGrid, publishes up to date wind generation and wind forecast profiles online allowing wind forecast error time-series to be calculated in order to analyse the evolution of forecast error over time [49]. EirGrid also has published the annual MAE of forecasts of 0-48 hour lead times for each of the years 2008-2010 showing the decrease in accuracy of a forecast with increasing lead time [80]. A forecast with a 2-day horizon is regularly published for NI and ROI by SEMO [95] but this is frequently updated overwriting existing information so "pure" point forecasts are not available from this source.

For this study it was necessary to synthesise wind power forecasts at specified accuracy levels. From studying the literature it was decided that the use of autoregressive moving average (ARMA) models would best replicate wind power forecast errors. Using an ARMA model it is possible to issue synthetic wind power forecast time-series that are statistically similar to real wind forecasts. An additional benefit of using ARMA models, which is demonstrated here, is the ability to generate specific levels of errors and associated probabilities of occurrence with the generated wind power forecasts. This gives much more detailed information for use in the DA UC economic dispatch decisions.

A code was developed in Matlab R2010b (Mathworks, USA) consisting of three processes in order to realistically replicate the wind forecasts and associated errors, illustrated in Fig. 8.1. The first step was to determine the parameters of the ARMA model α, β and σ_z. The parameter β was chosen first, this was determined from EirGrid's reported wind forecast error time-series [49]. It was determined through least-squares fitting that β = -0.1 best replicated the actual error growth with forecast lead time when the ARMA model was run at a 30 minute time resolution. The target annual MAE levels for different lead times are shown in Fig. 8.2, based on [80], which the generated wind forecasts aimed to mimic. Using the first process, P_1, of the method illustrated in Fig. 8.1, the parameters α and β were determined based on the 48 intervals (of 30 minutes each) of 367 days for 20 years, meaning the creation of 352,320 random numbers with a near-constant statistical spread between separate runs of P_1. For the parameter α, a value of 0.99 was determined to give the best fit to the error growth profile shown in Fig. 8.2 for the time period 18-42hrs for the chosen value of β. The last parameter σ_z

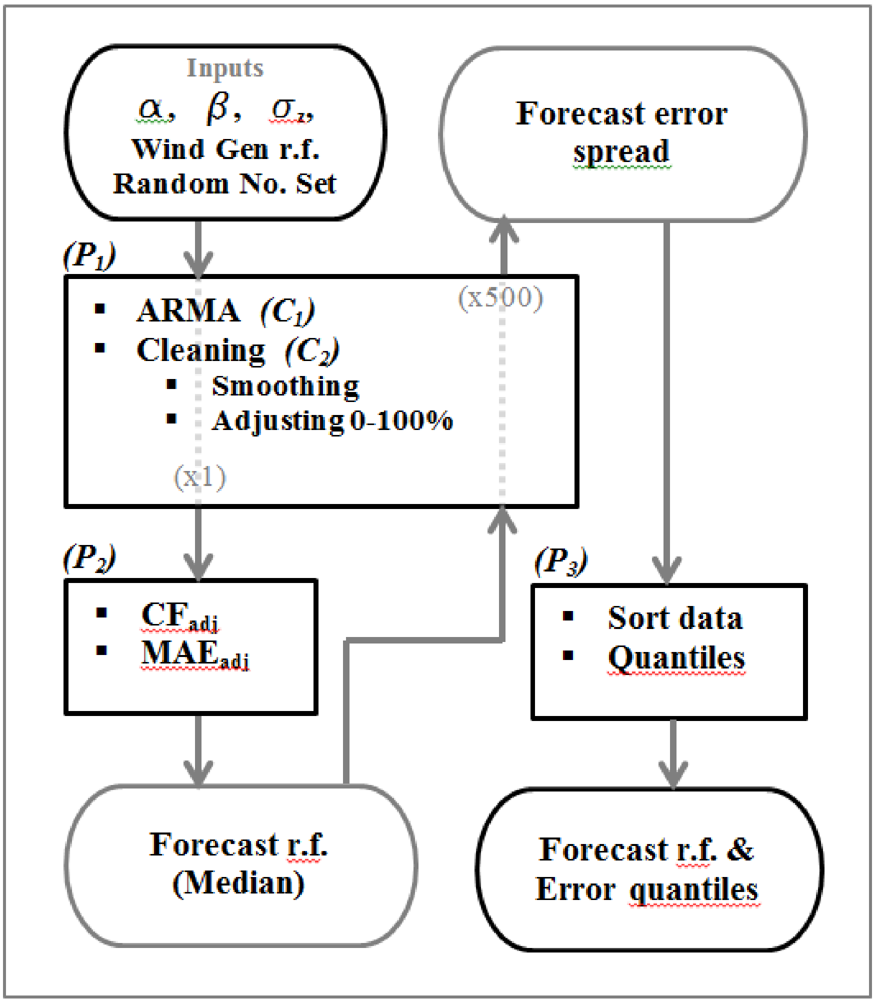
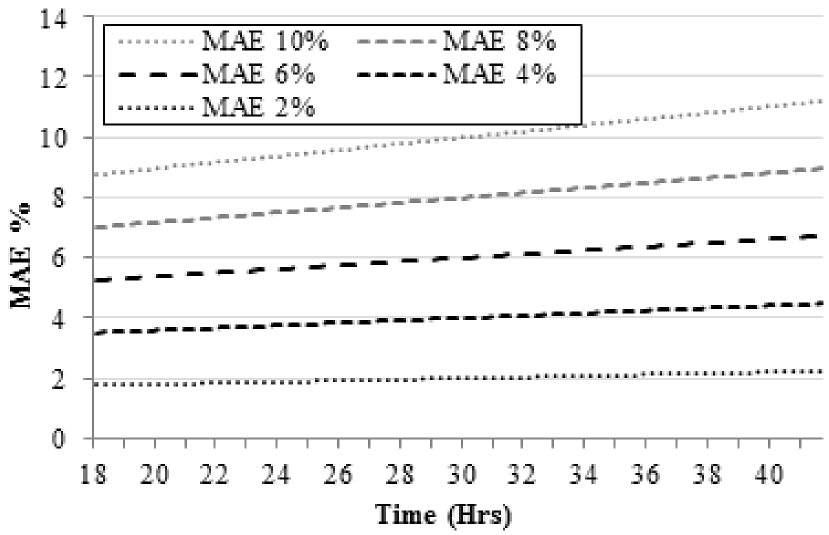


Figure 8.1: Flow chart describing the process of generating the wind forecast and associated error profiles

(0.390, 0.980, 1.550, 2.120, 2.695) was found to vary depending on the scenario of MAE (2, 4, 6, 8, 10% respectively).

The first process, P_1 in Fig. 8.1, consists of two main components. This code is run twice, first to create the median wind forecast and then to create the forecast error spread. The forecast error spread is created from the median wind forecast which is used as the base forecast from which a spread of 500 randomised forecast time-series are generated, shown in Fig. 8.3, using the same ARMA parameters used in the creation of the median wind forecast. The first component, C_1 in Fig. 8.1, of P_1 is an ARMA (Eqn. 8.4) model with three controlling parameters (α, β & σ_z) which creates 96 half hour intervals representing 0-48 hour point forecasts for the 366+1 days. The random numbers produced have a mean of zero and a standard deviation of σ_z and are normally distributed. This ARMA model was derived from that of [97],



[80]

Figure 8.2: Forecast MAE over lead times of 18-42hrs, based on averages calculated over multiple issues of forecasts reported by EirGrid.

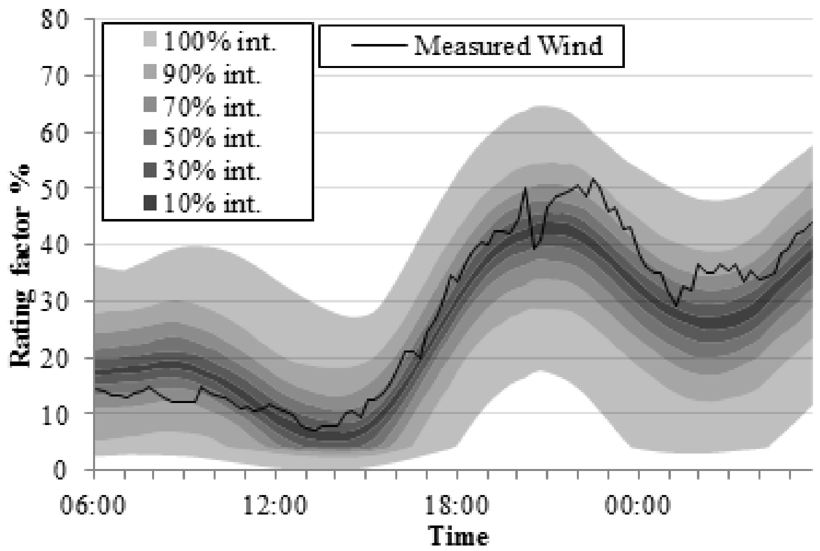


Figure 8.3: ARMA-generated DA interval wind forecast profile for the 6% MAE scenario and measured wind generation for the 2^{nd} April of the test year.

and is represented by:

$$
\begin{aligned}
Z(0) &= 0 \\
Z(t) &= \text{random numbers of standard deviation } \sigma_z \\
X(0) &= Z(0) \\
X(t) &= \alpha X(t-1) + Z(t) + \beta Z(t-1)
\end{aligned}
\tag{8.4}
$$

(t=1,2,3,...,N)

where: α, β & σ_z are the ARMA controlling parameters; t = time step (intervals of 30 minute for 2 days); $Z(t)$ = a random number for interval "t" with a standard deviation of σ_z; $X(t)$ = the wind energy forecast error for interval "t"; N = number of intervals in data.

The second, larger component, C_2, of the first process P_1, in Fig. 8.1, allows for the adjustment of the ARMA wind forecast into a more statistically representative time-series. This takes the forecast error created by the first component and based on this, assesses the forecast error within the 18-42 hour-ahead time window of interest determined from Table 8.1. The 367 "18-42 hour-ahead time windows of interest" are concatenated sequentially, one after another, making a complete wind forecast error time-series. The wind forecast error is then added to the actual wind power generation time-series, from ROI for the mean wind speed year of 2011 [49], giving the simulated wind power forecast time-series.

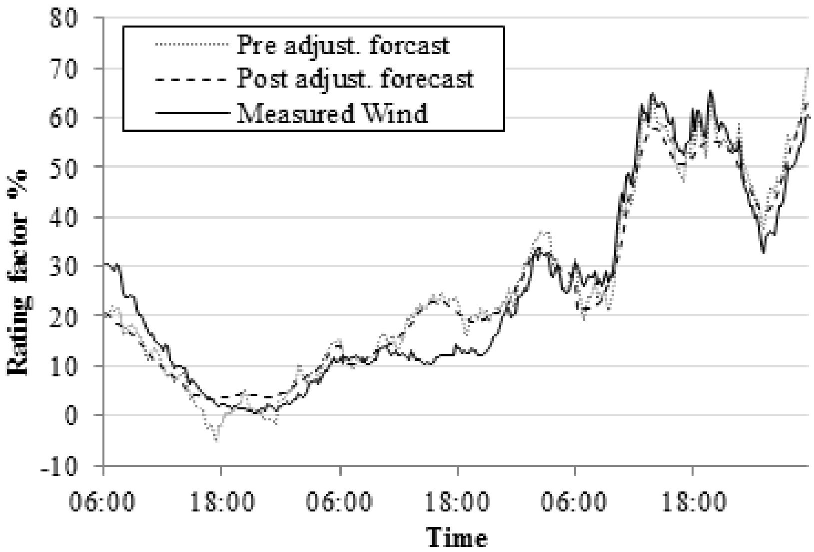


Figure 8.4: Wind forecast adjustment for the 6% MAE scenario and measured wind profile for the 21^{st} to 23^{rd} February of the test year.

The wind forecast must be adjusted as the generated values may sometimes fall outside the limits of 0-100% of installed wind capacity. Therefore, using Eqn. 8.5 the assumption was made that all data under the percentage rating factor (p) would be adjusted upwards to avoid negative generation. This was achieved by a linearly varying scaling factor with a value of 0 at the minimum value of the wind forecast generation profile and a value of 1 at p, the results of which are shown in Fig. 8.4 where p was taken as five. Values greater than 100%, due to their seldom occurrence, are simply set to 100% rating factor.

In the creation of the predicted (median, 50%) wind forecast, an extra adjustment (P_2 in Fig. 8.1) is added, where the data is uniformly adjusted by a multiplier to achieve the exact MAE% required. This is followed by an adjustment to achieve the same annual capacity factor as the actual wind generation. This is necessary as the limited number (367) of random forecast series within a year does not always guarantee convergence precisely at the desired value of the MAE. This also helps to reduce variations in the results between runs in one MAE scenario. This adjustment is described by:

$$WF_{ad}(t) = |WF_{min}| \left(\frac{p - WF(t)}{p + |WF_{min}|} \right) * \tag{8.5}$$

(t=1,2,3,. . . ,N)

where: t indicates the time step (15 minute intervals for 367 days); $WF(t)$ is the set of wind forecasts issued at interval "t"; WF_{min} is the minimum value of the wind forecast set WF; $WF_{ad}(t)$ is the adjusted set of wind forecast issued at interval "t" ; N is the number of intervals in the data; p is the percentage rating factor below which Eqn. 8.5 is applied.

The third and final process in Fig. 8.1, P_3, creates the error quantiles. The empirical error quantiles are taken from the sorted spread of wind forecast time-series created. The error quantiles were chosen at 5.0, 27.4, 50.0, 72.6 and 95.0% probabilities of occurrence, shown in Fig. 8.5, to best reflect the statistical spread of the wind forecast errors. It should be noted that the empirical quantiles method was chosen over distribution fitting as the error distribution is not normal at rating factors less than 7% and greater than 93%, and due to the findings of [147] that it is a simplification to assume that wind power forecast error is of a near-normal distribution.

8.3.3 All-island system and constraints

The AI system demand for 2020 was developed from 2012 AI data given in [139]. The 30-minute resolution AI system demand time-series, from a peak demand of 6496MW and annual total energy requirement (TER) of 36.56TWh was manipulated to achieve a peak demand of 7317 MW and TER of 39.85TWh in 2020 [9]. It is then scaled between the two nodes NI and ROI at

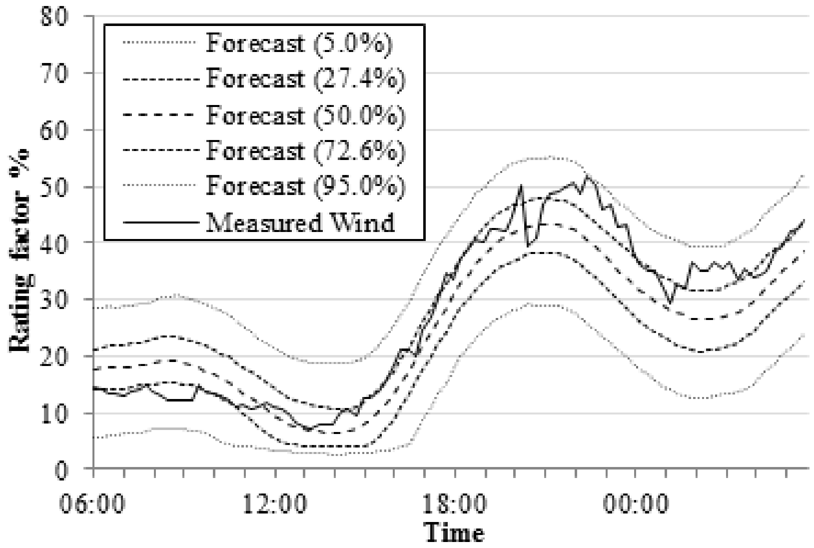


Figure 8.5: The five cumulative probability levels of DA wind forecast profile quantiles given to PLEXOS for the 6% MAE scenario and measured wind generation for the 2nd April of the test year.

0.252 and 0.748 respectively, based on the present-day ratio of demand between the two nodes.

The generation portfolio is based on what is predicted to be present on the AI electricity system in 2020 [9]. The generator specifications are taken from [139]. Changes to the generation portfolio, not present in [139], for ROI and NI include the removal of all oil-fired power stations in ROI along with the units B4-6 in NI, and the addition of generators which are shown in Table 8.2.

Only one of the two the OCGTs, Cahir or Culleen, was retained due to the recommendation to only include three of the four currently-planned OCGTs in the model of [9]. The new peaker plants, aggregated generation units (AGU) that mimic OCGT plants, and the new demand side units are all based on the specifications of the modern OCGT in Kilroot (KGT3) due to it being most recent OCGT addition to the SEM. Small scale hydro, tidal, small bioenergy energy plants have also been included in keeping with [9]. The non-wind priority dispatch plants were modelled with a zero generation cost in keeping with [154]. Fuel prices for 2020 were taken from [58]. The model also includes start-up costs and start-up fuel off-take which were taken from [161]. A carbon tax was included at €30 per tonne of CO_2. Interconnection between the SEM and Great Britain (GB) is represented by the ROI-GB East West Interconnector (EWIC) at 500MW and Moyle between NI and GB at 450MW in winter and 410MW in summer.

Table 8.2: Additions to the generation portfolio from the All Island Grid Capacity Statement 2013-2022 not present in the Commission for Energy Regulation's SEM 2012 forecast model.

Generator name	**Capacity (MW)**
ROI	
Cahir or Culleen (OCGT)	98
NO1 (OCGT)	98
Caulstown (OCGT)	55
AE1 (DSU)	12
DAE (DSU)	29
Wind	3786
Dublin waste to energy	62
Small scale hydro	21
Biogas from landfill	43
Three biomass plants (CHP)	50 (x3)
NI	
Aggregated generation unit (AGU)	47
Wind	1278
NI waste to energy	17
Small scale hydro	4
Tidal	154
Biogas from landfill	23
Small scale biogas	30
Three biomass plants	15 (x3)
Small scale biomass	14

[9, 139]

Operational constraints have a large effect on the results, particularly in terms of dispatch and wind curtailment [22]. The operational constraints applied here are based on [78], conservatively modified to reflect the changes that are likely occur by 2020, including increasing maximum flow between ROI and NI to 2000MW both ways, and raising the system-wide limit on non-synchronous sources to 70% of total generation and exports [22, 21].

8.4 Results

The results presented here are averaged over ten separate runs for each MAE scenario with standard deviations of the results shown only for total costs (Fig. 8.6). The key result of this work is the relationship between wind forecasting accuracy and total generation costs[4]. There is a clear trend of total generation costs reducing with improvements to wind forecasting accuracy shown in Fig. 8.6. The figure also shows that the magnitude of the savings is

[4]Total generation costs for AI refers only to cost of the conventional generation and does not include the cost of subsidies for renewables.

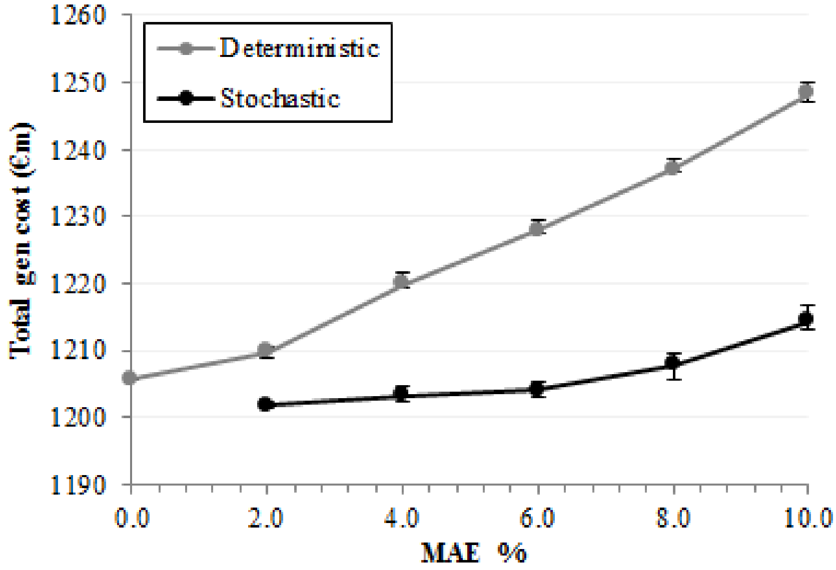


Figure 8.6: The mean total generation costs (€m) with standard deviation whiskers for both deterministic and stochastic modelling at different forecast accuracies (MAE%).

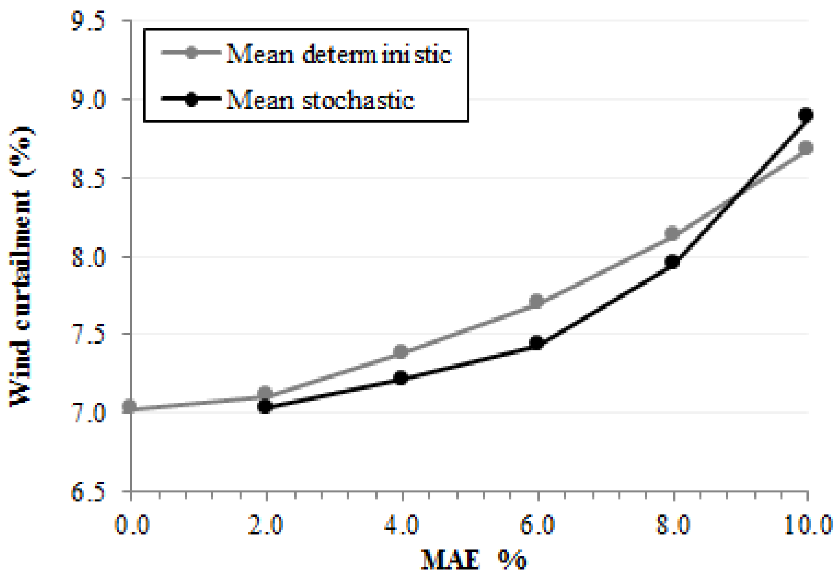


Figure 8.7: The mean percentage of wind curtailment for both deterministic and stochastic modelling at different forecast accuracies (MAE%).

very dependent on the method of scheduling, be it deterministic or stochastic. When using deterministic scheduling, total generation savings show an almost linear relationship of € 5m (0.41%) per year for every percentage point reduction in forecast MAE from 10% to 2%. However, when stochastic scheduling is employed, there is reduced advantage for improving wind forecast accuracy below 6% MAE, with savings of € 0.5m (0.04%) per year for

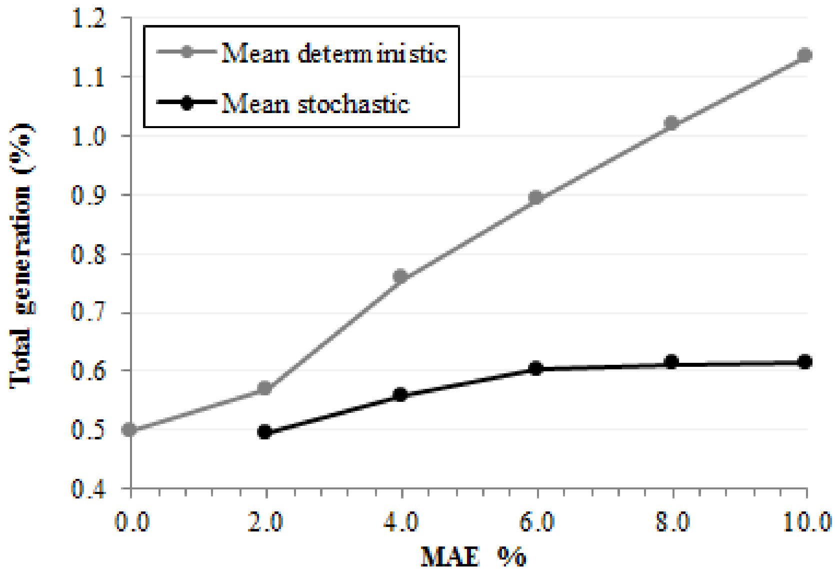


Figure 8.8: The mean OCGT generation as a percentage of total generation for both deterministic and stochastic modelling at different forecast accuracies (MAE%).

every percentage point decrease below this level. However, a clear advantage of improving wind forecast accuracy from 10% to 6% MAE remains, with €2.5m (0.20%) savings per year for every percentage point decrease in this range. The dependence of wind curtailment (Fig. 8.7) and OCGT generation (Fig. 8.8) on wind forecast errors are also presented for both scheduling methods.

Table 8.3: Mean number of OCGT start-ups, mean emissions intensity (kg /MWh), and mean of total generation (GWh) in the SEM for both deterministic and stochastic modelling at different forecast accuracies (MAE%).

	Forecast scenario (MAE)					
OCGT	**0%**	**2%**	**4%**	**6%**	**8%**	**10%**
Deterministic	381	528	617	704	792	892
Stochastic	-	433	457	451	445	439
Emissions	**0%**	**2%**	**4%**	**6%**	**8%**	**10%**
Deterministic	339.5	338.5	339.4	341.4	342.8	342.9
Stochastic	-	337.5	337.2	338.0	338.2	339.6
Total generation	**0%**	**2%**	**4%**	**6%**	**8%**	**10%**
Deterministic	40.22	40.48	40.49	40.46	40.48	40.51
Stochastic	-	40.38	40.30	40.18	40.05	39.88

Table 8.4: The mean percentage of total generation for the dispatch of generator technology type for deterministic modelling at different forecast accuracies (MAE%).

	Forecast scenario (MAE)					
Generator type	**0%**	**2%**	**4%**	**6%**	**8%**	**10%**
OCGT	0.50	0.57	0.76	0.89	1.02	1.14
CCGT	36.35	37.02	37.03	36.83	36.83	37.19
Steam Turbines	18.22	17.89	17.83	17.99	18.03	17.78
CHP and Waste	4.26	4.20	4.19	4.19	4.19	4.19
Wind	32.87	32.63	32.53	32.44	32.27	32.06
Other RES-E	7.79	7.68	7.67	7.66	7.66	7.65

Table 8.5: The mean percentage of total generation for the dispatch of generator technology type for stochastic modelling at different forecast accuracies (MAE%).

	Forecast scenario (MAE)					
Generator type	**0%**	**2%**	**4%**	**6%**	**8%**	**10%**
OCGT	-	0.49	0.56	0.60	0.61	0.61
CCGT	-	36.79	36.74	36.49	36.55	36.65
Steam Turbines	-	17.96	17.88	17.96	17.88	17.89
CHP and Waste	-	4.26	4.28	4.33	4.39	4.44
Wind	-	32.74	32.73	32.74	32.66	32.47
Other RES-E	-	7.77	7.81	7.86	7.91	7.95

8.5 Discussion

The perfect foresight (0% MAE) scenario is only presented to illustrate a lower bound to system costs incurred due to wind forecasting errors. In reality, it is unlikely that wind forecast accuracy for this system could be improved beyond the 2-4% MAE range. It was apparent from the work carried out on creating the wind forecasts in Section 8.3.2 that the 2% MAE wind forecast very closely resembles the result of time-smoothing of the actual wind generation. Therefore this discussion will focus on comparing the changes of effects on the AI electricity system from improvements in wind forecasting from 8% MAE, representative of the present-day accuracy of 7-9% MAE [80], to 4% MAE, assuming this to be a more realistic limit to possible future improvements.

It is important to note that there is some variation in the total AI generation between all the scenarios which distort the results. These variations are shown in Table 8.3 and occur due to changes in the scheduling of the interconnectors and the use of pumped hydro energy storage plant in the RT model. Due to these variations it is necessary to scale all total cost data in Fig. 8.6 to allow for comparisons between the scenarios to be made.

Overall, the results show that taking account of probabilistic wind forecasts by employing stochastic scheduling creates a much more efficient DA UC schedule than can be obtained from the deterministic approach. Changing from deterministic to stochastic scheduling leads to a greater saving than a 4% improvement in wind forecasting accuracy from present-day levels.

8.5.1 Costs

The results show that with improvements in wind forecast accuracy from 8% to 4% MAE, there are considerable savings available in terms of total system costs. These savings amount to 0.50% and 1.64% respectively, depending on whether deterministic or stochastic scheduling is used. This is a respective saving for stochastic and deterministic scheduling of € 1.2m and € 4.5m per year for every percentage point decrease in forecast MAE between 8% and 4% MAE.

8.5.2 Dispatch of renewables

With improvements in wind forecasts there is a reduction in the quantity of wind curtailment, shown in Fig. 8.7. There is very close agreement between the stochastic and deterministic scheduling for wind curtailment across the full range of scenarios and with the greatest reductions in wind curtailment occurring in the 10-4% range of MAE. There is a decrease in wind curtailment possible from 8% to 7.25% or 105 GWh in the 8% to 4% forecast MAE range. This result differs with work reviewed [99, 24, 23, 102, 103, 94, 55, 106] which finds that wind forecasting has a negligible effect on wind curtailment and continues to support the initial findings published in [22].

8.5.3 Dispatch of conventional generators

Similar to the effects on total generation costs, the effects on generator technology dispatch from wind forecast inaccuracies is much more apparent in deterministic than in stochastic scheduling, this being evident in Tables 8.4 & 8.5. It is shown in Fig. 8.8 that OCGT generation reduces almost linearly with wind forecast accuracy improvements when using the deterministic scheduling, with decreases in OCGT generation of 23% possible if wind forecast MAE is reduced from 8% to 4%. However while OCGT generation is also shown to reduce with wind forecast error under stochastic scheduling, this is to the lesser extent of 8%.

The trends in the number of OCGT start-ups shown in Table 8.3 very closely reflect the OCGT generation trends shown in Fig. 8.8. There is no noticeable change in the number of starts for the different wind forecast accuracies when using stochastic scheduling but when using deterministic scheduling there is an almost linear decrease in the number of OCGT start-ups required with improvements in the accuracy of wind forecasting.

There is no clear relationship evident in Tables 8.4 & 8.5 between the proportion of generation from CCGTs or steam turbines and improvements in wind forecast accuracy under either deterministic or stochastic scheduling. There is an apparent general trend of improvements in the carbon dioxide emission intensity with wind forecast improvements shown in Table 8.3, despite some variations occurring due to the sensitivity of CO_2 emissions to the coal-gas generation ratio.

8.6 Conclusion

The work presented here quantifies the value of wind forecast accuracy to an electricity system with high wind penetration, and in doing so helps to justify further investment in improving wind forecasting techniques. The results show that with a reduction in wind forecast errors from 8% MAE to 4% MAE, there are available savings in terms of total system costs under both stochastic and deterministic scheduling of 0.50% and 1.64% respectively. Operational advantages also come from improved wind forecasts, as there is general agreement between stochastic and deterministic scheduling in relation to wind curtailment, showing a reduction of 9% in wind curtailment. Improved wind forecasts also are shown to have an effect on OCGT scheduling with realistic possible decreases in OCGT generation of 23% using deterministic scheduling and 8% using stochastic scheduling. From this, there are clear benefits in improving the quality of wind energy forecasts as it allows for more efficient use of non-wind generators and the transmission system.

This work also strongly highlights the benefit of creating the day-ahead unit commitment schedule from wind forecasts through stochastic scheduling rather than deterministic scheduling. This allows the uncertainty associated with wind forecasts to be accounted for in the UC process. At today's wind forecast accuracy levels, switching from a deterministic to stochastic scheduling would allow savings of 2.46% of total system costs in 2020.

8.7 Added discussion

Due to variations between scenarios in total annual generation of the AI system it is necessary to factor all total cost data in Fig. 8.6 to allow for comparison between the scenarios. The total AI generation chosen as datum was the stochastic MAE2% scenario. It is also why the dispatch of generation types that are presented in Fig 8.8 and Table 8.4 and 8.5 are shown in percentage of total generation.

It also should be noted that when referring to the total cost of AI generation this refers only to cost of the conventional generation present on the AI system and does not include the cost of renewable tariffs which would almost double the total generation costs if included.

The explanation to why the perfect foresight scenario is more expensive than the stochastic 2% MAE scenario is due to the stochastic 2% MAE scenario accommodating forced outages more efficiently in the DA UC schedule (Fig. 8.6). This is due to more time been schedule for the large generators to be on-line, to accommodate the wind forecast inaccuracy, than in the deterministic scheduling.

Overall the results show that when modelling wind forecasts while taking account of the probabilistic error by using a stochastic scheduling creates a much more efficient DA UC schedule. Changing from modelling wind forecast from the deterministic to the stochastic scheduling has a greater saving than a realistic improvement in wind forecasting. For example the saving from the deterministic 8% MAE to 4% MAE scenarios is 20 €m (1.64%) per year, the saving from the stochastic 8% MAE to 4% MAE scenarios is 6 €m (0.50%) per year but the saving for the change from deterministic to stochastic 8% MAE scenarios is 30 €m (2.46%) per year.

Chapter 9

Discussion

9.1 Wind Capacity Required to meet 2020 Targets

The primary result of work presented in Chapter 6 is an estimate of the required installed wind capacities for both NI and ROI to meet their 2020 RES-E targets. It was shown that the wind capacity required to meet the RES-E targets varies considerably (Table 6.3), this being dependent on assumptions made about the future electricity system. This work indicated that the two largest factors influencing the required installed wind capacities are wind curtailment resulting from SOCs and the amount of non-wind, synchronous, renewables such as Biomass that will be constructed. The proportion of onshore/offshore wind in the generation mix also was shown to have small effects on the required installed capacity.

The wind capacities required are affected by the large variation in wind curtailment that occurs, based on assumptions made in relation to the SOCs and offshore/onshore installed wind capacity mixes. The installed wind capacity estimate ranges from 6287MW to 6890MW. This results in an extra cost of €905 million [1] between present day SOC assumptions and what was considered to be the lowest technically feasible wind curtailment scenario, assuming no new offshore wind is constructed anywhere in AI. In the context of the electricity system this is a considerable extra expense similar in magnitude to 1.5 times the cost of the EWIC interconnector between ROI and GB [60].

[1] The assumed cost of an installed MW of wind (2013 prices) is 1.5 million €/MW for onshore wind [38].

The results from Chapters 7 and 8 confirm that with the predicted generation portfolio put forward in [9], the AI electricity system is on target to meet its 2020 RES-E obligations on the condition that all the non-wind renewable generation is constructed (Fig. 8.5 and Table 8.5).

However the results in Chapter 6 also highlight the importance of assumptions made about the amount of non-wind, synchronous, renewable plant such as Biomass that will be installed. Given the lack of activity around the non-wind renewable sources, it has to be assumed that wind energy will have to replace this technology in the event of a shortfall in its construction in order to meet the 2020 RES-E targets. This has a large effect on how AI will meet its RES-E targets and how much wind curtailment will occur in the future. For AI to meet its RES-E targets in a wind scenario where it was assumed that no new offshore wind was installed and there is no contribution from new non-wind, synchronous, renewables, this resulted in a required wind capacity of 6287MW even though the highest feasible SNSP limit of 75% was used. This differs greatly with the estimate of [9] which assumed an installed wind capacity requirement for AI of 4778-5278MW for 2020. The omission of all new non-wind renewable sources in [39], leads to a higher percentage of total generation coming from wind energy in order to fulfil the 2020 RES-E targets. This increased wind capacity requirement leads to increased curtailment as the proposed alternative of biomass plants will be synchronous machines and not curtailable due to the SNSP limit.

On comparison of work presented in Chapter 6 to Chapter 7 and Chapter 8 with similar RES-E targets being meet (Fig. 8.5), large differences were shown in the required installed wind capacities. The installed wind capacity in Chapter 6 for the 70% SNSP scenario which excluded new non-wind renewables was 6349MW where the equivalent scenario in Chapters 7 and 8 including new non-wind renewables only have a installed wind capacity of 5064MW. It should be noted however, that there is not a linear relationship between increased biomass generation and the reduction in wind curtailment while meeting the RES-E targets. This is due to biomass being a priority dispatch generator which leads to a reduced amount of demand to be meet by conventional generation during times of high penetrations of wind.

There was a clear trend of a reduction in overall installed wind capacities with an increased proportion of installed wind offshore, however accounting for the cost[2] of the installation of offshore wind, it was shown to be of no economic benefit on comparison with onshore wind. However this was studied in isolation of the wider benefits from offshore wind, which is discussed further are Section 9.2.

9.2 The effects of increasing the proportion of offshore wind installed capacities

The effects of spatial correlation in generation output from the installed wind capacity in AI are discussed here. Offshore wind usually operates at a higher capacity factor, this combined with the greater spatial spread of installed capacity, acts to reduce the overall variability of aggregate wind generation output. This is examined by attempting to quantify the benefits of increasing the installation of offshore wind and in doing so helping to justify the higher installation costs associated with offshore wind.

9.2.1 Onshore/offshore mix and costs

On comparison of the installed wind capacities required, with a SNSP limit of 70%, from a low offshore wind scenario where no new offshore wind was constructed, to a high offshore wind scenario where 1309MW was installed offshore, there was 397 MW less installed wind capacity required to meet the RES-E targets in the high offshore scenario. However on the examination of the cost of installing offshore wind there was an extra €1972 million [3] difference required in wind farm installations. This cost differences however should be considered with the potential savings in the reduce grid reinforcement costs in the west of the Island, planned under Grid 25 [116], if a larger proportion of offshore wind is installed in AI. The main reason behind this would be that the electricity grid on the eastern side of the Island is stronger than on the western side and therefore more capable of dealing with the large amounts of variable generation. Offshore wind would also be located closer to the main load centres located on the east of the Island.

[2]The assumed cost of an installed MW of wind (2013 prices) is 1.5 million €/MW for onshore wind and 3.5 million €/MW for offshore wind [38].

[3]The assumed cost of an installed MW of wind (2013 prices) is 1.5 million €/MW for onshore wind and 3.5 million €/MW for offshore wind [38].

9.2.2 Onshore/offshore mix and wind curtailment

There was a clear benefit in the reduction in wind curtailment from having an increased proportion of the installed wind capacity placed offshore. There was a potential reduction shown of 1-1.5 percentage points in wind curtailment if the proportion of offshore wind was increased from approximately 0% of total wind capacity to 22%. This would be directly attributed to the reduced spatial correlation from the wider geographical spread of the installed wind capacity across AI.

If the assumption for the offshore wind capacity factor used (40%) was inaccurate and it is less than 40% there would be an overestimation of the energy yield resulting from the offshore wind scenarios assumed in the model. The impact of reducing the energy yield from offshore wind in the East of AI and increasing the amount of onshore wind turbines in the west of AI to compensate would reduce the geographical spread of the turbines. Albeit small, this would almost certainly increase wind curtailment if it were the case.

Incorporation of the AI transmission grid into the model may also have added to reductions in dispatchable wind in the form of wind constraints as the grid is not as well developed in western parts of ROI, where the largest proportion of wind will be installed. If Grid 25 [116] is not implemented fully then wind may be locally constrained due to the lack of transmission, especially in the west, even if the SNSP limit is not reached.

9.2.3 Onshore/offshore mix and conventional generation effects

On examination of the results of increasing the proportion of offshore wind, the overall effect on conventional generation was negligible. This could be due to the hourly resolution of wind data available shown in Section 5.4.1. Higher time resolution simulation may allow for the capturing of benefits of adding offshore wind to the generation mix such as the reduction the overall wind generation variability. Excessive cycling of conventional generation can be damaging and costly which is often overlooked due to the difficulty of quantifying its costs in economic terms. Savings would result from reduced ramping intensity and reduced variability of conventional generation. The reduced variability of conventional generation arises from the decreased spatial correlation from the increased geographical spread of the installed wind capacity and the higher capacity factors likely to be obtained at offshore wind farms.

9.3 Benefits of wind forecast improvement & stochastic unit commitment

This section is a discussion based on the effects from the unpredictable nature of wind generation. Chapter 8 illustrates the clear benefits from improving the accuracy in wind forecasts in terms of costs and wind curtailment. The benefits are also shown of TSOs switching DA UC decisions from the traditional deterministic wind forecast scheduling to that of a stochastic scheduling approach, where the known error of wind forecasting can be taken in accounted.

In Chapter 6 the model assumes perfect foresight on wind generation but in reality this is not the case. Chapter 8 attempts to quantify the effects of the perfect foresight assumption.

The perfect foresight (0% MAE) scenario was only presented to give a lower bound limit to system costs due to wind forecasting error. Realistically the most accurate wind forecast that could be achieved is likely to be in the range of 2-4% MAE at best. It is evident from the work carried out on creating the wind forecasts in Section 4.4 that the main source of error in a 2% MAE wind forecast is short-term temporal fluctuations which are difficult to forecast (Fig. 4.7). From this it should be thought while viewing the results, that realistic improvements in wind forecasting accuracy could be from present-day 7-9% MAE [80] to at most accurate a range of 2-4% MAE. Therefore in this discussion there will be a focus on comparing the changes of effects on the AI electricity system from improvements in wind forecasting from 8% MAE to 4% MAE, assuming this to be more realistic of possible future improvements to future wind forecasting accuracy.

The work presented in Chapter 8 could be best compared to the results of [24, 99]. However some fundamental differences remain between the pieces of work. The method shown in Chapter 8 assumes that the DA UC was created once with alterations only possible during RT simulation with in certain conditions, this differs from [99] which assumes the same increasing forecast accuracy over time with the rescheduling occurring at the intervals in time of the rolling UC. In [24] wind curtailment was shown to be negligible due to SOCs not being included in the model, this omission has underestimated wind curtailment results. Furthermore, the forecast MAE used in the models of [24, 99] is not stated.

9.3.1 Forecast error and scheduling method effects on costs

The results showed that with improvements in wind forecast accuracy from 8% to 4% MAE there are considerable savings available in terms of total system costs. The magnitude of the savings are dependent on the chosen method of scheduling, either deterministic or stochastic.

There were respective savings for stochastic and deterministic scheduling of €2.5m and €5m per year, for every percentage point decrease in forecast MAE between 8% and 6% MAE and €0.5m and €5m per year for every percentage point decrease in forecast MAE between 6% and 4% MAE (Fig. 8.6).

As shown in Chapter 8 deterministic scheduling is much more sensitive to changes in model inputs, however modelling wind forecasts while taking account of the probabilistic error by using stochastic scheduling creates a much more efficient DA UC schedule.

Taking account of probabilistic wind forecasts by employing stochastic scheduling creates a much more efficient DA UC schedule than can be obtained from the deterministic approach (Fig. 8.6). Changing from deterministic to stochastic scheduling leads to a greater saving than a 4% MAE improvement in wind forecasting accuracy from present-day levels while maintaining deterministic scheduling. This means that there are greater savings from changing to stochastic scheduling than from any realistic improvement in wind forecasting accuracy.

From the results shown in Chapter 8 the explanation as to why the perfect foresight scenario is more expensive than the stochastic 2% MAE scenario is due to the stochastic 2% MAE scenario accidentally accommodating forced outages more efficiently in the DA UC schedule due to more time being scheduled for the large generators to be on-line, to accommodate the wind forecast inaccuracy, compared to the deterministic scheduling.

9.3.2 Forecast error and scheduling method effects on wind curtailment

The inclusion of forecasting errors results in increased wind curtailment particularly on the higher SNSP limits such as 70%. The dispatch scheduling structure used by the TSO requires DA UC for the large generators and must rely on a wind forecast with an outlook over 24 hours. Due to the requirement for a certain number of large generators to be on-line in order to provide inertia and reactive power for grid stability, accurate forecasts result in the efficient DA commitment of large generators.

With improvements in wind forecasts there is a reduction in the quantity of wind curtailment (Fig. 8.7). There is very close agreement between stochastic and deterministic scheduling for wind curtailment across the full range of scenarios. There is a decrease in wind curtailment from 8% to 7.25% or an extra 105 GWh/yr of wind energy being utilised by improving the wind forecast from 8% to 4% MAE. This result differs with work reviewed [99, 24, 23, 102, 103, 94, 55, 106] which found that wind forecast accuracy has a negligible effect on wind curtailment.

9.3.3 Forecast error and scheduling method effects on conventional generation effects

Similar to the effects on total generation costs, the effects of wind forecast inaccuracies on dispatch of different generator technologies were much more apparent in deterministic than in stochastic scheduling (Tables 8.4 and 8.5).

With increasing wind forecast accuracy, there was a decrease in overall OCGT usage (Fig. 8.8). When using deterministic scheduling there were decreases in OCGT generation of 23% possible if wind forecast accuracy was increased from 8% to 4% MAE. While OCGT generation was also shown to reduce with the same improvement in wind forecast accuracy under stochastic scheduling, this was however to the lesser extent of only 8%. These results are due to larger forecasting errors creating greater requirements for generators that are not committed in the DA UC schedule, such as OCGT's, to be used to balance the system. This is an undesirable result for the TSO as OCGT's are relatively inefficient and have high marginal costs. OCGT's are mainly intended to be used as peaking plant and, while providing a very important service to the electricity system, their use should be minimised.

The trends in the number of OCGT start-ups very closely reflect the OCGT generation trends (Table 8.3 and Fig. 8.8). There is no noticeable change in the number of starts for the different wind forecast accuracies when using stochastic scheduling however when using deterministic scheduling there is an almost linear decrease in the number of OCGT start-ups required with improvements in the accuracy of wind forecasting.

There was an apparent and general trend of improvements in the carbon dioxide emission intensity with wind forecast improvements (Table 8.3), despite some variations occurring due to the sensitivity of CO_2 emissions to the coal-gas generation ratio.

9.4 The effects of system operational constraints for frequency response

This section centres on a discussion of the effects of maintaining sufficient amounts of inertia on the AI system to allow for frequency response to be kept within operational limits and illustrates the importance of increasing the SNSP limit as high as technically and economically feasible.

9.4.1 System wide operational constraints effects on costs

Due to the assumption that the RES-E target was met in all scenarios shown in Chapter 6, this resulted in the total conventional generation being approximately equal throughout scenarios presented and therefore was not reported. However comparisons can be drawn from Chapter 7 where total generation costs for the base case showed reductions from €1225m down to €1214m when allowing the SNSP limit to be relaxed from 60-75% for same amount of wind capacity installed (Fig. 7.4).

9.4.2 System wide operational constraints effects on wind curtailment

The work presented in Chapter 6 has shown that in 2020 there is a dramatic variation in wind curtailment estimates, from approximately 14.5% to 6.8%, with an increase in the SNSP limit from to 60% up to 75% respectively. Work in Chapter 7 and 8 both showed similar values, approximately 8% wind curtailment, for the corresponding scenarios of 70% SNSP limit with other local SOCs remaining unchanged even though there are different installed capacities of wind and biomass. This indicates that wind curtailment will occur regardless of the proportions of installed wind and biomass if AI is to meet its RES-E targets.

The importance of wind curtailment is not only to the cost of operating the system, but also to wind farm developers who would almost certainly not have accounted for wind curtailment levels of 14.5% in their financing plans. With wind curtailment in 2020 not being compensated, this would result in many current wind farm developments not being economical and would also result in future contracted wind farms not being built. This would completely undermine the ability of AI to meet the RES-E targets through market forces.

From Eqn. 4.7 it is evident that increasing exports to a maximum during times of high wind power penetration on the all-island system will be essential to reducing the amount of wind curtailment that will be necessary with a fixed SNSP. This raises an issue over the use of the interconnectors. A major influence on the AI's ability to export electrical energy to the GB will be GB's targets for installed wind capacity by 2020. In addition to this, the times of peak wind power on the All-island system and time differences, either leading or lagging, relative to wind power peaks in GB will also be important considerations for wind energy export.

In Chapter 6, GB wind generation was represented by scaling an AI time-series and adding a fixed time lag. This simplification may have large effects on the interconnectors' predicted ability to export at certain times. At times of near peak wind power on the AI system the time difference, leading or lagging, of wind power peaks in GB will be important. It was assumed that GB wind data was at a constant lag of two hours relative to of an east coast AI wind region and this may have resulted in an over-estimate of wind curtailment. This is due to the usage of the interconnections being restricted in times of peak wind generation in Ireland when in fact peak wind generation in GB may have occurred slightly earlier. To mitigate the assumptions made above, the spatial correlation of wind data, as described in Section 5.4.2, was taken into account for work presented in Chapters 7 and 8.

9.4.3 System wide operational constraints effects on conventional generation effects

There was notable difference in the minimum amount of conventional generation occurring for the extreme SNSP limit of 100% in scenarios with and without SOCs being accounted for (Figs. 6.5(c) and (f)). It is not a reasonable assumption to make to allow all conventional generation to be off line at any point in time as there would no synchronised inertia or reactive power support on the system. This situation occurring on the real AI electricity system today would result in inevitable blackout of the entire system.

9.5 The effects of local system operational constraints for voltage control and jurisdictional frequency response.

This section is a discussion about the effects on the AI electricity system of constraints imposed to maintain certain levels of voltage control and inertial response. In Chapter 6 it was shown that beyond a SNSP of 70%, local SOCs begin to contribute to the majority of wind curtailment. This unexpected result led to further investigative work shown in Chapter 7. It would be reasonable to assume that there will be relaxations of the SOCs in the future as this is being addressed by the TSOs EirGrid and SONI in the DS3 programme [81]. Chapter 7 attempted to address the issue of SOC relaxation effects and showed the strong effects that relaxation of SOCs would have on the future AI system in terms of total generation costs, wind curtailment and generator dispatch by technology type. This work also illustrates that allowing the relaxation of the system-wide SNSP limit constraint beyond 70% has almost negligible effects on the AI system and shows the importance of dealing with the local SOCs in conjunction with system-wide SOCs. This work is viewed as one side of the cost benefit analysis to implementation of system operational constraint relaxation with other side been the cost of implementation which is viewed as outside the scope of the thesis and is not researched in depth other than what is reported in Sections 3.2.1.

9.5.1 Local system operational constraints effects on costs

In Chapter 7 it was clear that the two local SOCs associated with urban voltage stability, Dub(2/3) and CPS(1), were the most costly constraints on the AI system [175]. This result was not expected as initially it was assumed that ROI and NI system stability SOCs would be the most influential along with the system-wide SNSP limit.

The most striking result from this study was the lack of reduction in total generation costs when the SNSP limit was raised above 65% unless both of the two most influential constraints, Dub(2/3) and CPS(1), are relaxed first (Fig. 7.4). This shows the cost effects of maintaining urban voltage control through traditional methods into the future. It also strongly indicates that tackling system-wide problems requiring a SNSP limit of above 65% is a secondary concern to that of "minimum number of conventional generators on-line" SOC's required to maintain reactive power supplies for local voltage control.

It was shown that relaxing the constraint Dub(2/3) has the biggest impact in terms of generation cost savings [175] and regardless of the SNSP limit imposed, this yields an almost constant saving of €38 million per year. Therefore Dub(2/3) should be considered as a priority to be relaxed first, subject to the cost and feasibility of the required grid upgrades. Comparison of the generation savings to the costs for installation of voltage control support devices strongly supports further investigation of reactive power support devices as even the installation of seven STATCOMs or synchronous condensers will still result in pay back in approximately one year if the Dublin voltage control SOCs can be relaxed (Table 3.3).

On examination of the combined effects of relaxing the five most influential SOCs there were potential savings of €95 million per year. This clearly illustrates the need for investment in the AI electricity system to help mitigate the issues associated with voltage control and frequency response that will be present in the future electricity system highlighted in [21, 80]. These annual savings justify investment into technologies, presented in Tables 3.2 and 3.3, permitting the relaxation of the local SOCs.

It was also notable that under 2020 predictions, savings are limited when the SNSP limit is relaxed past 70%, even if all the other SOCs are relaxed also. This would indicate that further relaxation of the Dub(1/2) or the NI-s(2) constraints may be necessary in order to deliver further reductions in total system cost.

9.5.2 Local system operational constraints effects on wind curtailment

Minimising the amount of wind curtailment is very desirable to help meet the 2020 renewable energy targets and in general to ensure maximum use of wind generation assets. It was shown in Chapter 7 that wind curtailment is strongly influenced by changes to SOCs.

An important finding presented in Chapter 6 was the inclusion of SOCs, in their present form, prevented the further reduction in wind curtailment beyond the 75% SNSP limit with minimal reductions in wind curtailment beyond 70% SNSP. This is a result of a minimum number of generators being forced to remain on-line generating at their minimum stable generation levels. The inclusion of SOCs in the model resulted in a minimum wind curtailment occurring of at least 6.5% irrespective of the SNSP limit imposed. Unlike the changes to total generation costs, wind curtailment is influenced more strongly by the reductions in the SNSP SOC than the four other "minimum number of conventional generators on-line" SOCs. It is also shown that with an increase in the SNSP limit beyond 75% there is little benefit in terms of wind curtailment if all other four SOCs are relaxed. This aspect, similar to total generation costs, would indicate that further relaxation of the Dub(1/2) or the NI-s(2) constraints may be necessary before wind curtailment can be reduced further.

There is the potential to reduce wind curtailment to 4% if the five most influential SOCs are relaxed, this is in comparison to the base-case scenario prediction that wind curtailment will be 8.3% if the SOCs are not relaxed from present-day values. With today's prices this equates to €42 million extra a year worth of wind energy that is theoretically available but not being utilised

[42].

There was also a clear benefit in the reduction of wind curtailment with just the relaxation of the voltage control SOCs, Dub(2/3) and CPS(1), with wind curtailment been reduced in the 70% SNSP case from 6.5% to 5.2%. This reduction in wind curtailment is achieved by allowing the CCGTs in the urban areas with high minimum stable level of generation, that are currently constrained to be on-line, to be replaced with cheaper coal plant that have lower minimum stable levels. It was interesting however to note that while it was more cost effective to relax Dub(2/3), it was however more beneficial in terms of wind curtailment to relax CPS(1) (Fig. 7.3.)

Following from the assumption made in relation to how wind curtailment is managed on the system, it was interesting to note how the relaxation of the SOCs causes a jurisdictional imbalance in wind curtailment. It was shown that NI stands to gain in terms of reduced wind curtailment however this is at ROI's expense (Fig. 7.6). This may lead to possible issues in the future regarding ROI wind farms being penalised with greater curtailment than NI wind farms if wind curtailment is dealt with on an individual TSO basis, or may lead to a need for a new constraint to equalise wind curtailment between the two jurisdictions, as explained in Section 4.5.3.

9.5.3 Local system operational constraints effects on conventional generation effects

As shown in the results from Chapter 6 there are large changes in the dispatch of conventional generators from the inclusion or exclusion of the local SOCs. These changes occur at the times of the lowest point of allowable conventional generation.

There was also a difference in the relative generation dispatch proportion of conventional generator technology types from mid-merit and base load plant which is a result of the SOCs controlling the use of the CCGTs for system stability issues. It is clear that the CCGTs, while more expensive to schedule than base load plants, play an important role in supporting the electrical system for issues such as local voltage control. In Chapter 7 the explanation of the total generation cost reductions achieved from the relaxation of local SOCs is the trend of replacement of CCGT generation for coal steam turbine generation (Fig. 7.4).

While the trends of OCGT usage in relation to changes in SNSP limit are not clear, it was evident that there is a small increase in OCGT usage with continued relaxation of the SOCs. On average for all SNSP scenarios there is an increase of an extra 44 GWh per year coming from OCGT when relaxing the four “minimum number of conventional generators on-line” SOCs. This is due to a higher frequency of extreme peaks and troughs forming in the conventional generation profile to accommodate the added wind energy resulting from relaxing the SOCs. This indicates that it is a cheaper solution to maintain coal plant on-line with low minimum stable generation levels and supplement generation with fast acting OCGT usage in times of large decreases in wind generation.

With the relaxation of the NI SOCs there was a dramatic shift in generation away from NI leading to NI being supported by ROI and GB through the North-South and Moyle interconnectors (Fig. 7.8). Remarkably, the system-wide SNSP limit constraint has almost no effect on this result. This shift in the relative proportions of total generation between the jurisdictions is a result of the NI local SOCs artificially keeping NI generation higher than would be the case in an unconstrained AI market model. This generation shift towards ROI also contributes to it being more efficient to curtail wind in ROI rather than NI as ROI already has a generation surplus (Fig. 7.6). This result emphasises the effects that SOCs have on the AI system on a jurisdictional basis. It also raise further questions over the full effects of the North-South interconnector being built.

9.6 Issues encountered and future work

There was an issue identified concerning OCGT usage from the “ROI-SW Generation, min no. on” SOC, shown in Table 4.4. It was found that this local constraint encouraged excessive usage of the OCGT’s and affected the DA UC of large generation units in the area of its influence. More importantly it was also increasing the shadow prices of the SEM which impacted the usage of interconnector schedule created in the day-ahead model. Therefore the OCGT memberships were omitted from the “ROI-SW Generation, min no. on” SOC in the DA model however was retained in the real-time model.

It is necessary for generators to synchronise to the grid over time, meaning PLEXOS® must schedule them in advance of actual commitment time. However there were infeasibilities occurring as a result of the committment of generators in the DA UC schedule and their forced outages ending in the RT. This ending of the forced outage and re commitment of the generator resulted in violation of ramping constraints. To resolve the infeasibilities that occurred in the simulation a penalty price of €1 million had to be introduced. This prevents infeasibilities occurring for a violation of a ramping constraint but imposes a large penalty on its violation to prevent it happening in all but necessary cases. This issue results from Irish SEM market rules on uplift calculations which assume that generators are modelled going from off-line to their minimum stable level (MSL) in one time interval of 30 minutes. This is too short a time period for larger generators to synchronise to the grid.

There is no functionality within PLEXOS® to allow the optimisation period's look-ahead window to use different data to that of the next optimisation period for the same overlapping time. This resulted in the optimisation period's look-ahead receiving the improved wind power forecast in the 06:00hrs-11:30hrs time period of the next simulation day.

Crucial now for the next step of development in this field is to start to simulate and understand the AI electricity system out to 2030. This includes development of the new I-SEM market, system services market and integration with the gas markets. Simulation of the issues raised in this thesis should be preformed for GB and mainland Europe as these much large, more complex systems will require a longer planing time for changes to there electricity systems than that of AI.

9.6.1 Omission of reserve

It was decided that reserve would not be included in the simulations carried out for this study. However PLEXOS® is capable of modelling all the reserve categories required by the SEM. This decision was necessary due to the dramatic increase in problem size associated with modelling reserves. From preliminary testing carried out it was found that the inclusion of the four types of reserve in the SEM increases model simulation time up to eightfold. Due to limited computational power available, there was a decision to be made between the inclusion of stochastic unit commitment or reserve modelling. It was decided that using stochastic unit commitment would be more relevant to the thesis' research question as capturing the effects of forecasting error was considered a priority.

Chapter 10

Conclusion and recommendations

To meet the 2020 RES-E targets set out for All-island of Ireland (AI) [1] there are large variations (ranging from 5064MW to 6890MW) in the amount of wind capacity required to be installed dependent on assumptions made. It has been shown that the two largest factors affecting the amount of wind capacity required are (1) wind curtailment occurring from system operational constraints (SOCs) and (2) the amount of non-wind, synchronous, renewables such as biomass that could be constructed. It is shown that if the entire projected capacity of 377MW non-wind renewable, synchronous, generation plant is constructed, then 5064MW of installed wind will meet the RES-E targets; however if none were constructed, then 5911MW of installed wind capacity would be required in the most optimistic scenario. The onshore/offshore wind mix also has small effects on the required installed capacity. Taking account of issues causing wind curtailment on the 2020 AI system dramatically increases the amount of installed wind capacity required to meet the RES-E targets. To help AI to meet its RES-E targets with the least amount of installed wind capacity it is clear that the system non-synchronous penetration (SNSP) limits must be increased as high as technically possible and also for the proportion of wind capacity installed offshore to be increased in the future.

A detailed examination of the effects of the relaxation of SOCs and the improvement of wind forecasting was also carried out. These effects are quantified in terms of changes to total generation costs, wind curtailment and generator dispatches.

[1] All-island of Ireland (AI), consist of Northern Ireland (UK) and the Republic of Ireland

There are large savings to be made with the relaxation of SOCs and improvements in wind forecasting. With the relaxation of the five most influential SOCs, there are potential savings in total generation costs of 7.8%. There are also large savings to be made with SOCs being individually relaxed. Most notably, if the Dub(2/3) SOC constraint requiring two large generators in the Dublin area are to be constantly on-line by day and three by night is relaxed to Dub(1/2), one by day and two by night, there is a saving of 3.1% of total system costs regardless of the SNSP limit imposed.

It has been highlighted that the relaxation of the SNSP limit is beneficial; however this will only deliver significant cost savings in conjunction with relaxing other SOCs associated with local voltage control. It has been demonstrated that increasing the SNSP limit beyond 65-70% has a limited value without prior relaxation of the other SOCs and it is also shown that there is limited value in increasing the SNSP limit beyond 70-75% even if all other influential SOCs are relaxed.

The results show that with a reduction in wind forecast errors from 8% mean absolute error (MAE) to 4% MAE, there are available savings in terms of total system costs under both stochastic and deterministic scheduling of 0.50% and 1.64% respectively. This work also strongly highlights the benefit of creating the day-ahead unit commitment schedule from wind forecasts through stochastic scheduling rather than deterministic scheduling as is presently the case. This allows the uncertainty associated with wind forecasts to be accounted for in the day ahead unit commitment process. At today's wind forecast accuracy levels, switching from deterministic to stochastic scheduling allows savings of 2.46% of total system costs in 2020.

Increasing the efficient use of the installed wind capacity in the future through minimising wind curtailment and therefore maximising usage of wind generation availability is of major importance. It has been highlighted that the relaxation of SOCs and the improvement in wind forecasts will both reduce wind curtailment significantly.

Wind curtailment is suggested to drop from an average of 14% to 8%, as the SOC of the SNSP limit alone is relaxed from to 60% to 70%. There is also a potential to reduce wind curtailment further from 8% to 4% when the four most influential local SOCs are relaxed and the SNSP limit is relaxed to 75%. By increasing the proportion of offshore wind, it is shown to aid in the reduction of wind curtailment by reducing the amount of wind curtailment occurring by at least one percentage point. Maintaining low amounts of wind curtailment is viewed as crucial to achieve continued investment in the wind energy industry; otherwise the installed wind capacities required for the RES-E targets will not be met. This work has also highlighted that an issue may arise in the future between the two jurisdictions (ROI and NI) with regards where best to curtail wind energy for the benefit of the system as a whole.

Reductions in wind curtailment come from realistic improvements in wind forecasts. There is a general agreement between stochastic and deterministic scheduling in relation to wind curtailment, showing possible reduction from 8.0% to 7.25% wind curtailment or an average 0.2 percentage point reduction in wind curtailment for every percentage point increase in MAE accuracy.

It has been shown that there are operational advantages from relaxing the SOCs for the dispatch of conventional generators allowing for achieving a more efficient generation schedule. However there are also negative effects, such as increased usage of open cycle gas turbines (OCGTs) as SOCs are relaxed. There is also a substantial effect on the relative contribution to total generation from the two jurisdictions when the NI SOCs are relaxed, with NI requiring support from ROI and GB in this case.

Improved wind forecasts also are shown to have an effect on OCGT scheduling with realistic possible decreases in OCGT generation of 23% using deterministic scheduling and 8% using stochastic scheduling.

10.1 Recommendations to Academia and the Transmission system operators

This work helps quantify the benefits and costs in terms of wind curtailment associated with of the relaxation of system operational constraints and improvements in wind forecast accuracy in an electricity system with high wind penetration. From this it is justified that further investigations should be carried out to mitigate problems associated with voltage stability and inertia requirements, and into improving wind forecasting techniques will be justified. These investigations should be carried out by both the Transmission system operator and academia alike.

10.2 Recommendations to the wind industry

Wind energy developers and existing wind farm owners should be particularly concerned by the predictions of increases in annual wind curtailment if changes are not made to how the electricity system is operated. It would be very much in the interest of the wind industry to investigate further the issues driving wind curtailment raised in this thesis.

This work also highlights the benefits in the reduction of wind curtailment from increasing offshore wind due to spatial correlation and therefore should be further investigated by offshore wind energy developers as a potential benefit in favour of regaining the offshore wind energy subsidies.

10.3 Recommendations to the Governments

The rise in wind curtailment also should be of concern to the Governments of ROI and NI. The current policy of meeting the 2020 renewable targets will not be met if wind energy developers find it no longer financially viable to invest due to high wind curtailment occurring. It is clear from the work done here that the Government must actively support the work of EirGrid and SONI's DS3 programme if the renewable targets are to be met.

10.4 Recommendations to the international community

The issues associated with large scale wind integration investigated in this thesis, while important for Ireland in the next five years, will also become important the GB synchronous system in the next 10 years as well as in the synchronous systems of Continental Europe in the next 30 years. This work illustrates the need for studies to be carried out on these larger systems to ensure adequate time to plan and invest in required changes.

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Appendix A

List of significant assumptions

Table A.1: The list of significant assumptions made and their potential effects

Assumption	Potential issues and effects	Section
Fuel prices	Coal to Gas price comparison is very important to scheduling base load plant	5.3.1
Installed wind capacity	The projected growth of the installed wind capacity may not occur due to an number of issues such as change in policy or increases in wind curtailment	5.2
Wind energy profiles	The wind energy profiles used represent one year of data and although an average wind speed year, do not account for hour to hour variability that occurs differently each year	5.4.1 5.4.2
Installed bioenergy capacity	The projected growth of the installed bioenergy capacity may not occur due to lack of investment. Also modelling their priority dispatch status effects results	4.6 5.1.1
Interconnector flow simulation	Interconnector flows are determined through a combination of GB market price and wind curtailment occurrence in GB, the details of which are difficult to estimate	5.5
System operating reserve	Non-inclusion of reserve will effect results by underestimation total generation costs and wind curtailment	4.5.4
No transmission system modelling	Inclusion of the transmission system results in an in better estimation of total generation costs and helps to capture wind constraint (localised wind curtailment)	3.4
System demand	The projected growth of total system demand will be dependent on the GDP growth and efficiency savings of AI. And profile changes due to demand side management	5.4.3
System operational constraints	The changes in how system operational constraints can be relaxed in reality may not be that assumed, resulting in reduced potential befits.	4.5.2
Post unit commitment relaxation	The PUCR assumes 200GWh of OCGT usage in 2020 with perfect foresight, this may be an under or over estimation	4.2.2
Model problem size reduction	The techniques used to reduce model problem size do effect results, mitigation of this is implemented.	4.8
Technical offer data	All technical offer data is taken from the CER's SEM 2012 forecast and backcase model [139, 161]	5.1.1