System Operator for Northern Ireland

All-Island Generation Capacity Statement
2014-2023

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This document incorporates the Generation Capacity Statement for Northern Ireland and the Generation Adequacy Report for Ireland.

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12 Manse Rd, Belfast, BT6 9RT, Northern Ireland.

The Oval, 160 Shelbourne Road, Ballsbridge, Dublin 4, Ireland.

Front cover images:

- RISE is a concept public art spherical metal sculpture by Wolfgang Buttress, constructed in early 2011, and is Belfast's largest public artwork. The globe-shaped, white and silver steel sculpture is a representation of a new sun rising to celebrate a new chapter in the history of Belfast.
- The Mary McAleese Boyne Valley Bridge spans the Boyne River, 3 kilometres west of Drogheda, on the boundary between County Meath and County Louth, and is part of the M1 Northern Motorway. Being a cable-stayed bridge, it can incorporate a much longer main span without the need for supports in the river, and so help to protect the environmentally sensitive river below from interference.

FOREWORD

EirGrid and SONI, as Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively, are pleased to present the All-Island Generation Capacity Statement 2014-2023.

This statement outlines the expected electricity demand and the level of generation capacity available on the island over the next 10 years. Generation adequacy studies have been carried out to assess the balance between supply and demand for a number of realistic scenarios.

The electricity transmission system of Ireland, or of Northern Ireland, can be, and has been, run as a completely separate system. However, there are many benefits to sharing resources:

- technically, a high voltage electricity network is more secure and can be operated more reliably when interconnected with another system;
- economically, advantage can be taken of the lowest-priced generators in either system;
- and environmentally, where less generators need to be built, more efficient, carbon-friendly generators can run more often, and more renewable energy can be transferred to where it is needed.

Consumers on the island have been benefitting from these advantages for many years because of the North-South Interconnector that currently joins the two jurisdictions. Also, many of these benefits accrue from the two interconnectors across the Irish Sea to Britain. Indeed, recent studies have indicated that the introduction of the East West Interconnector has reduced wholesale electricity prices by approximately 8%.

However, the transfer of power between Ireland and Northern Ireland is limited because of the size of the current North-South Interconnector. The surplus of generation in

Ireland cannot be fully utilised to help alleviate shortfall in Northern Ireland.

This becomes particularly pertinent when a significant amount of generation plant in Northern Ireland is required to close due to EU emissions directives in 2015. The second North-South interconnector will alleviate this and is expected to be in place by the end of 2017.

With regard to renewable energy sources (RES), both governments have set a target of generating 40% of all electricity from RES by 2020. Alongside other RES, we have predicted that to meet this ambitious target, current installed wind levels will need to be doubled to between 4,400 and 4,900 MW.

All this extra wind capacity will lead to new challenges in the way the system is operated. We are working with industry stakeholders to ensure the continued safe and secure operation of the power system.

I hope you find this document informative. I very much welcome feedback from you on how we can improve it and make it more useful.

Fintan Slye
Chief Executive, EirGrid Group.
February 2014

Table of Contents

Table of Figures

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

KEY MESSAGES

All–Island

- With the completion of the second North-South interconnector, there will be no significant transmission constraints between Ireland and Northern Ireland. All the generation on the island can then be utilised together to meet the combined demand in the most economic, secure and reliable manner possible.
- Generation adequacy studies carried out on a combined, all-island basis have shown that there would be sufficient generation plant on the island to meet the agreed standard for the years covered by this Statement.
- The second high-voltage interconnector between Ireland and Northern Ireland is expected to be in place by the end of 2017.
- The commissioning of the second North-South interconnector will improve security of supply in both jurisdictions.
- The demand forecast in both jurisdictions has been updated to reflect the latest economic predictions. This has resulted in a slightly reduced demand forecast in the short-to-medium term.

Northern Ireland

- Three particular factors are combining to increase the risk to security of supply in Northern Ireland in the coming years:

  a) Three steam units in Ballylumford are due to be decommissioned at the end of 2015, thus reducing the amount of plant available by 510 MW.

  b) The Moyle Interconnector capacity continues to be reduced to 250 MW due to a cable fault.

  c) Prior to the commissioning of the second North-South interconnector, Northern Ireland is limited in the amount of capacity reliance it can place on the existing North-South interconnector.

- Faced with these unfavourable factors, the ability of the generation plant in Northern Ireland to meet the electricity demand is expected to come under increasing pressure from the start of 2016 onwards. Any delay to the installation of the second North-South interconnector will increase the amount of time that Northern Ireland's security of supply is at particular risk.
- While Northern Ireland will continue to meet the adequacy standard from 2016 onwards with a reduced capacity margin of 200 MW, any deterioration from normal conditions could place the security of supply at increased risk.
- Being a relatively small system with a small number of large units, the consequences of one or more of these units becoming unavailable for a prolonged period are quite severe.
- Studies post 2015 have shown that if more than one prolonged generation outage happened at the same time, then Northern Ireland's generation adequacy would drop below standard, and thus placing security of supply at increased risk. This particular risk could be managed by the addition of between 220 and 300 MW of extra plant.
- To manage the increased risk, additional feasible options are being explored by the Utility Regulator and SONI, working with DETI.
- From 2021, the output from 476 MW of plant at Kilroot is projected to be severely restricted (with limited running hours) due to the Industrial Emissions Directive (IED).

The effect of this is that, even if the rest of the generation portfolio performs well, the Northern Ireland Generation Security Standard is still not met from 2021. The preferred, enduring solution to this situation is the installation of the second North-South Interconnector.

Ireland

- There is a considerable surplus of generation supply in Ireland, but with limited interconnection to Northern Ireland, most of this surplus cannot at present be utilised to alleviate the risk to security of supply there.
- A new Combined Cycled Gas Turbine plant is due to be commissioned at Great Island in mid 2014.
- While connection agreements are in place for other plant, EirGrid has taken the prudent decision not to include all of these in adequacy assessments of future scenarios.
- The oil units at Great Island and Tarbert are scheduled to close in 2014 and 2021 respectively.
- EirGrid has not been notified of other generation closures. However, it has been assumed in the Reference Case that some older plant will experience higher outage rates and/or close over the course of the study period.

INTRODUCTION

This statement sets out estimates of the demand for electricity in the period 2014-2023 and the likely generation capacity that will be in place to meet this demand. This is then assessed against the generation adequacy standards for Ireland, Northern Ireland and on an all-island basis in terms of the overall supply/demand balance.

METHODOLOGY

Generation adequacy is essentially determined by comparing generation capacity with demand. To measure the imbalance between them, a statistical indicator called the Loss of Load Expectation (LOLE) is used. When this indicator is at an appropriate level, called the generation adequacy standard, the supply/demand balance is judged to be acceptable.

The generation adequacy standard for Ireland is 8 hours LOLE per year, while in the smaller system of Northern Ireland the standard is more stringent, set at 4.9 hours LOLE. When studying an all-island system, a standard of 8 hours is deemed appropriate. These standards have been agreed by the Regulatory Authority in each respective jurisdiction.

The analysis presented here determines whether there is enough generation capacity to meet the adequacy standard. It establishes the amount of generation required when there is a deficit, or the amount of excess generation when there is a surplus. For example, when a surplus emerges in some years, the surplus is the amount of extra generation capacity that could be removed while still meeting the generation adequacy standard.

Currently, limited interconnection capacity between Ireland and Northern Ireland means that Ireland must limit its assumed capacity reliance on Northern Ireland to just 100 MW. Similarly, Northern Ireland has an assumed capacity reliance of 200 MW on Ireland. However, with the commissioning of an additional interconnector between the two jurisdictions, overall adequacy will improve.

Given the uncertainty that surrounds any forecast of generation and demand, the report examines a number of different scenarios. It is intended that the results from these scenarios would provide the reader with enough information to draw their own conclusions regarding future adequacy.

A key factor in the analysis is the treatment of generation plant availability. Plant can be out of service either for regular scheduled maintenance or due to an unplanned forced outage. Forced outages have a greater adverse impact on adequacy than scheduled outages, as they may coincide with each other in an unpredictable manner. The modelling technique utilised in this statement takes account of all combinations of generation forced outages for each half hour period in each year. Periods of scheduled maintenance are provided by the generators and are also accounted for.

Wind generation requires a special modelling approach to capture the effect of its variable nature. The approach used in this study bases estimated future wind performance on historical records of actual wind power output.

DEMAND FORECAST

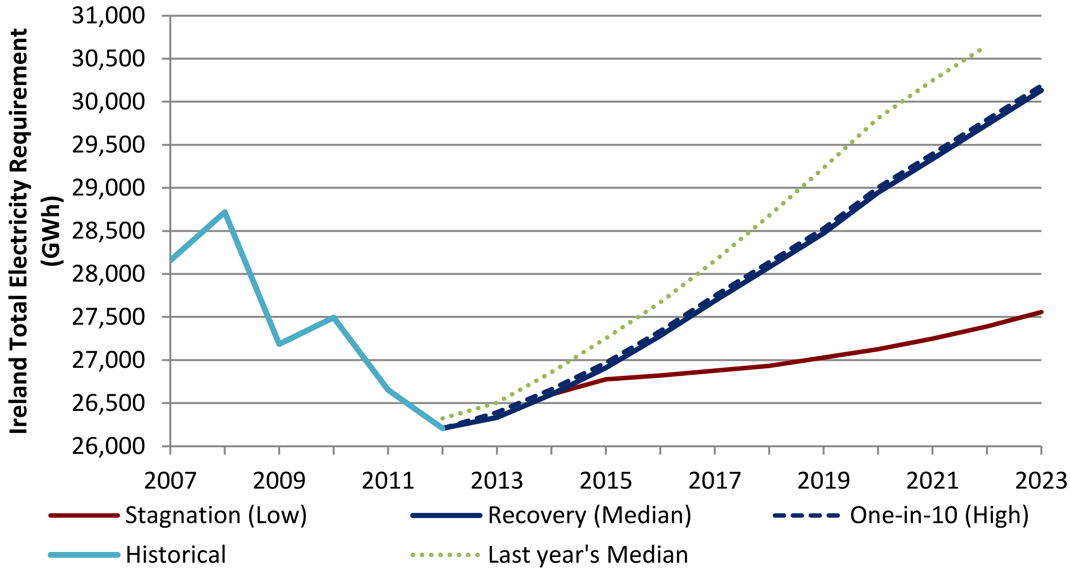
For both Ireland and Northern Ireland, the economic recession has led to a drop in electricity demand in recent years.

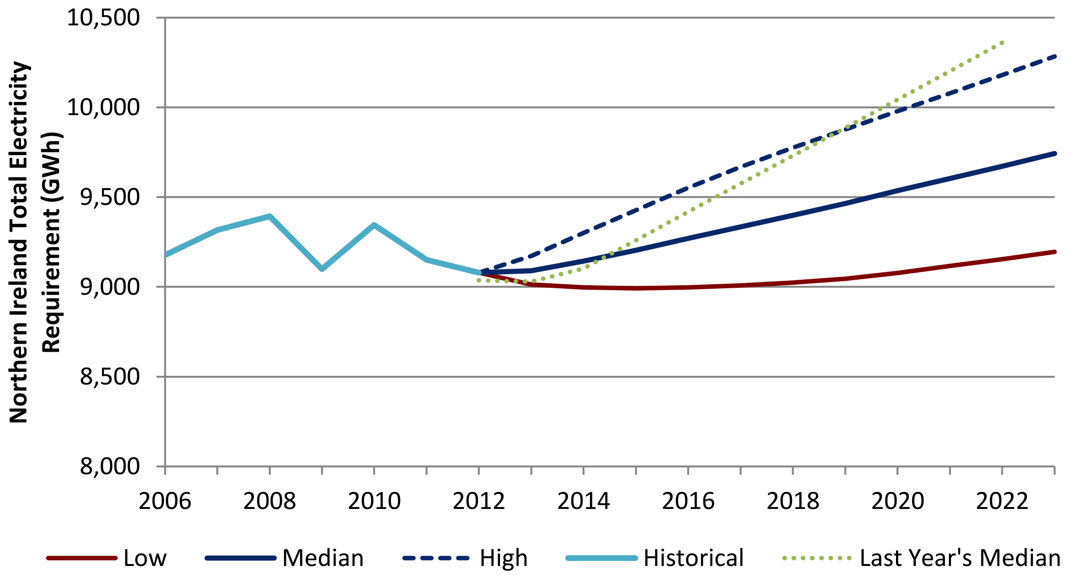
Going forwards, the median scenario for Ireland is informed by the Recovery Scenario in the ESRI's Medium Term Review. It sees a recovery to 2008 electricity demand levels by about 2019.

The low forecast, on the other hand, is based on ESRI's Stagnation scenario, where growth levels are much reduced.

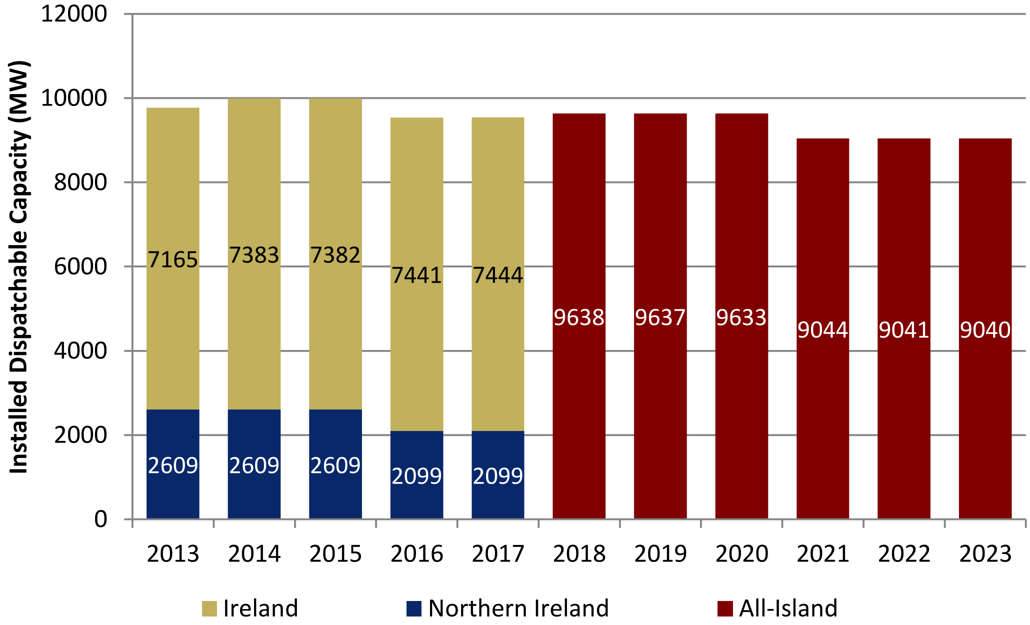
In Northern Ireland, the demand forecast has been reduced from the previous year's. This is due to indications from different institutions of decreased economic activity in the future. The median scenario predicts a return to 2008 levels by 2018.

In contrast, the low demand scenario has an almost flat profile.





CONVENTIONAL GENERATION



The assumptions for the generation portfolio are based on information received from the generators and connection agreements in place at the data freeze (October 2013). A variety of circumstances have been studied, looking at different supply and availability scenarios. The graph above outlines the dispatchable capacity assumed on the island over the next 10 years.

Once the second North-South interconnector is in place, the generation from both jurisdictions can be summed together as the combined, all-island generation portfolio.

Ireland

The East West Interconnector (EWIC) has been in full commercial operation since May 2013, with the capability of importing or exporting up to 500 MW at any given moment. Based on the Interconnector Feasibility Report, this interconnector is assumed to add the equivalent of 440 MW of additional generation capacity.

A new CCGT is due to be commissioned in 2014 at Great Island, Co Wexford.

Connection agreements are in place for up to 800 MW of further dispatchable conventional generation capacity. However, with the evident surplus of generation supply in Ireland, EirGrid is taking a cautious approach for the purposes of these adequacy studies, of assuming that not all of this contracted capacity will actually be realised.

The oil units at Great Island are due to close following the commissioning of the CCGT on that site in 2014. In addition, the oil units at Tarbert are scheduled to close in 2021. Overall, this leads to a reduction of 800 MW of capacity.

Though EirGrid has received no other notifications of closure, it seems prudent to assume that some of the older plant on the system will close or experience higher forced outage rates towards the end of the study period.

Northern Ireland

There is no significant new conventional generation currently planned for Northern Ireland over the next 10 years that this report covers.

Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by the end of 2015. This is due to environmental constraints introduced by the Large Combustion Plant Directive and will result in a reduction of 510 MW in capacity.

There is some uncertainty over the future running regime of the larger units at Kilroot due to emissions restrictions imposed by the Industrial Emissions Directive (IED) post 2021. In preparing this document, SONI has made assumptions according to the best information available, about how the IED will affect the running regime of these units.

Interconnection

One cable of the Moyle Interconnector is currently on a prolonged forced outage due to an undersea cable fault. Though various repair solutions are being progressed, it is not certain when or if the full capacity will be available for service again. Due to this uncertainty, SONI has taken the prudent decision to assume the Moyle's import capacity to be limited to 250 MW for the present adequacy studies.

RENEWABLE ENERGY

The Governments in both jurisdictions have adopted a target of generating 40% of all electricity consumed from Renewable Energy Sources (RES) by 2020. A large portion of this renewable electricity will come from wind power. Other RES will also play a part in meeting this target, such as hydro and biomass.

Ireland

Taking into account the electricity demand forecast and other RES, it is estimated that between 3,200 and 3,700 MW of wind power needs to be installed by 2020 to meet the 40% target in Ireland. This equates approximately to a doubling of the current capacity of 1800 MW. This estimation assumes average historical capacity factors, and a small percentage of wind generation being unusable for system security reasons.

Also, there are 81 MW of Waste-to-Energy projects connected or due to connect over the next few years. Approximately 50% of this waste is sourced from renewable materials. In addition, a significant growth in bioenergy is assumed.

Northern Ireland

A number of renewable generation projects are assumed to be commissioned over the 10 years that this report covers, equating to a total renewable generation capacity of over 2,100 MW in Northern Ireland by 2023.

SONI have estimated that in order to achieve the 40% RES target by 2020, the current wind capacity of 550 MW will have to more than double to reach almost 1200 MW.

Up to 600 MW of offshore wind is being planned, as well as 200 MW of tidal power and 45 MW of large scale biomass.

These assumptions have been derived from a number of sources, including the Strategic Energy Framework for Northern Ireland[1], the Strategic Environmental Assessment of offshore wind and marine renewable energy[2] and the Onshore Renewable Electricity Action Plan (OREAP)[3], all produced by the Department of Enterprise, Trade and Investment (DETI).

The assumptions also incorporate the announcements by the Crown Estates[4] who have now awarded development rights for three offshore renewable energy sites in Northern Ireland's coastal waters, including a 600 MW offshore wind farm and two 100 MW tidal sites.

These publications and announcements indicate that even higher amounts of renewable generation may connect over the next few years. However, for the adequacy studies, SONI have taken a more conservative view on the amount that will be connected, but have included enough renewable capacity to meet the Northern Ireland Executive's 40% renewable target by 2020.

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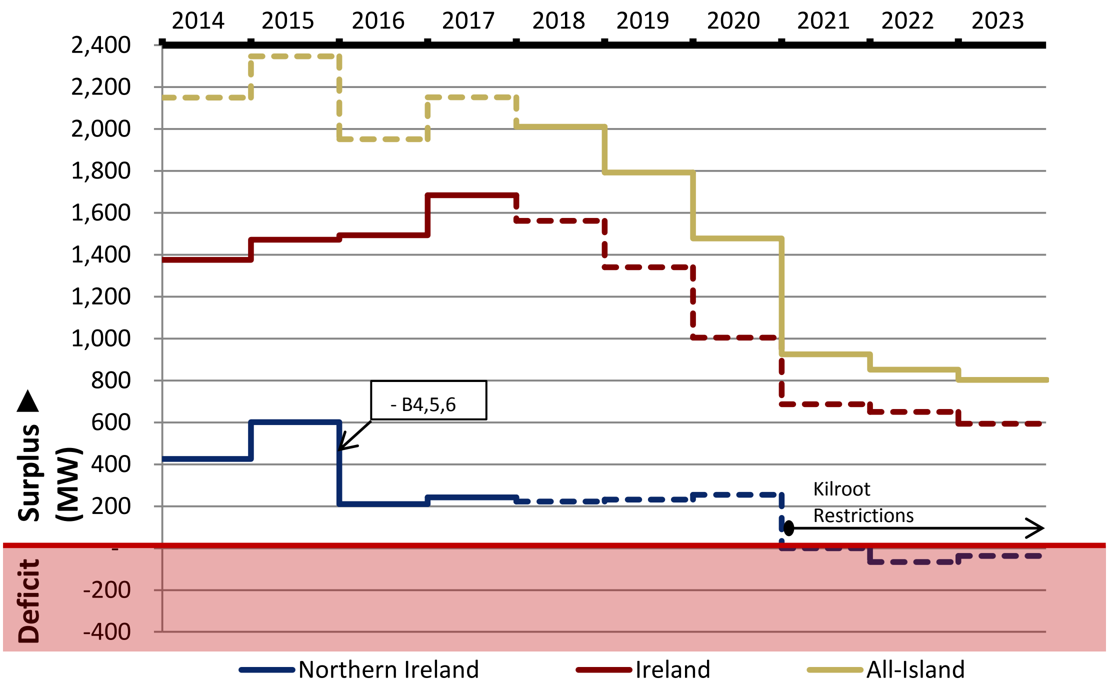
[1] Strategic Energy Framework (www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf)

[2] Strategic Environmental Assessment (SEA) (www.offshorenergyni.co.uk)

[3] Onshore Renewable Electricity Action Plan (OREAP) (www.onshorerenewablesni.co.uk)

[4] The Crown Estate: www.thecrownestate.co.uk

GENERATION ADEQUACY ASSESSMENTS



The figure above illustrates the generation adequacy results (translated from Loss Of Load Expectation (LOLE) into surplus/deficit of plant) for the Reference Case, i.e. with the most likely scenarios for demand forecast and generator availability.

If a system is estimated to have a higher LOLE than standard for a particular year, then the system is said to be in deficit. The amount of deficit is the MW capacity needed to bring the system back to the standard LOLE.

A plant surplus in any year indicates how much plant a system could do without and still meet the defined LOLE standard exactly.

Though results are shown for separate- and joint-system studies for all years above, it is only when the second North-South interconnector is in place (assumed to be at the end of 2017) that the combined, all-island assessment is applicable.

The dashed lines for the Ireland and Northern Ireland separate-system studies after 2017 illustrate the situation should the second North-South interconnector be delayed.

The dashed line for the all-island results before 2018 shows what the benefits could be if the second North-South interconnector were in place earlier than this. This approach allows a full consideration of the impact that the second North South interconnector has on both jurisdictions over the entire period of generation adequacy assessment.

Ireland is shown to be in surplus for all years of the study. Without the second North-South interconnector, this surplus cannot be shared on an all-island basis with Northern Ireland.

Risk to security of supply in Northern Ireland

When assessed separately, adequacy levels for Northern Ireland drop to low levels in 2016 due to three factors:

- the withdrawal of three units at Ballylumford,
- the Moyle is assumed to be still operating at reduced capacity,
- and the second North-South interconnector is not expected to be commissioned by then.

Were any plant to suffer a prolonged, unforeseen outage post-2015, then the risk to security of supply could fall below acceptable levels in Northern Ireland. Being a relatively small system with a small number of large units, the impact of even one prolonged outage could be quite substantial.

An investigation examining the effect of two prolonged outages in one year found the risk to security of supply to rise to very high levels. This risk could be managed by the addition of 220-300 MW of extra plant.

To manage the increased risk, additional feasible options are being explored by the Utility Regulator and SONI, working with DETI

Even if all generation plant performed at optimal levels, Northern Ireland would fall into deficit in 2021 due to further restrictions at Kilroot. If the second North-South interconnector is not in place at this stage, then the risk to security of supply becomes very high indeed.

1 INTRODUCTION

1 INTRODUCTION

This report is produced with the primary objective of informing market participants, regulatory agencies and policy makers of the likely generation capacity required to achieve an adequate supply and demand balance for electricity for the period up to 2023[5].

Generation adequacy is a measure of the capability of the electricity supply to meet the electricity demand on the system. The development, planning and connection of new generation capacity to the transmission or distribution systems can involve long lead times and high capital investment. Consequently, this report provides information covering a ten-year timeframe.

EirGrid, the Transmission System Operator (TSO) in Ireland, is required to publish forecast information about the power system, (as set out in Section 38 of the Electricity Regulation Act 1999 and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations).

Similarly, SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement, in accordance with Condition 35 of the Licence to participate in the Transmission of Electricity granted to SONI Ltd by the Department of Enterprise Trade and Investment.

This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2013-2022, published in January 2013.

All input data assumptions have been updated and reviewed. Any changes from the previous report, including those to the input data and consequential results, are identified and explained.

This report is structured as follows:

- Section 2 outlines the demand forecast methodology, and presents estimates of demand over the next ten years.
- Section 3 describes the assumptions in relation to electricity generation.
- Adequacy assessments are presented in Section 4
- Section 5 presents a detailed investigation into the security of supply in Northern Ireland, particularly after the decommissioning of 510 MW of plant at the end of 2015.
- A special report is presented in Section 6 on the neighbouring electricity market, with a particular emphasis on how trading here is affected by prices and market arrangements.

Appendices which provide further detail on the data, results and methodology used in this study are included at the end of this report.

[5] EirGrid and SONI also publish a Winter Outlook Report which is focused on the following winter period, thus concentrating on the known, short-term plant position rather than the long-term outlook presented in the Generation Capacity Statement. http://www.eirgrid.com/media/EirGridWinterOutlook2013-2014.pdf

2 DEMAND FORECAST

2 DEMAND FORECAST

2.1 Introduction

The forecasting of electricity demand is an essential aspect of assessing generation adequacy. This task has become more complicated in recent years with the changing economic climate. The economic downturn has led to significant reductions in both peak demand and energy consumption across the island. Some sectors have been affected more than others.

Also to be considered is the significant impact of the recent severe winters. These effects need to be modelled with reference to historical weather data.

EirGrid and SONI use models based on historical trends and economic forecasts to predict future electricity demands, as well as future peaks. These models are outlined in this section, along with the results they produce.

As the economies and drivers for economic growth have historically varied considerably in both jurisdictions, forecasts are initially built separately for Ireland and Northern Ireland. These are then combined to produce an all-island energy and peak demand forecast which is used in the all-island adequacy studies.

Forecasted demand figures are given in terms of Total Electricity Requirement (TER). All calculated TER and peak values are listed in Appendix 1.

Finally, information on typical load shapes is presented. Electrical energy, peak demand forecasts and load factor predictions are used to calculate future profiles.

2.1(a) Temperature Correction of Historical Demand

Of all the meteorological elements it has been found that temperature has the greatest effect on the demand for electricity in both Northern Ireland and Ireland. For this reason, historical demand peak data is adjusted to Average Cold Spell (ACS) temperatures[6]. ACS analysis produces a peak demand which would have occurred had conditions been averagely cold for the time of year. This ACS adjustment to each winter peak seeks to remove any sudden changes caused by extremely cold or unusually mild weather conditions.

Statistical analysis is carried out to determine the relationship between demand, temperature and day of the week using multivariate regression analysis over the winter periods. The resultant relationships are then applied to the current winter data to establish the adjusted ACS winter demand. When forecasting forwards, it is assumed that the weather is average, i.e. no temperature variations are applied.

2.1(b) Self-Consumption

Some industrial customers produce and consume electricity on site, many with the facility of Combined Heat and Power (CHP). This electricity consumption, known as *self-consumption*, is not included in sales or transported across the network. Consequently, an estimate[7] of this quantity is added to the energy which must be exported by generators to meet sales. The resultant energy is known as the Total Electricity Requirement (TER). As all generation sources (including an estimate of self-consumers) are considered in the analysis, it is this TER that is utilised for generation adequacy calculations.

[6] It should be noted that temperature has a lesser impact on annual electricity energy demand than it does on peak demand.

[7] Self-consumption represents approximately 2% of system demand. Therefore this estimation does not introduce significant error.

2.2 Demand Forecast for Ireland

2.2(a) Methodology for the Annual Electricity Demand Forecast Model

The electricity forecast model for Ireland is a multiple linear regression model which predicts electricity sales based on changes in the economic parameters of GDP[8] and PCGS[9].A spread of electricity forecasts are produced, covering the next ten years.

2.2(b) Historical data

Transporting electricity from the supplier to the customer invariably leads to losses. Based on the comparison of historical sales to exported energy, it is estimated that between 7 and 8% of power produced is lost as it passes through the electricity transmission and distribution systems. Recent figures have indicated that the proportion of losses is falling, though this needs careful analysis in the future to confirm the trend.

Past economic data is sourced from the most recent Quarterly National Accounts of the Central Statistics Office. Data from the past 18 years is analysed to capture the most recent trends relating the economic parameters to demand patterns.

2.2(c) Forecasting causal inputs

In order for the trained energy model to make future predictions, forecasts of GDP and PCGS are required. These forecasts are provided by the Economic and Social research Institute (ESRI), who have expertise in modelling the Irish economy and who were consulted during the process[10].

The short-term data comes from the Quarterly Economic Commentary published by the ESRI in October 2013. Longer-term trends arise out of the ESRI's Medium Term Review (MTR), published in July 2013. As a cross-check, the ESRI forecasts were compared with predictions from other institutions including the Department of Finance, the Central Bank of Ireland, the European Union and the International Monetary Fund.

The following table shows the economic inputs for producing the median 'Base Case' electricity forecast.

	GDP (volume)	Personal Consumption
2014-2020	3.8%	2.3%
2021-2025	2.2%	2.7%

Table 2-1 Economic projections based on the Recovery scenario of the Medium Term Review

2.2(d) Uncertainty around the median forecast

The Base Case demand forecast is the best estimate of what might happen in the future, and is related to the 'Recovery' scenario of the MTR. It also incorporates some reduction due to energy efficiency measures in line with Ireland's National Energy Efficiency Action Plan[11] (including the installation of smart meters).

In an effort to capture the uncertainty involved in any forecasting exercise, higher and lower forecasts have been made to bracket the median demand.

The lower TER forecast is based on the economic stagnation scenario of the MTR. This is quite a pessimistic scenario, where the EU as well as the Irish economy stagnates, and economic growth is much lower than in the recovery scenario. This low demand scenario should therefore capture the possible effects of lower than expected economic growth. It should also allow for the effects of milder-than-average weather and/or more energy saved through energy efficiency measures.

The higher electricity forecast is generated by imposing more severe weather conditions, specifically a winter where the lowest

[8] Gross Domestic Product is the total value of goods and services produced in the country.

[9] Personal Consumption of Goods and Services measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.

[10] http://www.esri.ie/irish_economy/

[11] http://www.dcenr.gov.ie/energy/energy+efficiency+and+affordability+division/national+energy+efficiency+action+plan.htm

temperatures are as cold as a one-in-10 year minimum. It is not suggested that every year in the coming decade will be this cold, but it is to demonstrate an upper bound to the electricity forecast.

While temperature has a significant effect on the peak demand, it is not so influential on the annual energy.

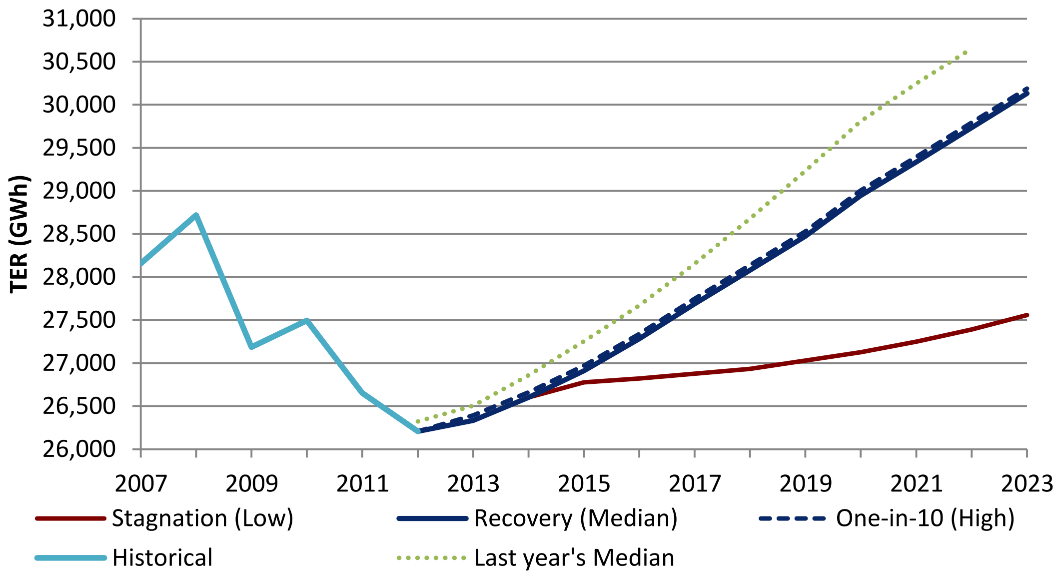


Figure 2-1 Total Electricity Requirement Forecast for Ireland. The figure for 2013 is based on real data available at EirGrid's National Control Centre up to October, and so estimates are made for the remaining months

2.2(e) Peak Demand Forecasting

The peak demand model is based on the historical relationship between the annual electricity consumption and winter peak demand. This relationship is defined by the Annual Load Factor (ALF), which is simply the average load divided by the peak load.

Before applying this model, it is necessary to assess the effect of **Demand-Side Management** (DSM) schemes

For the last ten years, EirGrid operated a DSM scheme called the Winter Peak Demand Reduction Scheme (WPDRS), which rewarded participating customers for reducing their electricity demand at peak winter hours. This scheme was effective in reducing the winter peak by over 100 MW. However, it has since ceased to function and winter 2013/14 will be the first winter without it. Therefore, it is uncertain how the actual winter peak will be affected.

It is likely that there will still be a certain amount of peak reduction by former WPDRS participants – some of this could be due to customers reacting to high evening peak prices. More peak reduction should be available when called from the new Demand Side Units (DSU), such as Activation Energy and DAE.

All in all, it has been decided that for the purposes of peak forecasting, a half-and-half approach might be suitable, i.e. that the ending of the WPDRS will result in the peak rising by half of the former peak reduction attributed to WPDRS. This situation merits careful monitoring into the future, so that any adjustments to the modelling procedure can be assessed.

As discussed already, **temperature** has a more significant effect on electricity demand, as was particularly evident over the two severe winters of 2010 and 2011, when temperatures plunged and demand rose. ACS correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences, see Figure 2-2.

The temperature-corrected peak curve is used in the ALF model which can then be forecast forwards using the previously-determined energy forecasts, see Figure 2-3.

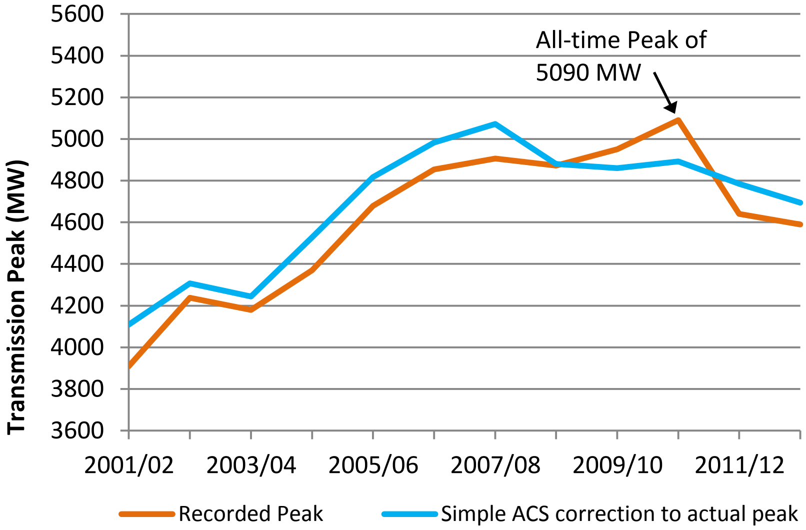


Figure 2-2 Past values of recorded maximum demand in Ireland, and the ACS corrected values

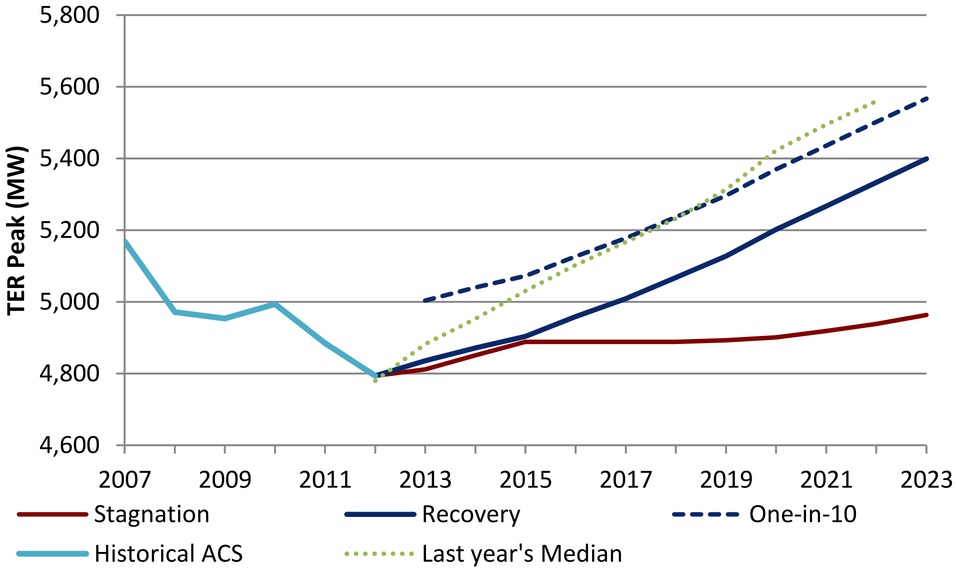


Figure 2-3 Forecast of Ireland's TER Peak for the Recovery and Stagnation scenarios, under Average Cold Spell conditions. The dashed blue line shows the peaks that could result if the weather were not average, but as severe as the coldest in 10 winters. For comparison purposes, last year's Median peak forecast is shown in green dots.

2.3 Demand Forecast for Northern Ireland

2.3(a) Methodology

The TER forecast for Northern Ireland is carried out with reference to economic parameters. Various publications, including Danske Bank Sectoral Forecast[12], highlight uncertainty surrounding Northern Ireland's economic recovery. These latest economic projections have led to a lowering in the electricity demand forecast.

The Strategic Energy Framework for Northern Ireland[13] sets out the Northern Ireland contribution to the 1% year-on-year energy efficiency target for the UK. This has also been incorporated in the demand forecast.

2.3(b) Demand Scenarios

Given the high degree of economic uncertainty into the future, SONI believe it prudent to consider three alternative scenarios for the economy, each of which can then be factored in to derive an estimate of energy production. The three scenarios consist of a pessimistic, realistic and optimistic view that take account of current economic outlook predictions.

Combining both the temperature and economic scenarios allows for median, high and low demand forecasts to be formulated.

The median demand forecast is based on an average temperature year, with the central economic factor being applied and this is SONI's best estimate of what might happen in the future.

The low demand forecast is based on a relatively high temperature year, with the pessimistic economic factor being applied. Conversely, the high demand forecast is based on a relatively low temperature year, with the more optimistic economic factor being applied.

[12] http://danskebank.co.uk/en-gb/About-the-bank/Bank-in-brief/Economic-Research/Pages/IndustrySectoralForecasts.aspx

[13] http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf

2.3(c) Self Consumption

In addition to industrial self-consumers[14], a growing amount of small scale embedded generation is appearing on the Northern Ireland system which also produces and consumes electricity on site. These include technologies such as small scale wind turbines, photo-voltaic and biofuels which serve domestic dwellings, community centres, farms, etc. This self consumption, is not included in the SONI sent-out[15] annual energy.

In isolation each individual small scale embedded generator of this type does not have a significant effect on the demand profile; however they do become significant on a cumulative basis. SONI have been working closely with Northern Ireland Electricity (NIE) and referencing the Renewable Obligation Certificate Register (ROC Register)[16] to establish the amount of this embedded generation that is currently connected on the Northern Ireland system, as well as referencing Northern Ireland Planning Service[17] data to try and establish what amounts will be connecting in the future.

This has enabled SONI to make an informed estimate of the amount of energy contributed to the total demand by self consumption, which is then added to the energy which must be exported by generators to meet all demand, resulting in the Total Energy Requirement (TER).[18]

2.3(d) TER Forecast

It can be seen that the new TER forecast for Northern Ireland (Figure 2-4) has been reduced compared to the previous forecast published in the Generation Capacity Statement 2013-2022. The reduced forecast is

[14] SONI carry out an annual analysis to determine the amount of "Customer Private Generation" (CPG), where customers run their own generation effectively giving demand reduction.

[15] Exported = Net of Generator House Loads

[16] https://www.renewablesandchp.ofgem.gov.uk/

[17] www.planningni.gov.uk

[18] Self-consumption in Northern Ireland currently represents approximately 1.7% of TER and this grows to approximately 2.6% by the final year of the study.

primarily due to a combination of economic uncertainty as well as the continued drive for energy efficiency.

The Northern Ireland TER forecast predicts a return to 2010 levels by 2018.

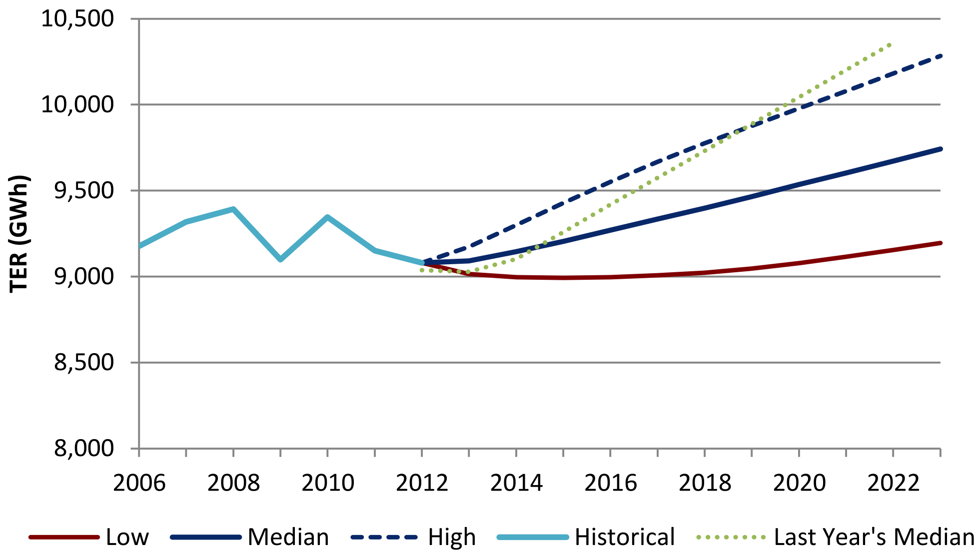


Figure 2-4 Northern Ireland TER Forecast

2.3(e) Peak Demand Forecasting

The Northern Ireland peak demand forecast is carried out using similar methodology as the Ireland peak forecast described in Section 2.2.

The demand peaks over the last decade reflect Customer Private Generation (CPG), consisting of customers running private embedded diesel generation. Analysis was carried out over the 2012/13 winter period to calculate the amount of CPG that was actually running and was found to be 31 MW. This has the effect of suppressing the peak (in effect, this is Demand-Side Management) and is assumed to continue over the ten years of this report.

The Northern Ireland 2012/13 generated winter peak, which occurred on 11th December 2012 @ 17:30, consisted of the following dispatch data (where CDGUs refers to Centrally Dispatched Generation Units):

CDGUs + Interconnectors	= 1670 MW
Renewable + Small Scale	= 142 MW
Customer Private Generation	= 31 MW
TOTAL GENERATED PEAK	**= 1843 MW**

When average cold spell temperature correction (ACS) is applied using the methodology as described above, the figure of 1843 MW is corrected down by 10 MW, providing an ACS corrected figure of 1833 MW for the 2012/13 winter period, see Figure 2-5.

As with the annual electricity usage forecast outlined in section 2.3(b), three peak forecast scenarios have been built. These consist of a pessimistic, realistic and optimistic view with adjustments that take account of current economic outlook predictions.

The ACS generated peak demand is converted to the ACS exported peak by assuming a house load of approximately 4.5% and is the equivalent to the Transmission Peak.

The TER Peak is then derived by adding a further estimation of the contribution to peak demand that the self consuming small scale generation makes as described in section 2.3(c). On average, over the 10 years of the study, this has the effect of adding approximately 44 MW to the Transmission Peak.

Figure 2-6 shows the TER peak forecast for Northern Ireland. Again it can be seen that the resulting forecast for Northern Ireland has been reduced compared to the previous forecast published in the 2013-2022 Generation Capacity Statement.

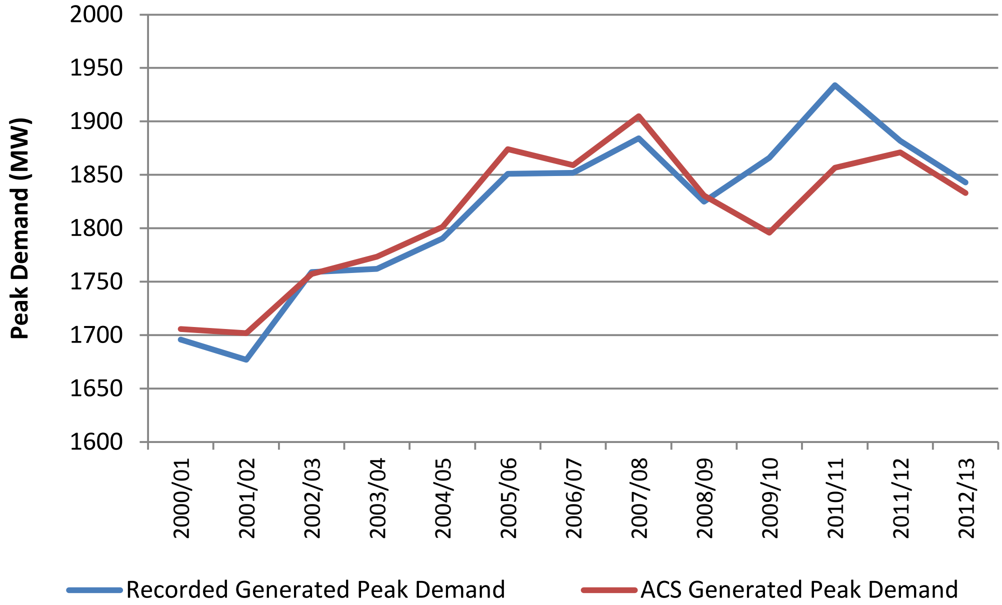


Figure 2-5 Recorded and ACS-corrected peaks (generated level) for Northern Ireland. The most significant corrections are for 2009/10 and 2010/11, when the temperature deviated most from normal

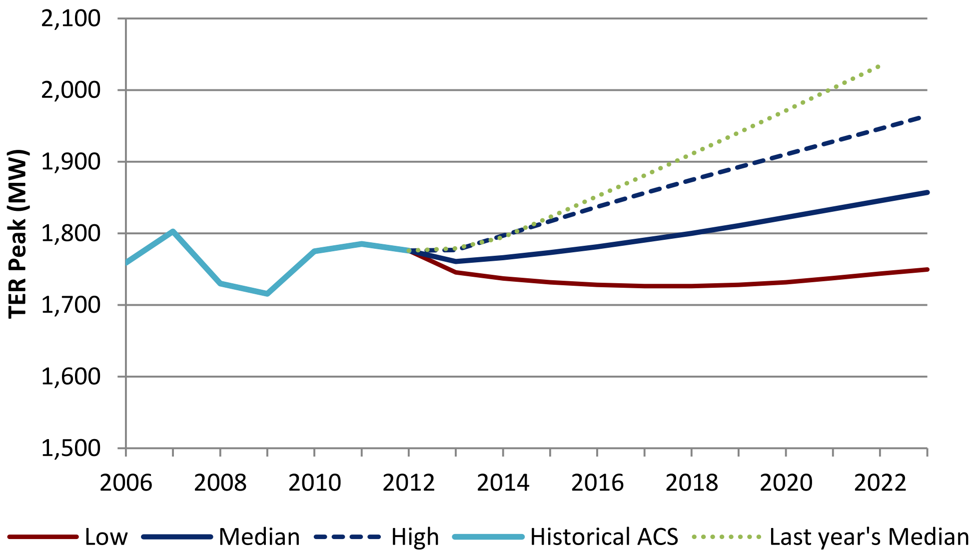


Figure 2-6 ACS TER Peak forecasts for Northern Ireland

2.4 All–Island Forecasts

The combined all-island TER forecast comes from summing together the demands from each jurisdiction, see Figure 2-7.

The annual peaks for Ireland and Northern Ireland do not generally coincide. In Northern Ireland, annual peaks may occur at the start or at the end of the year, whereas in Ireland peaks tend to occur in December.

To create a forecast of all-island peaks, future demand profiles have been built for both regions based on the actual 2012 demand shape. This gives yearly all-island peaks which are less than the sum of the equivalent peaks for each region – just one of the benefits of switching to an all-island system. The forecasted all-island peaks are shown in Figure 2-8, where ACS conditions are assumed for the future.

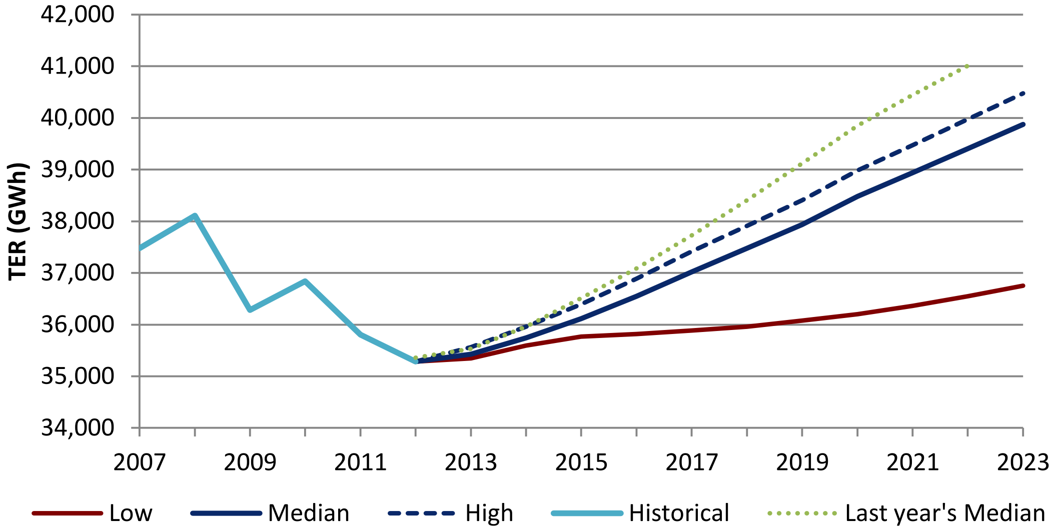


Figure 2-7 Combined All-island TER forecast

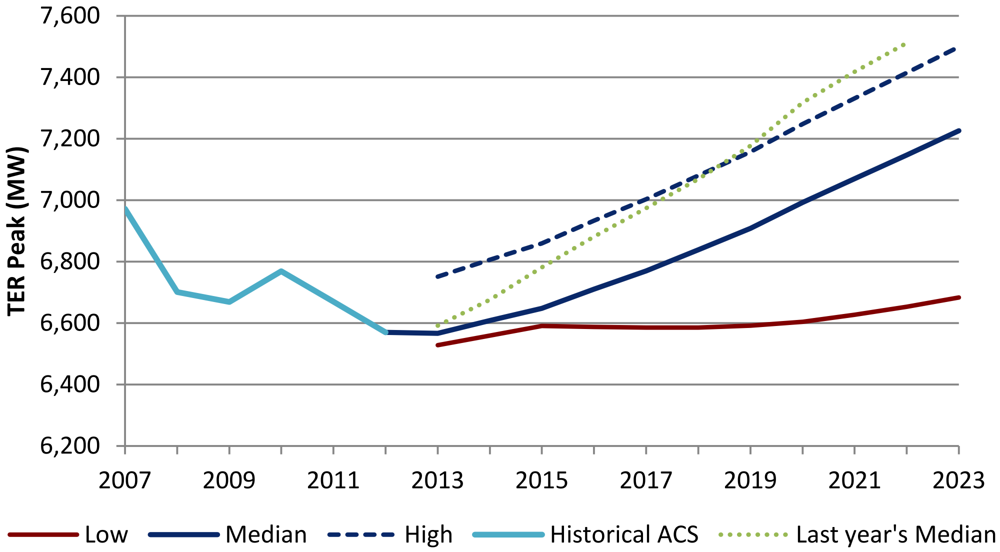


Figure 2-8 Combined all-island TER Peak forecast

2.5 Annual Load Shape and Demand Profiles

To create future demand profiles for the adequacy studies, it is necessary to use an appropriate base year profile which provides a representative demand profile of both jurisdictions. This profile is then progressively scaled up using forecasts of energy peak and demand. The base year chosen for the profile creation was 2012 for both jurisdictions.

2012 was chosen because it was the most recent profile available, and it was deemed to be a year representative of contemporary demand patterns. The choice of a typical year for load profiling is a matter for continual review.

Electricity usage generally follows some predictable patterns. For example, the peak demand occurs during winter weekday evenings while minimum usage occurs during summer weekend night-time hours. Peak demand during summer months occurs much earlier in the day than it does in the winter period.

Figure 2-9 shows typical daily demand profiles for a recent winter weekday. Many factors impact on this electricity usage pattern throughout the year. Examples include weather, sporting or social events, holidays, and customer demand management.

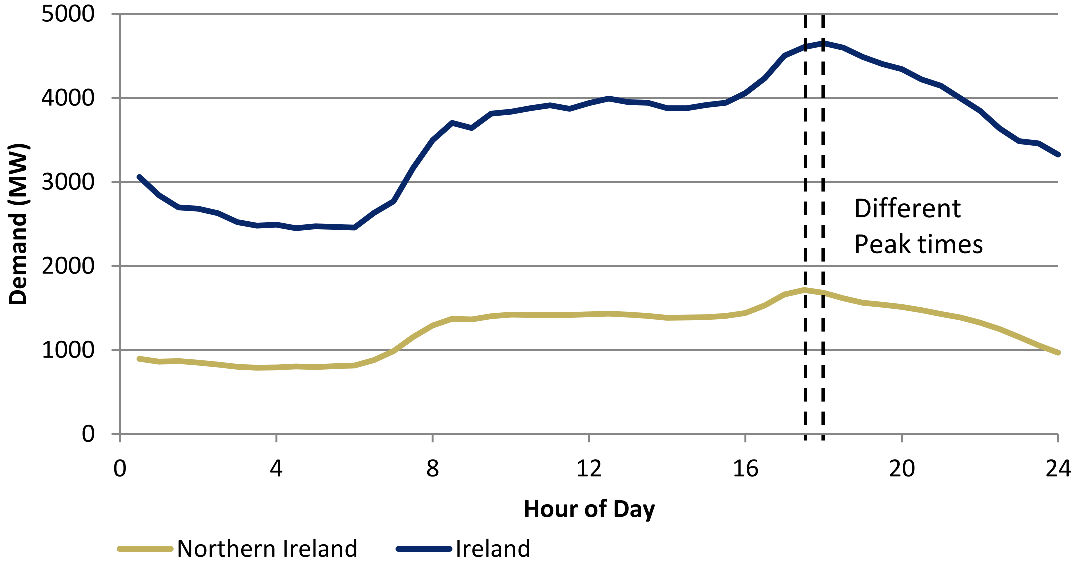


Figure 2-9 Typical winter day profile

2.6 Changes in Future Demand Patterns

The Government of Ireland has a plan to increase energy efficiency by 20% by 2020. This includes such actions as replacing existing lighting with energy efficient sources, and increasing the thermal insulation standards for newly built housing, as well as government grants for retrofitting existing houses to improve their efficiency[19]. This will undoubtedly have an effect on the demand profile.

Developments in electric vehicles and the roll out of smart-metering will also have an influence on the demand shape in Ireland. While the exact effect is yet uncertain, EirGrid have carried out studies investigating the potential changes[20].

Similarly, the Northern Ireland Government, through the Department of Enterprise, Trade and Investment (DETI) have set targets of contributing to the 1% year-on-year energy efficiency savings target for the UK as set out in the Strategic Energy Framework for Northern Ireland[21]. It is envisaged that they will be able to achieve this through a number of different schemes.

These include, for example, the introduction of Energy Performance Certificates, amending building regulations to progressively improve the thermal performance of buildings, and providing services through the Government's regional business development agency (Invest NI[22]) to help businesses identify and implement significant energy efficiencies.

There are also moves by the Northern Ireland Executive to encourage a higher uptake of electric vehicles, by the introduction of a number of free car charging points throughout Northern Ireland through the ECAR project[23]. At present there are approximately 160 charging points installed. However, it is difficult to predict at this stage as to whether or not electric vehicles will have a significant effect on the Northern Ireland demand profile in the future due to the uncertainty around the actual uptake of electric vehicles.

Trials are currently ongoing to evaluate the effect of the use of smart metering in Northern Ireland[24], which could also have a significant effect on the demand profile. SONI will monitor the results of this trial to take account of any significant effects that smart metering may have on the future demand profiles.

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[19] http://www.seai.ie/Grants/Home_Energy_Saving_Scheme/, http://www.seai.ie/Grants/Warmer_Homes_Scheme/

[20] See for e.g. GAR 2009-2015, GAR 2008-2014

[21] http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf

[22] http://www.investni.com/index/already/maximising/managing_energy_and_waste.htm, http://www.nibusinessinfo.co.uk/bdotg/action/layer?site=191&topicId=1079068363

[23] http://www.nidirect.gov.uk/e-car-northern-ireland

[24] www.nie.co.uk/Network/Future-networks/Smart-meters

3 ELECTRICITY GENERATION

3 ELECTRICITY GENERATION

3.1 Introduction

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity added (Northern Ireland)			10								
Capacity removed (Northern Ireland)				-510							
Capacity added (Ireland)		431		62		98					
Capacity removed (Ireland)		-212							-592		
Minor Adjustments		-1	-1	-3	3	-3	-1	-4	3	-3	-1
Net Impact		218	9	-451	3	95	-1	-4	-589	-3	-1
Total Dispatchable Capacity	**9774**	**9992**	**10001**	**9550**	**9553**	**9648**	**9647**	**9643**	**9054**	**9051**	**9050**

Table 3-1 Changes in dispatchable capacity on the island over the next 10 years. All figures are in MW.

Generation adequacy describes the balance between demand and generation supply. This section describes all significant sources of electricity generation connected to the systems in Ireland and Northern Ireland, and how these will change over the next 10 years, as summarised in Table 3-1. Issues that affect security of generation supply, such as installed capacity, plant availability, and capacity credit of wind, are examined.

In predicting the future of electricity generation supply in Ireland and Northern Ireland, EirGrid and SONI have endeavoured to use the most up-to-date information available at the time of the data freeze for this report (October 2013). EirGrid have taken the prudent approach of assuming that not all of the contracted plant will be commissioned, and that some of the older plant in Ireland will, in effect, shut down over the course of the study period.

Interconnection will continue to play an important role in future generation supply security. The East-West Interconnector has connected the transmission systems of Ireland and Wales, and can transmit 500 MW in either direction. Along with the existing Moyle Interconnector[25] that connects the transmission systems of Northern Ireland and Scotland, this has significantly enhanced the overall interconnection between the island of Ireland and Great Britain.

The second major North-South interconnector connecting Northern Ireland and Ireland will lead to a more secure, stable, and efficient all-island system. This North-South interconnector is assumed to be operational by the end of 2017.

3.2 Plant Types

One of the most important characteristics of a generator, from a TSO perspective, is whether or not the plant is 'fully dispatchable'. For a plant to be fully dispatchable, EirGrid or SONI must be able to monitor and control its output from their control centres. Since customer demand is also monitored from the control

[25] Due to the uncertainty as to if or when the ongoing cable fault on Pole 1 of the Moyle Interconnector will be repaired and available for service again, the Moyle's import capacity is assumed to be 250 MW Jan–Dec. (Under non-fault conditions the Moyle import capacity would be 450 MW Nov-Mar and 410 MW Apr-Oct).

centres, EirGrid and SONI can adjust the output of fully-dispatchable plant in order to meet this demand.

Although fully-dispatchable plant normally consists of the larger units on the system, smaller units can also be fully-dispatchable if they wish to take part in the market. For example, in Northern Ireland there are now three 3 MW gas units operated by Contour Global, and a 64 MW Aggregated Generating Unit operated by iPower. Also there are some new Demand Side Units in Ireland which take part in the market and are fully dispatchable.

There is an amount of generation whose output is not currently monitored in the control centres and whose operation cannot be controlled. This non-dispatchable plant, known as embedded generation, has historically been connected to the lower voltage distribution system and has been made up of many units of small individual size.

Large wind farms fall into a different category. Since the maximum output from wind farms is determined by wind strength, they are not fully controllable, i.e. they may not be dispatched up to their maximum registered capacity if the wind strength is too low to allow this. However, their output can be reduced by EirGrid or SONI if required (for example, due to transmission constraints), and they are therefore categorised as being partially dispatchable. In accordance with the EirGrid Grid Code[26] and the Distribution Code[27] in Ireland, wind farms with an installed capacity greater than 5 MW must be partially dispatchable.

In accordance with the SONI Grid Code[28] and the Distribution Code[29] in Northern Ireland, a wind farm with a registered capacity of 5 MW or more must be controllable by the TSO and is defined as a "Controllable Wind Farm Power Station" (CWFPS). A "Dispatchable Wind Farm Power Station" is further defined as a DWFPS which must have a control facility in order to be dispatched via an electronic interface by the TSO. In both cases these would be categorised as being partially dispatchable.

3.3 Changes to Conventional Generation in Ireland

This section describes the changes in fully dispatchable plant capacities which are forecast to occur over the next ten years. Plant closures and additions are documented. In Ireland, the only new generators that are documented here are those which have a signed connection agreement with EirGrid[30] or the DSO (Distribution System Operator), and have indicated a commissioning date to EirGrid by the data freeze date.

3.3(a) Plant Commissionings

- SSE plans to commission a new Combined-Cycle Gas Turbine (CCGT) plant at Great Island in Co Wexford in 2014. The existing oil units there will subsequently be decommissioned. The Firm Access Quantity (FAQ) at this site is assumed to be initially 216 MW, until an additional FAQ of 215 MW is assigned in 2016.

- A Waste-to-Energy converter, located in Dublin, should be able to supply 62 MW.

- Two Demand Side Units have changed their capacity since the previous GCS: Activation Energy now has a dispatchable capacity of 38 MW and DAE Virtual Power has 22 MW.

The conventional plant in Table 3-2 has connection agreements in place:

Plant	Capacity (MW)
Great Island CCGT	431
Dublin Waste to Energy	62
Nore OCGT	98
Suir OCGT	98
Cuileen OCGT	98
Ballakelly CCGT	445

Table 3-2 Contracted generation capacity for Ireland, up to 2023.

26 www.eirgrid.com/operations/gridcode/

27 www.esb.ie/esbnetworks/en/about-us/our_networks/distribution_code.jsp

28 www.soni.ltd.uk/gridcode.asp

29 http://www.nie.co.uk/documents/Connections/Distribution_Code_1_May_2010.aspx

30 i.e. a signed Connection Offer has been accepted and any conditions precedent fulfilled.

Of the plant in Table 3-2, only Great Island CCGT has a firm commissioning date in the next year. EirGrid has taken the prudent view that not all of the other planned plant in the table above will be commissioned.

In recent years, two large CCGTs have commissioned in the Cork region. Network reinforcements are required to enable all thermal generation to be exported from the Cork region. In the absence of such reinforcement, the output of generation in this region will have to be constrained from time to time. This would impact on the capacity benefit of this generation.

Network reinforcements are planned for the Cork region, however, in the meantime, Whitegate is modelled at full capacity, and there is an export limit of 690 MW from the Aghada site. This site comprises of Aghada AD1 (258 MW), Aghada CT 1, 2 and 4 (3 X 90 MW), and the new Aghada AD2 (432 MW), with a total export capacity of 960 MW.

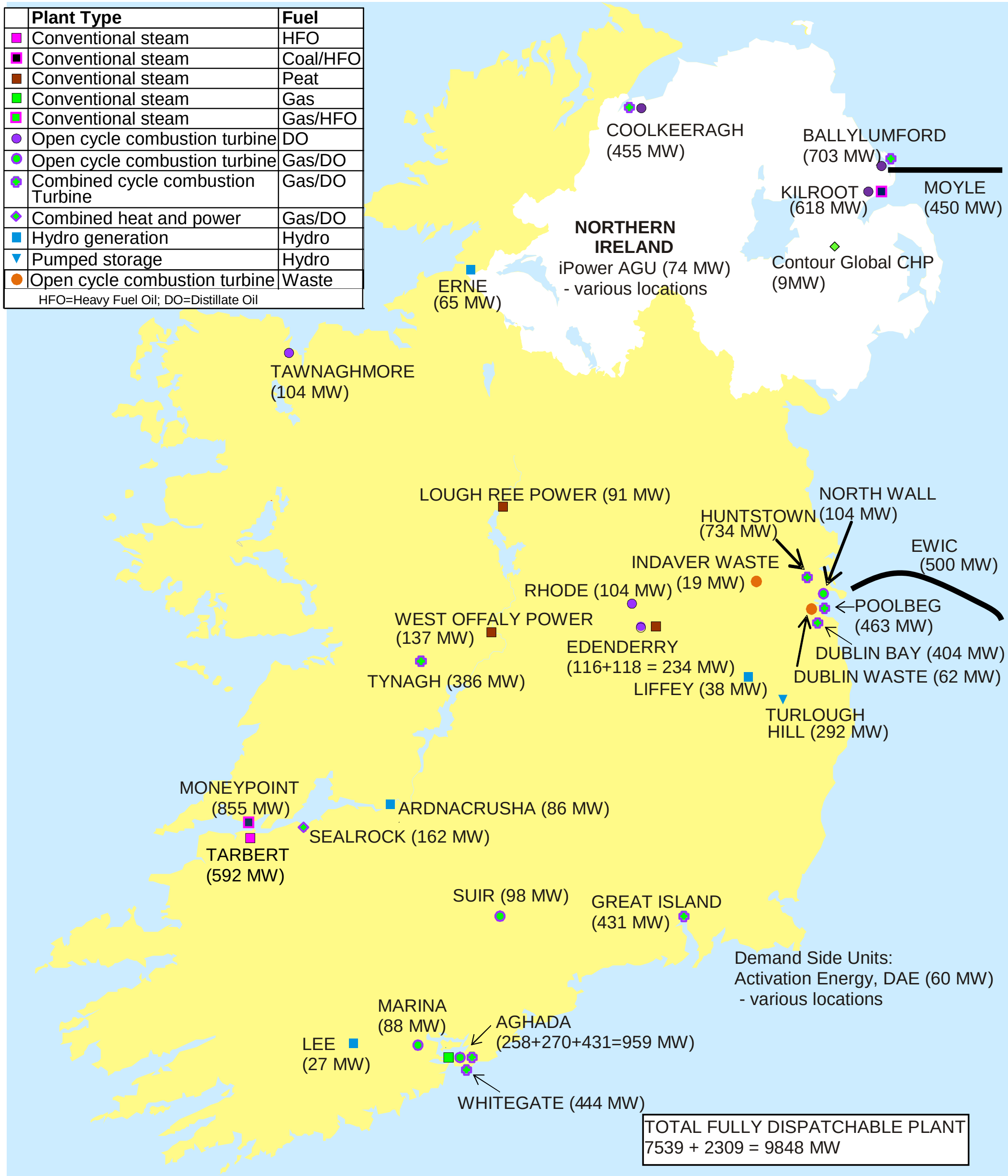

Figure 3-1 Fully dispatchable plant and undersea interconnectors installed in 2018, at exported capacities. All figures shown are Registered Capacities (except new plant which are at the planned Maximum Export Capacity) – generators and interconnectors may often operate at a lower capacity.

3.3(b) Plant Decommissionings

Some older generators will come to the end of their lifetimes over the next ten years. The generators have confirmed decommissioning dates, as shown in Table 3-3.

Plant	Export Capacity (MW)	Expected closure date
Great Island 1,2,3	212	2014
Tarbert 1, 2, 3, 4	592	2021

Table 3-3 Confirmed closures of conventional generators in Ireland

3.3(c) Ireland's Base Case

Other than the generators listed in Table 3-3, EirGrid has received no other notification of plant closures. However, EirGrid has assumed that some older generators will shut towards the latter end of the 10 year period. An alternative approach could be to model these units with higher forced outage rates, which would have the same effect as closure.

Also, in order to be prudent with respect to commissioning plant, EirGrid has taken the view for its adequacy assessments not all of the contracted generators in Table 3-2 will be realised.

3.4 Changes to Conventional Generation in Northern Ireland

- There is no significant new conventional generation currently planned for Northern Ireland over the next 10 years.
- Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by 2016. This is due to environmental constraints introduced by the Large Combustion Plants Directive[31] and will result in a reduction of 510 MW in capacity.
- From 2016, KPS1 and KPS2 at Kilroot will have to comply with the Industrial Emissions Directive (IED)[32]. SONI have discussed with AES Kilroot how the workings of the IED will affect KPS1 and KPS2 running regimes.

In the assumptions for the studies, the emission restrictions imposed on KPS1 and KPS2 by the IED have been taken into account. This includes limited emissions each year from 2016-2020, followed by severely restricted running hours from 2021-2022. The IED greatly affects their ability to contribute to system adequacy beyond 2020.

It should be noted that at this stage, the workings of the IED are not fully finalised and therefore these assumptions are AES Kilroot's best informed estimates at this stage, based on all the information they have to date as to what affect the IED will have on them.

In Northern Ireland, transmission network capacity limitations can restrict the amount of power that can be exported onto the transmission network to the east of the province at Islandmagee (Ballylumford). Under these conditions it would not be possible to export the total plant capacity at Islandmagee.

However, with the Moyle Interconnector's capacity assumed to be limited to 250 MW throughout each year of the study (due to the uncertainty as to if or when the ongoing cable fault on Pole 1 will be repaired and available for service again), this restriction does not come into effect.

[31] Large Combustion Plants Directive: http://ec.europa.eu/environment/air/pollutants/stationary/lcp/legislation.htm

[32] Industrial Emissions Directive (IED) http://ec.europa.eu/environment/air/pollutants/stationary/ied/legislation.htm

3.5 Interconnection

Interconnection allows the transport of electrical power between two transmission systems. Interconnection with Great Britain over the Moyle and the East-West interconnectors provides significant capacity benefit. Further transmission links between Ireland and Northern Ireland will enhance generation adequacy in both jurisdictions.

3.5(a) North–South Interconnector

With the completion of the second high capacity transmission link between Ireland and Northern Ireland (assumed for the end of 2017), an all-island generation adequacy assessment can be carried out from 2018 onward. In this all-island assessment, the demand and generation portfolios for Northern Ireland and Ireland are aggregated.

Prior to the completion of the additional North-South interconnector project, the existing interconnector arrangement between the two regions creates a physical constraint that affects the level of support that can be provided by each system to the other. On this basis it has been agreed that each TSO is obliged to help the other in times of shortfall.

With this joint operational approach to capacity shortfalls, it was agreed that the level of spinning reserve would be maintained by modifying interconnector flows. Reductions in reserve would be followed by load shedding by both parties as a final step to maintaining system integrity.

Generation adequacy assessments for each region are carried out with an assumed degree of capacity interdependence from the other region. This is an interim arrangement until the additional interconnector removes this physical constraint. The capacity reliance used for the adequacy studies are shown in Table 3-4.

	North to South	South to North
Capacity Reliance	100 MW	200 MW

Table 3-4 Capacity reliance at present on the existing North-South interconnector

It should be noted that although the capacity reliance used in the studies limits the North-South flow to 100 MW and South-North flow to 200 MW, flows in excess of this can take place during real time operations.

3.5(b) Moyle Interconnector between Northern Ireland and Scotland

The Moyle Interconnector is a dual monopole HVDC link with two coaxial undersea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The total installed capacity of the link is 500 MW.

However, at the time of writing this report, one cable of the Moyle Interconnector is on a prolonged forced outage due to an undersea cable fault. This follows previous prolonged faults on both cables in 2011 and on one of the two cables in 2010.

Though various repair solutions are being progressed, it is not certain when or if the full capacity will be available for service again. Due to this uncertainty, SONI has taken the prudent decision to assume the Moyle's [33] import (and export[34]) capacity to be limited to 250 MW for the present adequacy studies. The Forced Outage Probability[35] (FOP) used in these studies for the Moyle has been adjusted to reflect the recent outages.

It should be noted that any increase in the Moyle Interconnector's capacity during the study period will help the Northern Ireland adequacy position.

All interconnector capacity is auctioned by SONI on behalf of Mutual Energy Limited[36]. This capacity is purchased by market

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[33] Under non-fault conditions the Moyle import capacity is 450 MW Nov-Mar & 410 MW Apr-Oct: www.mutual-energy.com/Download/110930%20MIL%20SONI%20NG%20Capacity%20Calc%20combined%20Sept%202011.pdf

[34] Issues with transmission access rights in Scotland may further limit its export capacity to 80 MW from 2017.

[35] Forced Outage Probability (FOP) is the time a generator is on forced outage as a proportion of the time it is not on scheduled outages.

[36] www.mutual-energy.com

participants. In the SEM the unused capacity can, in emergency situations, be used solely to meet peak demand. Therefore this capacity assessment assumes the capacity of the Moyle Interconnector as a maximum of 250 MW.

Ofgem's recent Electricity Capacity Assessment Report (2013)[37] takes 'a cautious view on interconnector flows in the Reference Scenario by assuming full exports to Ireland and no net flows to mainland Europe under normal operation of the market.'

So, even though there are warnings about power shortage risks in Great Britain by 2015, their base case is still treating the interconnectors to Northern Ireland and Ireland as negative generation which is in line with SONI's assumptions for the Moyle Interconnector. National Grid's most recent Electricity Ten Year Statement[38] also assumes that 'at times of peak electricity demand… electricity will always be flowing from GB to Ireland.'

3.5(c) East West HVDC Interconnection between Ireland and Wales

The East-West interconnector (EWIC) connects the transmission systems of Ireland and Wales with a capacity of 500 MW in either direction. However, it is not easy to predict whether or not imports for the full 500 MW will be available at all times. Based on analysis[39], EirGrid has estimated the capacity value of the interconnector to be 440 MW for these generation adequacy studies. Similar to the Moyle, EWIC is treated as negative generation by National Grid.

A FOP somewhat lower than that for the Moyle interconnector has been used to represent EWIC for the adequacy studies.

3.6 Wind Capacity and Renewable Targets

In both Ireland and Northern Ireland, there are government policies which target the amount of electricity sourced from renewables.

Biofuels, hydro and marine energy will make an important contribution to these targets. However, it is assumed that these renewable targets will be achieved largely through the deployment of additional wind powered generation. Table 3-5 shows the existing and planned wind generation on the island. Appendix 2 has detailed lists of all the currently installed windfarms on the island.

Compared to the previous GCS, there is a significant increase in the amount of wind contracted in Ireland, particularly from the 'Gate 3' process.

	Connected (MW)	Contracted/ Planned (MW)
Ireland TSO	794	1439
Ireland DSO	978	2152
Northern Ireland	553	481
Totals	**2325**	**4072**

Table 3-5 Existing (connected) and planned (contracted) wind farms, as of October 2013. Planned refers to wind farms that have signed a connection agreement in Ireland, or that have received planning approval in Northern Ireland. These figures are based on the best information available.

Wind generation does not produce the same amount of energy all year round due to varying wind strength. The wind capacity factor gives the amount of energy actually produced in a year relative to the maximum that could have been produced had wind farms been generating at full capacity all year.

3.6(a) Wind Power in Ireland

In October 2009 the Irish Government announced a target of 40% of electricity generated to come from renewable sources by 2020. This is part of the Government's strategy to meet an overall target of achieving 16% of all energy from renewable sources by 2020.

Installed capacity of wind generation has grown from 145 MW at the end of 2002 to

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37 Ofgem Electricity Capacity Assessment: https://www.ofgem.gov.uk/electricity/wholesale-market/electricity-security-supply

38 http://www2.nationalgrid.com/UK/Industry%20information/Future%20of%20Energy/Electricity%20Ten%20Year%20Statement/

39 Interconnection Economic Feasibility Report: http://www.eirgrid.com/media/47693_EG_Interconnect09.pdf

1,772 MW at the time of writing. This value is set to increase over the next few years as Ireland endeavours to meet its renewable target in 2020.

The actual amount of renewable energy this requires will depend on the demand in future years, the forecast of which has decreased due to the economic downturn.

Also, the assumptions made for other renewable generation will have a bearing on how much wind energy will need to be generated to reach the 40% target.

Lastly, a small amount of available energy from wind cannot be used due to transmission constraints or system curtailment – the exact amount has to be estimated, and is therefore another source of potential error.

With these uncertainties in mind, not one figure but a band of possible outcomes has been estimated for wind capacity in 2020. Figure 3-2 indicates these targets between about 3,200 and 3,700 MW.

This would mean a doubling of capacity from today's levels, or an average of 290 MW of extra wind capacity installed per year.

Based on historical records (historical wind capacity factors are shown in Figure 3-4), it is assumed that onshore wind has a capacity factor of 31.5%. 2010 was considered to be particularly poor wind year in terms of nationwide average wind speeds.

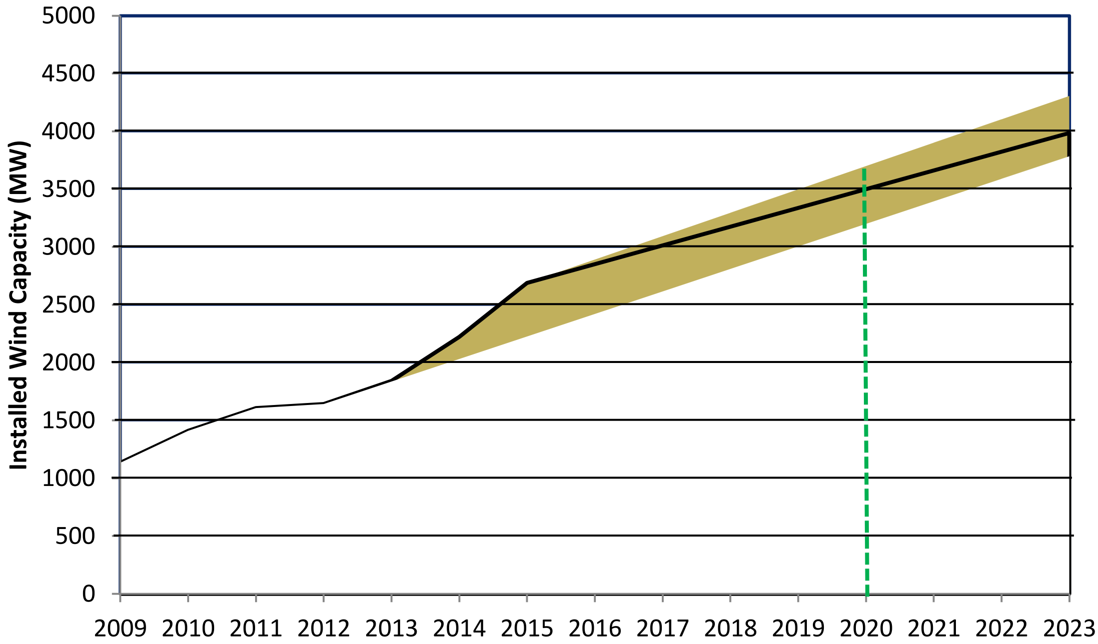

Figure 3-2 Band of possible wind capacity requirements to meet the 2020 renewable target.

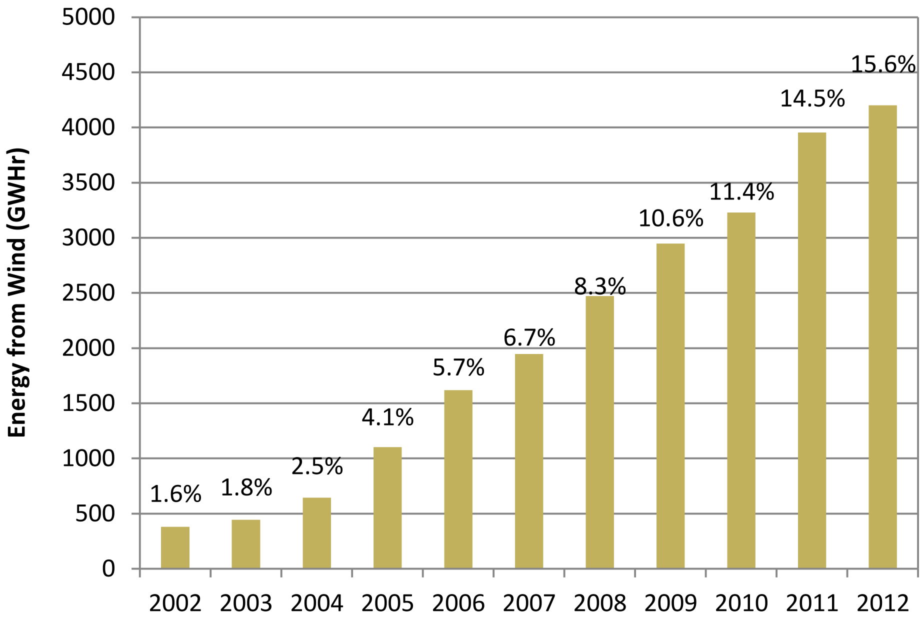

Figure 3-3 Historical wind generation in annual energy terms for Ireland (normalised), also given as a percentage of total electrical energy produced that year.

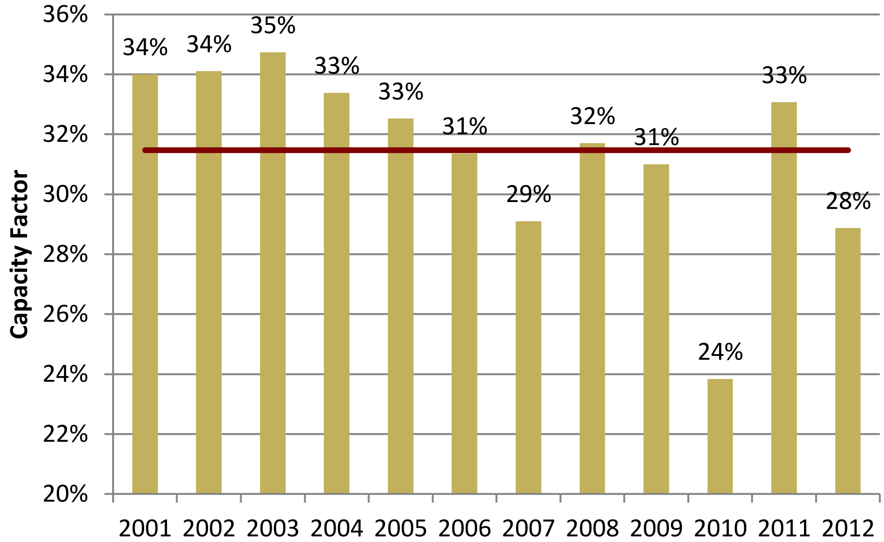

Figure 3-4 Historical wind capacity factors for Ireland, with the average marked in a red line.

3.6(b) Wind Power in Northern Ireland

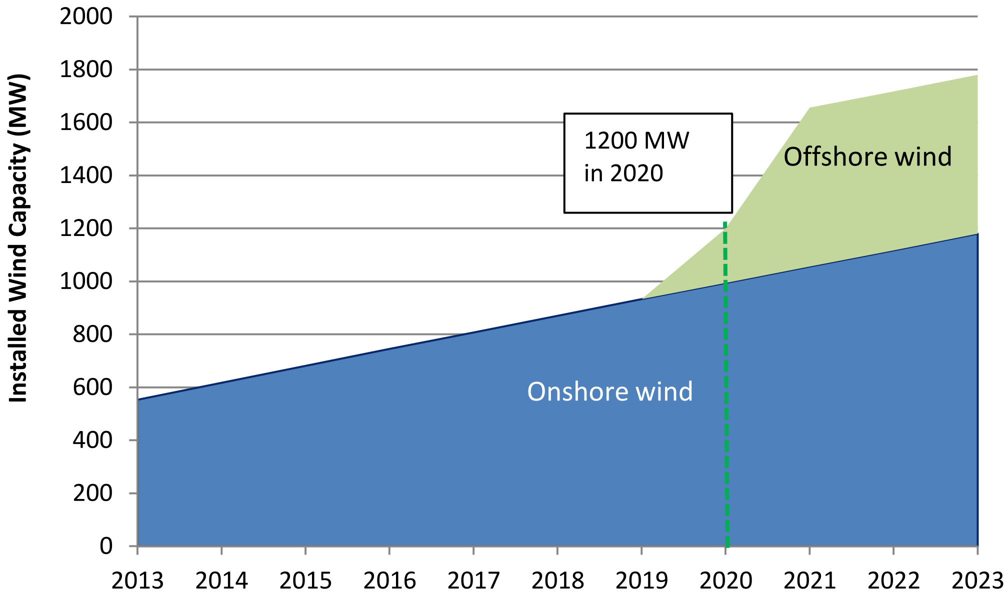

Figure 3-5 Northern Ireland wind levels assumed for this report

The Strategic Energy Framework for Northern Ireland[40] restated the target of 12% of electricity consumption from renewable resources by 2012 with a new additional target of 40% of electricity consumption from renewable resources by 2020. For 2012, 12.5% of electricity consumption came from renewable sources in Northern Ireland, and so surpassing the 12% target and showing an improvement as compared to 2011 when a contribution of 11.9% was observed.

Installed capacity of wind generation has grown from 37 MW in 2002 to 553 MW (including 22 MW of small scale wind) at the time of writing. This is set to increase rapidly over the next number of years as increasing levels of planning applications[41] for new wind farms are made. While taking into account a contribution from other renewables such as tidal and biomass, it is this increasing level of wind that is expected to be the main contributor to achieving the 40% target by 2020.

It is estimated that an installed wind capacity of circa 1200 MW will be enough to achieve the 40% figure by 2020 (912 MW of large scale onshore, 82 MW of small scale onshore and 206 MW of offshore). The figures for the amount of large scale onshore wind in each study year have been derived by incrementing the amount of connected onshore wind each year which will allow this target of 912 MW to be met by 2020.

While the exact amount is as yet uncertain, for the purposes of the studies for this report SONI assume that by 2023 there will be 600 MW of offshore wind connected.

Figure 3-5 shows the expected growth of wind installed in Northern Ireland, both onshore and offshore.

These assumptions have also referenced a number of other sources, including the Strategic Environmental Assessment (SEA) of

40 Strategic Energy Framework (www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf)

41 Information of current wind farm applications can be found on the Northern Ireland Planning Service website (http://www.planningni.gov.uk/index/advice/advice_apply/advice_renewable_energy/renewable_wind_farms.htm)

offshore wind and marine renewable energy[42] and the Onshore Renewable Electricity Action Plan (OREAP)[43] produced by the Department of Enterprise, Trade and Investment (DETI).

The wind energy assumptions also incorporate the announcements by the Crown Estates[44] who have now awarded development rights for three offshore renewable energy sites in Northern Ireland's coastal waters including a 600 MW Offshore wind farm, and two 100 MW Tidal sites as well as information provided on wind farm connections by Northern Ireland Electricity (NIE) and the Northern Ireland Planning Service[45].

These sources indicate that even higher amounts of wind generation may connect over the next few years. However, SONI have taken a more conservative view on the amount that will be connected for the adequacy studies and have included enough capacity to meet the Northern Ireland Executive's 40% renewable target by 2020.

For the purposes of calculating the forecasted energy produced by renewable, SONI assumes that large scale onshore wind has a capacity factor[46] of 30%, large scale offshore wind 35%, tidal 20% and large scale biomass 80%. There is also a factor to take account of an amount of potential energy from wind which cannot be used due to transmission or system constraints. It should be further noted that the actual amount of renewable energy required to meet the 40% target by 2020 will depend on the demand in future years, as the 40% figure is based on electricity consumption and not on installed capacity.

Figure 3-5 illustrates the installed wind levels in Northern Ireland assumed for this report. Most of this wind will be built in the west of Northern Ireland, and transmission reinforcements will be required to transport it to the east, where demand is highest. To avoid extensive potential wind energy constraints, and to enable Northern Ireland to meet Government renewable targets, considerable investment is now urgently required on the Northern Ireland transmission system. The levels of connected wind capacity required are dependent on a number of key transmission corridors being reinforced by the asset owner, Northern Ireland Electricity, alongside the completion of the second North South interconnector as highlighted in their Medium Term Plan[47].

Figure 3-6 shows the increase in energy supplied from wind generation in recent years. In 2005, just 3.4% of Northern Ireland's electricity needs came from wind generation. This share had grown to 11.7% by 2012.

Historical capacity factors for Northern Ireland are shown in Figure 3-7. The average wind capacity factor for the last 8 years is 30.9%. It can be seen that in 2012 the wind capacity factor is lower than the average.

[42] Strategic Environmental Assessment (SEA) (www.offshorenergyni.co.uk)

[43] Onshore Renewable Electricity Action Plan (OREAP) (www.onshorerenewablesni.co.uk)

[44] The Crown Estate: www.thecrownestate.co.uk

[45] http://www.planningni.gov.uk/index/advice/advice_apply/advice_renewable_energy/renewable_wind_farms.htm

[46] Capacity factor gives the amount of energy actually produced in a year relative to the maximum that could have been produced, had a generator been generating at full capacity all year.

[47] NIE Medium Term Plan: www.nie.co.uk/Network/Major-projects/Rebewable-investment

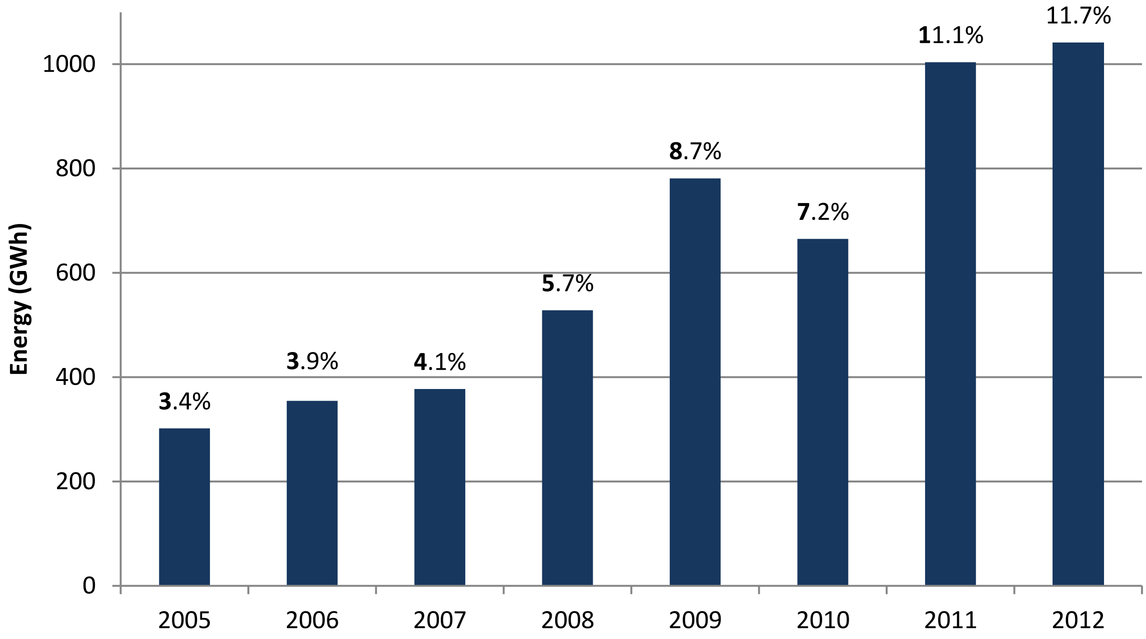

Figure 3-6 Historical wind generation for Northern Ireland in annual electricity terms, also given as a percentage of total electricity produced that year. Figures are based on sent-out metering available to SONI.

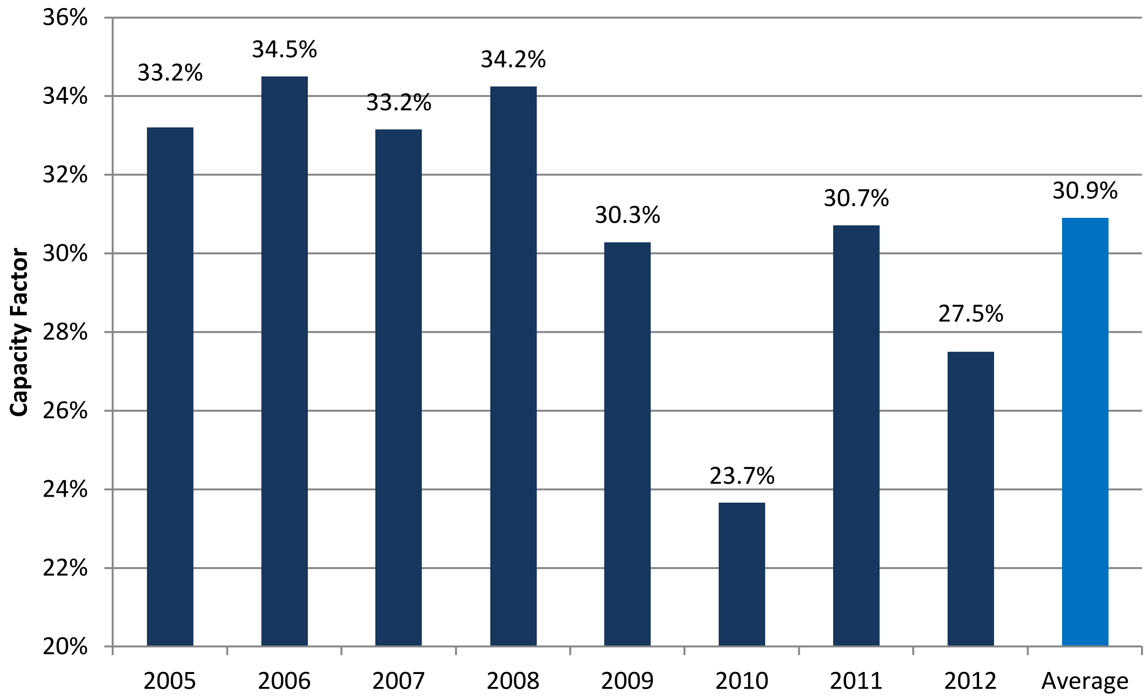

Figure 3-7 Northern Ireland historical wind capacity factors. Figures based on sent-out metering available to SONI

3.6(c) Modelling of Wind Power in Adequacy Studies with Wind Capacity Credit

Due to its relatively small geographical size, wind levels are strongly correlated across the island. Wind generation across the island tends to act more or less in unison as wind speeds rise and fall. The probability that all wind generation will cease generation for a period of time limits its ability to ensure continuity of supply and thus its benefit from a generation adequacy perspective.

The contribution of wind generation to generation adequacy is referred to as the capacity credit of wind. In our studies, capacity credit has been determined by subtracting a forecast of wind's half hourly generated output from the electricity demand curve. The use of this lower demand curve results in an improved adequacy position. This improvement can be given in terms of extra megawatts of installed conventional capacity. This MW value is taken to be the capacity credit of wind.

(Please note that an alternative methodology for incorporating wind in adequacy studies is described in APPENDIX 3, and will be further explored in the future.)

The capacity credit of wind will vary from year to year, depending on whether there is a large amount of wind generation when it is needed most. Analysis of many different years showed the behaviour of the 2009 profile to be close to average in terms of capacity credit. 2010 was considered a poor wind year, and so was not used for these studies. 2011 was below average.

It can be seen in Figure 3-8 that there is a benefit to the capacity credit of wind when it is determined on an all-island basis. The reason for this is that a greater geographic area gives greater wind speed variability at any given time. If the wind drops off in the south, it may not drop off in the north, or at the very least there will be a time lag. The result is that the variation in wind increases and the capacity contribution improves.

Despite its limited contribution towards generation adequacy, wind generation has other favourable characteristics, such as:

- The ability to provide sustainable energy
- Zero carbon emissions
- Utilisation of an indigenous, free energy resource
- Relatively mature renewable-energy technology

This, combined with excellent natural wind resources in both Ireland and Northern Ireland, will ensure that wind generation will be developed extensively to meet the two Governments' renewable energy targets for 2020 in both jurisdictions.

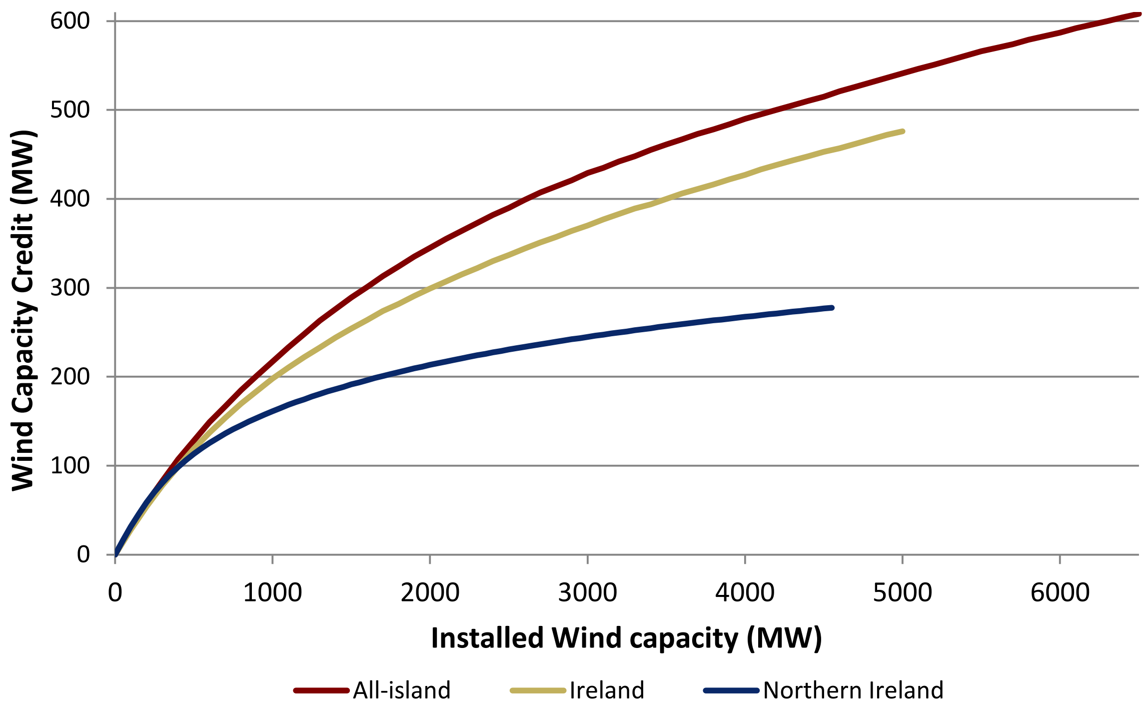

Figure 3-8 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation. For Ireland, the wind profiles were taken from 2012, the most recent, typical year. The curve for Northern Ireland is based on an average over several years.

3.7 Changes in other Non-Conventional Generation

This section discusses expected developments in demand side generation, CHP, biofuels, small scale hydro and marine energy over the next 10 years. All assumptions regarding this non-conventional generation are tabulated in Appendix 2. Though relatively small, this sector is growing and making an increasing contribution towards generation adequacy, and in meeting the 2020 renewables targets.

As discussed in Section 2.3, SONI have obtained information from NIE on the estimated amount of embedded generation that is present on the Northern Ireland system. Other sources, such as the Ofgem Renewable Obligation Certificate Register (ROC Register) and information for the Northern Ireland planning service have also been used to try and gain a better estimate of current and future levels. SONI assumptions based on these sources estimates circa 96 MW[48] of this small scale generation is currently connected to the Northern Ireland system, with various levels of this being utilised for self consumption on site.

3.7(a) Demand-Side/Industrial Generation

Industrial generation refers to generation, usually powered by diesel engines, located on industrial or commercial premises, which acts as on-site supply during peak demand and emergency periods. The condition and mode of operation of this plant is uncertain, as some of these units would fall outside the jurisdiction of the TSOs.

Demand-side generation has been ascribed a capacity of 9 MW in Ireland for the purposes of this report.

A dispatchable Aggregated Generating Unit (AGU) operates in Northern Ireland which

48 Mainly includes Diesel Generators, CHP and Small Scale Wind but also PV, Gas, Hydro, Biofuels and Land Fill Gas

consists of a number of individual diesel generators grouping together to make available their combined capacity to the market. The amount of capacity available to this AGU is expected to increase to 74 MW over the coming years. It should be noted that this is an exportable capacity and is not considered as demand side generation in this context.

3.7(b) Small-scale Combined Heat and Power (CHP)

Combined Heat and Power utilises generation plant to simultaneously create both electricity and useful heat. Due to the high overall efficiency of CHP plant, often in excess of 80%, its operation provides benefits in terms of reducing fossil fuel consumption and CO_2 emissions.

Estimates give a current installed CHP capacity (mostly gas-fired) of roughly 141 MW in Ireland (not including the 161 MW centrally dispatched CHP plant operated by Aughinish Alumina). The target for total CHP in Ireland[49] was 400 MW by 2010, whereas what was achieved was in the region of 300 MW. With the withdrawal of government incentives for fossil fuelled CHP, this area is not likely to grow much more.

In Northern Ireland, there is currently an estimated 11 MW of small scale CHP connected to the distribution system. (3 MW of which is renewable and 8 MW non-renewable). Without more detailed information an assumption has been made that for the purposes of this statement, the estimated 11 MW in 2013 will rise to 12 MW by 2023.

CHP is promoted in accordance with the European Directive 2004/8/EC. The Strategic Energy Framework[50] for Northern Ireland acknowledges that the uptake of CHP in the region has been limited and therefore DETI have decided to encourage greater scope for combined heat and power in Northern Ireland.

3.7(c) Biofuel

There are a number of different types of biofuel-powered generation plant on the island.

In Ireland, there is currently an estimated 46 MW of landfill gas powered generation. The peat plant at Edenderry aims to power 30% of its output using biomass by 2015. The REFIT 3[51] incentive for biomass-fuelled CHP plant aims to have 150 MW installed by 2020. With some of this plant already planned, it has been assumed for the purpose of this report that the whole 150 MW will be achieved on time. This plant makes a significant contribution to the 40% RES target.

Currently in Northern Ireland, there is an estimated 12 MW of small scale biofuels (5 MW of biomass & 7 MW of biogas) and 13 MW of landfill gas powered generation. For the purposes of this report, and in the absence of more detailed information, it has been assumed that by 2023 the small scale biofuels capacity will rise to 50 MW (17 MW of biomass & 33 MW of biogas) while landfill gas powered generation capacity will reach 27 MW.

For the studies it is also assumed in Northern Ireland that 45 MW of large scale biomass will be commissioned during the study period at 3 separate sites, each of which will have a capacity of 15 MW. These may be dispatchable due to their size, although at this stage there are no signed agreements or target connection dates in place.

3.7(d) Small-scale hydro

It is estimated that there is currently 21 MW of small-scale hydro capacity installed in rivers and streams across Ireland, with a further 4 MW in Northern Ireland. Such plant would generate roughly 60 GWh per year, making up approximately 0.1% of total annual generation. While this is a mature technology, the lack of suitable new locations limits increased contribution from this source. It is assumed that there are no further increases in small

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49 Energy White Paper 2007 'Delivering a Sustainable Energy Future for Ireland', March 2007.

50 www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf

51 http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/REFIT.htm

hydro capacity over the remaining years of the study.

3.7(e) Marine Energy

With the large amount of uncertainty associated with this new technology, EirGrid has taken the prudent approach that there will be no commercial marine developments operational before 2023.

In Northern Ireland the Strategic Environmental Assessment (SEA)[52] proposes a target of 300 MW from tidal generation by 2020. It is unclear at this stage as to which tidal technology will be used to achieve this.

However, the Crown Estates[53] have awarded development rights for two 100 MW Tidal sites off the North Coast of Northern Ireland.

Therefore, for the purposes of this report, SONI have used a conservative assumption for tidal generation of 154 MW by 2020 and 200 MW by 2023.

3.7(f) Compressed Air Energy Storage (CAES)

SONI is in discussions with a renewables development company about connection of a proposed Compressed Air Energy Storage (CAES) Plant in the Larne area. Such an energy storage facility could potentially act as an ancillary services and balancing facility for renewable generation. A CAES plant uses a large compressor to store excess energy off the grid. It converts the excess electric energy to compressed air which is stored in an underground geological cavern, then released through an electric generator for later use. This technology could be applied to store surplus renewable energy, whilst also enabling variability balancing on the transmission system. The potential exists for a CAES facility consisting of up to 270 MW of generation and 210 MW of compression. Such a facility would be connected to the transmission system.

These discussions are still at an early stage and therefore for the purposes of this report, this has not been included in the Northern Ireland generation assumptions at this stage.

3.7(g) Waste To Energy

The Indaver plant in Co Meath is estimated to source half its waste from renewable sources, and so contributes to the overall renewables targets. The proposed waste-burning facility in Dublin also estimates 50% RES in the waste it will burn.

Evermore Waste Project is a proposed wood-fuelled energy-from-waste plant in Northern Ireland due to become operational in 2015. The 15.8 MW combined heat and power (CHP) plant will divert two million tonnes of wood from landfill over its lifespan, and around 110,000 tonnes per annum.

3.8 Plant Availability

It is unlikely that all of the generation capacity connected to the system will be available at any particular instant. Plant may be scheduled out of service for maintenance, or forced out of service due to mechanical or electrical failure. Forced outages have a much greater negative impact on generation adequacy than scheduled outages, due to their unpredictability.

The base case availability scenario used in this report combines the most likely availability scenario as considered by each TSO: EirGrid-calculated availability for Ireland and the high availability forecasted by SONI for Northern Ireland. While this is the most likely scenario, other availability scenarios have been examined to prepare for a range of possible outcomes.

Both EirGrid and SONI have concerns that maintenance patterns may change as a result of increased two shifting. Two shifting is where a generator is taken off overnight or at minimum load times. This will occur more frequently with increased penetration of wind generation, and will result in the requirement for additional maintenance and increased Scheduled Outage Days (SODs). We will continue to monitor the operation of plant and the impact of this on availability.

[52] Strategic Environmental Assessment (www.offshorenergyni.co.uk). DETI is also developing an Onshore Renewable Electricity Action Plan (OREAP) for Northern Ireland. (www.onshorerenewablesni.co.uk)

[53] The Crown Estate: www.thecrownestate.co.uk

3.8(a) Ireland

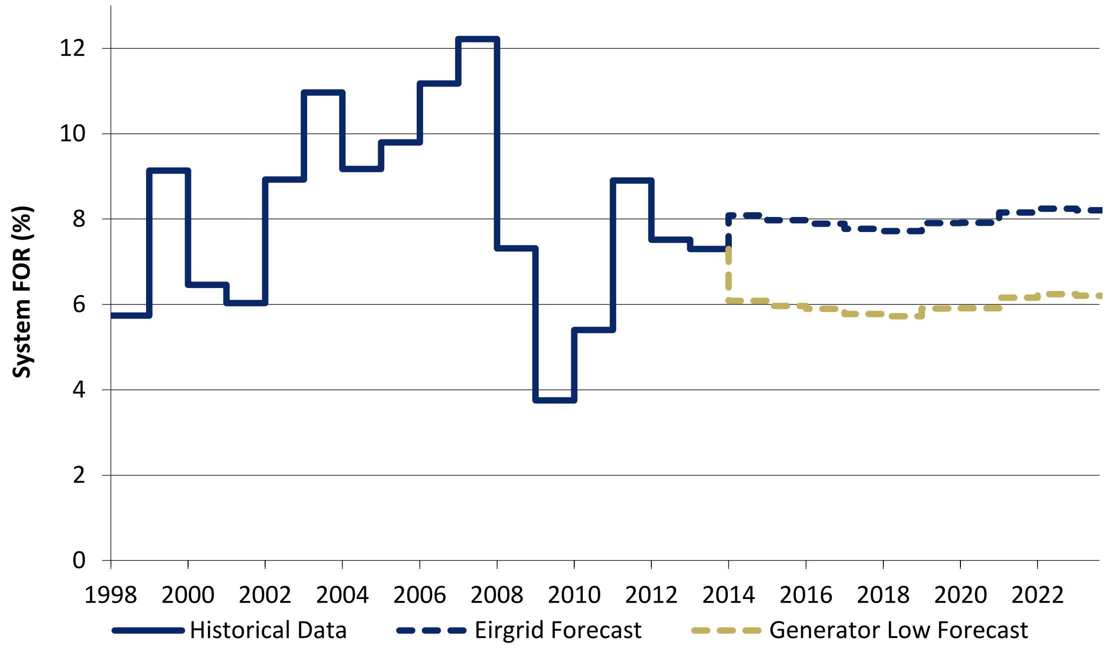

Figure 3-9 Historical and predicted Forced Outage Rates for Ireland. Future rates as predicted by both EirGrid and the generators are shown.

Figure 3-9 shows the system-wide forced-outage rates (FOR)[54] for Ireland since 1998, as well as predicted values for the study period of this report.

After rising steadily in the years up to 2007, FORs in Ireland have started to drop in the past few years. One cause for this improvement is the introduction of new generators and removal of old generators. Another contributing factor is reduced demand, which means older peaking units are called on less often, giving them less of an opportunity to fail. However it must be noted that major impact events (e.g. Turlough Hill) have led to poorer availability in 2010 and 2011.

The operators of fully-dispatchable generators have provided forecasts of their availability performance for the ten year period 2014 to 2023. However, in the past these forecasts have not given an accurate representation of the amount of outages on the system. This is primarily due to the effect high-impact low-probability (HILP) events.

HILP events are unforeseen occurrences that don't often transpire but, when they do, will have a significant adverse impact on a generator's availability performance, taking it out of commission for several weeks. The probability of this occurring to an individual generator is low. However, when dealing with the system as a whole, there is a reasonable chance that at least one generator is undergoing such an event at any given time. EirGrid studies[55] have indicated that HILPs will make up around one third of forced outages on average.

EirGrid has incorporated these HILPs to create a more realistic system availability forecast. This EirGrid availability forecast is used as the base case for these studies.

[54] The FOR is the percentage of time in a year that a plant is unavailable due to forced outages.

[55] GAR 2009-2015

3.8(b) Northern Ireland

Generators are obligated to provide SONI with planned outage information in accordance with the Grid Code (Operating Code 2). Each power station provides this information for individual generating units indicating the expected start and finish dates of required maintenance outages for 7 years ahead. For the purposes of this report, a further 3 years has been assumed by SONI based on the maintenance cycles for each generating unit to enable this statement to look 10 years ahead.

Future FOR predictions are based on the historical performance of generators and the Moyle Interconnector or by making comparisons with similar units for newly commissioned plant.

Figure 3-10 shows the system forced-outage rates (FOR) for Northern Ireland since 2003, as well as predicted values for the study period of this report. This analysis is focused on fully dispatchable plant and does not include the Moyle Interconnector. After rising steadily in the years up to 2007, FORs in Northern Ireland have started to fall over the past few years. This coincides with the introduction of the Single Electricity Market (SEM) where incentives have been put in place to encourage better generator availability. Another contributing factor is reduced demand resulting from the ongoing economic downturn, which means older peaking units are called on less often, giving them less of an opportunity to fail.

Figure 3-11 shows the historical availabilities in Northern Ireland along with the projected high and low availabilities. The average high availability over the 10-year period is 88.9% and the low availability figure is 83.3%.

Historically the availability of Moyle has been much higher than conventional generation. However, at the time of writing this report, one cable of the Moyle Interconnector is on a prolonged forced outage due to an undersea cable fault and SONI is unaware of a firm, planned repair date. This follows previous prolonged faults on both cables in 2011 and on one of the two cables in 2010. As such, the Forced Outage Probability (FOP) used in adequacy assessments for the Moyle has been adjusted to reflect the recent outages.

It is necessary to present a range of availability scenarios for the future. The high availability scenario is based on the actual historical performance of generators in Northern Ireland, which historically are considered good. The low availability has been calculated with a pessimistic view of FORs, where the performance of all generators drops to a level corresponding to the worst performing unit connected on the system during each study year.

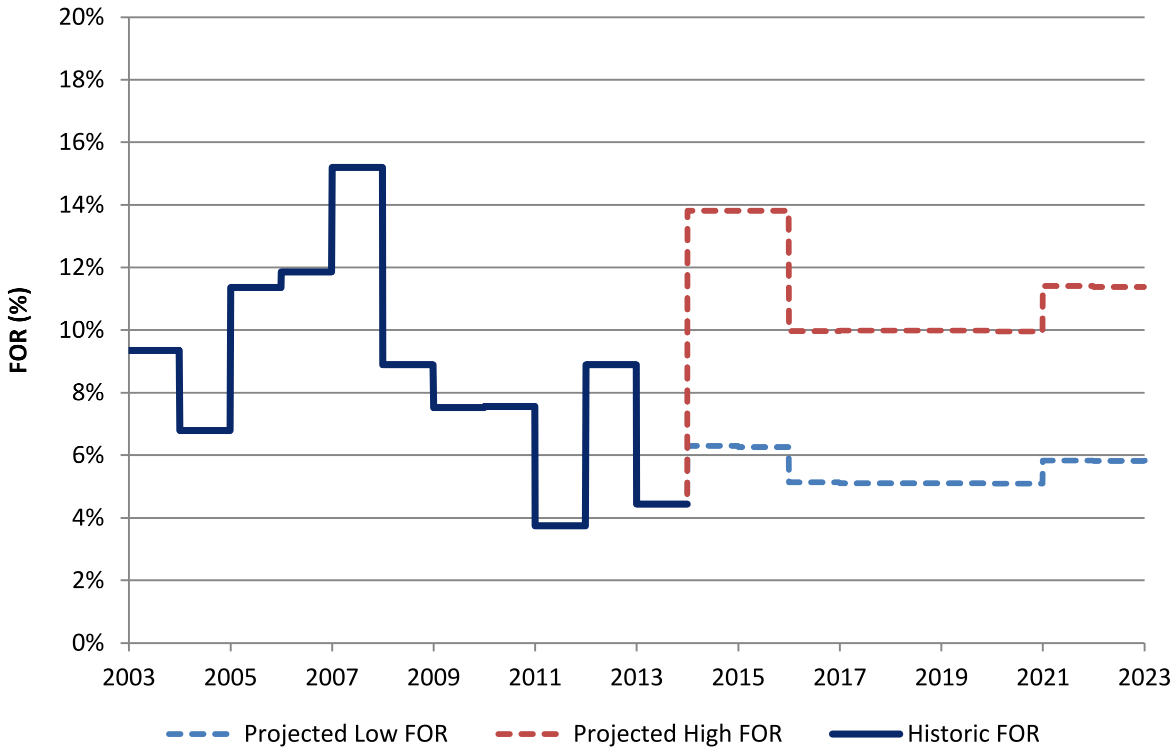

Figure 3-10 Historical and predicted Forced Outage Rates for Northern Ireland (not including the Moyle Interconnector)

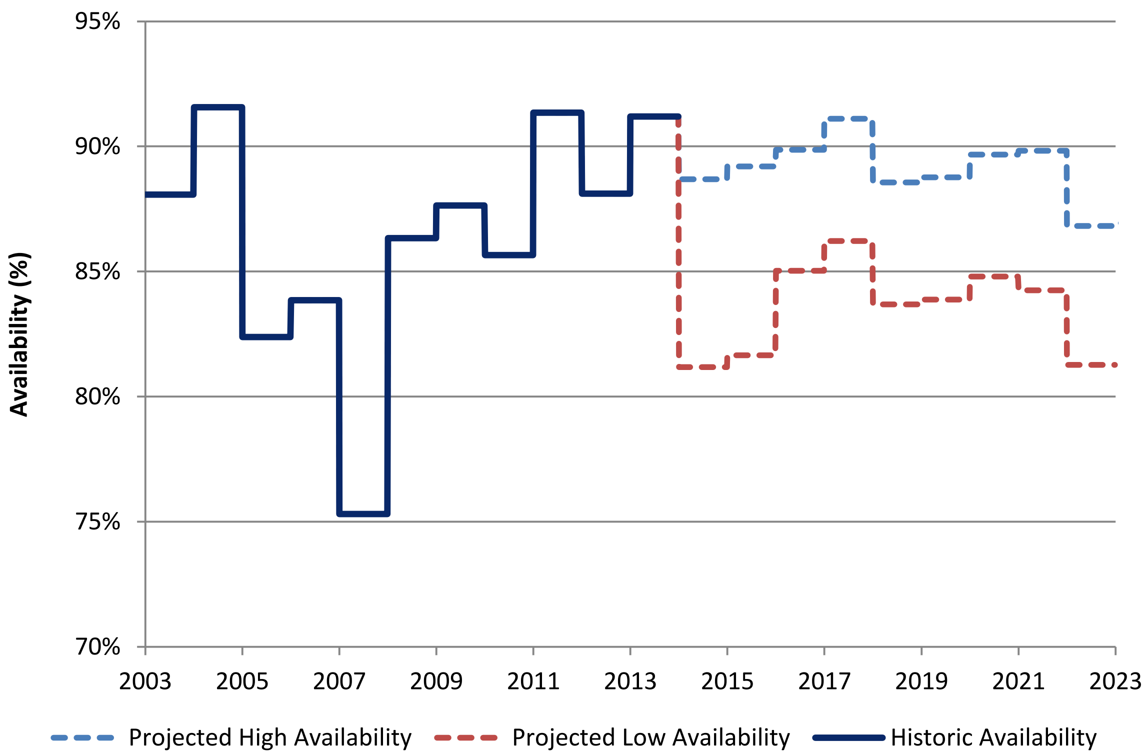

Figure 3-11 Historical and predicted Plant Availabilities in Northern Ireland (without Moyle)

4 ADEQUACY ASSESSMENTS

4 ADEQUACY ASSESSMENTS

4.1 Introduction

This section presents the results from the adequacy studies, given in terms of the plant surplus or deficit (see APPENDIX 3 for information on the methodology used). Generation adequacy assessments are carried out in three different ways:

- for Ireland alone,
- for Northern Ireland alone,
- and for both systems combined, i.e. on an all-island basis.

The overall adequacy position improves on completion of the additional North-South interconnector.

Alongside the base case, results are presented for different plant scenarios, including

- the unavailability of interconnector flows between the island of Ireland and Great Britain,
- and the loss of a CCGT in each jurisdiction.

Different demand growth and plant availability scenarios are also examined to illustrate their effect on generation adequacy. All results are presented in full tabular form in APPENDIX 4.

In addition to the cases presented in this section, the next section 5 (on page 52) explores in-depth the security of supply situation faced by Northern Ireland post 2015.

4.2 Base Case

4.2(a) Presentation of Results

The adequacy assessments from the base case are presented in Figure 4-1, in terms of the amount of surplus or deficit as assessed for the system for any particular year. When a result for any year results in a deficit, it is plotted below the red line, e.g. Northern Ireland in 2022.

The base case assumes the following:

- median demand growth in both jurisdictions (this is referred to as the Recovery scenario in Ireland),
- the EirGrid-calculated availability for the generation portfolio in Ireland,
- and high availability (based on historical performance) for the Northern Ireland generation portfolio.

For the single-area studies, Northern Ireland is assumed to place 200 MW reliance on Ireland, and Ireland places 100 MW reliance on Northern Ireland. For the all-island combined study, these reliance values are not used.

In the single-area studies, the Wind Capacity Credit curve relevant to that particular jurisdiction is used. For the all-island studies, the combined all-island WCC curve is used, matching the total amount of installed wind on the island to the appropriate capacity credit.

As the second North-South interconnector is assumed to be commissioned by the end of 2017, then the single-area studies are only relevant until then. However, they have been continued beyond 2017 (as dashed lines) to illustrate the situation should the interconnector project be delayed.

Similarly, the results for the combined, all-island system are applicable only from 2018 onwards. However, results are shown before this time in dashed lines to convey the situation should the interconnector be completed early.

4.2(b) Discussion of Results

The results for Ireland show it to be in a large surplus of over 1,000 MW for most years. This begins to fall off towards the later years as older plant is assumed to come to the end of their lives. There is a large drop in 2021 as all the units at Tarbert are decommissioned.

In addition to these plant shut-downs, changes in adequacy are caused from year to year by demand growth, plant additions and increased wind penetration.

For Northern Ireland, the adequacy situation is sufficient until the removal of ST4, 5 and 6 from Ballylumford at the end of 2015. Thereafter, the surplus drops to modestly low levels of about 200 MW. If there were no deviations from the Base Case assumptions, then the risk to supply would be acceptable in the years 2016-2020. However, should any unforeseen prolonged outage occur during this time, then the risk to security of supply in Northern Ireland rises to substantial levels, as discussed in more detail in Section 5.

By 2021, more severe restrictions are placed on the Kilroot coal plant, and this has the result of pushing Northern Ireland into deficit in the Base Case. If the second North-South interconnector is not in place by this time, then the risk to security of supply increases significantly.

However, once the additional North-South interconnector is completed, the adequacy can be assessed on an all-island basis, and the gold line indicates that no deficits are expected in this case.

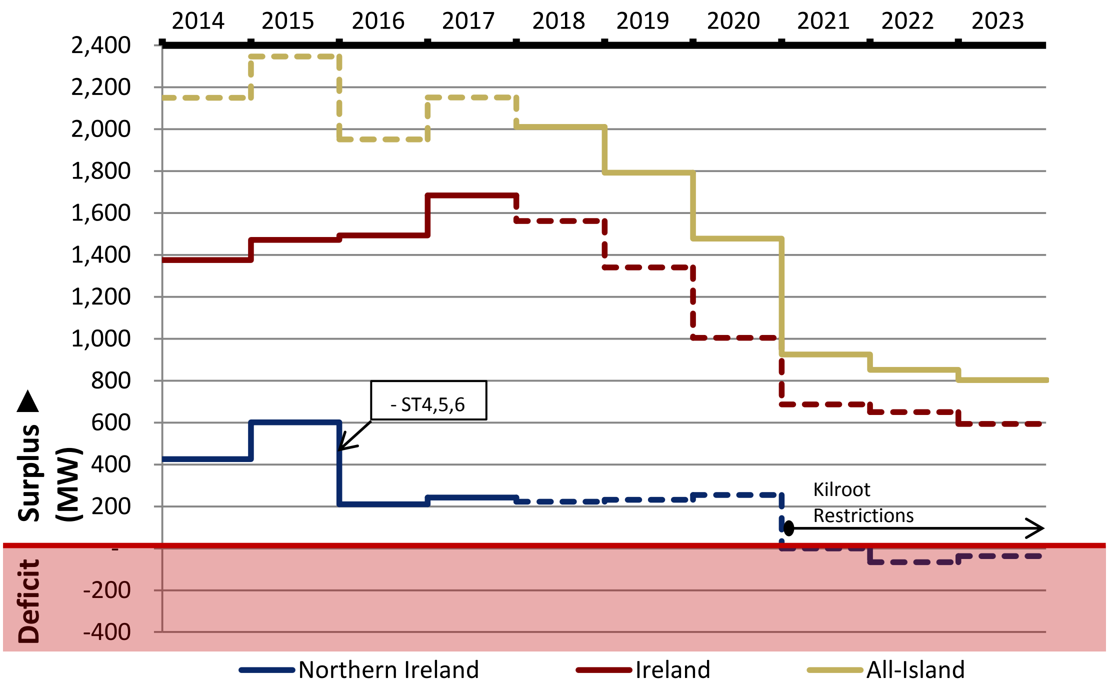

Figure 4-1 Adequacy results for the Base Case scenario, shown for Ireland, Northern Ireland and on an all-island basis.

4.3 Loss of Interconnection with Great Britain

Due to the recent long-term forced outages on the Moyle interconnector, it was thought prudent to examine a situation where both undersea interconnectors with Great Britain (Moyle and East-West) are unavailable.

Figure 4-2 shows how the surplus reduces dramatically from the base case scenarios. In particular, Northern Ireland would be in effective deficit from 2016, and particularly so from 2021. This again shows the importance of the planned extra North-South interconnector to enable SONI to maintain generation security standards in Northern Ireland.

In combination with the plant being shut down in Ireland, this scenario would result in a less favourable adequacy situation from 2021 in Ireland, as well as in the all-island combined study.

This scenario also highlights the implications if energy is unavailable to import from Great Britain to either Ireland via EWIC, or to Northern Ireland via Moyle, due to any capacity shortfall or market conditions that may occur in GB. However, as discussed in Section 3.5, National Grid and Ofgem treat both the EWIC and Moyle as negative generation even at their peak demand times.

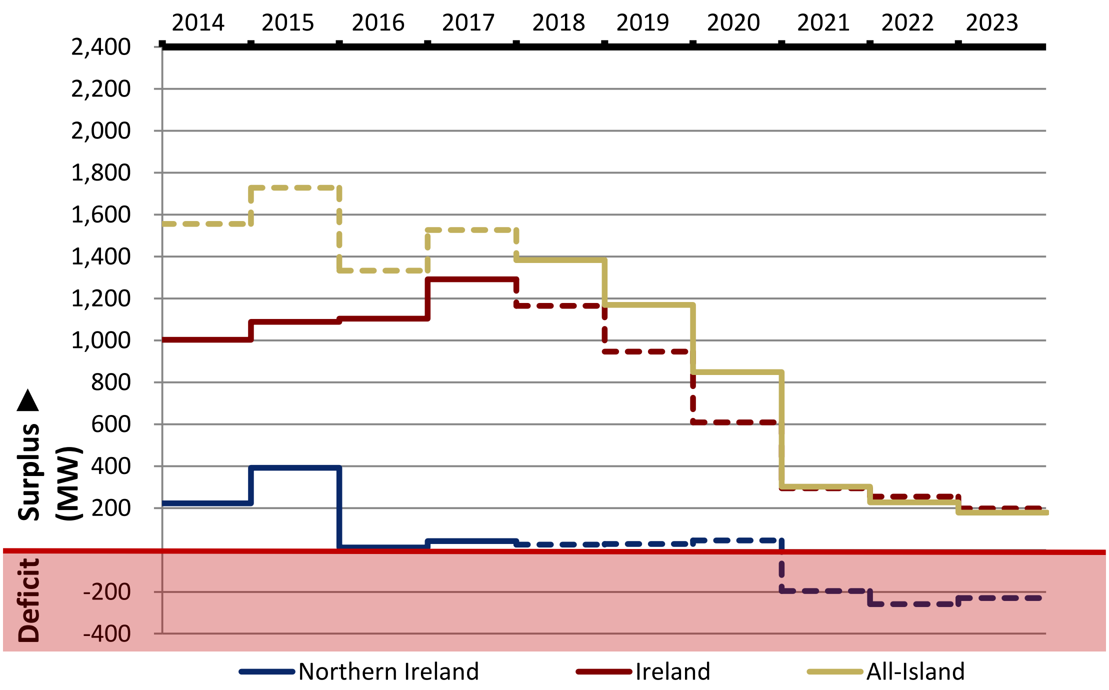

Figure 4-2 The adequacy situation without the interconnectors to Great Britain

4.4 Loss of a CCGT in each Jurisdiction

To plan the running of a secure power system, it would be advisable to model a future scenario where a major, unforeseen event could have a large effect on system adequacy.

Therefore, starting from the Base Case, one CCGT is removed from each jurisdiction for all years, to investigate the effect this would have on overall generation adequacy.

As in the previous scenario without interconnection, this scenario also results in falling adequacy levels, see Figure 4-3. Northern Ireland would be in effective deficit from 2016 onwards, with a significant risk to security of supply, particularly if any other unforeseen outage were to occur. Once again, this underlines the case for installing the second North-South interconnector to provide for long-term security of supply in Northern Ireland as well as in Ireland.

With its large surplus of plant, the adequacy in Ireland remains well above standard for most years. However, by 2021, the surplus falls to low levels, and so the security of supply begins to be put at risk. This is also evident in the all-island case.

Even though these large outages are applied to all ten years of the study, it is not being suggested that a ten year outage is a realistic outcome. Rather, this study seeks to illustrate the effect that a year-long outage would have on any particular year.

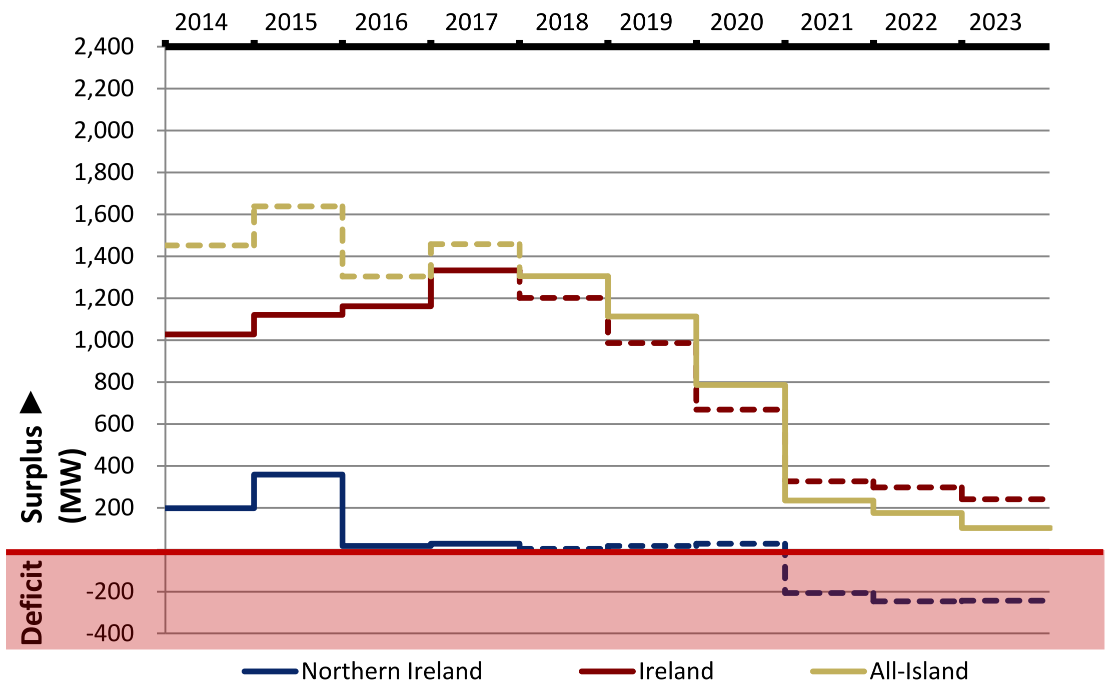

Figure 4-3 The adequacy situation with one CCGT unavailable in each jurisdiction.

4.5 Availability Scenarios

When assessing the generators' performance, their own predictions don't always match historical outcomes. Therefore, it is prudent to investigate different overall system availability scenarios.

For the Base Case, the generators in Ireland were assigned their own median predictions of availability, except for three random, large-scale generators on which were imposed major outages (High Impact, Low Probability, or HILP-type outages).

Now we compare the adequacy outcome of the Base Case with a scenario where all of the generators' data is used (i.e. with no HILPs). The difference in total system availability between the two scenarios is approximately 2%.

With the system performing better, the surplus results are greater, see the red dotted line compared to the solid line in Figure 4-4. In other words, the effect of adding the three HILPS is to decrease the surplus by an average of about 300 MW.

For the Base Case in Northern Ireland, the generators are assigned an availability derived from their average performance over the past 12 years. However, another scenario is investigated where all the generators are assigned the availability of the worst performing unit, resulting in a drop in total system availability of approximately 6%.

Were this lower availability to be the outcome, then the surplus is reduced by an average of 130 MW.

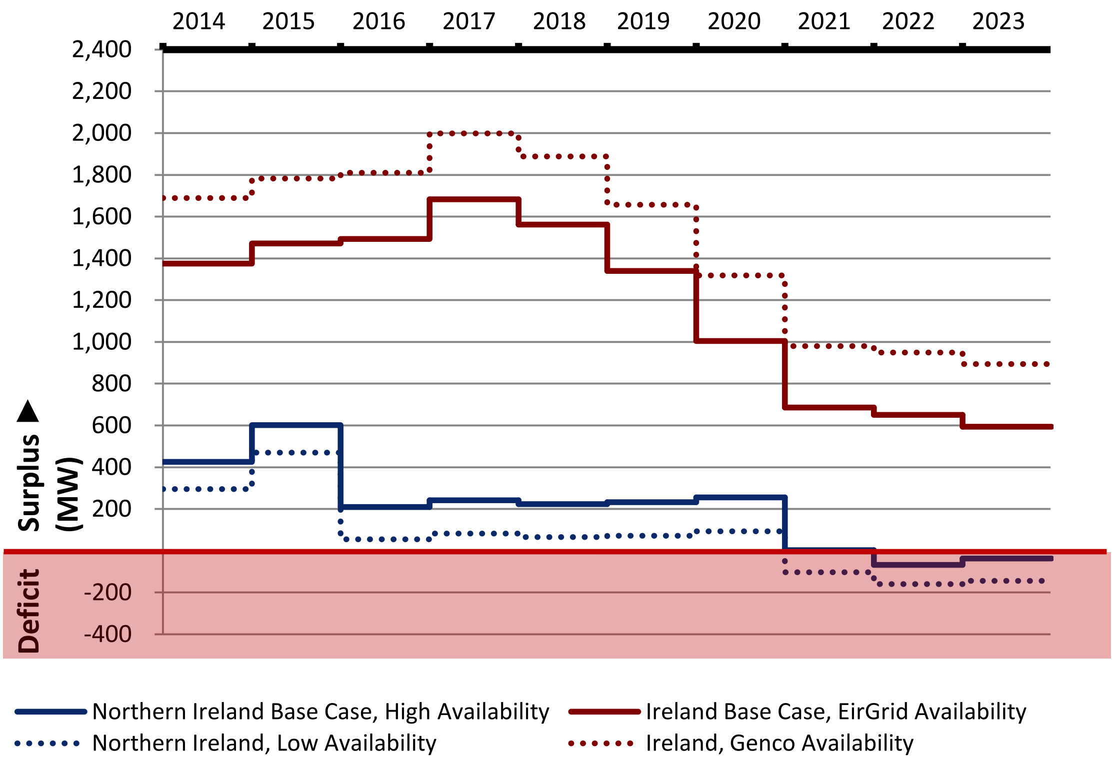

Figure 4-4 Different availability scenarios for Ireland and Northern Ireland.

4.6 Demand Scenarios

With much uncertainty attached to economic forecasting in recent years, it is prudent to examine the effect of different demand scenarios on the adequacy outcome.

In Ireland, the Median electricity demand scenario is based on the ESRI's Recovery scenario in their Medium Term Review. This is predicated upon a recovery in the Irish economy.

However, there is a real possibility that the economy in Ireland will not recover in the near future, but rather, will stagnate. This would lead to much lower growth in electricity demand, as depicted in EirGrid's low demand scenario. This, in turn, would result in higher surpluses in the years ahead, rising to a difference of nearly 400 MW by 2023, see Figure 4-5.

EirGrid has also made a high demand forecast, based on the possibility of a very cold winter (the coldest out of ten years). In this scenario, the surplus is reduced by about 100 MW from the Base Case.

For Northern Ireland, the low demand scenario is based on a lower economic forecast and a milder winter. It results in a slightly higher adequacy forecast, with a margin of approximately 80 MW over the median scenario by 2023.

Similarly for the high demand in Northern Ireland, it shifts the adequacy results about 80 MW lower by 2023.

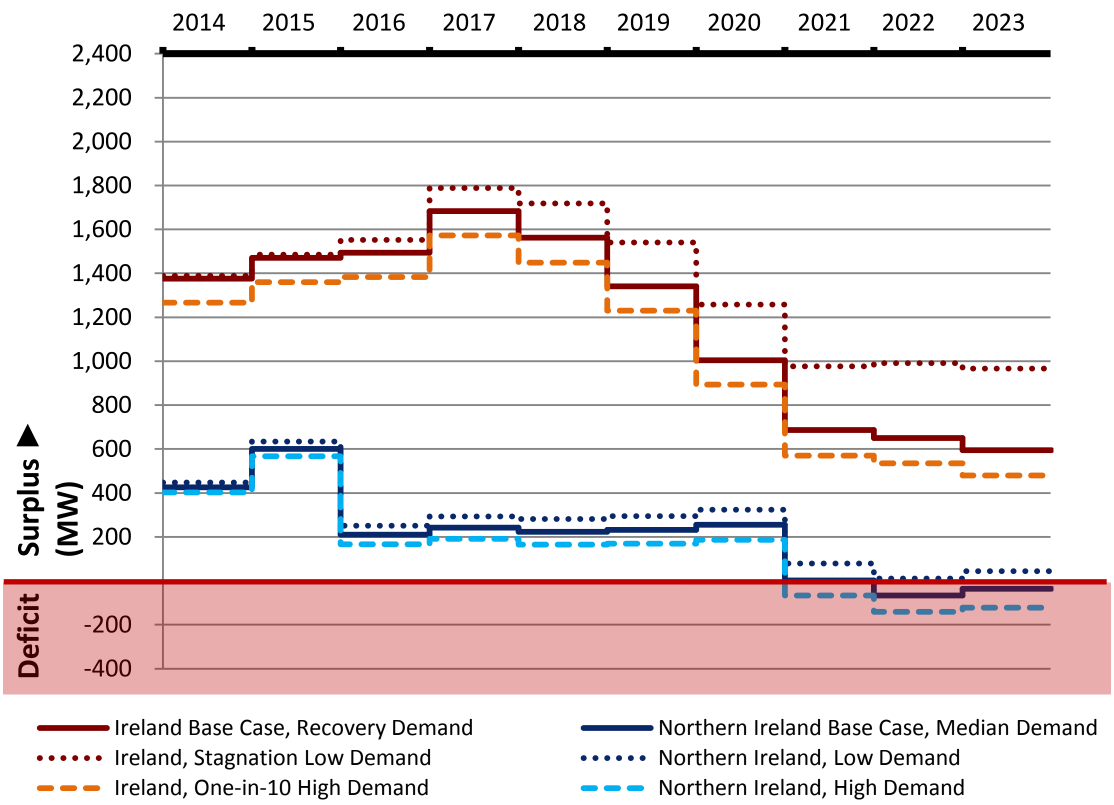

Figure 4-5 Different demand scenarios for Ireland and Northern Ireland

5 SECURITY OF SUPPLY IN NORTHERN IRELAND

5 SECURITY OF SUPPLY IN NORTHERN IRELAND

5.1 Introduction

As has been noted in the previous Section, the security of electricity supply in Northern Ireland becomes potentially more risky after the decommissioning of three generating units in Ballylumford at the end of 2015. This section assesses the impact of this in more detail, and makes proposals on measures to deal with potential shortfalls.

This analysis has been provided to the Utility Regulator Northern Ireland, and is referenced in an information paper[56] by DETI and the Utility Regulator.

5.2 Adequacy Assessment for the Base Case

When assessed as a single area with limited interconnection to Scotland and Ireland, the surplus in Northern Ireland drops from 600 MW to just 200 MW in 2016 after the loss of the three Ballylumford units due to the introduction of more stringent emission levels, see Figure 4-1.

While this indicates that Northern Ireland is within standard, this is only the case if the rest of the system performs within the boundaries of the Base Case. If any prolonged generator outages were experienced, then the standard could be breached and the risk to security of supply could increase to unacceptable levels.

As Northern Ireland is dependent on a small number of large generating units, the difference between being in or out of standard is finely balanced.

The adequacy standard in Northern Ireland is set at 4.9 hours Loss Of Load Expectation[57]. If a study estimates the LOLE to be 4.9 hours, then this can be translated to 0 MW of surplus.

In the base case for Northern Ireland in 2016, the LOLE is calculated to be 1 hour LOLE, which equates to 200 MW of surplus. Note that the relationship between LOLE and surplus is a non-linear one.

5.3 HILP Events

Any number of scenarios could be imagined where a High Impact Low Probability (HILP) event could cause the LOLE to rise to unacceptable levels.

For this particular study, it was decided to examine a case where the Moyle interconnector was completely unavailable, **and** where a large generating unit experiences a prolonged outage. It is not suggested that such occurrences could happen every year, but it is merely to illustrate what the consequences would be if they both happened in any one year.

This HILP scenario would cause the total system availability to drop from about 88% to 75%. This is not unprecedented; such low levels of availability occurred in 2007 (see Figure 3-11).

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[56] http://www.uregni.gov.uk/news/view/security_of_electricity_supply_in_northern_ireland_updated_information_paper/

[57] The LOLE is the number of hours in a year that the available generation is unable to meet the expected demand, i.e. when there could be load-shedding. It is calculated on a probabilistic basis.

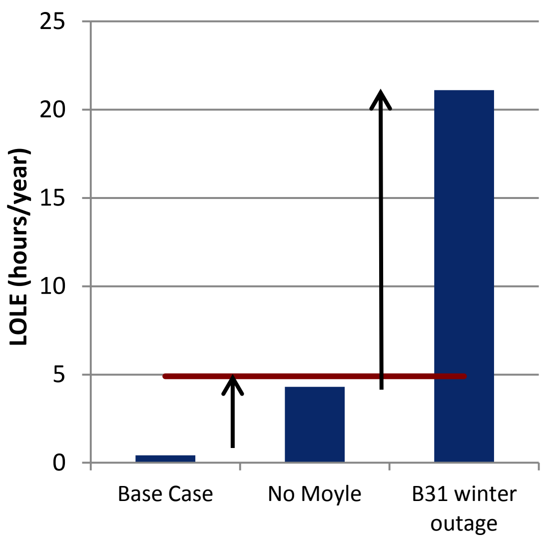

Figure 5-1 For the Base Case in 2016, there is a very low LOLE. Challenging circumstances could push the overall LOLE higher than the acceptable limit of 4.9 hours (shown in red).

Figure 5-1 shows how the Northern Ireland LOLE would rise in 2016 if the system suffered these particular HILPs. From the Base Case scenario of 1 hour LOLE, it increases to 21 hours if Moyle was unavailable for the full year, **and** if B31 suffered a prolonged winter outage.

To put this into context, the average size of a demand shortage in this extreme scenario would be 95 MW, and it is likely to occur for up to 21 hours over the course of the winter months.

In conclusion, while the Base Case shows the system to be within standard even after the decommissioning of the three Ballylumford units, an unexpected prolonged outage could place the system under stress and substantially increase the risk to security of supply.

5.4 Options to manage the risk

When the planned North-South interconnector is commissioned, then Northern Ireland need no longer be assessed on its own. When assessed on an all-island basis, the security of supply is well within the accepted standard for the next decade. Figure 4-1 shows the all-island adequacy estimated at 800 MW of surplus in 2023.

However, the second North-South interconnector is not assumed to be in place until the end of 2017 at the earliest, and so in the meantime, the risk to security of supply for Northern Ireland increases from the beginning of 2016.

The Moyle Interconnector is currently operating at reduced capacity due to a cable fault, and so is only available for 250 MW of capacity. It is not envisioned that a permanent repair will be in place by 2016, when the Ballylumford units are required to shut. However, as noted in the information paper by DETI and the Utility Regulator, two interim repairs are being progressed, which, if successful, would see capacity restored to 450 MW by close of 2014.

For long-term security of supply for both jurisdictions, the second North-South Interconnector offers the most robust, enduring solution. However, in order to fill the gap before this is in-service, how much additional plant would be sufficient to facilitate the management of this risk, particularly in the event of a prolonged outage? From adequacy studies, this has been estimated to be between 220 and 300 MW.

To manage the increased risk, additional feasible options are being explored by the Utility Regulator and SONI, working with DETI.

6 INTERCONNECTION AND NEIGHBOURING MARKETS

6 INTERCONNECTION AND NEIGHBOURING MARKETS

The Single Electricity Market (SEM) is the wholesale electricity market operating in Ireland and Northern Ireland. It is connected to the British electricity market, BETTA (British Electricity Trading and Transmission Arrangements), via two interconnectors across the Irish Sea, Moyle and the East West Interconnector (EWIC). As a special report in this GCS, the following section compares the two markets, and explores the benefits provided by interconnection.

6.1 The Moyle and EWIC Interconnectors

The Moyle Interconnector has connected the transmission system in Northern Ireland to that in Scotland since 2002. Moyle originally had an import capacity of 450 MW and an export capacity of 295 MW, however a fault on one of the cables has reduced this to 250 MW in both directions since 2012. Issues with transmission access rights in Scotland may further limit its export capacity to 80 MW from 2017.

EWIC connects the transmission systems in Ireland and Wales. It became fully operational in May 2013 and provides 500 MW of power in each direction.

The flows on Moyle have nearly always been imports into the SEM, typically at full capacity during the day time with a dip in imports at night. Similarly, EWIC has been consistently importing into the SEM, and tends to be at maximum capacity from about 9am to 11pm. These imports have been shown to reduce wholesale electricity prices in the SEM.

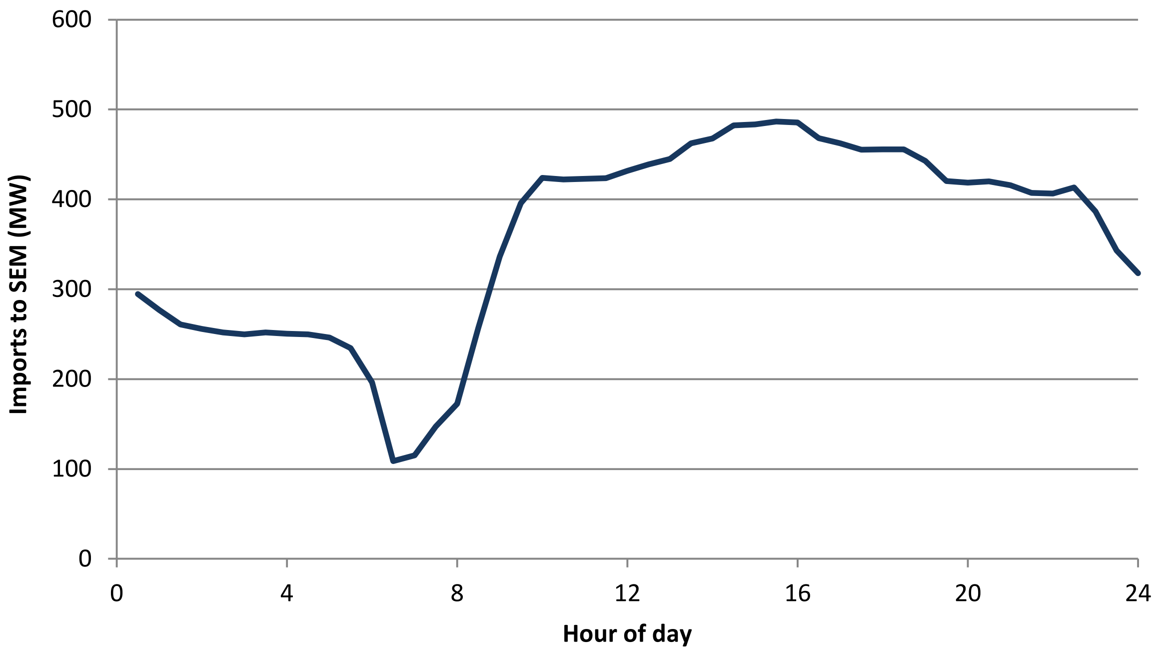

Figure 6-1 Average EWIC flows as set by market trades since it became fully operational in May 2013

6.2 SEM vs. BETTA

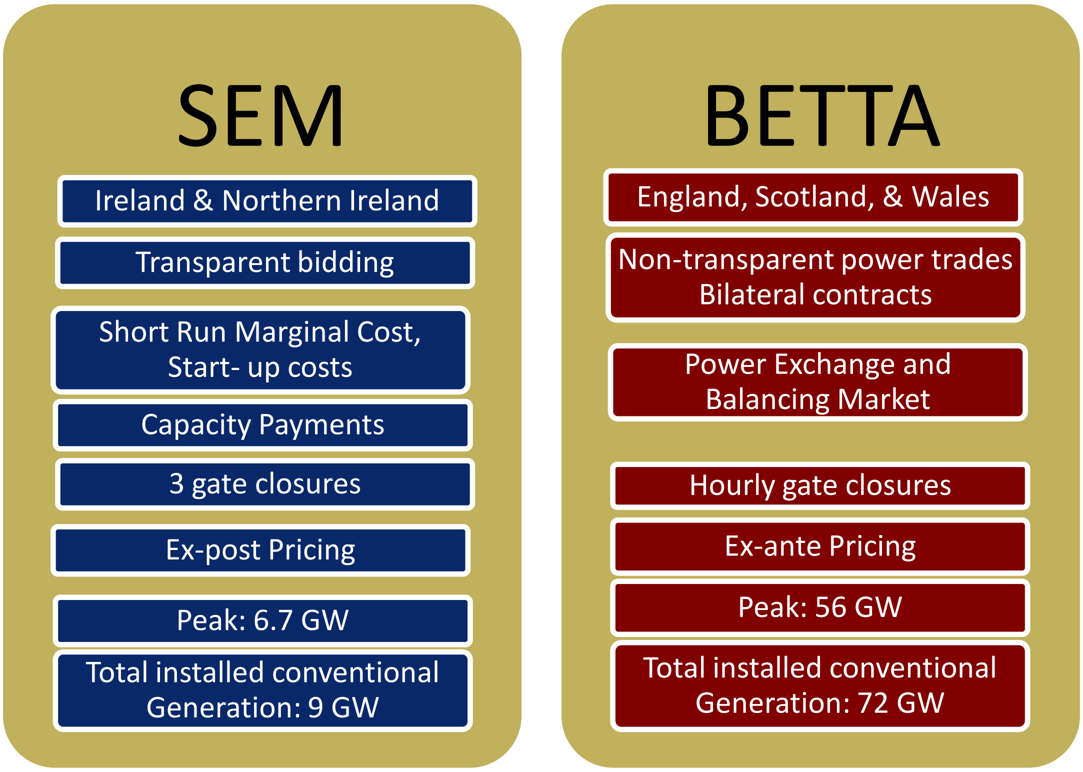

Figure 6-2 Comparison of the components of SEM and BETTA

6.2(a) Bidding

In SEM, generators larger than 10 MW are obliged to sell all of their electricity into a common pool. The price of electricity reflects the cost of producing it, and is governed by the Bidding Code of Practice (BCOP).

In BETTA, generators sell much of their power in advance of delivery at a set price, through bilateral contracts. There is no obligation to disclose the prices used in these contracts. Power is also traded in power exchanges up to one hour ahead of real time operation. In previous years, only 10-15% of power in Britain was sold in this manner, though this has risen recently. There is no BCOP in BETTA, and generators are free to price their power as they see fit.

6.2(b) Pricing

In the SEM, all generators and suppliers receive and pay the same wholesale price for electricity, called the System Marginal Price (SMP). The SMP has two components – Shadow Price and Uplift. The Shadow Price is set by the most expensive unit generating electricity in the market at that time, also called the marginal unit. The Uplift component is added to the Shadow Price, and allows a generator to cover its start-up costs (the additional costs incurred due to starting up a generator).

In BETTA, the price of power purchased through bilateral contracts is generally not disclosed. The price of power sold through power exchanges is set by the most expensive unit cleared, and these prices are publicly available for a fee.

The clean spark spread is a measure of the difference between the price generated electricity receives and the cost of generating power from a typical gas CCGT. Recently, the clean spark spreads in BETTA have been close to zero[58], suggesting that a gas CCGT will not recover its capital costs through the wholesale market.

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[58] http://www.allislandproject.org/GetAttachment.aspx?id=4182743c-f87f-4b26-a80f-b07a3706143a

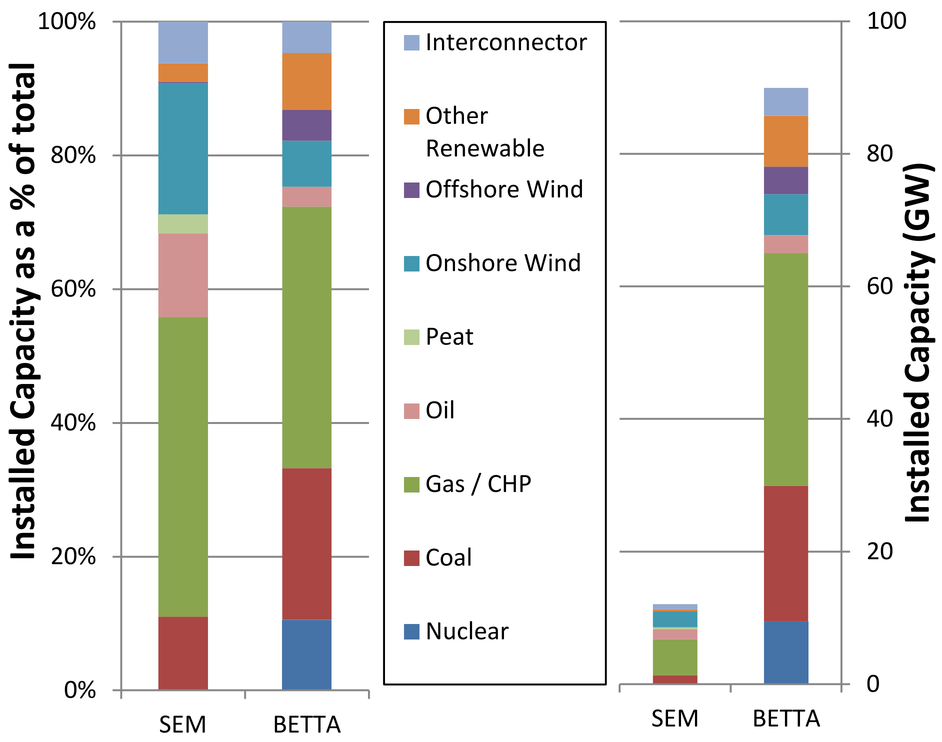

Figure 6-3 Comparison of the generation in both regions by fuel type.

6.2(c) Price visibility

In BETTA, prices are set (or firm) ex-ante, and participants know what price they will pay or receive for power in advance of delivery. In the SEM, prices are calculated ex-post, and the market engine is rerun after actual power delivery to account for unforeseen changes such as generator failure, changes in wind or demand forecasts, etc. This means that participants will not know the final price until four days after the power has been delivered.

6.2(d) Capacity payments

In the SEM, generators receive capacity payments for being available. Interconnector traders selling power into the SEM receive capacity payments, while those exporting power must pay them[59]. Capacity payments do not exist in GB as of yet, and so these extra payments tend to increase the price differential between the two markets, making it more attractive to export from BETTA to SEM.

However, it is likely that capacity payments will be introduced in the future as part of Electricity Market Reform in Britain (see section 6.3(a) below). The structure of these capacity payments is currently under consultation, and it is uncertain how this might affect trading between the two markets.

6.2(e) Generation by fuel type

The make-up of the generation portfolio in the two regions is shown in Figure 6-3. BETTA has a higher proportion of coal plant than SEM, and also has a significant level of nuclear generation. The price of coal is currently low compared to gas, and nuclear power plants have a low short-run marginal cost. This tends to result in a lower cost of generating electricity in BETTA relative to the SEM. In addition, most gas in SEM is transported through BETTA and as such is more expensive, further increasing the difference in generation costs between the two regions.

[59] Strictly speaking, they receive a negative capacity payment.

6.3 Forecasting Future Flows

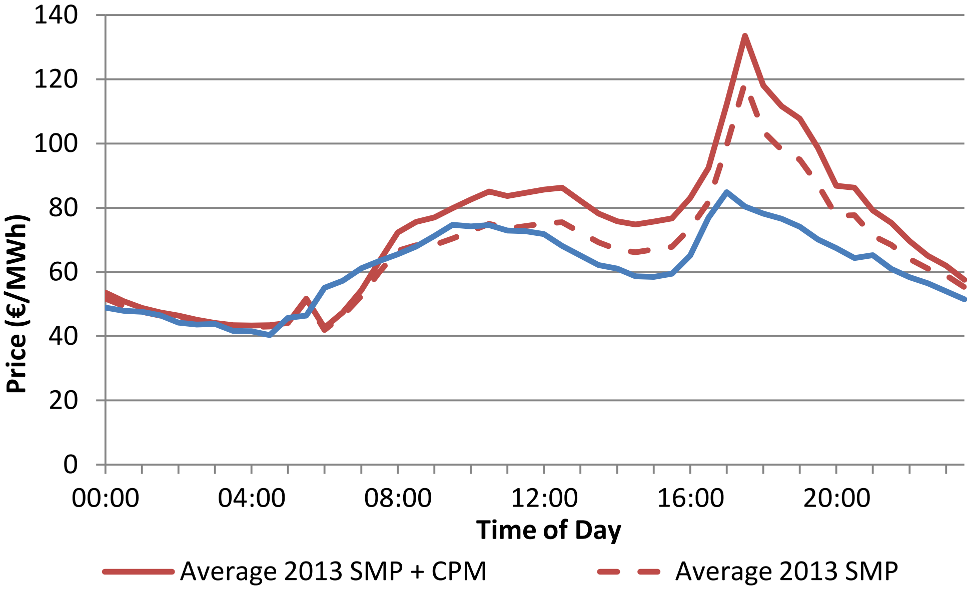

Figure 6-4 Comparison of the System Marginal Price in SEM, and APX prices (which represent the opportunity cost for power in BETTA) for 2013. SMP values are shown with and without capacity prices added on.

Future flows on the interconnectors will be influenced by new policies and market structures in both regions.

To date, prices in BETTA have on average been lower than those in the SEM, particularly once capacity payments are included. This is shown in Figure 6-4, which compares 2013 prices from the two regions. The price difference is negligible at night time and is most noticeable around the evening peak, when uplift tends to form a larger component of the SMP.

It is possible that this price difference may shrink or even switch over the next few years. The introduction of the Carbon Price Floor (see below) in Britain in 2013 is leading to increasing generation costs for fossil fuel power plants in BETTA.

Also, Britain may be at risk of generation shortages in the future. Some power plants are expected to close down over the coming years due to old age and non-compliance with emissions directives. Others may experience a drop in market share and, without a financial incentive, may be forced to close.

6.3(a) Electricity Market Reform

The British Government is attempting to deal with the issue of future supply shortages by promoting investment into electricity generation through an initiative known as 'Electricity Market Reform' (EMR). These reforms also hope to promote an increase of the penetration of low-carbon technologies in the British market.

The key components of EMR are the introduction of a capacity market, and a FIT (Feed in Tariff) with a Contract for Difference (CfD) scheme to offer a guaranteed energy price to low-carbon generation.

In addition to CfDs, the British government through HM Treasury have introduced the Carbon Price Floor mechanism to increase the competitiveness of low-carbon generation types. The Carbon Price Floor is a method for taxing carbon dioxide produced through generating electricity. This followed a significant drop in the price of carbon as set by the EU Emission Trading Scheme (ETS). The price support set by the Carbon Price Floor, which is charged on top of the ETS price, has already been fixed at £9.55[60] for 2014/15 and £18.08[61] for 2015/2016. This is equivalent to adding £4 and £7 respectively to the cost of

60 http://www.hmrc.gov.uk/budget2012/tiin-0701.pdf

61 http://www.hmrc.gov.uk/budget2013/tiin-1006.pdf

generating one MWh from a typical gas CCGT. The Carbon Price floor aims to make the total carbon price reach £30 by 2020 and £70 by 2030.

It should be noted that the carbon price floor does not apply to electricity generators in Northern Ireland operating in the SEM.

6.3(b) Internal Energy Market for Europe

The Internal Energy Market (also known as the European Target Model) is designed to establish a reliable and cost-effective energy market, improving competitiveness across the European Union, and hastening progress towards full decarbonisation. The ultimate goal is a market in which consumers in any member state can purchase their energy from any supplier in the European Union.

A group of directives and regulations known as the Third Energy Package form the cornerstone of the Internal Energy Market, which Ireland and Northern Ireland have committed to achieving by 2016. Aspects of the Internal Energy Market, such as firm day-ahead price coupling and continuous intraday trading, will have significant impacts on the Single Electricity Market arrangements. It should, in theory, make it easier to trade across the Moyle and EWIC interconnectors.

The design of the new energy market for Ireland and Northern Ireland will be consulted upon by the Regulatory Authorities in early 2014.

6.4 Interconnector Flow and Prices

In general, interconnector imports reduce wholesale prices in the SEM, as the demand to be met by generators in the SEM is effectively reduced, and so the most expensive generators are used less.

Since EWIC became fully operational in May 2013, flows have been predominantly importing to the SEM. A study was carried out by the Single Electricity Market Operator (SEMO) examining the effect of EWIC on prices. The study examined the first six months of its operation, effectively rerunning the market schedule for those months and graphing the differential with and without EWIC in full operation. The results are presented in Figure 6-5 below. On average EWIC reduced the SMP by €4/MWh, or 8%, for those months.

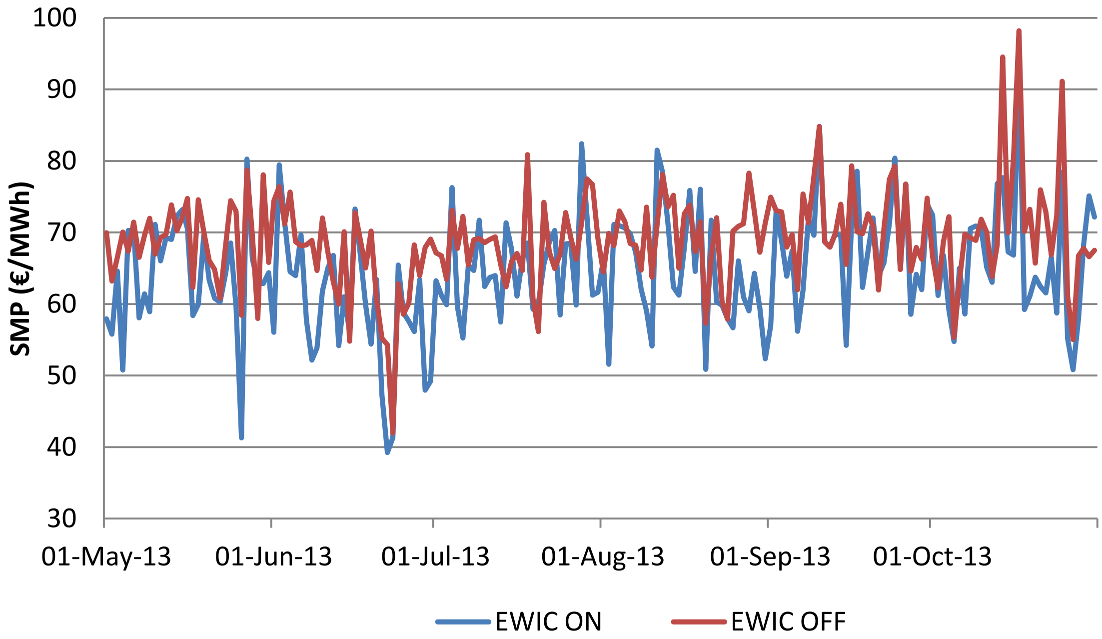

Figure 6-5 Load weighted SMP for May-Oct 2013 with and without EWIC. On average, EWIC reduced SMP by €4/MWh

APPENDICES

APPENDIX 1 DEMAND FORECAST

Med	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2014	26,601	1.0%	9144	0.6%	35,745	0.9%	4871	1766	6608	4774	1728	6473
2015	26,910	1.2%	9205	0.7%	36,115	1.0%	4903	1773	6647	4806	1733	6510
2016	27,280	1.4%	9269	0.7%	36,550	1.2%	4958	1781	6710	4861	1739	6571
2017	27,687	1.5%	9334	0.7%	37,021	1.3%	5009	1790	6769	4911	1746	6628
2018	28,078	1.4%	9399	0.7%	37,477	1.2%	5068	1800	6838	4971	1755	6696
2019	28,471	1.4%	9465	0.7%	37,936	1.2%	5127	1810	6907	5030	1764	6765
2020	28,945	1.7%	9535	0.7%	38,480	1.4%	5201	1822	6993	5104	1775	6849
2021	29,337	1.4%	9603	0.7%	38,940	1.2%	5266	1834	7069	5169	1786	6925
2022	29,734	1.4%	9672	0.7%	39,407	1.2%	5333	1845	7147	5236	1797	7002
2023	30,130	1.3%	9743	0.7%	39,873	1.2%	5399	1857	7226	5301	1808	7078

Table A-1 Median Electricity Demand Forecast – all figures are for a 52-week year.

Notes: Electricity sales are measured at the customer level. To convert this to Total Electricity Requirement (TER), it is brought to exported level by applying a loss factor (for both transmission and distribution) and adding on an estimate of self-consumption.

The Transmission Peak (or Exported peak) is the maximum demand met by centrally-dispatched generation, measured at exported level by the Control Centre. To calculate the TER Peak, an estimation of the contribution from embedded generation is added to the Transmission peak. When forecasting the transmission peak, it is assumed that the wind contribution is zero.

Low	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2014	26,601	1.0%	8997	-0.2%	35,597	0.7%	4850	1737	6559	4753	1699	6424
2015	26,776	0.7%	8992	-0.1%	35,768	0.5%	4888	1731	6590	4790	1691	6453
2016	26,819	0.2%	8997	0.1%	35,816	0.1%	4888	1728	6587	4790	1685	6448
2017	26,876	0.2%	9007	0.1%	35,884	0.2%	4888	1726	6585	4790	1682	6444
2018	26,934	0.2%	9023	0.2%	35,957	0.2%	4888	1726	6585	4790	1681	6443
2019	27,030	0.4%	9046	0.3%	36,076	0.3%	4892	1728	6591	4795	1682	6449
2020	27,126	0.4%	9077	0.3%	36,203	0.4%	4901	1732	6604	4804	1685	6460
2021	27,249	0.5%	9116	0.4%	36,365	0.4%	4918	1738	6626	4821	1690	6482
2022	27,391	0.5%	9155	0.4%	36,546	0.5%	4938	1743	6652	4841	1695	6507
2023	27,556	0.6%	9195	0.4%	36,751	0.6%	4963	1749	6683	4865	1700	6537

Table A-2 The low scenario forecast of electricity demand

High	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2014	26,659	1.0%	9300	1.4%	35,959	1.1%	5039	1797	6806	4942	1758	6671
2015	26,968	1.2%	9427	1.4%	36,396	1.2%	5072	1817	6858	4974	1776	6722
2016	27,339	1.4%	9551	1.3%	36,890	1.4%	5127	1837	6933	5030	1794	6794
2017	27,745	1.5%	9667	1.2%	37,412	1.4%	5177	1856	7002	5080	1812	6862
2018	28,136	1.4%	9776	1.1%	37,912	1.3%	5236	1874	7080	5139	1829	6938
2019	28,529	1.4%	9877	1.0%	38,406	1.3%	5296	1892	7156	5198	1846	7014
2020	29,003	1.7%	9979	1.0%	38,981	1.5%	5369	1910	7248	5272	1863	7104
2021	29,395	1.4%	10079	1.0%	39,474	1.3%	5435	1928	7331	5338	1880	7186
2022	29,793	1.4%	10181	1.0%	39,973	1.3%	5501	1946	7414	5404	1897	7269
2023	30,189	1.3%	10284	1.0%	40,473	1.2%	5567	1964	7498	5470	1915	7352

Table A-3 The high scenario forecast of electricity demand

APPENDIX 2 GENERATION PLANT INFORMATION

Year end:	ID	Fuel Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Aghada	AD1	Gas	258	258	258	258	258	258	258	258	258	258	258
	AT1	Gas/DO	90	90	90	90	90	90	90	90	90	90	90
	AT2	Gas/DO	90	90	90	90	90	90	90	90	90	90	90
	AT4	Gas/DO	90	90	90	90	90	90	90	90	90	90	90
	AD2	Gas/DO	431	431	431	431	431	431	431	431	431	431	431
Activation Energy	AE1	DSU	38	38	38	38	38	38	38	38	38	38	38
DAE Virtual Power	DP1	DSU	22	22	22	22	22	22	22	22	22	22	22
Dublin Bay	DB1	Gas/DO	405	404	403	402	405	404	403	402	405	404	403
Edenderry	ED1	Milled peat/biomass	118	118	118	118	118	118	118	118	118	118	118
Edenderry OCGT	ED3	DO	58	58	58	58	58	58	58	58	58	58	58
	ED5	DO	58	58	58	58	58	58	58	58	58	58	58
Great Island	GI1	HFO	54	0	0	0	0	0	0	0	0	0	0
	GI2	HFO	49	0	0	0	0	0	0	0	0	0	0
	GI3	HFO	109	0	0	0	0	0	0	0	0	0	0
Great Island CCGT	GI4	Gas/DO	0	431	431	431	431	431	431	431	431	431	431
Huntstown	HNC	Gas/DO	341	340	340	339	339	338	338	337	337	336	336
	HN2	Gas/DO	399	398	398	397	397	396	396	395	395	394	394
Indaver Waste	IW1	Waste	16	18	19	19	19	19	19	19	19	19	19
Lough Ree	LR4	Peat	91	91	91	91	91	91	91	91	91	91	91
Marina CC	MRC	Gas/DO	88	88	88	88	88	88	88	88	88	88	88
Moneypoint	MP1	Coal/HFO	285	285	285	285	285	285	285	285	285	285	285
	MP2	Coal/HFO	285	285	285	285	285	285	285	285	285	285	285
	MP3	Coal/HFO	285	285	285	285	285	285	285	285	285	285	285
North Wall CT	NW5	Gas/DO	104	104	104	104	104	104	104	104	104	104	104
Poolbeg CC	PBC	Gas/DO	463	463	463	463	463	463	463	463	463	463	463
Rhode	RP1	DO	52	52	52	52	52	52	52	52	52	52	52
	RP2	DO	52	52	52	52	52	52	52	52	52	52	52
Sealrock	SK3	Gas/DO	81	81	81	81	81	81	81	81	81	81	81
	SK4	Gas/DO	81	81	81	81	81	81	81	81	81	81	81
Tarbert	TB1	HFO	54	54	54	54	54	54	54	54	0	0	0
	TB2	HFO	54	54	54	54	54	54	54	54	0	0	0
	TB3	HFO	241	241	241	241	241	241	241	241	0	0	0
	TB4	HFO	243	243	243	243	243	243	243	243	0	0	0
Tawnaghmore	TP1	DO	52	52	52	52	52	52	52	52	52	52	52
	TP3	DO	52	52	52	52	52	52	52	52	52	52	52
Tynagh	TYC	Gas/DO	387	387	386	386	386	386	386	385	385	385	385
West Offaly	WO4	Peat	137	137	137	137	137	137	137	137	137	137	137
Whitegate	WG1	Gas/DO	444	444	444	444	444	444	444	444	444	444	444
Ardnacrusha	AA1-4	Hydro	86	86	86	86	86	86	86	86	86	86	86
Erne	ER1-4	Hydro	65	65	65	65	65	65	65	65	65	65	65
Lee	LE1-3	Hydro	27	27	27	27	27	27	27	27	27	27	27
Liffey	LI1,2, 4,5	Hydro	38	38	38	38	38	38	38	38	38	38	38
Turlough Hill	TH1-4	Pumped storage	292	292	292	292	292	292	292	292	292	292	292
EWIC	EW1	DC Interconnector	500	500	500	500	500	500	500	500	500	500	500
Extra Planned Generation*			0	0	0	62	62	160	160	160	160	160	160
		Total Dispatchable:	**7165**	**7383**	**7382**	**7441**	**7444**	**7539**	**7538**	**7534**	**6945**	**6942**	**6941**
		Year end:	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**

Table A-4 Registered Capacity of dispatchable generation in Ireland. Some capacities include minor degradation over the years.

DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil.

***Note**- The figures for extra planned generation are based on assumptions derived from generator information, and do not constitute EirGrid's formal acceptance of commissioning dates.*

Year end:	ID	Fuel Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ballylumford	ST4	Gas* / Heavy Fuel Oil	170	170	170	0	0	0	0	0	0	0	0
	ST5	Gas* / Heavy Fuel Oil	170	170	170	0	0	0	0	0	0	0	0
	ST6	Gas* / Heavy Fuel Oil	170	170	170	0	0	0	0	0	0	0	0
	B31	Gas* / Distillate Oil	245	245	245	245	245	245	245	245	245	245	245
	B32	Gas* / Distillate Oil	245	245	245	245	245	245	245	245	245	245	245
	B10	Gas* / Distillate Oil	97	97	97	97	97	97	97	97	97	97	97
	GT7 (GT1)	Distillate Oil	58	58	58	58	58	58	58	58	58	58	58
	GT8 (GT2)	Distillate Oil	58	58	58	58	58	58	58	58	58	58	58
Kilroot	ST1	Heavy Fuel Oil* / Coal	238	238	238	238	238	238	238	238	238	238	238
	ST2	Heavy Fuel Oil* / Coal	238	238	238	238	238	238	238	238	238	238	238
	KGT1	Distillate Oil	29	29	29	29	29	29	29	29	29	29	29
	KGT2	Distillate Oil	29	29	29	29	29	29	29	29	29	29	29
	KGT3	Distillate Oil	42	42	42	42	42	42	42	42	42	42	42
	KGT4	Distillate Oil	42	42	42	42	42	42	42	42	42	42	42
Coolkeeragh	GT8	Distillate Oil	53	53	53	53	53	53	53	53	53	53	53
	C30	Gas* / Distillate Oil	402	402	402	402	402	402	402	402	402	402	402
Moyle Interconnector	Moyle	DC Link #	250	250	250	250	250	250	250	250	250	250	250
Contour Global (CHP)	CGC3	Gas	3	3	3	3	3	3	3	3	3	3	3
	CGC4	Gas	3	3	3	3	3	3	3	3	3	3	3
	CGC5	Gas	3	3	3	3	3	3	3	3	3	3	3
iPower AGU	AGU	Distillate Oil	64	64	74	74	74	74	74	74	74	74	74
Total Dispatchable			**2609**	**2609**	**2619**	**2109**	**2109**	**2109**	**2109**	**2109**	**2109**	**2109**	**2109**

Table A-5 Dispatchable plant in Northern Ireland

** Where dual fuel capability exists, this indicates the fuel type utilised to meet peak demand.*

 # Moyle Interconnector normal capacity: Import = 450 MW Nov-Mar & 410 MW Apr-Oct. (Export = 295 MW Sep-Apr & 287 MW May-Aug). It is assumed that both the Import and Export capacity on the Moyle Interconnector will be restricted to 250 MW for the foreseeable future due to an undersea cable fault on Pole 2.

Year:	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Large Scale On-Shore Wind	531	586	640	695	749	804	859	912	967	1021	1076
Large Scale Off-Shore Wind	0	0	0	0	0	0	0	206	600	600	600
Large Scale Biomass	0	0	15	30	45	45	45	45	45	45	45
Tidal	1	1	1	1	1	51	131	154	201	201	201
Small Scale Wind	22	31	41	50	58	66	74	82	89	96	104
Small Scale Biogas	7	10	13	18	23	26	28	30	31	32	33
Landfill Gas	13	15	16	18	19	20	21	23	24	25	27
Waste To Energy	0	0	17	17	17	17	17	17	17	17	17
Small Scale Biomass	5	7	9	10	11	12	13	14	15	16	17
Other CHP	8	8	8	8	8	8	8	8	8	8	8
Renewable CHP	3	3	3	4	4	4	4	4	4	4	4
Small Scale Hydro	4	4	4	4	4	4	4	4	4	4	4
Small Scale Solar	2	2	2	2	3	3	3	3	3	3	3
Total (MW)	**596**	**667**	**769**	**857**	**942**	**1060**	**1207**	**1502**	**2008**	**2072**	**2139**

Table A-6 Partially/Non-Dispatchable Plant in Northern Ireland

Year:	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
All Wind	553	617	681	745	807	870	933	1200	1656	1717	1780
All Biomass/Biogas/Landfill Gas	25	32	53	76	98	103	107	112	115	118	122
Tidal	1	1	1	1	1	51	131	154	201	201	201
Waste To Energy	0	0	17	17	17	17	17	17	17	17	17
Renewable CHP	3	3	3	4	4	4	4	4	4	4	4
Hydro	4	4	4	4	4	4	4	4	4	4	4
Solar	2	2	2	2	3	3	3	3	3	3	3
Total (MW)	**588**	**659**	**761**	**849**	**934**	**1052**	**1199**	**1494**	**2000**	**2064**	**2131**

Table A-7 All Renewable Energy Sources in Northern Ireland

Year end:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Wind-Onshore	1817	2198	2665	2827	2989	3151	3313	3475	3637	3799	3961
Wind-Offshore	25	25	25	25	25	25	25	25	25	25	25
Wind-Total	**1842**	**2223**	**2690**	**2852**	**3014**	**3176**	**3338**	**3500**	**3662**	**3824**	**3986**
Small-scale Hydro	21	21	21	21	21	21	21	21	21	21	21
Biomass/Landfill gas, with 150 MW Biomass CHP by 2020	46	49	74	102	127	155	180	205	205	205	205
Tidal/Wave	0	0	0	0	0	0	0	0	0	0	0
Industrial	9	9	9	9	9	9	9	9	9	9	9
Conventional CHP	141	141	141	141	141	141	141	141	141	141	141
Total	**2059**	**2443**	**2935**	**3125**	**3312**	**3502**	**3689**	**3876**	**4038**	**4200**	**4362**

Table A-8 Partially/Non-Dispatchable Plant in Ireland

Year end:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
All Wind	1842	2223	2690	2852	3014	3176	3338	3500	3662	3824	3986
All Hydro	237	237	237	237	237	237	237	237	237	237	237
Biomass/LFG	46	49	74	102	127	155	180	205	205	205	205
Waste (assume 50% renewable)	8	9	9	41	41	41	41	41	41	41	41
Edenderry on Biomass	29	29	35	35	35	35	35	35	35	35	35
Total RES	**2162**	**2547**	**3045**	**3266**	**3453**	**3644**	**3831**	**4018**	**4180**	**4342**	**4504**

Table A-9 All Renewable Energy Sources in Ireland

	Wind Farm	**Capacity**		**Wind Farm**	**Capacity**
Transmission Connected	Slieve Kirk	73.6	**Distribution Connected**	Altahullion 2	11.7
Distribution Connected	Corkey	5		Bessy Bell 2	9
	Rigged Hill	5		Owenreagh 2	5.1
	Elliott's Hill	5		Slieve Divena	30
	Bessy Bell	5		Garves	15
	Owenreagh	5.5		Gruig	25
	Lendrum's Bridge	5.9		Tappaghan 2	9
	Lendrum's Bridge 2	7.3		Hunters Hill	20
	Altahullion	26		Crockagarran	17.5
	Tappaghan	19.5		Screggagh	20
	Snugborough	13.5		Curryfree	15
	Callagheen	16.9		Church Hill	18.4
	Lough Hill	7.8		Crighshane	32.2
	Bin Mountain	9		Carrickatane	20.7
	Wolf Bog	10		Carn Hill	13.8
	Mantlin (Slieve Rushen 2)	54		**Total**	**531**

Table A-10 Existing wind farms in Northern Ireland as of end October 2013.

Wind Farm	**Phase**	**MEC (MW)**	**Wind Farm**	**Phase**	**MEC (MW)**
Ballywater	1	31.5	Derrybrien	1	59.5
Ballywater	2	10.5	Dromada	1	28.5
Boggeragh	1	57	Garvagh-Glebe	1	58.2
Booltiagh	1	19.5	Glanlee	1	29.8
Booltiagh	2	3	Golagh	1	15
Booltiagh	3	9	Kingsmountain	1	23.8
Castledockrell	1	20	Kingsmountain	2	11.1
Castledockrell	2	2	Lisheen	1	36
Castledockrell	3	3.3	Lisheen	1	19
Castledockrell	4	16.1	Meentycat	1	71.0
Clahane	1	37.8	Meentycat	2	14
Coomacheo	1	41.2	Mountain Lodge	1	24.8
Coomacheo	2	18	Mountain Lodge	3	5.8
Coomagearlahy	1	42.5	Ratrussan	1	48
Coomagearlahy	2	8.5		**Total**	**794**
Coomagearlahy	3	30			

Table A-11 Transmission connected wind farms in Ireland, as of end of October 2013.

Name	MEC (MW)	Name	MEC (MW)
Tournafulla (2)	17.2	Glanta Commons (1)	19.55
Altagowlan (1)	7.65	Glanta Commons (2)	8.4
Anarget (1)	1.98	Glenough (1)	33
Anarget (2)	0.02	Gneeves (1)	9.35
Arklow Bank (1)	25.2	Gortahile (1)	21
Ballaman formerly (Kennystown) (1)	3.6	Greenoge (1)	4.99
Ballincollig Hill (1)	15	Grouse Lodge (1)	15
Ballinlough (1)	2.55	Inverin (Knock South) (1)	3.3
Ballinveny (1)	2.55	Inverin (Knock South) (2)	0.66
Ballymartin (1)	6	Kealkil (Curraglass) (1)	8.5
Ballymartin (2)	8	Killybegs (1)	2.55
Bawnmore (1) formerly Burren (Cork)	24	Kilronan (1)	5
Beale (2)	2.55	Kilvinane (1)	4.5
Beale Hill (1)	1.65	Knockastanna (1)	7.5
Beallough (1)	1.7	Knockawarriga (1)	22.5
Beam Hill (1)	14	Lackan (1)	6
Beenageeha (1)	3.96	Lahanaght Hill (1)	4.25
Bellacorick (1)	6.45	Largan Hill (1)	5.94
Black Banks (1)	3.4	Lenanavea (2)	4.65
Black Banks (2)	6.8	Lios na Carraige (1)	0.017
Burtonport Harbour (1)	0.66	Loughderryduff (1)	7.65
Caherdowney (1)	10	Lurganboy (1)	4.99
Cark (1)	15	Mace Upper (1)	2.55
Carnsore (1)	11.9	Meenachullalan (1)	11.9
Carrane Hill (1)	3.4	Meenadreen (1)	3.4
Carrig (1)	2.55	Meenanilta (1)	2.55
Carrigcannon (1)	20	Meenanilta (2)	2.45
Carrons (1)	4.99	Meenanilta (3)	3.4
Carrowleagh (1)	34.15	Meenkeeragh (1)	4.2
Clydaghroe (1)	4.99	Mienvee (1)	0.66
Coomatallin (1)	5.95	Mienvee (2)	0.19
Coreen (1)	3	Milane Hill (1)	5.94
Corkermore (1)	9.99	Moanmore (1)	12.6
Corrie Mountain (1)	4.8	Moneenatieve (1)	3.96
Country Crest (1)	0.5	Moneenatieve (2)	0.29
Crocane (1)	1.7	Mount Eagle (1)	5.1
Crockahenny (1)	5	Mount Eagle (2)	1.7
Cronalaght (1)	4.98	Mountain Lodge (2)	3
Cronelea (1)	4.99	Muingnaminnane (1)	15.3
Cronelea (2)	4.5	Mullananalt (1)	7.5
Cronelea Upper (1)	2.55	Owenstown (1)	0.018
Cronelea Upper (2)	1.7	Raheen Barr (1)	18.7
Cuillalea (1)	3.4	Raheen Barr (2)	8.5
Cuillalea (2)	1.59	Rahora (1)	4.25
Culliagh (1)	11.88	Rathcahill (1)	12.5
Currabwee (1)	4.62	Reenascreena (1)	4.5
Curraghgraigue (1)	2.55	Richfield (1)	20.25
Curraghgraigue (2)	2.44	Richfield (2)	6.75
Donaghmede Fr Collins Park	0.25	Seltanaveeny (1)	4.6
Dromdeeveen (1)	10.5	Shannagh (1)	2.55
Dromdeeveen (2)	16.5	Skehanagh (1)	4.25
Drumlough Hill (1)	4.8	Skrine (1)	4.6
Drumlough Hill (2)	9.99	Slievereagh (1)	3
Dundalk IT (1)	0.5	Sonnagh Old (1)	7.65
Dunmore (1)	1.7	Sorne Hill (1)	31.5
Dunmore (2)	2.5	Sorne Hill (2)	7.4
Flughland (1)	9.2	Spion Kop (1)	1.2
Garracummer (1)	36.9	Taurbeg (1)	26
Garranereagh (1)	8.75	Templederry (1)	3.9
Gartnaneane (1)	10.5	Tournafulla (1)	7.5
Gartnaneane (2)	4.5	Tullow Mushroom Growers Ltd (1)	0.133
Geevagh (1)	4.95	Tullynamoyle (1)	9
Gibbet Hill (1)	15	Tursillagh (1)	15
Glackmore Hill (1)	0.6	Tursillagh (2)	6.8
Glackmore Hill (2)	0.3	WEDcross (1)	4.5
Glackmore Hill (3)	1.4	**Total**	**978**

Table A-12 Distribution connected wind farms in Ireland, as of end of October 2013

APPENDIX 3 METHODOLOGY

GENERATION ADEQUACY AND SECURITY STANDARD

Generation adequacy is assessed by determining the likelihood of there being sufficient generation to meet customer demand. It does not take into account any limitations imposed by the transmission system, reserve requirements or the energy markets.

In practice, when there is not enough supply to meet load, the load must be reduced. This is achieved by cutting off electricity from customers. In adequacy calculations, if there is predicted to be a supply shortage at any time, there is a Loss Of Load Expectation (LOLE) for that period. In reality load shedding due to generation shortages is a very rare event.

LOLE can be used to set a security standard. Ireland has an agreed standard of 8 hours LOLE per annum, and Northern Ireland has 4.9 hours. If this is exceeded in either jurisdiction, it indicates the system has a higher than acceptable level of risk. The security standard used for all-island calculations is 8 hours.

It is important to make a further comparison of the proportional Expected Unserved Energy (EUE). LOLE is concerned only with the likely number of hours of shortage; EUE goes further and takes account also of the extent of shortages.

System	LOLE hrs/year	EUE per million
Ireland	8.0	34.5
Northern Ireland	4.9	33.8

Table A- 13 LOLE standards for both jurisdictions, and their related Expected Unserved Energy (EUE)

The comparison of Ireland and Northern Ireland standards in terms of EUE suggests that the standard in Northern Ireland when expressed in LOLE terms is appropriate for a relatively small system with relatively large unit sizes. The standard in Northern Ireland, taken in conjunction with the larger proportional failures, results in a comparable EUE to Ireland.

With any generator, there is always a risk that it may suddenly and unexpectedly be unable to generate electricity (due to equipment failure, for example). Such events are called forced outages, and the proportion of time a generator is out of action due to such an event gives its forced outage rate (FOR).

Forced outages mean that the available generation in a system at any future period is never certain. At any particular time, several units may fail simultaneously, or there may be no such failures at all. There is therefore a probabilistic aspect to supply, and to the LOLE. The model used for these studies works out the *probability* of load loss for each half-hour period – it is these that are then summed to get the yearly LOLE, which is then compared to the security standard.

It is assumed that forced outages of generators are independent events, and that one generator failing does not influence the failure of another.

LOSS OF LOAD EXPECTATION

AdCal software is used to calculate LOLE. The probability of supply not meeting demand is calculated for each hour of each study year. The annual LOLE is the sum of the contributions from each hour.

Consider now the simplest case of a single-system study, with a deterministic load model (that is, with only one value used for each load), and no scheduled maintenance, so that there is one generation availability distribution for the entire year.

If

$L_{h,d}$ = load at hour h on day d
G = generation plant available
H = number loads/day to be examined (i.e. 1, 24 or 48)
D = total number of days in year to be examined

then the annual LOLE is given by

$$\text{LOLE} = \sum_{d=1,D} \sum_{h=1,H} \text{Prob.}(G < L_{h,d})$$

This equation is used in the following practical example.

SIMPLIFIED EXAMPLE OF LOLE CALCULATION

Consider a system consisting of just three generation units, as in Table A-14.

	Capacity (MW)	Forced outage probability	Probability of being available
Unit A	10	0.05	0.95
Unit B	20	0.08	0.92
Unit C	50	0.10	0.90
Total	80		

Table A-14 System for LOLE example

If the load to be served in a particular hour is 55 MW, what is the probability of this load being met in this hour? To calculate this, the following steps are followed:

1) How many different states can the system be in, i.e. if all units are available, if one is forced out, if two are forced out, or all three?

2) How many megawatts are in service for each of these states?

3) What is the probability of each of these states occurring?

4) Add up the probabilities for the states where the load cannot be met.

5) Calculate expectation.

Only states 1, 2 and 3 are providing enough generation to meet the demand of 55 MW. The probabilities for the other five *failing* states are added up to give a total probability of 0.1036. So in this particular hour, there is a chance of approximately 10% that there will not be enough generation to meet the load. It can be said that this hour is contributing about 6 minutes (10% of 1 hour) to the total LOLE for the year. This is then summed for each hour of the year.

1)	1)	2)	3)	3)	4)	4)
State	**Units in service**	**Capacity in service (MW)**	**Probability for (A*B*C)**	**Probability**	**Ability to meet 55 MW demand**	**Expectation of Failure (LOLE)**
1	A, B, C	80	0.95*0.92*0.90 =	0.7866	Pass	0
2	B, C	70	0.05*0.92*0.90 =	0.0414	Pass	0
3	A, C	60	0.95*0.08*0.90 =	0.0684	Pass	0
4	C	50	0.05*0.08*0.90 =	0.0036	Fail	0.0036
5	A, B	30	0.95*0.92*0.10 =	0.0874	Fail	0.0874
6	B	20	0.05*0.92*0.10 =	0.0046	Fail	0.0046
7	A	10	0.95*0.08*0.10 =	0.0076	Fail	0.0076
8	none	0	0.05*0.08*0.10 =	0.0004	Fail	0.0004
Total				**1.0000**		**0.1036**

Table A- 15 Probability table

ALTERNATIVE TREATMENT OF WIND IN ADEQUACY STUDIES: LOAD MODIFICATION

An alternative approach to modelling wind was also examined, because there are some concerns that the Wind Capacity Credit (WCC) methodology might not be appropriate with more and more wind coming on the system.

Instead of ascribing a WCC to an amount of future wind capacity in an adequacy study, this alternative approach lowers every half hour of the load forecast for a future year by a wind profile built from a past year wind shape. This wind profile was 'grown' proportionally from a past year wind shape to represent a future year with the appropriate wind capacity installed.

The choice of this past year is crucial.

From an analysis of the results of many adequacy studies with different past wind year shapes, a 'representative wind year' was chosen, i.e. a year who's wind shape is typical, that affected the generation adequacy study in the most 'average' way.

This 'Load Modification' approach can then be used with the representative year, on future generation adequacy studies.

When this was carried out on the dataset for the present GCS, the results differed only slightly from those with the WCC approach. These two methods will be further investigated and compared in the future.

INTERPRETATION OF RESULTS

While the use of LOLE allows a sophisticated, repeatable and technically accurate assessment of generation adequacy to be undertaken, understanding and interpreting the results may not be completely intuitive. If, for example, in a sample year, the analysis shows that there is a loss of load expectation of 16 hours, this does not mean that all customers will be without supply for 16 hours or that, if there is a supply shortage, it will last for 16 consecutive hours.

It does mean that if the sample year could be replayed many times and each unique outcome averaged, that demand could be expected to exceed supply for an annual average duration of 16 hours. If such circumstances arose, typically only a small number of customers would be affected for a short period. Normal practice would be to maintain supply to industry, and to use a rolling process to ensure that any burden is spread.

In addition, results expressed in LOLE terms do not give an intuitive feel for the scale of the plant shortage or surplus. This effect is accentuated by the fact that the relationship between LOLE and plant shortage/surplus is highly non-linear. In other words, it does not take twice as much plant to return a system to the 8 hour standard from 24 hours LOLE as it would from 16 hours.

The adequacy calculation assumes that forced outages are independent, and that if one generator trips it does not affect the likelihood of another generator tripping. In some situations, it is possible that a generator tripping can cause a system voltage disturbance that in turn could cause another generator to trip. Any such occurrences are a matter for system security, and therefore are outside the scope of these system adequacy studies.

As for common-mode failures, it is possible that more than one generating unit is affected at the same time by, for example, a computer virus or by extreme weather, etc. However, it could be considered the responsibility of each generator to put in place measures to mitigate against such known risks for their own units

SURPLUS & DEFICIT

In order to assist understanding and interpretation of results, a further calculation is made which indicates the amount of plant required to return the system to standard. This effectively translates the gap between the LOLE projected for a given year and the standard into an equivalent plant capacity (in MW). If the system is in surplus, this value indicates how much plant can be removed from the system without breaching the LOLE standard. Conversely, if the system is in breach of the LOLE standard, the calculation indicates how much plant should be added to the system to maintain security.

The exact amount of plant that could be added or removed would depend on the particular size and availability of any new plant to be added. The amount of surplus or deficit plant is therefore given in terms of Perfect Plant. Perfect Plant may be thought of as a conventional generator with no outages. In reality, no plant is perfect, and the amount of real plant in surplus or deficit will always be higher.

It should be noted that actual loss of load as a result of a supply shortage does not represent a catastrophic failure of the power system[62]. In all probability such shortages, or loss of load, would not result in widespread interruptions to customers. Rather, it would likely take the form of supply outages to a small number of customers for a period in the order of an hour or two. This would be done in a controlled fashion, to ensure that critical services are not affected.

[62] In line with international practice, some risk of such supply shortages are accepted to avoid the unreasonably high cost associated with reducing this risk to a negligible level.

APPENDIX 4 ADEQUACY ASSESSMENT RESULTS

This section shows the results from the adequacy studies as presented in Section 4.

Median	Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Surplus /Deficit (MW)	Northern Ireland	425	601	210	242	223	232	255	-1	-67	-37
	Ireland	1375	1471	1494	1684	1562	1341	1005	686	650	594
	All-Island	2149	2346	1951	2152	2010	1792	1477	925	851	803

*Table A-16 The surplus of perfect plant in each year for the **base case scenario**, i.e. Median demand growth, and availability as calculated by EirGrid for the generation in Ireland, and the high availability scenario for the Northern Ireland portfolio. All figures are given in MW of perfect plant. See Section 4.2 for details.*

Median	Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Surplus /Deficit (MW)	Northern Ireland	223	392	11	42	25	29	44	-196	-259	-229
	Ireland	1003	1089	1103	1292	1164	946	609	294	254	198
	All-Island	1555	1728	1332	1527	1383	1169	848	302	227	178

*Table A-17 Results for the Base Case, **without the two interconnectors to Britain**.*

Median	Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Surplus /Deficit (MW)	Northern Ireland	198	358	18	28	4	18	29	-207	-247	-244
	Ireland	1027	1120	1162	1333	1202	986	668	326	298	241
	All-Island	1451	1637	1303	1458	1305	1112	786	235	175	103

*Table A-18 Results for the Base Case, **without one CCGT in each jurisdiction***

	Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Northern Ireland	High Availability	425	601	210	242	223	232	255	-1	-67	-37
	Low Availability	295	469	55	83	65	72	93	-103	-160	-144
Ireland	Generator Availability	1690	1783	1810	1999	1887	1657	1319	980	950	894
	EirGrid Availability	1375	1471	1494	1684	1562	1341	1005	686	650	594

*Table A-19 Comparison of **different availability scenarios**. Median demand in all cases.*

	Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Northern Ireland	High Demand	402	567	167	191	165	169	186	-67	-141	-122
	Low Demand	447	634	251	293	281	295	324	79	10	44
Ireland	One-in-10 year Demand	1267	1360	1384	1573	1449	1230	894	570	535	479
	Stagnation Demand	1388	1485	1553	1788	1718	1541	1258	977	991	966

Table A-20 Comparison of ***different Demand scenarios***.