SONI
System Operator for Northern Ireland

EIRGRID

All-Island Generation Capacity Statement 2012-2021

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For queries relating to this document or to request a copy contact Adrian.henning@soni.ltd.uk or Noelle.Ameijenda@EirGrid.com

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FOREWORD

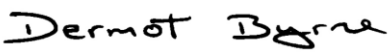
EirGrid and SONI, as Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively, are pleased to present the All-island Generation Capacity Statement 2012-2021.

Last year, the first All-Island Generation Capacity Statement was published. Both TSOs have collaborated again to produce this year's all-island report on generation adequacy. Reflecting the structure of the Single Electricity Market, this builds on Government and regulatory policies of developing a harmonised approach to energy that supports energy sustainability and economic competitiveness in the north and south of the island. This document therefore assesses the generation adequacy situation for the period 2012 to 2021 for both Ireland and Northern Ireland, as well as on an all-island basis.

Both jurisdictions have experienced a drop in demand due to the economic downturn. Coupled with the connection of new generation and increased interconnection, this means that there is adequate capacity to meet demand in accordance with the loss of load standards over the next ten years. While this is not a guarantee that there will not be load shedding, it does mean that the probability is very low.

The amount of wind generation installed on the island has been increasing steadily, and is now approaching 2,000 MW. The record for instantaneous wind generation is 1474 MW in Ireland, 378 MW in Northern Ireland (November 2011). Both governments have committed to a target of achieving 40% of all energy from renewable sources by 2020. Much of this renewable energy will come from wind, but with the many benefits of wind power come the challenges. The management of large amounts of non-synchronous generation (essentially wind and High Voltage DC interconnection) on a relatively small island is a complex task.

Following on from previous studies, a new programme of work entitled 'Delivering a Secure Sustainable Electricity System' (DS3) has been initiated across SONI and EirGrid to investigate this area further. Its remit includes enhancing the portfolio performance, developing new operational policies and system tools to efficiently use the plant portfolio to the best of its capabilities, and regularly reviewing the needs of the system as the portfolio capability evolves. As an integral part of this programme, the TSOs have invited stakeholders to contribute through an Advisory Council. Please consult our website for further information.



Dermot Byrne

Chief Executive, EirGrid Group

December 2011

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KEY MESSAGES

All-island

- The all-island generation adequacy standard of 8 hours Loss Of Load Expectation (LOLE) is met for all study years, under all scenarios.
- The addition of the second high-voltage tie-line between Ireland and Northern Ireland improves security in both jurisdictions. This is planned to be operational by 2017.
- There will be a significant increase in wind generation capacity driven by both Governments' 40% renewables target in 2020. This, combined with the shutdown of older flexible conventional plant, highlights the likely requirement for a more flexible generation plant portfolio to enable both TSOs to deal with wind management issues.

Ireland

- The adequacy situation is positive for the next ten years, i.e. the adequacy standard of 8 hours LOLE is satisfied.
- The opening of the East-West Interconnector in 2012 will allow flows of up to 500 MW in both directions between Ireland and Great Britain.
- Other major portfolio additions assumed for this study include the opening of four new Open Cycle Gas Turbines (OCGT), one Combined Cycle Gas Turbine (CCGT) and two new Waste-to-Energy Projects.
- The oil units at Tarbert and Great Island are due to close over the next ten years.
- It is estimated that Ireland will need a total installed wind capacity of between 3,500 and 4,000 MW by 2020 to meet its 40% renewables target.

Northern Ireland

- The Northern Ireland Generation Security Standard of 4.9 hours Loss Of Load Expectation (LOLE) is met for all years in the base case scenario.
- Without additional tie-line capacity between Northern Ireland and Ireland, surpluses in Northern Ireland are reduced to modest levels of circa 100-200 MW.
- There is no new conventional generation currently planned for Northern Ireland over the next 10 years.
- 510 MW of conventional plant will be decommissioned from Ballylumford by 2016.
- More onerous scenarios, based on the assumption of a prolonged major outage of a large CCGT plant or of the Moyle Interconnector, could result in a deficit position for Northern Ireland. This is particularly true for a prolonged major outage of the Moyle Interconnector.
- It is estimated that Northern Ireland will need a total installed wind capacity of circa 1,300 MW by 2020 to meet its 40% renewables target.

INTRODUCTION

This statement is produced in accordance with the requirements of Ireland's Electricity Regulation Act 1999 and Statutory Instrument No. 60 of 2005, European Communities (Internal Market in Electricity) Regulations. This statement also fulfils SONI's Licence obligation to prepare a seven year Generation Capacity Statement as set out under Condition 35 of SONI's Licence to participate in the Transmission of Electricity. It sets out estimates of the demand for electricity in the period 2012-2021 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.

The general form and content of the document has been approved by the Commission for Energy Regulation (CER) and the Utility Regulator for Northern Ireland (URegNI). This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2011-2020.

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, and 4.9 hours LOLE per year for Northern Ireland. When studying an all-island system, a standard of 8 hours is used. These standards have been agreed by the Regulatory Authorities in both jurisdictions.

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 has a formal capacity reliance of 200 MW from Northern Ireland. Similarly, Northern Ireland has a formal capacity reliance of 100 MW from Ireland. However, with the commissioning of an additional tie-line between the two jurisdictions, adequacy will improve further.

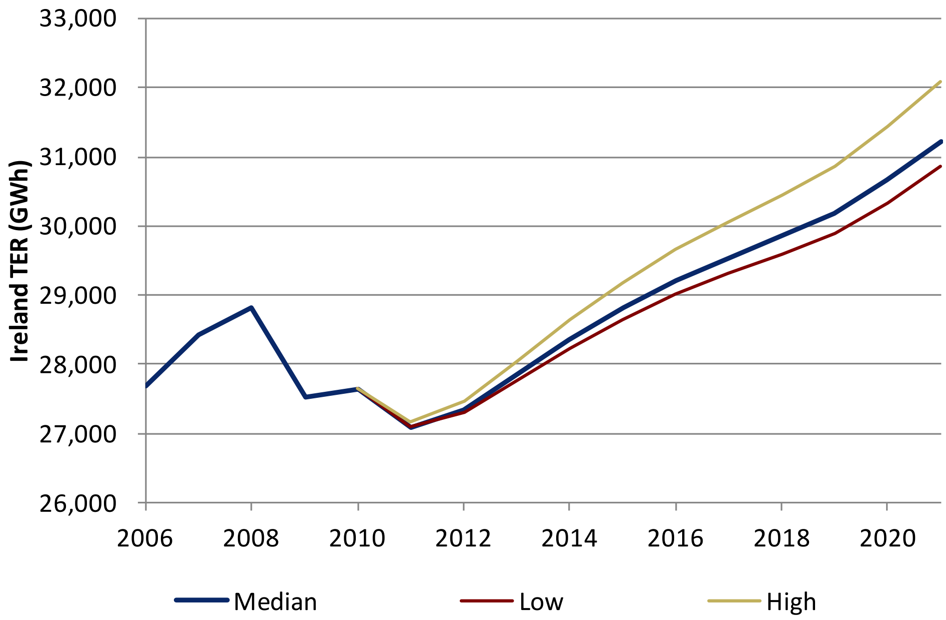
Given the uncertainty that surrounds any forecast of generation and demand, the report examines a number of different scenarios. It is intended that the results from these scenarios would provide the reader with enough information to draw their own conclusions regarding future adequacy.

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.

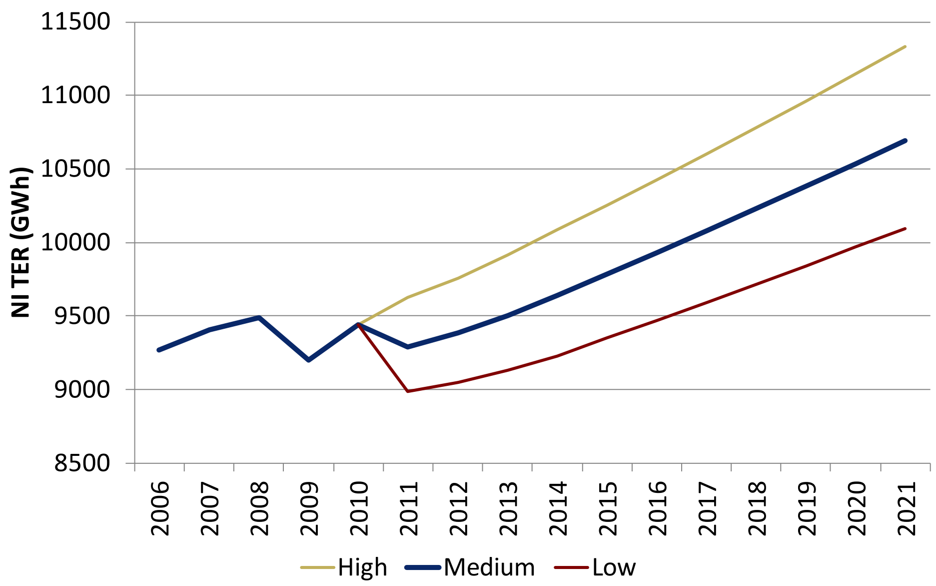
Wind generation requires a special modelling approach to capture the effect of its variable nature. The approach used in this study bases estimated future wind performance on historical records of actual wind power output.

DEMAND FORECAST

For both Ireland and Northern Ireland, the recession has led to a drop in demand in recent years. Although an increase was observed in 2010, the TSOs believe this was mainly due to the extreme inclement winters that affected both the beginning and the end of 2010. For both jurisdictions, low, median and high demand scenarios have been created to allow for uncertainty in forecasting, with the median forecast seen as most likely.



The forecast of Total Electricity Requirement (TER) for Ireland (see above) shows a relatively slow recovery compared to the growth rates seen over the last two decades. It is expected that demand will not return to 2008 levels until 2015 in the median forecast.



Northern Ireland's forecast (above), follows a similar pattern to that of Ireland's. With the ongoing economic difficulties, it is anticipated that the demand levels in 2012 will only rise moderately and it will be 2014 before demand levels gradually return to a steady growth rate of 1.5%.

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 (1st October 2011). A variety of scenarios have been studied, looking at different supply, demands, and availabilities.

Ireland

The East-West Interconnector is due to commission in 2012. It is the second transmission cable connecting the island of Ireland to Great Britain, and will be able to import or export 500 MW at any given moment. Based on the Interconnector Feasibility Report, this interconnector is assumed to add the equivalent of 440 MW additional generation capacity.

Four new OCGTs and one CCGT are due to connect, adding a generation capacity of 808 MW.

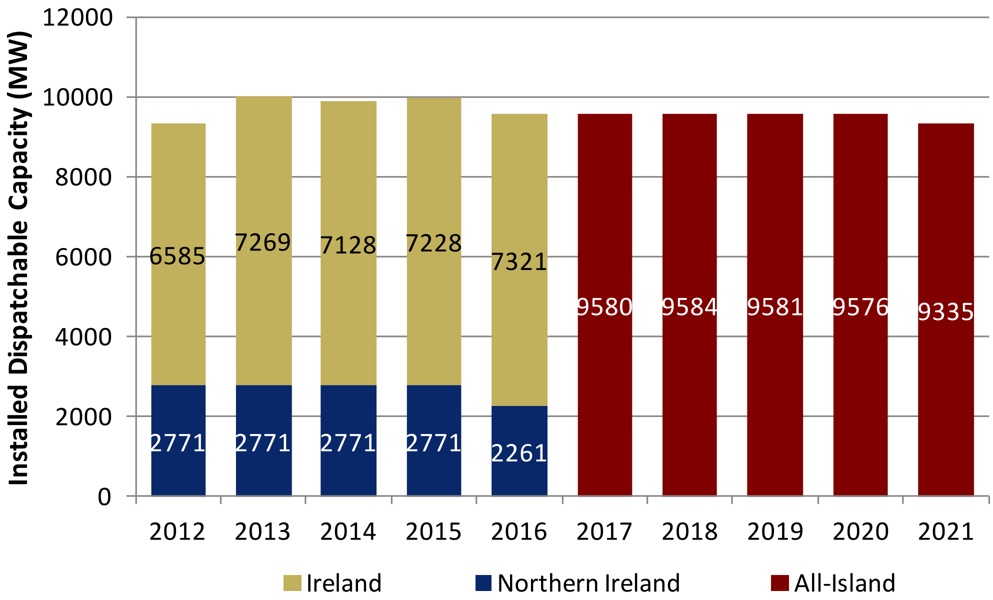
Generators powered by heavy fuel oil (HFO) are steadily disappearing from Ireland. In the next few years, all the units at Great Island and three of the units at Tarbert are due to close, leading to a reduction in capacity of 561 MW. The final Tarbert unit is due to decommission at the end of 2020, removing 241 MW from the system.

Northern Ireland

There is no new conventional generation currently planned for Northern Ireland over the next 10 years that this report covers[1].

Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by 2016. This is due to environmental constraints introduced by the Large Combustion Plant Directive and will give a reduction of 510 MW in capacity.

The graph below outlines the dispatchable capacity on the island over the next 10 years.



[1] Although Kilroot still hold a formal connection offer for additional generation capacity, they have been unable to confirm a commissioning date for this additional generation. Therefore, SONI has omitted any assumed capacity for this from the adequacy studies. It should be noted that this in no way affects the connection offer still held by Kilroot, and that they can still act upon the offer up to October 2012.

RENEWABLE ENERGY

The governments of both Ireland and Northern Ireland have set a target of 40% of electricity consumed to be produced from renewable sources by 2020. This will, in the most part, be achieved through wind generation, though other renewables will play a role.

Ireland

Using the median demand forecast, it has been calculated that between 3500 and 4000 MW of wind capacity needs to be installed in Ireland to generate 40% of electricity from renewables. This assumes average historical capacity factors, and a small percentage of wind generation being unusable for system security reasons.

In line with Ireland's National Renewable Energy Action Plan 2010, it is assumed that a modest amount of marine generation will appear in Ireland from 2017. There are also 77 MW of Waste to Energy projects connected or due to connect over the next few years. In addition, a significant growth in bioenergy is assumed.

Northern Ireland

A number of renewable generation projects are assumed to be commissioned by 2021 giving a total renewable generation capacity of 1482 MW in Northern Ireland. This includes onshore wind (1042 MW), offshore wind (300 MW), tidal (50 MW) and large scale biomass (90 MW).

These assumptions have been derived by referencing the Strategic Environmental Assessment (SEA)[2] and the Strategic Energy Framework[3] (SEF) produced by the Department of Enterprise, Trade and Investment (DETI). These DETI publications indicate that even higher amounts of renewable 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.

Information provided for onshore wind farm connections by Northern Ireland Electricity (NIE), the Northern Ireland Planning Service[4] indicate that there will be much more onshore wind connected by 2021. However, again SONI have taken a more conservative view on the amount of onshore wind connected for the adequacy studies, but are confident that at least enough onshore wind will connect to reach the 40% target in 2020.

It is estimated that Northern Ireland will need a total installed renewable capacity of circa 1,448 MW in 2020 to meet its 40% renewables target. Wind power will be the main contributor to this target, with 978 MW of onshore and 300 MW of offshore installed capacity in 2020.

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[2] Strategic Environmental Assessment (www.offshorenergyni.co.uk). DETI is also developing an Onshore Renewable Electricity Action Plan (OREAP) for Northern Ireland. The OREAP considers the contribution of onshore renewable electricity technologies to the 40% renewable electricity target by 2020. A consultation is due to be launched on this at the end of October 2011. For More Information go to www.onshorerenewablesni.co.uk

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

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

GENERATION ADEQUACY ASSESSMENTS

In determining future generation adequacy, the impact of varying demand growth and availability was examined. Also investigated were the potential effects of losing a CCGT in both Ireland and Northern Ireland, and the phased closure of older plant in Ireland. In another scenario, the possibility was explored whereby no energy could flow over the interconnectors to Great Britain – this could be due to the unavailability of both Moyle and East-West interconnectors, or due to market conditions in Great Britain.

Ireland

Generation Adequacy in Ireland is positive in all scenarios across all years. The only scenario where the surplus dips close to 200 MW is with the removal of older plant. However, as the assessment should be on an all-island basis by then, there should not be an adequacy issue were this scenario to arise.

Northern Ireland

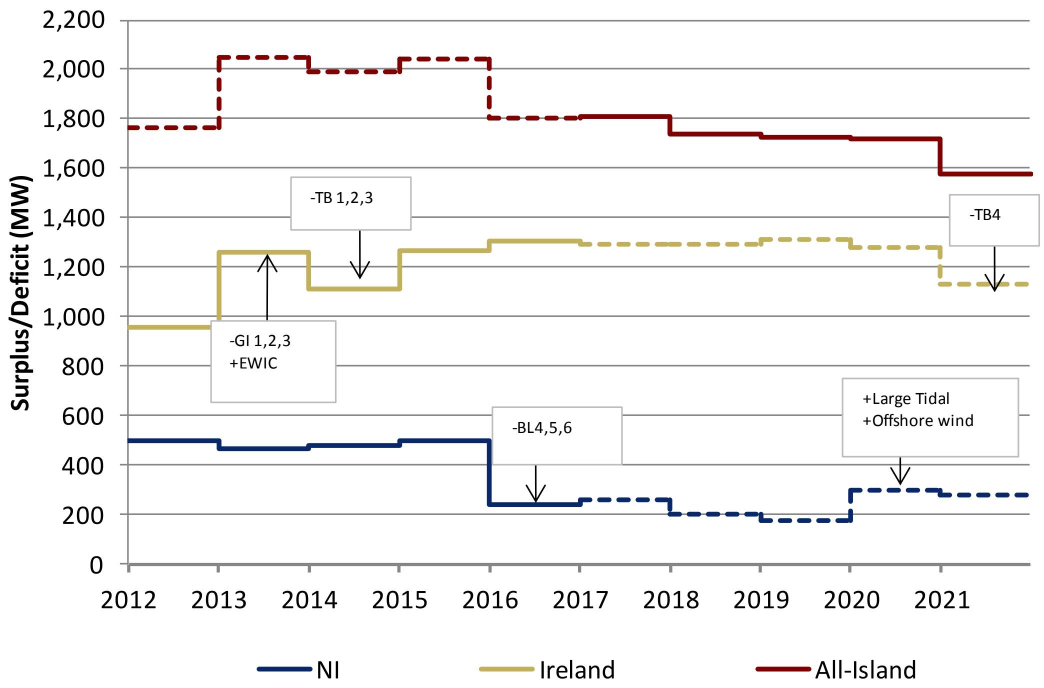
Without the introduction of an additional tie-line to Ireland, and following the decommissioning of older plant in Northern Ireland, by 2016 surpluses in Northern Ireland are reduced to circa 100-200 MW even with increasing levels of renewable generation capacity. The analysis has considered other more onerous scenarios for the loss of a large CCGT in Northern Ireland and the loss of the Moyle Interconnector with Great Britain. Both of these scenarios resulted in a deficit position for Northern Ireland.

This highlights the importance of the additional North-South tie-line project to maintain generation security standards in Northern Ireland.

All–Island

Following the introduction of the additional tie-line, the benefits are highlighted in the All-Island analysis, where surpluses of circa 1700-1800 MW are possible.

The results from the base case studies are shown below, with planned decommissionings and other changes to the portfolio indicated.



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 2021[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 2011-2020, published in December 2010.

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.
- The report concludes with Section 5, which outlines the TSOs' joint Programme for a Secure Sustainable Power System - this examines the significant work that is required to manage the integration of very high levels of generation from non-synchronous sources (essentially wind generation and HVDC imports).
- 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.

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. 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 actual 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.

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

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

2.2 Ireland's Annual Electricity Demand Forecast Model

2.2(a) Structure of the forecast model

The energy forecast model for Ireland is a multiple linear regression model which predicts electricity sales based on changes in the economic parameters of GDP[6] and PCGS[7]. However, before the econometric model is applied, the historic energy figures are corrected for the effect of temperature. Three electricity sales forecasts (high, median and low) are produced for Ireland for the next ten years.

Transporting electricity from the supplier to the customer invariably leads to losses. These losses must be added to the forecasted sales figures to give the amount of electricity needed to be generated. Based on analysis carried out by ESB networks, it is estimated that 8.3% of power produced is lost as it passes through the electricity transmission and distribution systems.

Some large-scale industrial customers produce and consume electricity on site. This electricity consumption, known as self-consumption, is not included in sales or transported across the network. Consequently, an estimate[8] 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

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

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

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

all generation sources are considered in the analysis, it is this TER that is utilised for generation adequacy calculations.

2.2(b) Training the forecast model

Historic demand data is initially corrected for temperature variations (using a simple model of past trends) - a colder than average year is corrected down, while a warm year is corrected up. When forecasting forwards, it is assumed that the weather is average, i.e. no temperature variations are applied.

Past economic data is sourced from the most recent Quarterly National Accounts of the Central Statistics Office. Data from the past 16 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 ESRI, who have expertise in modelling the Irish economy and who were consulted during the process.

The forecast for 2012 comes from the Quarterly Economic Commentary published by the ESRI in August 2010. For 2013 and beyond, ESRI issued an updated forecast in November 2011[9] in conjunction with the Sustainable Energy Authority of Ireland (SEAI) using ESRI's HERMES model. The growth rates for the economic forecast are outlined in Table 2-1.

	GDP (volume)	Personal Consumption
2012	2.3%	0.0%
2013-2015	3.0%	0.2%
2016-2020	3.3%	2.9%

Table 2-1 Economic growth rates for Ireland used to build the median demand forecast

2.2(d) Uncertainty around the median forecast

The median demand forecast is the best estimate of what might happen in the future. However, in an effort to capture the uncertainty involved in any forecasting exercise, higher and lower forecasts have been made to bracket the median demand (by +0.25% and -0.13% respectively).

The low demand scenario should capture the possible effects of lower than expected economic growth, milder than average weather and more energy saved through energy efficiency measures (including the installation of smart meters).

Conversely, the high demand scenario could account for higher economic growth, colder weather, less energy efficiency savings and more power drawn by electric vehicles and/or heating load in the future.

2.3 Northern Ireland's Annual Electricity Demand Forecast Model

2.3(a) Historic Northern Ireland Methodology

In recent years the Northern Ireland energy forecast procedure was deterministic and used statistical regression analysis to establish the relationship between demand and other factors which influence demand. Growth rates were then established and applied to base year demands to establish future forecasts. These forecasts were then validated against econometric indices and predictions.

[9] This forecast was for the SEAI publication 'Energy Forecasts for Ireland to 2020'.

2.3(b) Current Northern Ireland Methodology

The above procedure has been reasonably accurate and produced values close to the observed values. However, since 2008, there has been an increase in the difference between the predicted values and the actual values observed. SONI believe this is explained by the drastic downturn in the global economy that began during the second half of 2008. This ongoing economic downturn has had a major affect on both peak demand and energy consumption in Northern Ireland.

As the statistical analysis procedure looks back over historic time scales to maximise data correlation it means this technique is appropriate when considering general longer term trends in energy usage patterns. However, when sudden non-incremental swings occur, it is necessary to consider shorter term econometric indices and demand data analysis must be more granular in nature. It is for this reason the traditional forecasting approaches have been modified to increase accuracy in the short term.

It should be noted that the deterministic statistical regression is the preferred SONI forecasting method. Its forecast outputs will continue to be monitored closely as it is expected that they will become more accurate as future underlying growth returns to a steady year-on-year rate.

2.3(c) Temperature & Demand in NI

It is important to consider the effect of temperature on energy demand given the significant impact that the recent severe winters have had. Following on from last year's annual energy forecast, SONI have carried out further studies to allow the effect of temperature to be taken into consideration as part of the forecasting process. These studies have revealed a significant correlation between temperature and energy demand throughout the year and this has been used to forecast ahead based on average temperature years.[10] It also allows for average low temperature years and average high temperature years to be taken into consideration.

2.3(d) 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 will 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 realistic 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 an average high temperature year, with the pessimistic economic factor being applied. Conversely, the high demand forecast is based on an average low temperature year, with the optimistic economic factor being applied.

In July 2011, SONI published a document called "Forecast of Northern Ireland Energy Production and Peak Demand - July 2011"[11] where further details can be found regarding SONI's forecast.

[10] It should be noted that temperature has a lesser impact on annual electricity energy demand than it does on peak demand as the temperature effect is generally found to balance more over the course of a year.

[11] Forecast of Northern Ireland Energy Production and Peak Demand - July 2011 (http://www.soni.ltd.uk/upload/Forecast%20of%20Northern%20Ireland%20Energy%20Production%20&%20Peak%20Demand%20-%20July%202011.pdf)

2.3(e) Self Consumption and TER

Some industrial customers produce and consume electricity on site at varying times throughout the year[12]. As well as this, 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 electricity consumption, known as self consumption, is not included in the SONI Sent-Out[13] 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 recently obtained information from Northern Ireland Electricity (NIE) on the amount of this embedded generation that is connected on the Northern Ireland system. This has, for the first time, allowed SONI to make an informed estimate of the amount of energy contributed to the total demand by this self consumption which is then added to the energy which must be exported by generators to meet all demand, including this self consumption. The resultant energy is known as the Total Energy Requirement (TER). It is this TER that is utilised for generation adequacy calculations as the analysis needs to consider the ability to meet this total annual energy.[14]

SONI will continue to work closely with NIE in the future to ensure that as more of this self consumption is added to the Northern Ireland system, their estimations of such are updated accordingly.

In previous SONI Generation Capacity Statements TER was referred to as Sent-Out Energy (MWh). This Sent-Out Energy did not include an estimation for self-consumption.

2.4 Resultant Electricity Demand Forecasts

The models' forecast of the Total Electricity Requirement for each region over the next ten years are shown in Figure 2-1 and Figure 2-2 for Ireland and Northern Ireland respectively.

The 2011 median demand in Ireland is based on real data available to EirGrid through the National Control Centre. As only information up until October was available by the data freeze date, estimates were made for the remaining 3 months.

Northern Ireland's forecast follows a similar pattern to that of Ireland's. With the ongoing economic recession, it is anticipated that the demand levels in 2012 will only rise moderately and it will be 2014 before demand levels gradually return to a steady growth rate of 1.5%.

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[12] 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.

[13] Exported = Net of Generator House Loads

[14] Self-consumption in Northern Ireland represents approximately 2.5% of TER.

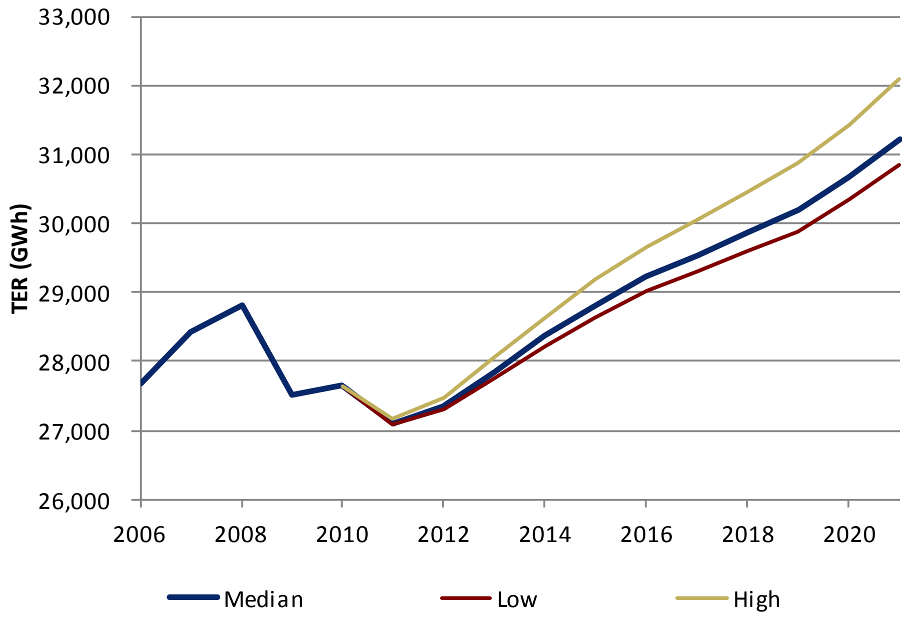

Figure 2-1 TER forecasts for Ireland

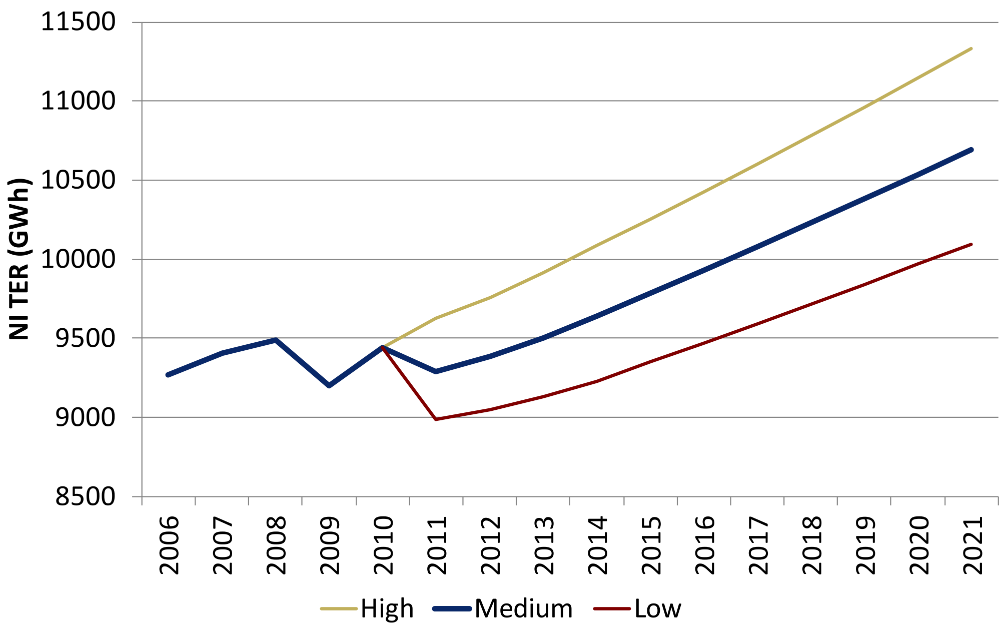

Figure 2-2 TER forecasts for Northern Ireland

The combined All-island TER Forecast for the two regions is shown in Figure 2-3.

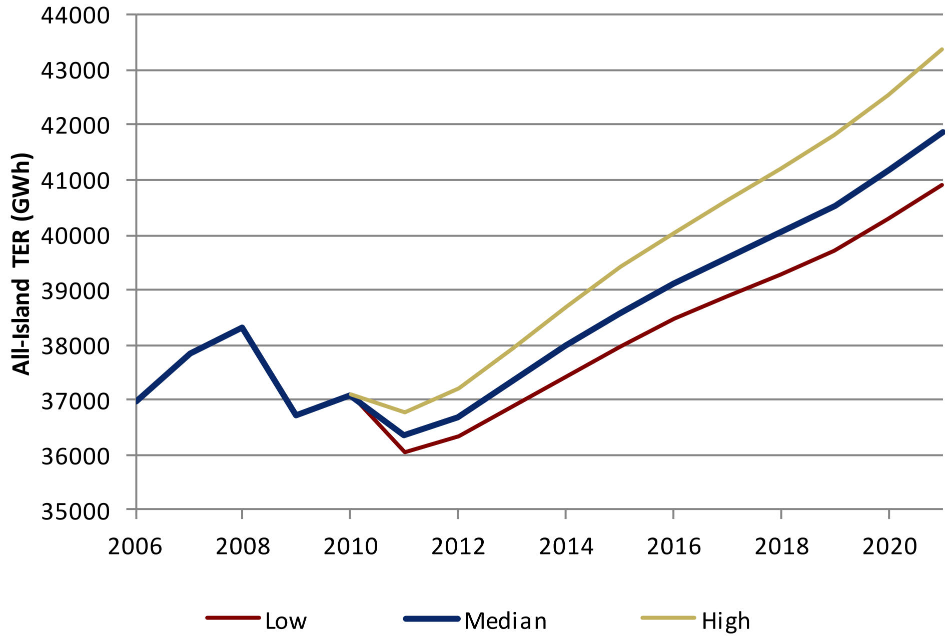

Figure 2-3 All-island TER forecasts

Further details on the demand forecast, including tabulated figures, can be found in APPENDIX 1.

2.5 Peak Demand Forecasting, Ireland

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 other disparate factors which can affect the somewhat erratic winter peak, including

- temperature and weather conditions
- changing electricity usage patterns
- Demand-Side Management (DSM) schemes

As part of DSM measures, the winter peak is lowered by the Winter Peak Demand Reduction Scheme (WPDRS). This effect has been estimated and allowed for in the current model. Although this scheme is likely to change in the future, the resultant effect on adequacy should be small, given that the system is in large surplus. However its impact should be monitored.

Temperature has a most significant effect on electricity demand, as was particularly evident over the previous two severe winters when temperatures plunged and demand rose.

Detailed temperature records from four observing stations were obtained from Met Éireann, and analysis was carried out over the last ten winters. A statistically-relevant relationship was found between the normalised daily peaks and the weighted effective mean temperature for the day.

This was used to correct the past winter peak demands to a temperature standard known as Average Cold Spell (ACS) conditions, i.e. each winter peak was adjusted, using the temperature-load relationship, to what it would have been had an average temperature occurred. The average temperature was taken to be the median over 25 years of winter temperature minima.

This has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences, see Figure 2-4.

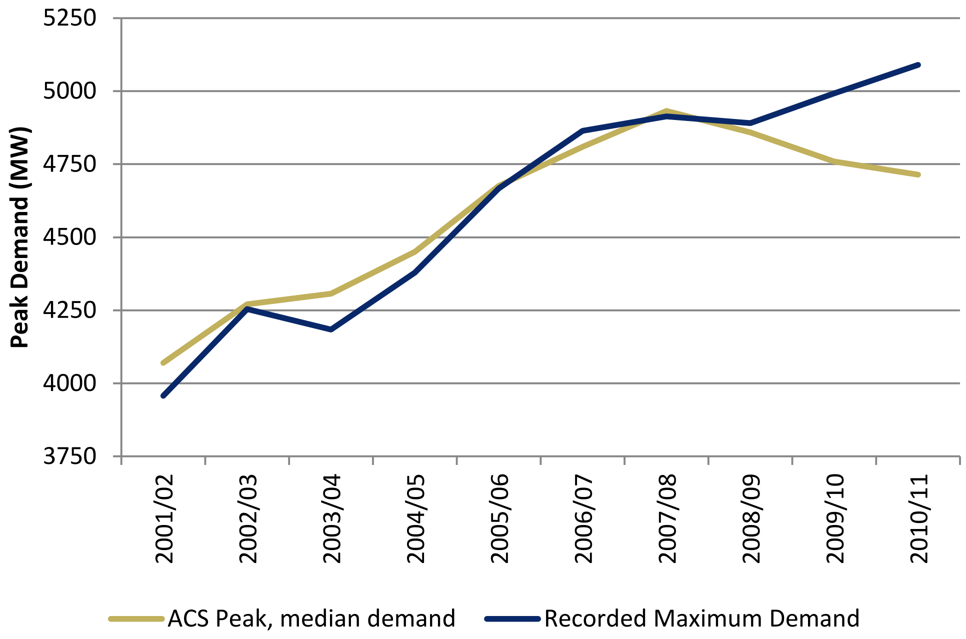

Figure 2-4 Past values of the recorded maximum demand in Ireland, and the ACS corrected values

2.6 Peak Demand Forecasting, Northern Ireland

The Northern Ireland peak demand forecast is carried out using similar methodology as the Ireland peak forecast described in Section 2.5.

Of all the meteorological elements it has been found that temperature has the greatest effect on the demand for electricity in Northern Ireland. For this reason, demand data is adjusted to ACS temperatures. ACS analysis produces a peak demand which would have occurred had conditions been averagely cold for the time of year.

The ACS adjustment to each winter peak removes any sudden changes caused by unexpected inclement weather conditions. Over each winter period of November through to February, temperature and demand data is collated to enable the annual winter calculation of the ACS effective mean temperature which represents the temperature conditions that prevailed during that particular winter.

Analysis can then be carried out using historical temperature data. The average cold spell effective mean temperature is determined from an assessment of the effective mean temperatures for each winter over the last 25 years. The winter peak demands are then corrected to this historical average.

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.

The demand peaks over the last decade reflect Customer Private Generation (CPG)[15], consisting of customers running private embedded diesel generation. Analysis was carried out over the 2010/11 winter period to calculate the amount of CPG that was actually running and was found to be 68 MW.

[15] Some customers reduce their demand at peak hours, thus lessening the actual peak that needs to be supplied. In some cases this is achieved by the use of diesel generators to supply their own load.

This has the effect of suppressing the peak and is assumed to continue over the ten years of this report.

In recent previous years the CPG figure was much higher. However, SONI believe this has reduced significantly due a number of reasons including;

- the effect of the ongoing recession resulting in the closure of businesses and factories;
- the overall tariff signal that gave financial incentives to businesses and factories to reduce their demand at peak times has now been removed[16];
- the establishment of a dispatchable Aggregated Generating Unit (AGU) in Northern Ireland which consists of a number of individual diesel generators grouping together to make available their combined capacity to the market. These diesel generators may have previously contributed to CPG

The Northern Ireland 2010/11 generated winter peak which occurred on 21st December 2010 @ 17:30 consisted of the following data:

CDGU + Interconnectors	= 1851 MW
Renewable + Small Scale	= 16 MW
Customer Private Generation	= 68 MW
TOTAL GENERATED PEAK	**=1935 MW**

When average cold spell temperature correction (ACS) is applied using the methodology as described above, the figure of 1935 MW is corrected down by 78 MW, providing an ACS corrected figure of 1857 MW for the 2010/11 winter period, see Figure 2-5.

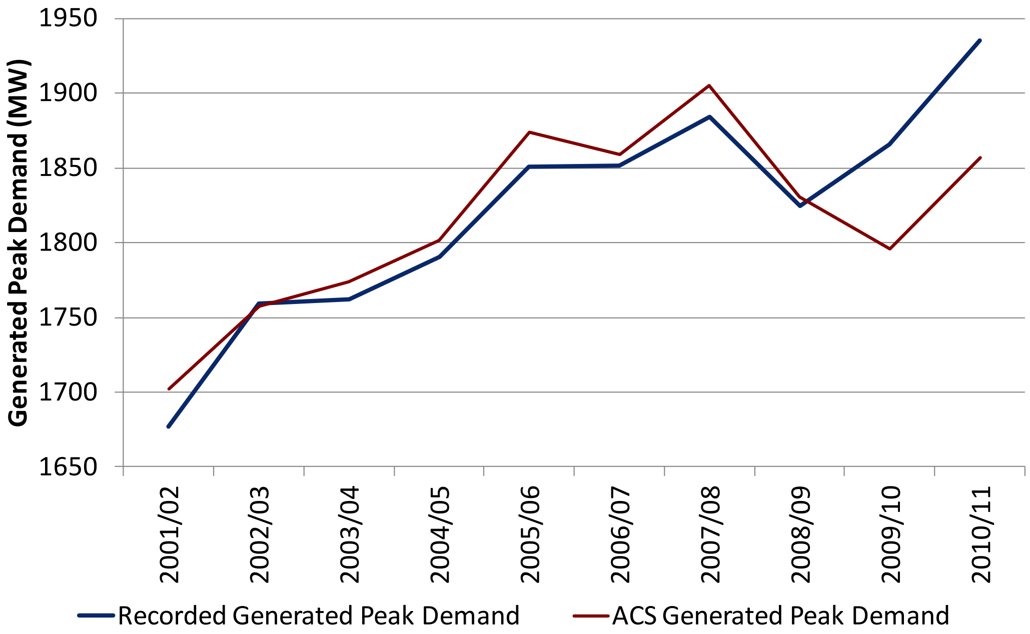

Figure 2-5 Actual and ACS-adjusted generated peaks for Northern Ireland

ACS Peak demand in Northern Ireland has generally seen steady incremental growth over the last fifteen years. During the 2008/09 winter, the ACS peak demand fell significantly due to the onset of the economic downturn. This decline in ACS peak demand continued into the 2009/10 winter before rising again in the 2010/11 winter. The ACS analysis has had the effect of reducing the recorded

16 Arrangements between individual customers and their supplier may still exist where a financial incentive may still be available from the supplier to reduce the demand at peak times.

generated peak demand down by approximately 70 – 80 MW during the past two winters which were the most severe winters experienced in Northern Ireland for many years.

The Northern Ireland peak demand forecast had, until recently, used statistical regression analysis to produce future forecasts, which were validated against econometric indices and predictions. Since 2008, however, the economic crisis has had a major affect on both peak demand and energy in Northern Ireland.

As with the annual electricity usage forecast outlined in section 2.3, 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.

It should be noted that the generation adequacy assessment is based on the generation sent out (exported, net of house loads). In Northern Ireland the analysis for the peak demand forecast is carried out using Generated Peak Demand. Therefore a statistically derived conversion factor of 0.954 is applied to the generated peak demand forecasts to convert them to generated peak demand in sent out terms 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(b). This has the effect of adding approximately 90 MW to the Transmission Peak.

In previous SONI Generation Capacity Statements TER Peak was referred to as Sent-Out Peak (MW). This Sent-Out Peak did not include an estimation for the contribution of self consuming units to the peak.

2.7 Peak Demand Forecast Results

For Ireland, 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 2-6.

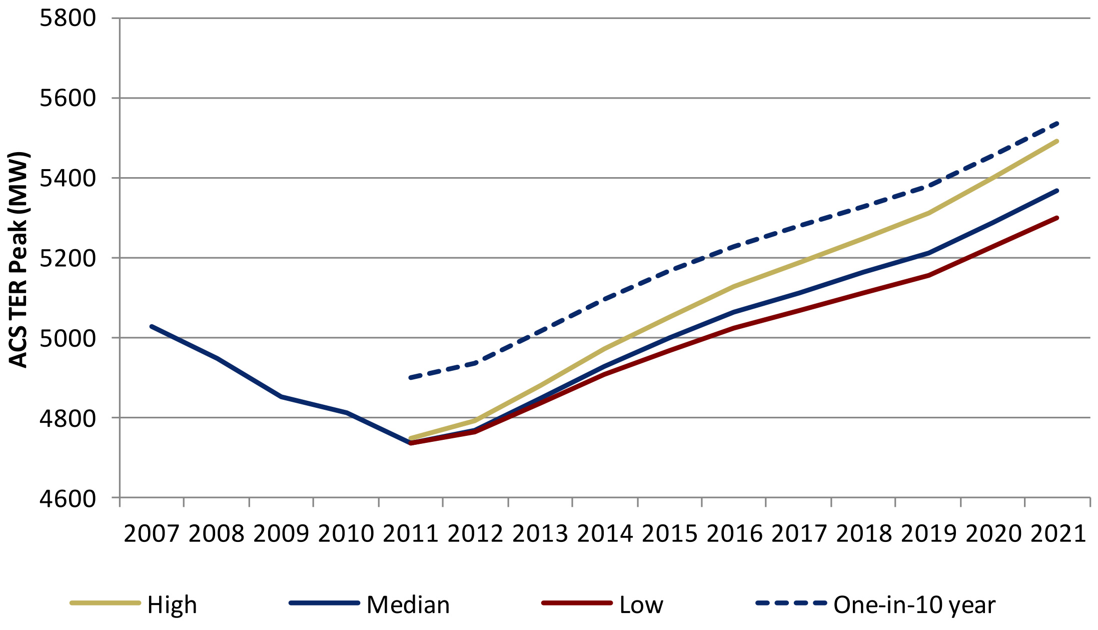

Figure 2-6 TER peak forecasts for Ireland

The ACS peak is made from the median energy demand scenario. Above and below that, an ACS peak is built from the high and low energy demand scenarios. These three scenarios assume typical, ACS conditions. An alternative upper margin comes from assuming not ACS conditions, but rather a lower temperature (lowest expected once in 10 years) and median demand. The outturn peak is most likely to lie within these bounds.

Figure 2-7 shows the resultant TER peak forecast for Northern Ireland for the next 10 years. In the median scenario it is not expected that the normal 1.5%[17] growth rate will return until the 2014/15 winter and it is then expected continue on at this normal 1.5% growth year on year from then.

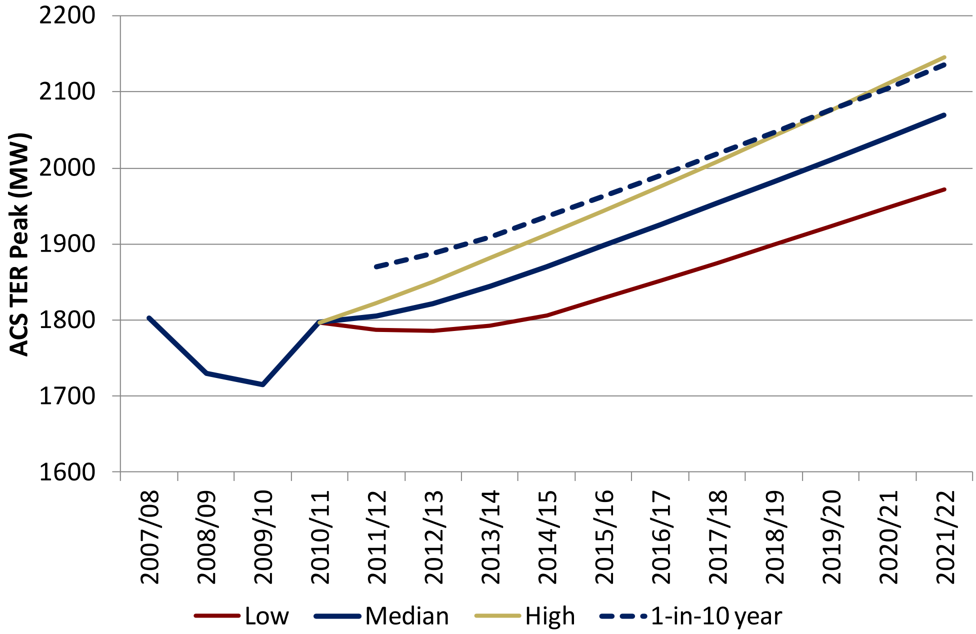

Figure 2-7 TER peak forecasts for Northern Ireland

2.8 All-Island Peak Forecasts

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 all-island peaks, future demand profiles have been built for both regions based on the actual 2007 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.

[17] Before the ongoing economic downturn began towards the end of 2008 the Peak Demand in Northern Ireland had an underlying year-on-year growth of ~1.5%.

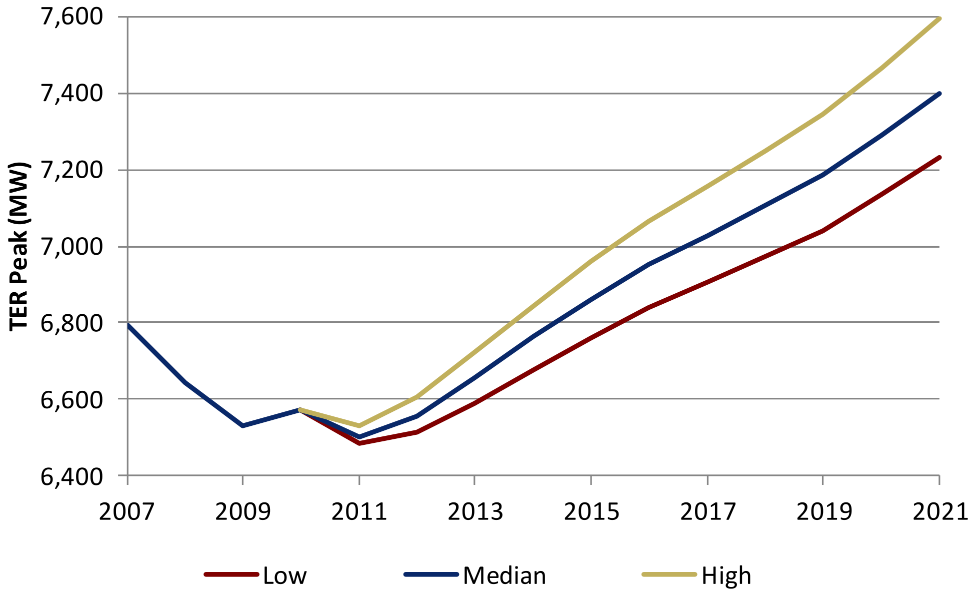

Figure 2-8 The all-island TER peak forecast

Tabulated figures of the peak demand forecasts can be found in APPENDIX 1.

2.9 Annual Load Shape and Demand Profiles

To create future demand profiles for our 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 2007 for both jurisdictions.

The 2008 profile was not used as a base year as it was deemed to be an abnormal year. This is due to both economies entering a recession, reducing growth in electricity demand as the year progressed. Likewise, the 2009 and 2010 demand profiles have been deemed as abnormal as the recession continued to affect both demand profiles. The 2010 profile was also affected by the prolonged cold spells both at the beginning and end of the year.

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.

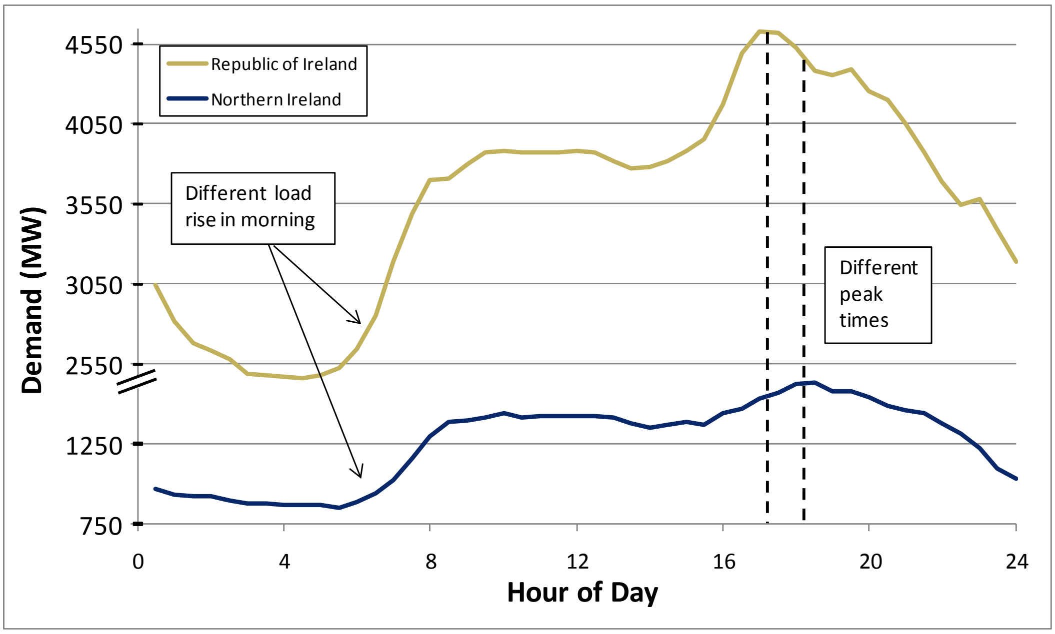

Figure 2-9 Typical winter day profile.

2.10 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[18]. 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[19].

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 Framework for Northern Ireland[20]. 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[21]) to help businesses identify and implement significant energy efficiencies.

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

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

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

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

3 ELECTRICITY GENERATION

3 ELECTRICITY GENERATION

3.1 Introduction

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 (1st October 2011).

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capacity Removed (NI)					510					
Capacity added (Ireland) [22]		459	215	98	98					
Capacity Removed (Ireland)		212	351							243
Minor degradation		-3	-5	2	-5	-2	4	-3	-5	2
EWIC		440								
Net Impact		684	-141	100	-417	-2	4	-3	-5	-241
Total Dispatchable capacity	9356	10040	9899	9999	9582	9580	9584	9581	9576	9335

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

Interconnection will continue to play an important role in future generation supply security. The East-West Interconnector, connecting the transmission systems of Ireland and Wales, is due for completion in 2012. This will be able to transmit 500 MW in either direction. Along with the existing Moyle Interconnector[23] that connects the transmission systems of Northern Ireland and Scotland, this will significantly enhance the overall interconnection between the island of Ireland and Great Britain.

The second major North-South tie-line connecting Northern Ireland and Ireland will lead to a more secure, stable, and efficient all-island system. The North-South tie-line is planned to be operational by 2017.

[22] There is no new conventional generation currently planned for NI over the next 10 years.

[23] Capacity of Moyle Interconnector:
Import = 450 MW Nov-Mar & 410MW Apr-Oct. Export = 295MW Sep-Apr & 287MW May-Aug as per the Moyle Interconnector Capacity Statement, September 2011 (http://www.mutual-energy.com/Download/110930%20MIL%20SONI%20NG%20Capacity%20Calc%20combined%20Sept%202011.pdf).

3.2 Generation Portfolio changes in Ireland

- Four new open cycle gas turbine (OCGT) power stations have signed to connect to the system over the next four years, giving an additional capacity of 349 MW.
- A Waste-to-Energy converter, located in Dublin, will be able to supply 62 MW. A smaller 15 MW Waste-to-Energy converter in Meath has commissioned in 2011.
- All Great Island units will be decommissioned, reducing capacity by 212 MW. Endesa plan to replace this with a new CCGT.
- All units in Tarbert are due to decommission by 2021, resulting in a reduction of 592 MW.
- There will be a large amount of wind generation installed in Ireland over the next ten years. While the exact amount is uncertain, to reach the renewable target (40% of energy from renewable sources by 2020), installed wind capacity is projected to grow by between 1,900 to 2,400 MW

3.3 Generation Portfolio changes in Northern Ireland

- There is no 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 Plant Directive and will give a reduction of 510 MW in capacity.
- A number of renewable generation projects are assumed to be in place by 2021 in Northern Ireland. These will consist of onshore wind (1042 MW), offshore wind (300 MW), tidal (50 MW) and large scale biomass (90 MW).

  These assumptions have been derived by referencing the Strategic Environmental Assessment (SEA)[24] and the Strategic Energy Framework[25] (SEF) produced by the Department of Enterprise, Trade and Investment (DETI) along with information provided on wind farm connections by Northern Ireland Electricity (NIE), and the Northern Ireland Planning Service[26].

  They are also based on the assumption that the Government target for Northern Ireland of 40% of electricity production from renewable sources as set out in the SEF will be met by 2020. The 40% target takes into account a contribution from all renewables, but the main contribution will be made up from onshore wind. It is estimated that an installed onshore wind capacity of 978 MW will be enough to achieve the 40% figure in 2020.

  The DETI publications, NIE information and Planning Service information indicate that even higher amounts of renewable generation will connect over the next number of years which would result in exceeding the 40% target in 2020. However, for the adequacy studies, SONI have taken a more conservative view on the amount that will be connected, but are confident that at least enough will be connected to reach the 40% target.

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[24] Strategic Environmental Assessment (www.offshorenergyni.co.uk). DETI is also developing an Onshore Renewable Electricity Action Plan (OREAP) for Northern Ireland. The OREAP considers the contribution of onshore renewable electricity technologies to the 40% renewable electricity target by 2020. A consultation is due to be launched on this at the end of October 2011. For more information go to www.onshorerenewablesni.co.uk

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

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

3.4 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 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 26 MW Aggregated Generating Unit operated by iPower.

There is an amount of generation connected 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[27] and the Distribution Code[28] in Ireland, wind farms with an installed capacity greater than 5 MW must be partially dispatchable.

In accordance with the SONI Grid Code[29] and the Distribution Code[30] 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.

3.5 Changes in Conventional Generation

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, only new generators which have a signed connection agreement with EirGrid[31] or SONI, and have indicated a commissioning date by the data freeze date are included in adequacy assessments. Also, only planned decommissionings that EirGrid or SONI have been officially notified of by the data freeze date are considered in the base case studies.

3.5(a) Plant Commissionings

Table 3-2 lists thermal generators that have signed agreements and confirmed dates to connect to the island over the next ten years.

27 www.eirgrid.com/operations/gridcode/

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

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

30 www.nie.co.uk/suppliers/distribution.htm

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

Plant	Export Capacity (MW)
Great Island CCGT	459
Nore Power	98
Caulstown	55
Dublin Waste to Energy	62
Cuilleen OCGT	98
Suir OCGT	98

Table 3-2 Confirmed contracted conventional generation capacity for the island up to 2021

It should also be noted that a connection offer for a 440 MW CCGT generator in Co. Louth has been signed. However, as a commissioning date has not been given for this project, it has not been included in these studies.

Endesa plans to commission new plant immediately after the closure of the existing units at Great Island (see section 3.5(b)). 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 2021.

The closure of Tarbert 4, and the opening of a new OCGT there, is dependent on market conditions – therefore Eirgrid will not be including a new unit at Tarbert in its base case.

Although Kilroot still hold a formal connection offer for additional generation capacity, they have been unable to confirm a commissioning date for this additional generation. It had been assumed in previous SONI Seven Year Statements that the additional capacity would consist of a new 400 MW CCGT. As AES have been unable to provide a firm commissioning date, SONI has omitted this capacity from the adequacy studies in order to present as accurate a forecast as possible. It should be noted that this in no way affects the connection offer still held by Kilroot, and that they can still act upon the offer up to October 2012.

In Ireland, two large CCGTs have recently 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.

Works are currently underway in the Cork region. It is thought that this will allow Whitegate to export its full capacity, while there will be a collective 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 90MW), and the new Aghada AD2 (432 MW), with a total export capacity of 960 MW.

Likewise 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. Under these conditions it is not possible to export the total plant capacity at Islandmagee.

To model this within the adequacy studies, only two units from Unit 4, Unit 5 or Unit 6 at Ballylumford are included each year. A lower predicted Forced Outage Probability (FOP) for the two units that have been included in the studies is used to reflect that fact that if one of them is forced out due to a fault, the third unit can be run in its place.[32]

[32] Please note that in terms of availability, all 3 units 4, 5 and 6 at Ballylumford are normally available for dispatch. There are also exceptions to all 3 units not being able to export fully at the same time, for example, all 3 of these Ballylumford units can export when the Moyle Interconnector is on an outage. It should be further noted that Unit 5 is a non-firm unit.

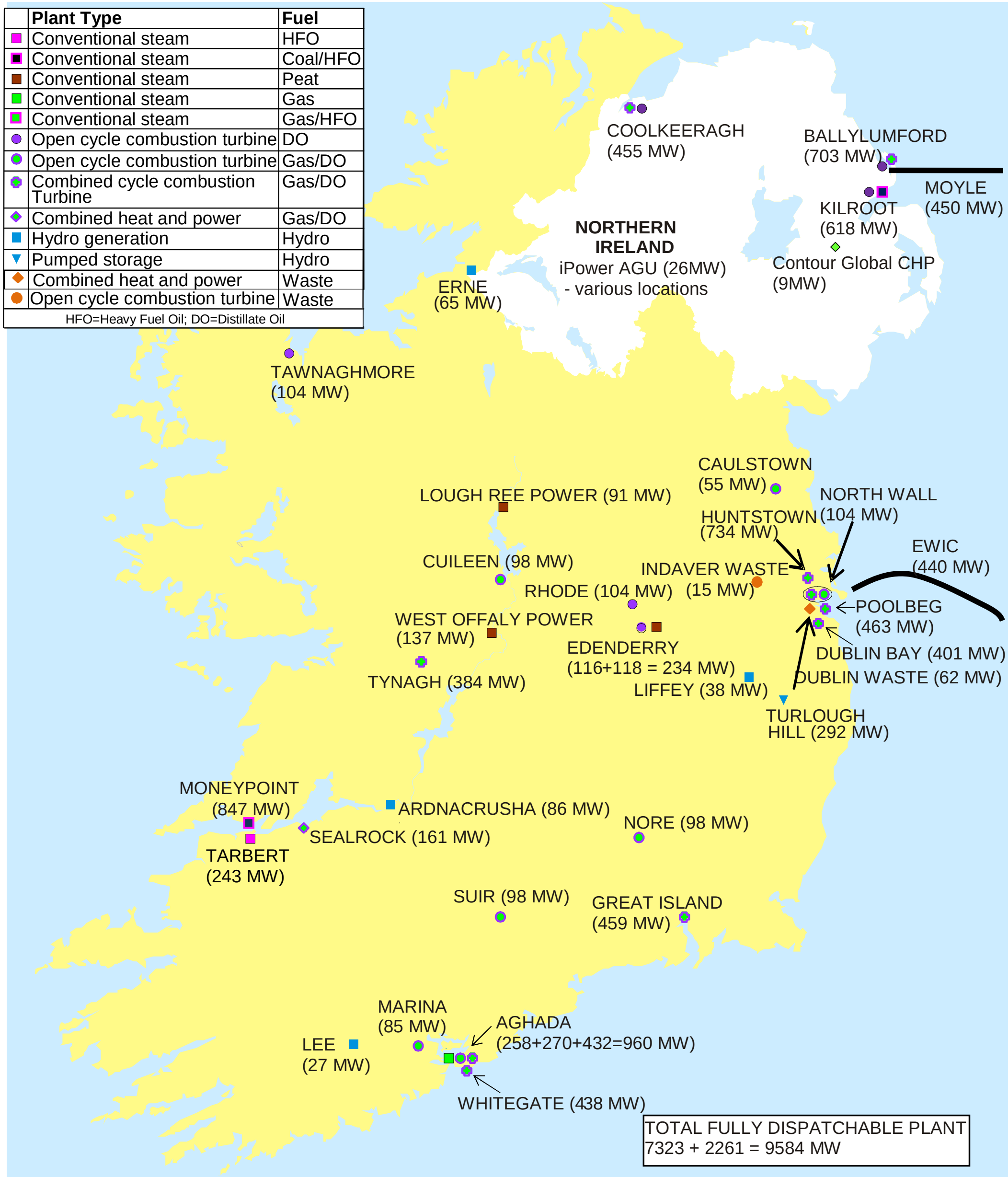

Figure 3-1 Fully dispatchable plant installed in 2018, at exported capacities. All figures shown are maximum export capacities – generators may often operate at a lower export capacity.

3.5(b) Plant Decommissionings

As well as the new plant mentioned above, some older generators will come to the end of their lifetimes over the next ten years. Confirmed decommissionings are shown in Table 3-3.

Plant	Export Capacity (MW)
Great Island 1,2,3	212
Tarbert 1 & 2	108
Tarbert 3	241
BL 4,5,6	510
Tarbert 4	241

Table 3-3 Confirmed closures of conventional generators to 2021

In addition to the closures above, the OCGT at Marina in Cork has a limited number of run hours permitted before it needs to be either shut down or upgraded. Current running regimes mean that this will occur shortly. This will remove 85 MW from the island's generation capacity. As ESB Energy International have the option to upgrade the plant, it has not been removed it from the base case studies (though a scenario is examined where it and other older plant are not included).

ESB Energy International has not provided a date for return-to-service of the North Wall CCGT, and therefore EirGrid has omitted this plant in these adequacy studies.

3.6 Interconnection

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

3.6(a) North-South Tie-line

With the completion of the second high capacity transmission link between Ireland and Northern Ireland, an all-island generation adequacy assessment has been carried out from 2017 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 tie-line project, the existing tie-line 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 the interconnector flow. Further 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 a formal degree of capacity interdependence from the other region. This is an interim arrangement until the additional tie-line removes this physical constraint. The capacity reliance and actual transfer capacity values on the existing tie-line are shown in Table 3-4.

	North to South	South to North
Total Transfer Capacity[33]	430 MW	380 MW
Net Transfer Capacity	330 MW	170 MW
Capacity Reliance	200 MW	100 MW

Table 3-4 Transfer capacity and capacity reliance at present on the existing North-South tie-line

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

3.6(b) Moyle Interconnector between Northern Ireland and Scotland

The Moyle Interconnector is a dual monopole HVDC link with 2 coaxial undersea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The total installed capacity of the link is 500 MW.

[33] As per SONI 7 Year Transmission Statement 2011/12 -2017/18, http://www.soni.ltd.uk/upload/2011_TSCS_PRINT_VERSION.pdf

The current available Net Transfer Capacity (NTC) import from Great Britain to Northern Ireland is 450 MW during the winter and 410 MW from April to October inclusive.[34] An emergency flow of up to 50 MW is available should the frequency in Ireland reach 49.6Hz and a further 25 MW available at 49.5Hz. All interconnector capacity is auctioned by the SONI on behalf of Mutual Energy Limited[35]. This capacity is purchased by market participants. In the SEM the unused capacity can, in emergency situations, be used solely to meet peak demand. It is for this reason that this capacity assessment assumes the capacity of the Moyle Interconnector as a maximum of 450 MW.

The Balancing & Services Agreement between SONI and the TSO in GB, National Grid (NG), facilitates energy purchases including emergency assistance up to the appropriate NTC of the interconnector. The availability level attributed to the Moyle interconnector includes an assumption that there would be capacity available in the GB system, which has 83 GW[36] of installed net generating capacity.

It should also be noted that there have been occasions when energy has not been available during a capacity shortfall either for balancing trades or emergency assistance. A 450 MW import capability on Moyle tends to project a healthy position with respect to capacity adequacy in NI. The achievement of high levels of generation capacity security in NI in practice comes with a large degree of operational complexity and uncertainty in the commercial markets SONI now operate in. As flows are difficult to predict, margins can be tight and complex to manage in operational timescales.

National Grid's current Seven Year Statement[37] assumes that exports of 400-500 MW at peak times are expected to flow to Northern Ireland via the Moyle Interconnector. In line with the SONI assumption of modelling the Moyle Interconnector as 450 MW of available capacity in the generation adequacy studies, this is conversely treated as negative generation by National Grid in their studies. Even with the 400-500 MW treated as negative generation by National Grid, their plant margins are still within acceptable standards.

At the time of writing this report, the Moyle Interconnector was on a prolonged forced outage due to undersea cable faults on both of its cables. This follows a previous prolonged fault that affected one of the two cables in the last quarter of 2010. Therefore in the adequacy studies carried out for this report, the Forced Outage Probability[38] (FOP) for the Moyle has been adjusted accordingly to reflect this.

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

The East-West interconnector (EWIC) will connect the transmission systems of Ireland and Wales, and is due to be completed in 2012. The interconnector will be able to carry up to 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 in National Grid's current Seven Year Statement. It also states that it is expected that exports of 400-500 MW to Ireland via EWIC will occur even at peak times. This is in line with the estimations EirGrid have for modelling EWIC in the generation adequacy studies.

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[34] Moyle Export from Northern Ireland to Great Britain = 295 MW Sep-Apr & 287 MW May-Aug as per the Moyle Interconnector Capacity Statement, September 2011 (http://www.mutual-energy.com/Download/110930%20MIL%20SONI%20NG%20Capacity%20Calc%20combined%20Sept%202011.pdf).

[35] www.mutual-energy.com

[36] Source: www.entsoe.eu

[37] http://www.nationalgrid.com/uk/Electricity/SYS/current/

[38] 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.

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

A FOP similar to that for the Moyle interconnector has been used for the adequacy studies.

3.7 Wind Capacity & Renewables Targets

In both Ireland and Northern Ireland, government policy exists which makes targets of the amount of electricity sourced from renewables. Biofuels, hydro and marine energy will make an important contribution to these targets (see sections 3.8(c), 3.8(d)3.8(a) and 3.8(e)). However, it is assumed that these renewable targets will be achieved largely through the deployment of additional wind powered generation. Figure 3-10 shows the location of existing and planned wind generation on the island.

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 windfarms been generating at full capacity all year.

3.7(a) Ireland

In October 2009 the Government announced a target of 40% of electricity production 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 nearly 1,600 MW at the time of writing. This value is set to increase over the next few years as Ireland endeavours to meet its renewables target in 2020. The actual amount of renewable energy this requires will depend on the demand in future years (the forecast of which has, of course, 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 potential 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 was estimated for wind capacity in 2020. Figure 3-2 indicates these targets between about 3500 MW and 4000 MW. A certain amount of this contribution is from offshore wind generation, as set out in Ireland's National Renewable Energy Action Plan (NREAP[40]). There are a number of offshore projects in the Gate 3 Connection Offer Process.

Based on historical records, it is assumed that onshore wind has a capacity factor of 31%, and offshore 37%. As a reference point, the energy obtained from wind generation over the past nine years is shown in Figure 3-3.

[40] http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/Renewable+Energy+Directive+and+National+Renewable+Energy+Action+Plan.htm

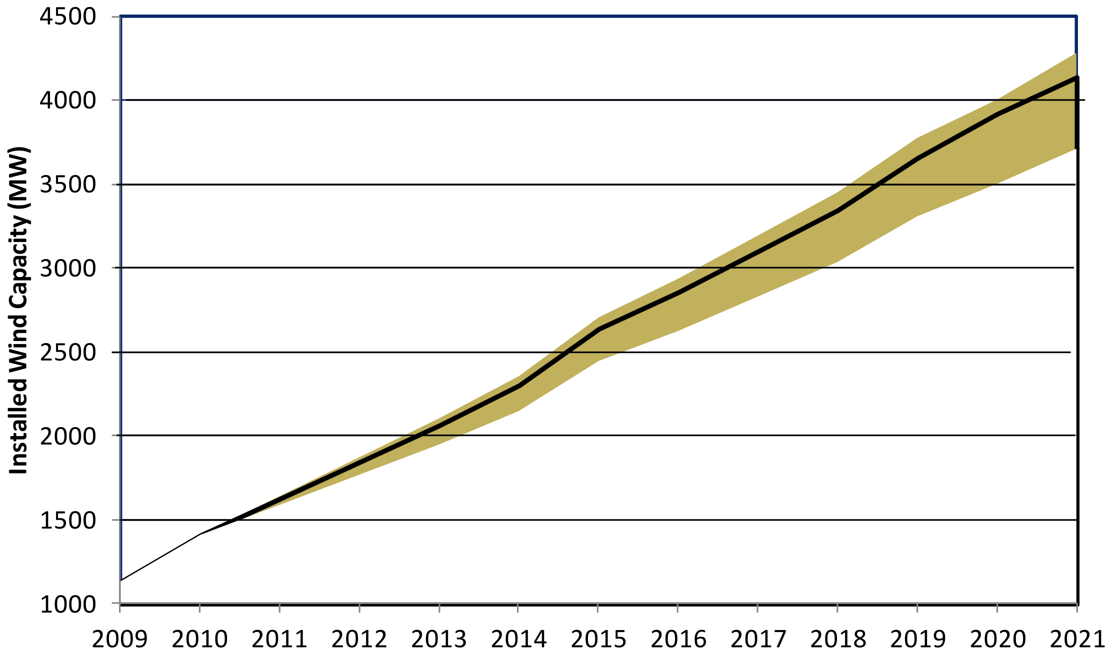

Figure 3-2 Band of predictions for Wind capacity levels in Ireland assumed for this report, determined using a linear projection of installed wind capacity required to meet 2020 targets.

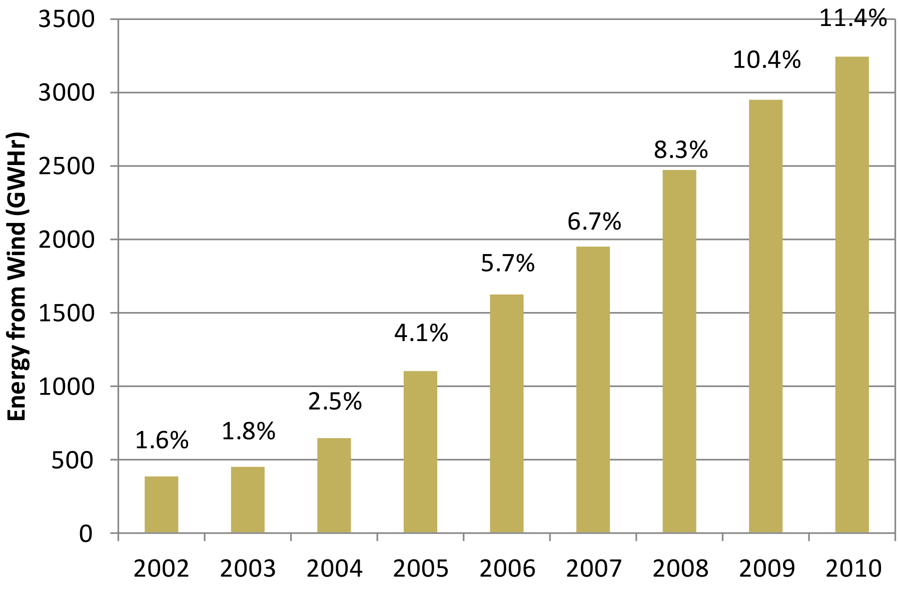

Figure 3-3 Historical wind generation in annual energy terms for Ireland (normalised), also given as a percentage of total electrical energy produced that year.

Historical wind capacity factors are shown in Figure 3-4. 2007 was considered to be a poor wind year in terms of nationwide average wind speeds. Wind conditions recovered in 2008 and 2009, but 2010 was the worst performance of the decade. An average capacity factor of 30.6% was used for future wind years for this report.

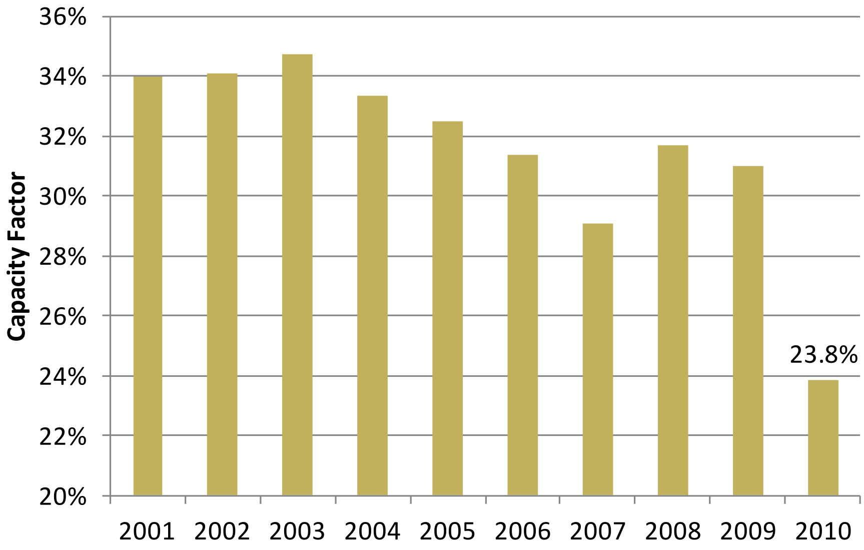

Figure 3-4 Historical wind capacity factors for Ireland.

The Government's White Paper on renewable energy[41] declared that 15% of electricity should be produced from renewable sources by 2010. Though Ireland has enough wind generation to achieve this target on a typical wind year, the wind capacity factor for 2010 was low, and only 14% of energy came from renewables.

3.7(b) Northern Ireland

The Strategic Energy Framework for Northern Ireland[42] restated the current 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 2010, 7.93% of electricity consumption was from renewable sources in NI. This is seen as relatively low, mainly due to the wind being the main contributor of the renewable generation portfolio and 2010 being a poor wind year.

Installed capacity of wind generation has grown from 37 MW in 2002 to 398 MW at the time of writing (see APPENDIX 2). This is set to increase rapidly over the next number of years as increasing levels of planning applications[43] for new wind farms are made. It is this increasing level of wind that is expected to be the main contributor to achieving the 40% target.

While the exact amount is as yet uncertain, for the purposes of the studies for this report SONI assume that by 2021 there will be an installed wind capacity of 1342 MW in NI (1042 MW of onshore and 300 MW of offshore). This is based on the assumption that the Government target for NI of 40% of electricity production from renewable sources will be met by 2020. The 40% target also takes into account a contribution from other renewables, such as tidal and biomass as outlined below.

However, the main contribution will be made up from wind. It is estimated that an installed wind capacity of circa 1278 MW will be enough to achieve the 40% figure by 2020. (978 MW of onshore and 300 MW of offshore).

The figures for the amount of 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 978 MW to be met by 2020.

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[41] Energy White Paper 2007 'Delivering a Sustainable Energy Future for Ireland', March 2007.

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

[43] 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)

Information provided on wind farm connections by Northern Ireland Electricity (NIE), the Northern Ireland Planning Service[44], along with assumptions made on what amount of wind capacity will actually receive the planning permission required indicate that there will be much more onshore wind connected by 2020. However, SONI have taken a more conservative view on the amount of onshore wind connected for the adequacy studies, but are confident that at least enough onshore wind will connect to reach the 40% target.

This assumes that onshore wind has a capacity factor[45] of 30%, offshore wind 35%, tidal 20% and large scale biomass 80%. It should be 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% is based on electricity consumption and not on installed capacity.

Figure 3-5 below illustrates the 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 as shown in Figure 3-5 are dependent on a number of key transmission corridors being reinforced by the asset owner, Northern Ireland Electricity.

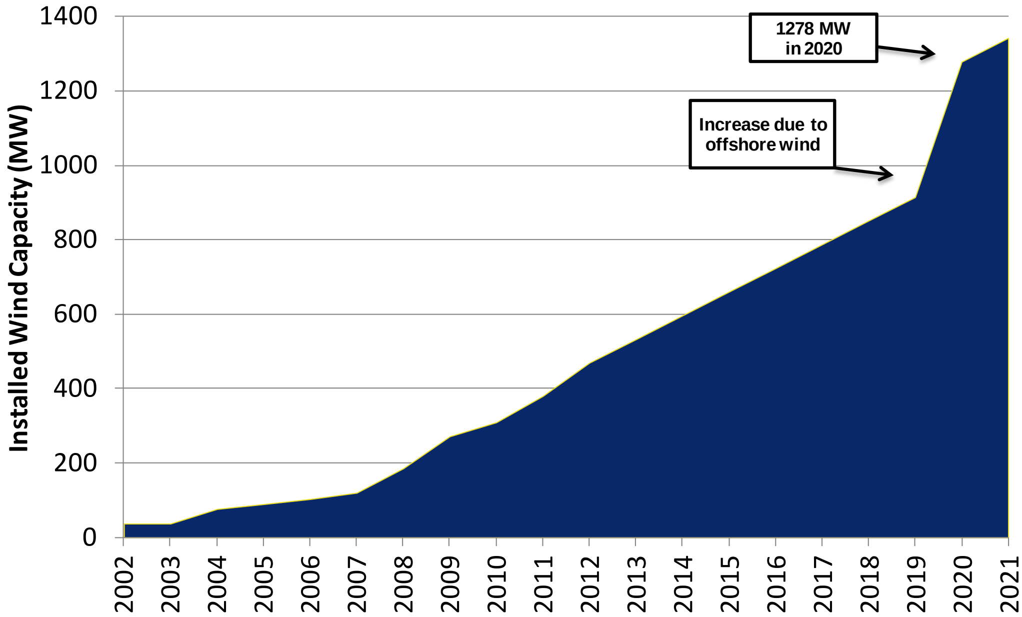

Figure 3-5 Northern Ireland wind levels assumed for this report

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 8.7% by the end of 2009, before falling to 7.2% in 2010, which is generally considered a poor wind year.

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

[45] 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.

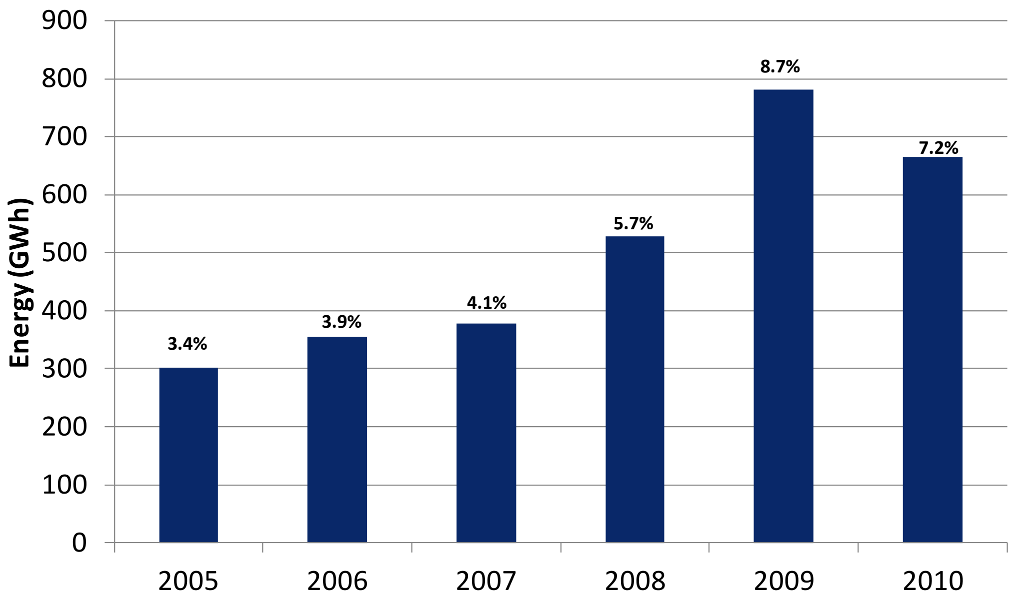

Figure 3-6 Historical wind generation in annual energy terms for Northern Ireland, also given as a percentage of total electrical energy produced that year

Historical capacity factors for Northern Ireland are shown in Figure 3-7. The average wind capacity factor for the last 6 years is 31.5%. Again, it can be seen that in 2010 the wind capacity factor is much lower than in the previous 5 years due to 2010 being a poor wind year.

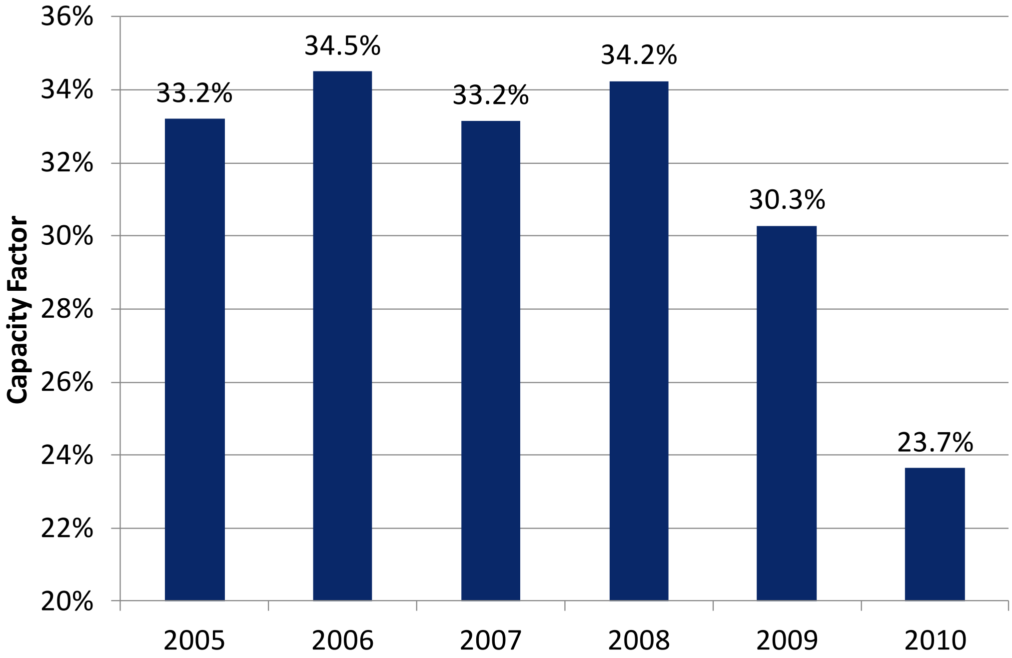

Figure 3-7 Historical wind capacity factors for Northern Ireland

The Strategic Energy Framework for Northern Ireland restated the target of 12% of electricity produced from renewable sources by 2012. This target is achievable, however only if a typical wind year occurs, and with a contribution from other small scale renewable generation sources. The wind capacity factor for 2010 was very low relative to previous years and is the worst year on record. If 2012 experiences the same wind profile as 2010, then this 12% target will not be met. 2011 to date has seen an improvement from 2010. An estimate of the monthly capacity factors for 2011 to the end of October is shown in Figure 3-8.

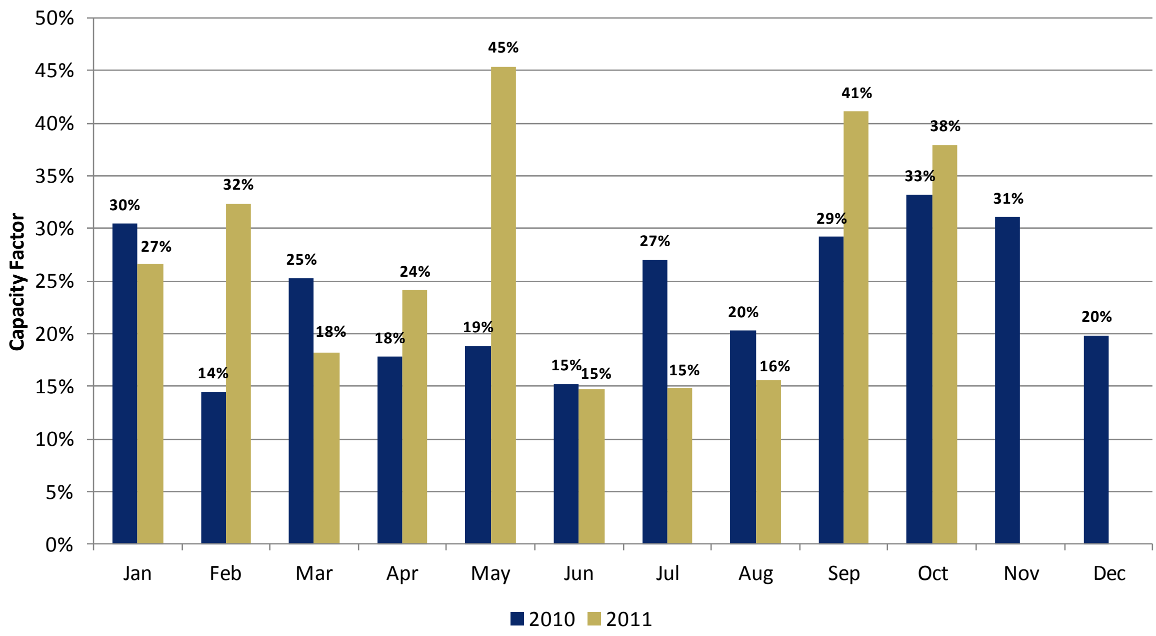

Figure 3-8 Monthly wind capacity factors in Northern Ireland for 2010 and 2011.

3.7(c) 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.

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 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.

It can be seen in Figure 3-9 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.

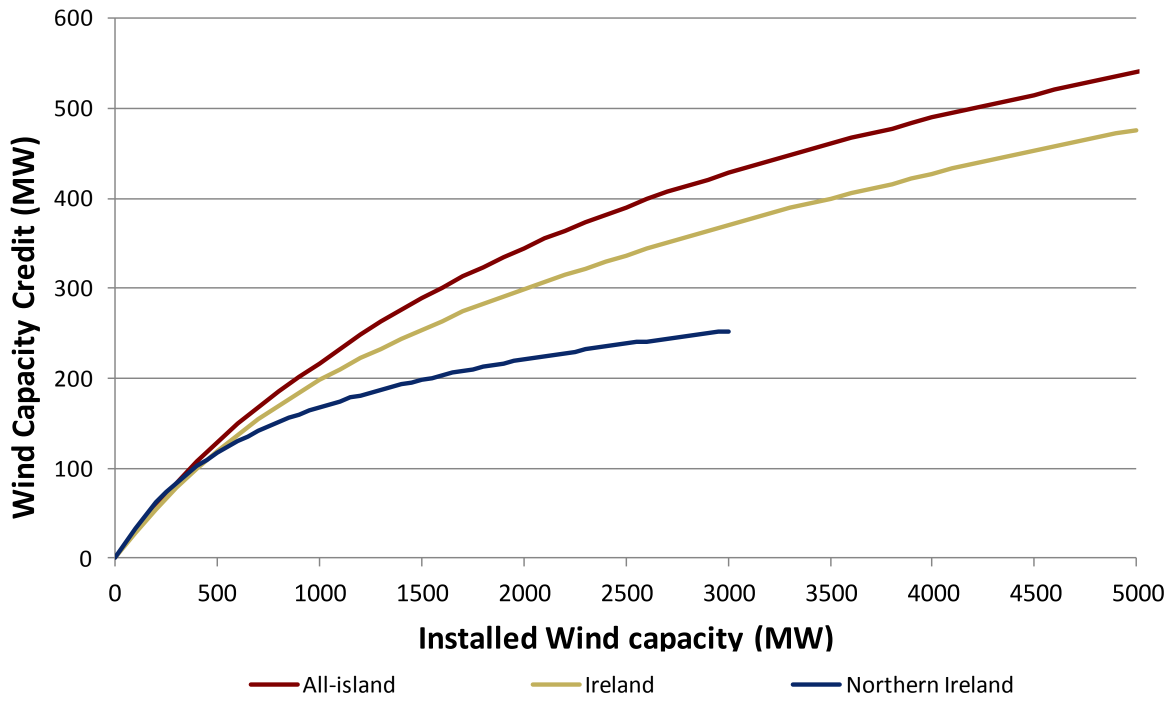

Figure 3-9 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation. For Ireland, the wind profiles were taken from 2009, the most recent, typical year. (2010, was considered a poor year for wind.) The curve for Northern Ireland is based on an average over several years.

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 3-10 Existing and planned wind farms, as of October 2011. 'Planned' refers to wind farms that have signed a connection agreement with EirGrid in Ireland, or that have received planning approval in Northern Ireland.

3.8 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.

3.8(a) Demand-side generation

Industrial generation refers to generation, usually powered by diesel engines, located on industrial or commercial premises, to act 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.

In Northern Ireland, it is assumed that industrial generation has a capacity of 1 MW from 2015, rising to 4 MW in 2021. This is an estimation of the amount of small scale industrial generation that is capable of exporting onto the system.

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. SONI assumptions based on this NIE information estimates circa 118 MW[46] of this small scale generation on the Northern Ireland system. It is assumed that this is used only for self consumption.

A dispatchable Aggregated Generating Unit (AGU) also operates in Northern Ireland which consists of a number of individual diesel generators grouping together to make available their combined capacity to the market. It should be noted that this is an exportable capacity and is not considered as demand side generation in this context.

3.8(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[47] 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 8 MW of small scale CHP connected to the distribution system. Without detailed public information an assumption has been made that for the purposes of this statement, the estimated 8 MW in 2011 will rise to 17 MW by 2021 in Northern Ireland.

Currently CHP is promoted in accordance with the European Directive 2004/8/EC. The Strategic Energy Framework[48] 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.

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

[47] Energy White Paper 2007 'Delivering a Sustainable Energy Future for Ireland', March 2007.

[48] www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf

3.8(c) Biofuel

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

In Ireland, there is currently an estimated 38 MW of landfill gas powered generation. The peat plant at Edenderry aims to power 30% of its output using biomass by 2015. A new incentive (REFIT 3)[49] 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 1.5 MW of small scale biofuels (Biomass & Biogas) and 11 MW of landfill gas powered generation. For the purposes of this report, and in the absence of detailed public information, it has been assumed that by 2021 the small scale biofuels capacity will rise to 2 MW while landfill gas powered generation capacity will reach 25 MW. It should be noted that DETI has recently revised the Northern Ireland Renewable Obligation (NIRO)[50] to increase support to developing technologies such as bioenergy.

For the studies it is also assumed in Northern Ireland that 90 MW of large scale biomass will be commissioned and that this will connect from 2015 onwards at 3 separate sites, each of which will have a capacity of 30 MW. These may be dispatchable due to their size, although at this stage there are no signed agreements or target connection dates in place.

3.8(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 hydro capacity over the remaining years of the study.

3.8(e) Marine Energy

The marine energy assumptions for Ireland are taken from the NREAP report. This assumes that the currently developing technology will be deployed on a commercial basis from 2017, rising to 75 MW in 2020.

In Northern Ireland the Strategic Environmental Assessment (SEA)[51] 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. Therefore, for the purposes of this report SONI have used a conservative assumption for tidal generation of 50 MW by 2020.

3.9 Plant Availability

It is unlikely that all of the generation capacity connected to the system is 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.

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

[50] The Northern Ireland Renewables Obligation (NIRO) is the main support mechanism for encouraging the generation of electricity from renewable energy sources in Northern Ireland. More information is available at http://www.detini.gov.uk/deti-energy-index.htm

[51] 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)

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.

3.9(a) Ireland

Figure 3-11 shows the system-wide forced-outage rates (FOR)[52] 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 two major impact events[53] 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 2012 to 2021. 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.

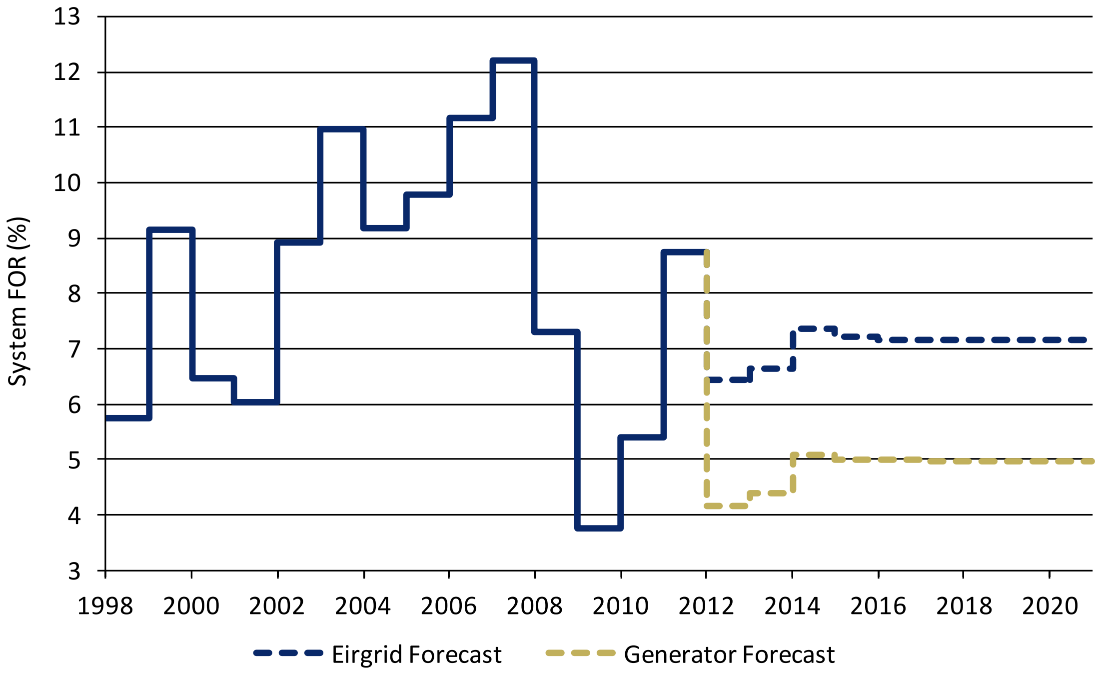

Figure 3-11 Historic and predicted Forced Outage Rates for Ireland. Future rates as predicted by both EirGrid and the generators are shown. Due to its atypical outage rates, Poolbeg Unit 3 has been excluded from historic calculations.

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

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

[53] Both Turlough Hill and North Wall CC are currently experiencing major outages

undergoing such an event at any given time. EirGrid studies[54] 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.

3.9(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.

SONI has concerns that these 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). SONI will continue to monitor the operation of plant and the impact of this on availability.

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

Figure 3-12 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.

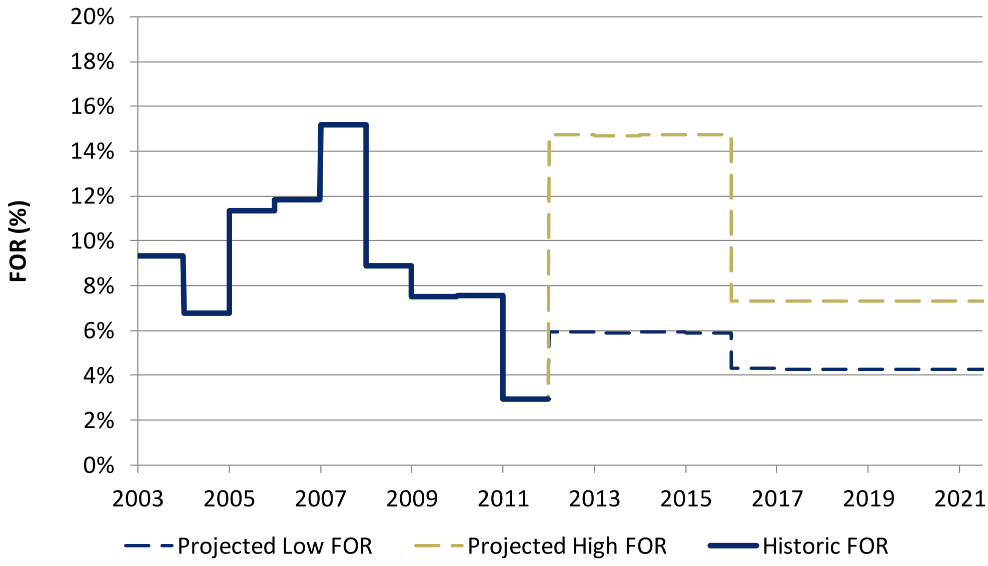

Figure 3-12 Historic and predicted Forced Outage Rates for Northern Ireland (not including the Moyle Interconnector)

[54] see GAR 2009-2015

It is possible to derive availability figures on an overall system basis. This is achieved by calculating the amount of MWh unavailable as a result of FOPs and SODs. The actual availability is the remaining potential MWh available to meet customer demand.

Figure 3-13 shows the historic availabilities in Northern Ireland along with the projected high and low availabilities. The average high availability over the 10-year period is 90.7% and the low availability figure is 85.3%. This analysis is focused on fully dispatchable plant and does not include the Moyle Interconnector.

Historically the availability of Moyle has been much higher than conventional generation. However, at the time of writing this report, the Moyle Interconnector was on a prolonged forced outage due to undersea cable faults on both of its cables. This follows a previous prolonged fault that affected one of the two cables in the last quarter of 2010. Therefore in the adequacy studies carried out for this report, the FOR for the Moyle has been adjusted accordingly to reflect this.

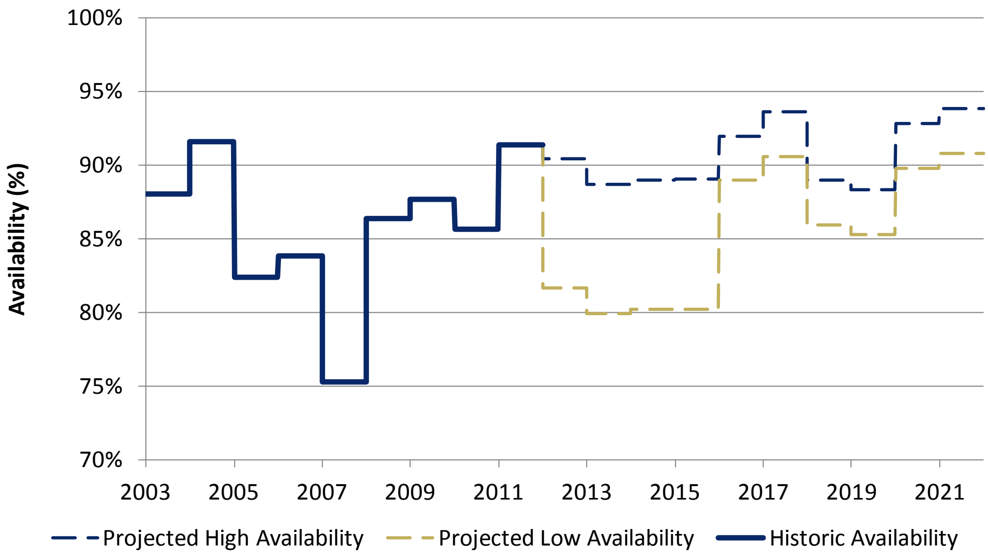

Figure 3-13 Historic and predicted Plant Availabilities in Northern Ireland (without Moyle)

It is necessary to present a range of availability scenarios for the future. The high availability scenario is based on the actual historic 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.

4 GENERATION ADEQUACY ASSESSMENTS

4 GENERATION 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 shown in three ways: on an Ireland, Northern Ireland, and all-island basis. The adequacy position in both jurisdictions improves on completion of the additional North-South tie-line.

All-island studies for the years prior to the commissioning of the additional North-South tie line are shown as dashed lines for illustrative purposes only, i.e. to show what could be the case if the tie line was completed earlier than 2017. Conversely, single area studies (for Ireland or Northern Ireland alone) are dashed lines after 2017, to portray the situation if the additional tie line was delayed.

Different demand growth and plant availability scenarios are examined to illustrate their effect on generation adequacy. Also considered are the effects of the loss of a CCGT in each jurisdiction, the unavailability of interconnector flows between the island of Ireland and Great Britain, and also the loss of aging plant in Ireland. All results are presented in full tabular form in APPENDIX 4.

4.2 Base Case

The results from the base case scenario to 2021 are shown in *Figure 4-1*. The base case assumes median demand growth in both jurisdictions, the EirGrid-calculated availability for the generation portfolio in Ireland, and high availability (based on historic performance) for the Northern Ireland generation portfolio.

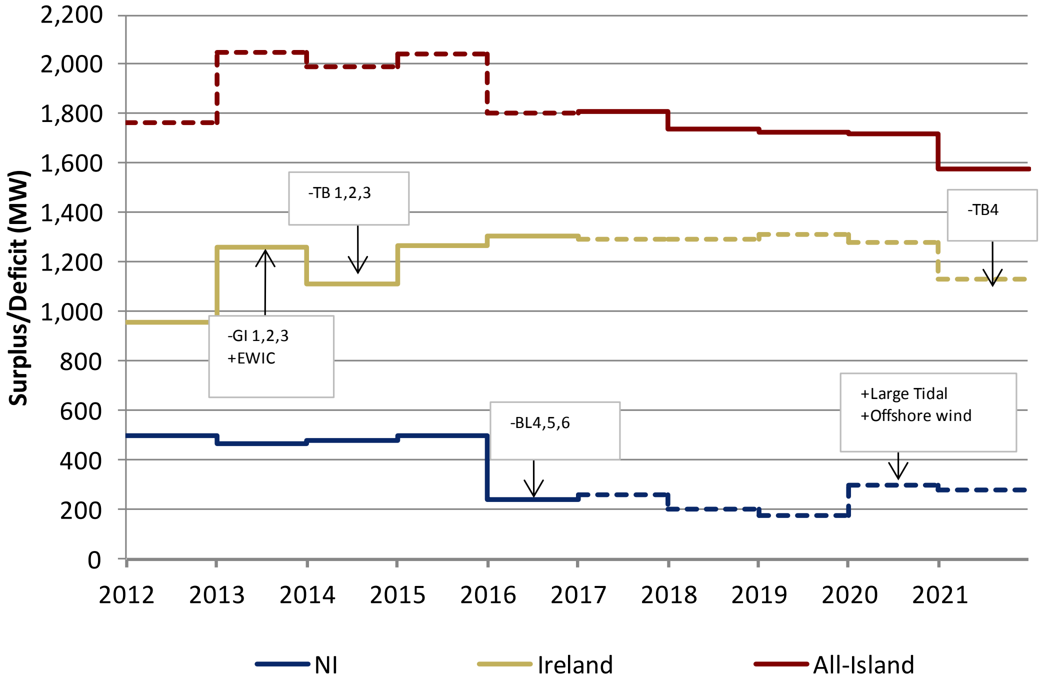

Figure 4-1 Adequacy results for the base case scenario, shown for Ireland, Northern Ireland, and on an all-island basis. Dashed lines convey the results if the additional North-South tie line is completed earlier or later than 2017.

Plant decommissionings and the introduction of the East-West interconnector are indicated. In addition to these, demand growth, plant additions and increased wind penetration will cause shifts from year to year. *Figure 4-1* shows the adequacy results for Ireland, Northern Ireland, and on an all-island basis. As mentioned in Section 3.6(a), single area studies for Ireland include a reliance on Northern Ireland of 200 MW. Similarly, Northern Ireland can rely on Ireland for 100 MW in their single area studies.

Ireland is in surplus for all years in the study. The main drivers for this are reduced demand due to the recession, the addition of new generators, and improved generator availability. The surplus is well over 1200 MW for most years, with the closure of old plant more than compensated for by additional interconnection and new plant.

In Northern Ireland there is a surplus for all years of the study. However, without additional interconnection capacity, surpluses in Northern Ireland are at modest levels of circa 200 MW from 2016 to 2019. This highlights the importance of additional interconnection capacity to enable SONI to maintain generation security standards in Northern Ireland.

All surpluses are enhanced on switching to an all-island system, see red line.

4.3 Impact of Demand Growth

4.3(a) Economic-driven changes to demand growth

Changing demand will have a significant impact on generation adequacy. The effect of a higher demand forecast on the adequacy situation is illustrated in Figure 4-2, with base-case availability (where the EirGrid calculated availability is assumed for the generation portfolio in Ireland, and the high availability for the Northern Ireland generation portfolio).

As expected, the high demand scenario leads to reduced adequacy when compared with the base case. In Ireland, even the high demand scenario consistently shows positive adequacy, with a generation surplus of about 1200 MW.

In the Northern Ireland high demand scenario, the surplus dips to 150 MW in 2016, again highlighting the importance of additional interconnection capacity to enable SONI to maintain generation security standards in Northern Ireland.

For the all-island case, the average difference that the high demand makes is 180 MW.

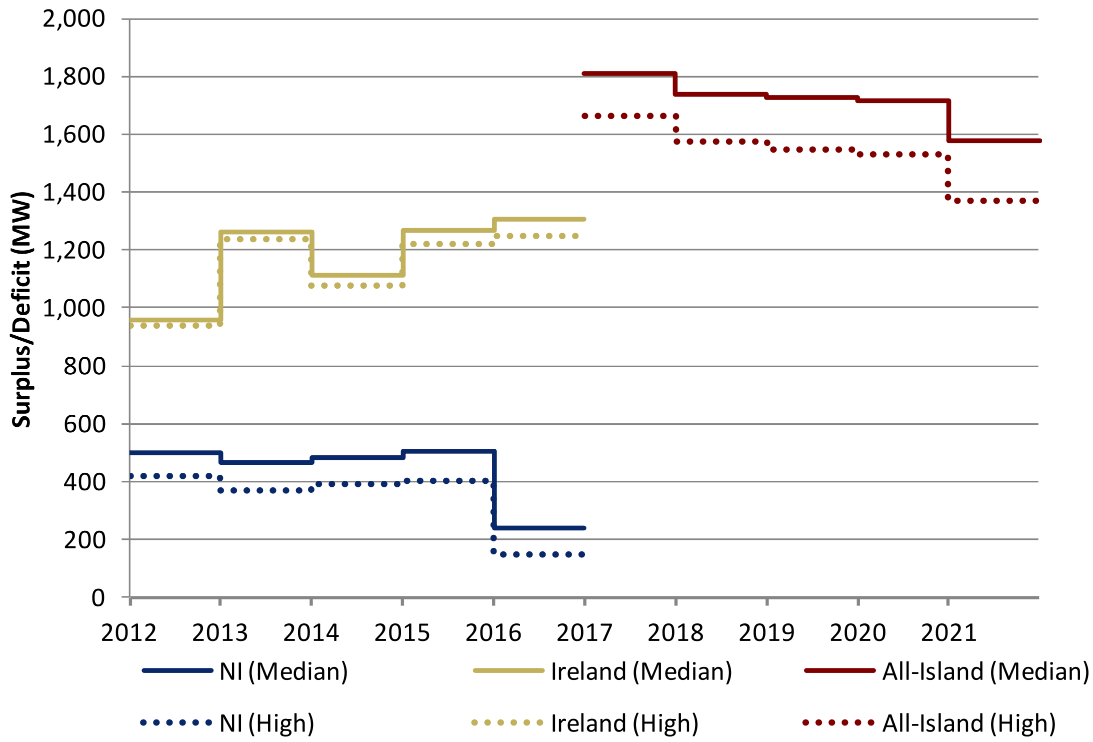

Figure 4-2 The solid lines show the base cases with median demand, while the effect of high demand growth is shown with dotted lines. (All with base-case availability.)

4.3(b) Increase in demand due to a severe winter

Figure 4-3 illustrates the effect of a severe winter, where the demand has been increased in every year. (Not every year is expected to have a severe winter, but the effect is shown for each year individually.) The extra demand models the effect of having the coldest conditions experienced in ten years.

For Ireland, the surplus decreases by an average of 100 MW as compared with the normal median demand scenario.

For Northern Ireland, the One-in-10 winter conditions have a smaller detrimental effect on the adequacy situation, averaging 26 MW.

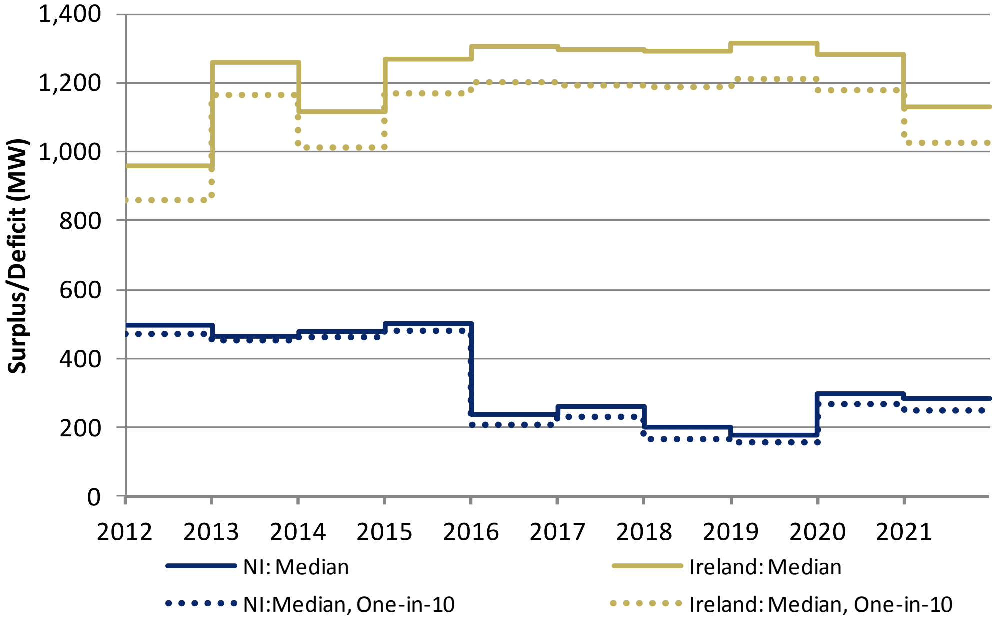

Figure 4-3 The solid lines show the base cases with median demand, while the effect of imposing severe winter conditions (One-in-10 year) on the median demand scenario is shown in dotted lines. (All with base case availability.)

4.4 Availability

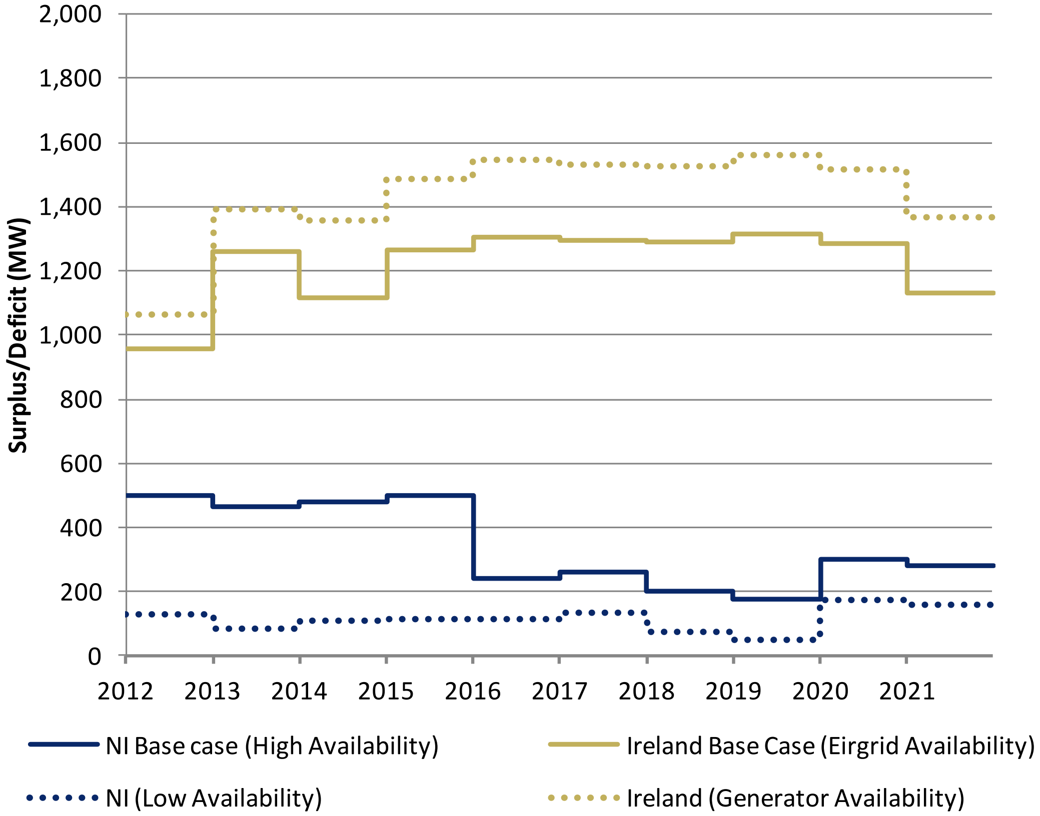

Figure 4-4 Comparison of availability scenarios for Ireland and Northern Ireland

If the Generator's own availability scenario is utilised for Ireland (i.e. if the generator's perform to their own standard rather than a more realistic outcome as estimated by Eirgrid), then Figure 4-4 shows that the increase in the surplus is of the order of 200 MW.

The impact of plant availability for Northern Ireland is also shown in Figure 4-4. For the first four years of the study, the difference between the surplus for the high and low availability cases is circa 400 MW, as shown. This difference reduces from 2016 onwards due to the methodology used to determine the low availability case in Northern Ireland.

In the low availability case, all units are given the same availability as the worst performing unit on the system at any one time. Units may be added or removed each year, which may change the availability which is applied to all units, as the unit that is added or removed may be the worst performing unit. Thus, in the low availability scenario, the drop in surplus from 2015 to 2016 is not as noticeable as it is in the base case.

4.5 Loss of a CCGT in each Jurisdiction

In order to run a stable and secure power, it is prudent to examine the effect of major events which could have serious consequences to electricity supply. A scenario has been considered where a major combined cycle generator is out of action in both Northern Ireland and Ireland. To see how the systems would cope under major stress, this scenario was run with high demand and low availability.

Because of the large amount of other plant available, Ireland remains in surplus in this situation.

However, with this onerous scenario, Northern Ireland is in a deficit situation for all years, see Figure 4-5. This analysis highlights the importance of the additional North-South tie-line capacity (and/or additional conventional generation capacity) to enable SONI to maintain generation security standards in Northern Ireland. It should be noted that if the additional North-South tie-line should not be in place until 2017, then this situation would leave Northern Ireland below the 4.9 hours/year LOLE standard and in a capacity deficit under this scenario.

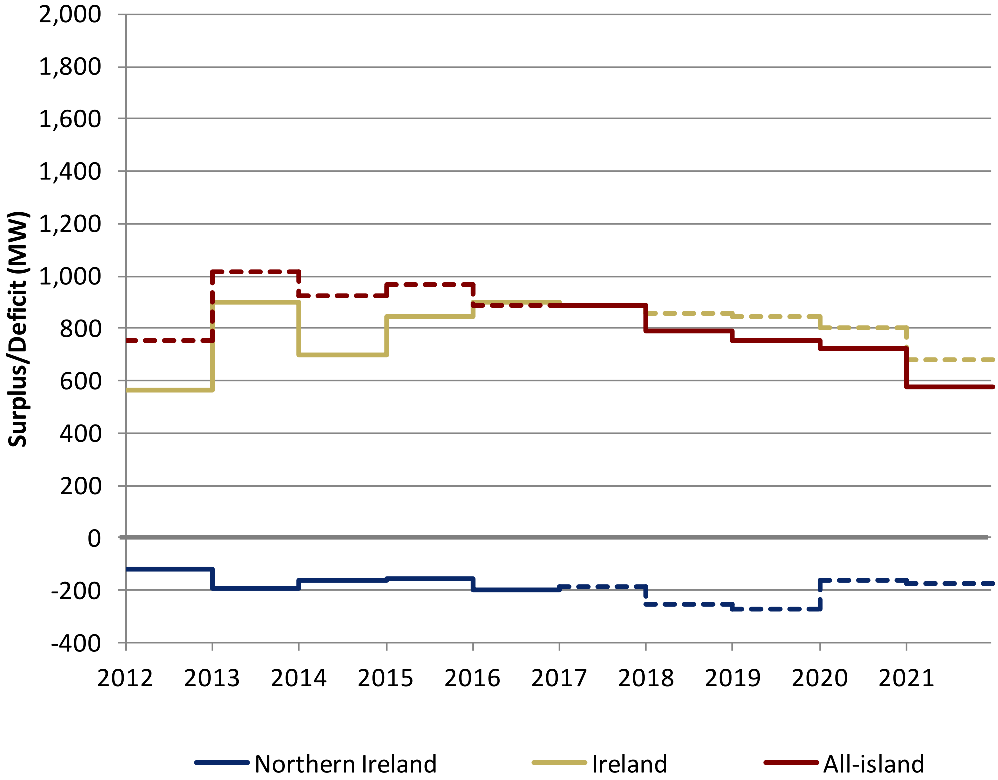

Figure 4-5 This shows the loss of two CCGTs for the high demand scenario and low availability. Dashed lines convey the results if the additional North-South tie line is completed earlier or later than 2017.

4.6 Loss of Interconnection with Great Britain

Due to the recent long-term forced outage on the Moyle interconnector, it was thought prudent to examine a situation where both undersea interconnectors with Great Britain (Moyle and the East-West) are unavailable. Figure 4-6 shows how the surplus reduces dramatically from the base case scenarios. In particular, Northern Ireland would be in deficit from 2016. This again shows the importance of the planned extra North-South tie-line to enable SONI to maintain generation security standards in Northern Ireland.

This study also highlights the implications if energy is unavailable to import from Great Britain to either Ireland via EWIC or Northern Ireland via Moyle due to any capacity shortfall or market conditions that may occur in GB. However, as discussed in Section 3.6, National Grid's current Seven Year Statement treats both the EWIC and Moyle as negative generation even at peak demand times. Even when the interconnectors are treated this way by National Grid in their studies, their plant margins are still within acceptable standards.

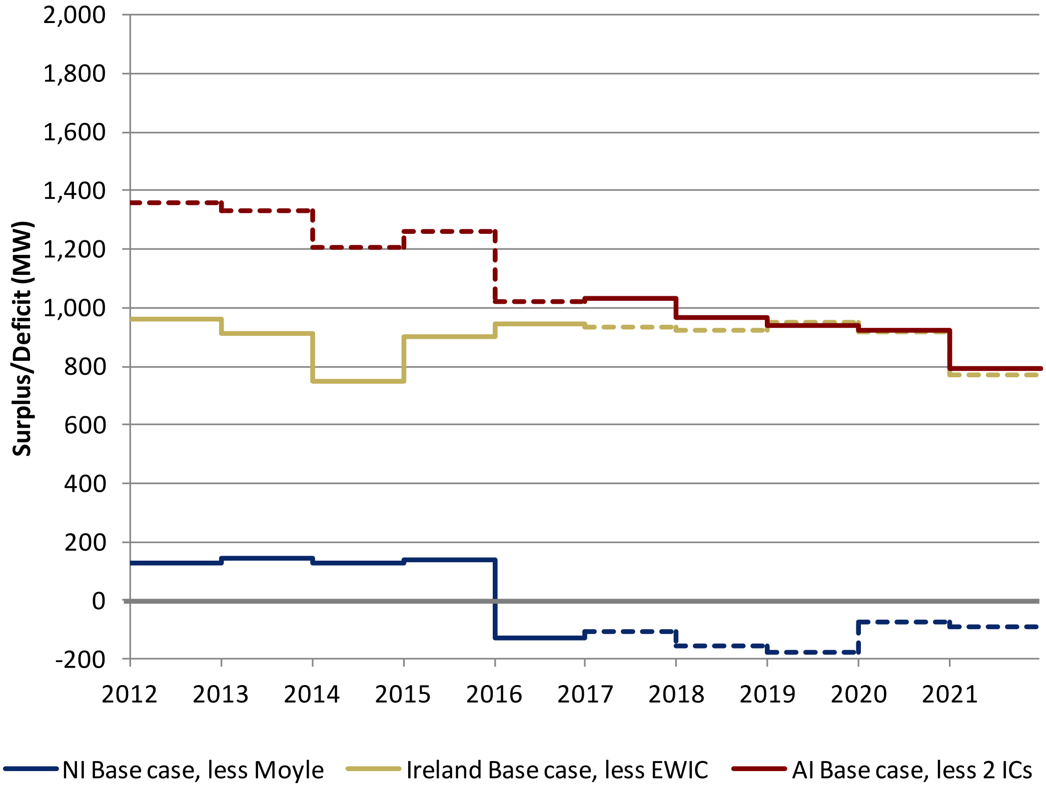

Figure 4-6 The effect of losing the benefit of the 2 undersea interconnectors from the Base Cases

4.7 Closure of old plant in Ireland

The introduction of European legislation[55] means that generators must adhere to strict emission limits. Recently, further legislation[56] has made these emission limits even more stringent. Ireland has a National Emissions Reduction Plan which controls the maximum emissions from older generators until

[55] Large Combustion Plant Directive, see http://europa.eu/legislation_summaries/environment/air_pollution/l28028_en.htm

[56] Industrial Emissions Directive, see http://europa.eu/rapid/pressReleasesAction.do?reference=IP/07/1985&format=HTML&aged=0&language=EN&guiLanguage=en

2016. After this, some of these generators must either be improved to reduce their emissions, or shut down.

A scenario has been developed in which these older generators are phased out of commission in a gradual fashion. While EirGrid has not been notified of any plant decommissionings other than those listed in Table 3-3, it must prepare against uncertainties which may have severe consequences on security of supply. For this scenario, EirGrid has therefore made its own best estimation on which generators to phase out and when.

In addition, the Public Service Obligation levy that benefitted the peat-burning units will start to cease to be effective from 2016, and so this scenario includes their shutdown.

In Northern Ireland, plant is covered under the UK's National Emissions Reduction Plan which forms part of the Large Combustion Plants Directive (2001/80/EC). It is expected that this will not require any upgrades or closures of existing plant within the time period covered by this report, apart from Ballylumford Units ST4, ST5 and ST6 as mentioned in section 3.5(b). The baseline scenario has therefore been used for Northern Ireland.

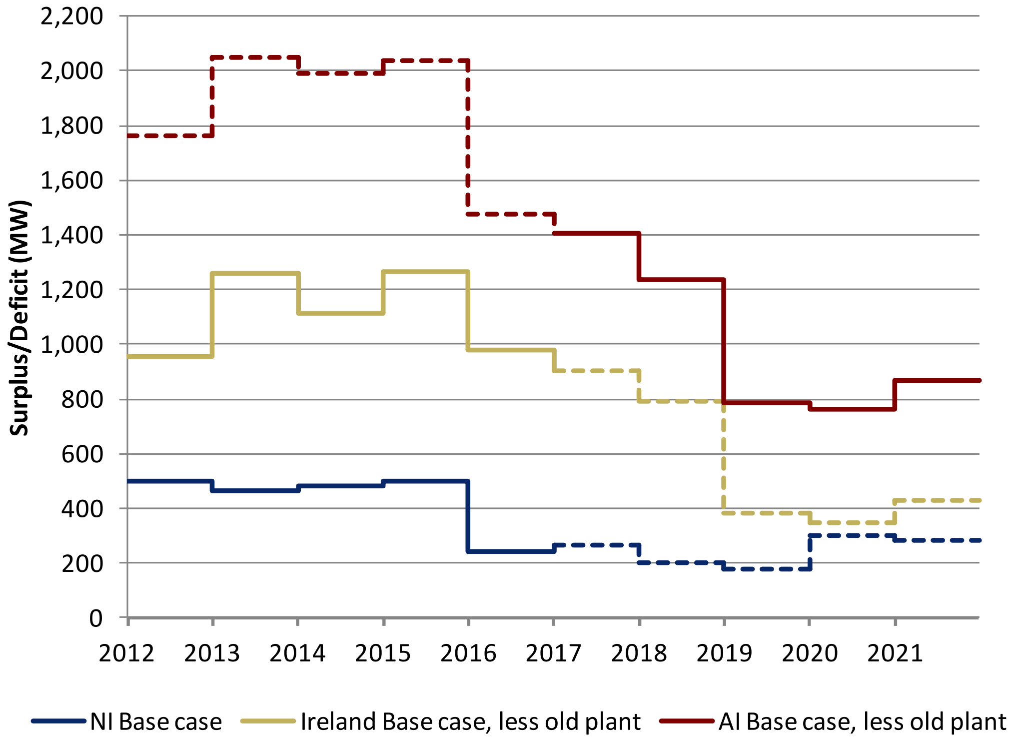

Figure 4-7 Median demand, base-case availability, with older plant removed.

With the loss of plant, the surplus for Ireland drops dramatically but to manageable levels of approximately 400 MW by 2019, as shown in Figure 4-7 for the base-case demand and availability.

5 DELIVERING A SECURE SUSTAINABLE ELECTRICITY SYSTEM (DS3)

5 DELIVERING A SECURE SUSTAINABLE ELECTRICITY SYSTEM (DS3)

5.1 Background

As previously stated in Chapter 3, both governments in Ireland and Northern Ireland have set the challenging target of 40% electricity consumption to be generated from renewable sources by 2020. On the basis of current demand forecasts[57] this equates to approximately 16,500 GWh an all-island basis by 2020. Along with other renewable generators, the installed wind capacity will need to rise to between 4,800 to 5,300 MW to meet these targets. This level of wind power plant penetration is unprecedented in a single system (see Figure 5-1) and poses significant challenges to the real-time operation of the power system.

EirGrid and SONI have carried out pioneering studies over the past number of years to better understand the changing behaviour of the power system and examine the technical challenges with integrating significant volumes of wind power generation. The results of these studies can be found in the 'Facilitation of Renewables'[58] and 'Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment'[59] reports. The key message from these studies is that the 2020 renewables targets are achievable; however, significant challenges to the operation of the system will have to be overcome.

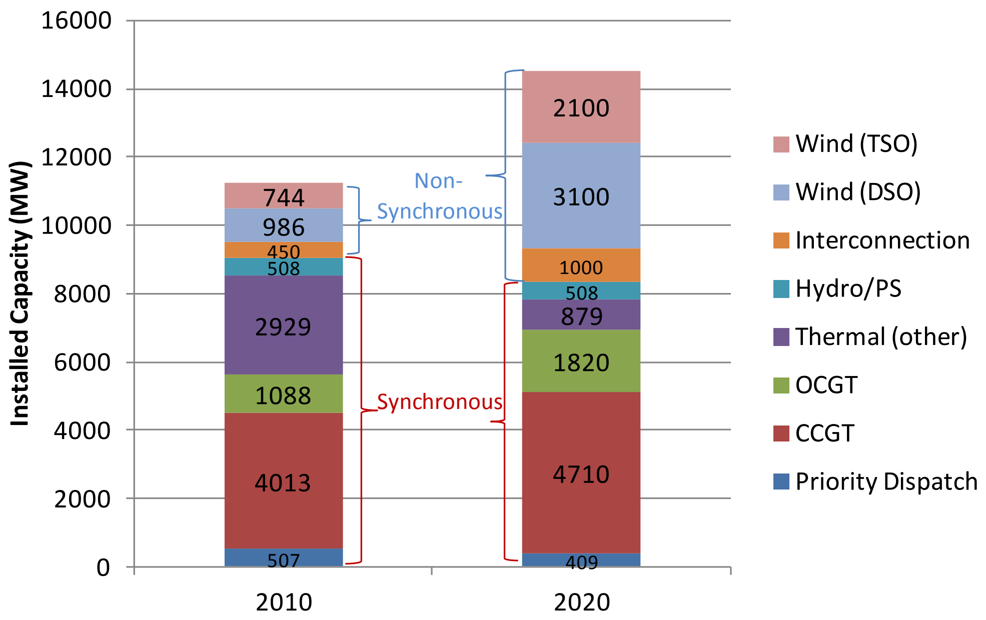

Figure 5-1 All-Island portfolio breakdown by generation type - 2010 and 2020

[57] See the All-Island TER in Table A-1
[58] http://www.eirgrid.com/media/FacilitationRenewablesFinalStudyReport.pdf
[59] http://www.eirgrid.com/media/Ensuring_a_Secure_Reliable_and_Efficient_Power_System_Report.pdf

In particular, the 'Facilitation of Renewables' studies showed that it is possible today to securely operate the power system with up to 50% of generation coming from non-synchronous sources (essentially HVDC imports and wind generation) [Green Zone - Figure 5-2]. In addition, the studies indicated that it was possible to operate the system with up to 75% of non-synchronous generation [Amber Zone -Figure 5-2] but mitigating actions would be required to resolve a number of technical challenges. The studies indicated that secure operation beyond a 75% level of non-synchronous generation was not possible given the capabilities of known technology.

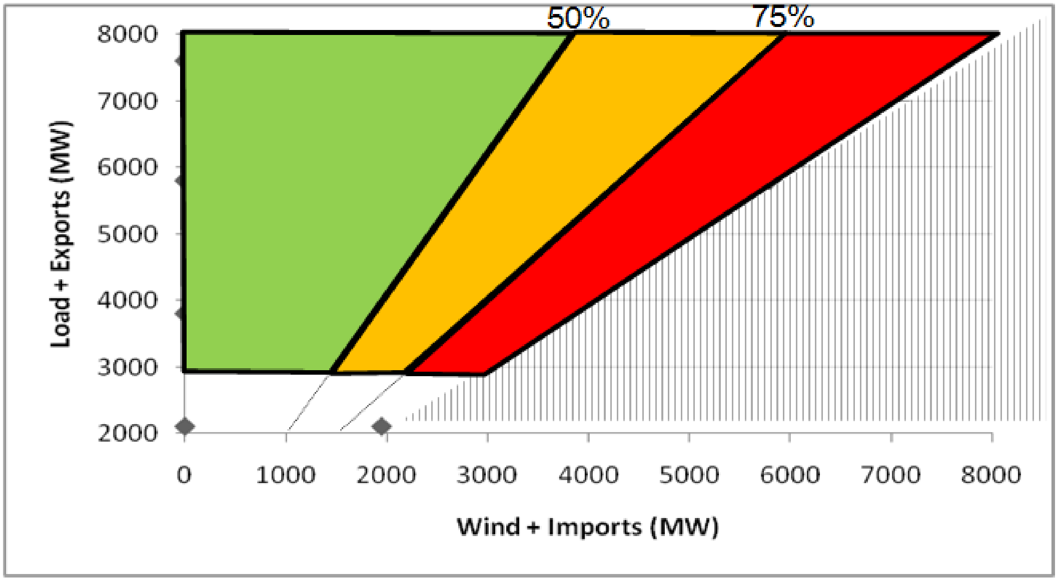

Figure 5-2 Zones in the Ireland and Northern Ireland Power System ('Facilitation of Renewables' studies, 2010)

An all-island programme of work entitled 'Delivering a Secure Sustainable Electricity System (DS3)' has been developed by EirGrid and SONI to resolve the technical challenges associated with having up to 75% of generation from non-synchronous sources. This is in order to ensure a secure, efficient and reliable power system which meets both Governments' targets of 40% electricity consumption from renewable sources by 2020.

5.2 Programme Objectives

The key objectives of the all-island DS3 programme are as follows:

- to ensure continued security of supply on the island in the context of a changing plant portfolio.
- to assist in the delivery of the 2020 renewable policy targets set out in the Renewables Directive 2009/29/EC and detailed in legislation by minimising curtailment of renewable generation.

There are three main work areas within the programme:

1. System Performance and Incentivisation: Identifying and incentivising the necessary system portfolio capability and performance required to operate a secure power system with increasing penetration of renewables. This includes enhancing existing performance monitoring processes, ensuring Grid Code compliance and reviewing system services arrangements.

2. System Operational Policies: The development and updating of the necessary operational policies to ensure system security primarily in respect of frequency and voltage over various time periods, including but not limited to operating reserves, ramping services, management of uncertainty and TSO-DSO voltage co-ordination.

3. System Tools: The design, development and implementation of enhanced system tools in order to manage the increased operational complexity and provide decision support tools consistent with the changing needs of the power system.

5.3 Programme Workstreams

In order to achieve the deliverables in the DS3 programme, the programme is further broken down into eleven workstreams; Frequency Control, Voltage Control, System Services Review, Demand Side Management (DSM), Grid Code, Performance Monitoring, Rate of Change of Frequency (RoCoF), Model Development & System Studies, Renewable Data, Wind Security Assessment Tool (WSAT) and Control Centre Tools & Capabilities.

From an industry perspective, the three most pertinent workstreams are:

System Services Review: The changing nature of the power system due to increasing renewable penetration has significant implications for the needs of the power system, particularly in respect of system services. A comprehensive review of system services is now required. This review will include:

- an identification of system needs – now and projected for the future
- a review of the effectiveness of existing services and payment structures
- the potential development of new services and new/revised payment structures to foster a continued focus on performance and where appropriate to drive investment

A multi-stage consultation process approach is proposed. The initial consultation will be high level and seek views from the industry on the scope of the review, the structures for system services, eligibility considerations, the contractual arrangements and the degree of interaction with the other components of the wholesale market.

Demand-Side Management (DSM): There is provision within the SEM for demand side participation in the form of Demand Side Units (DSUs) and Aggregator Generator Units (AGUs). Units like these could assist with the operational integration of renewable generation by providing system services. The regulatory authorities have undertaken a programme of work to develop a Strategic Demand Response Programme for the island of Ireland. In this regard, a Decision Paper entitled 'Demand Side Vision for 2020'[60] was published in May 2011. Key areas of work within this workstream include the Grid Code, System Services, Contracts & Licensing and overall readiness for the efficient operation of such units.

Grid Code: The Grid Codes set the (minimum) standards relating to the operation and use of the Transmission System for plant or apparatus connected to the Transmission or Distribution Systems. Recent technical studies carried out by EirGrid and its consultants have shown that very high wind penetrations will necessitate further Grid Code changes to ensure system stability. These changes form a key part of the DS3 programme. The modifications to the Grid and Distribution Codes will include wind farm performance standards, RoCoF standards, demand side management and new technologies.

5.4 Wind Farm Performance

The 'Facilitation of Renewables' studies indicated that at high system non-synchronous penetration levels the transient stability of the system will be significantly compromised (Figure 5-3). This arises

[60] http://www.cer.ie/GetAttachment.aspx?id=5c03dac7-a347-44e9-b4da-978b30e8de35

since, with fewer on-line synchronous generating units, there is a reduction in synchronising torque (the forces that keep generators operating in unison). As the instantaneous penetration of wind increases relative to system demand (plus exports), the percentage of contingencies with a critical clearance time (CCT) less than 200ms increases. Since critical clearance time is a measure of the transient stability of the system (with higher CCT denoting greater stability), this means that the system becomes less transiently stable at high wind penetration relative to system demand.

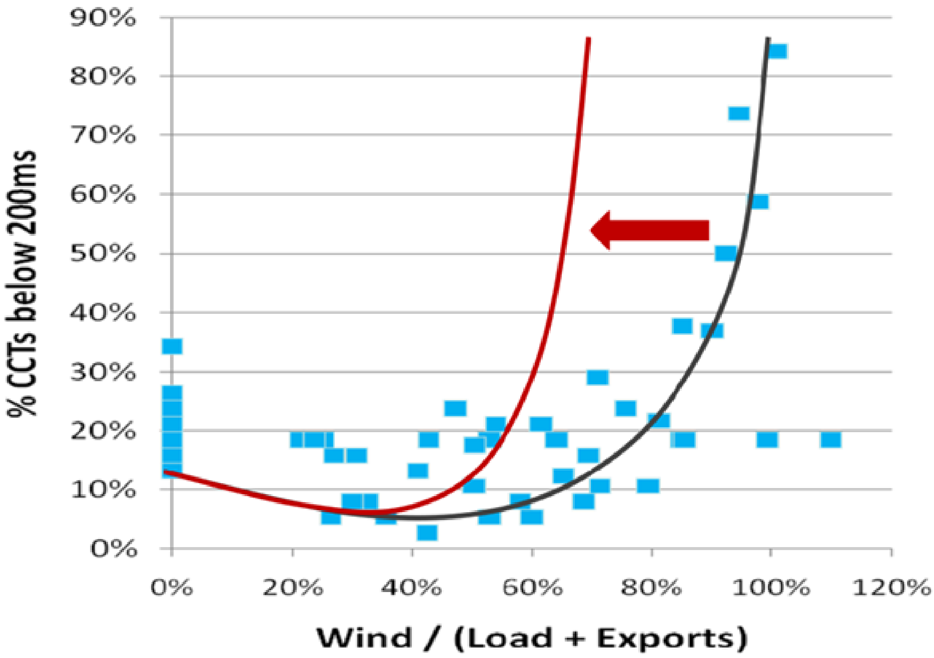

Figure 5-3 Percentage of contingencies causing Critical Clearance Times (CCT) lower than 200ms vs SNSP ('Facilitation of Renewables', 2010). Potential impact (red curve) on transient stability if wind farms' dynamic reactive power capability is not clarified in the Grid Code

Provision of dynamic reactive power in a measured fashion from network devices (e.g. wind farms) during voltage disturbances could be used to mitigate many, if not all, of these issues. These mitigation strategies rely on wind farms and other devices being able to provide significant reactive current during voltage disturbances. Currently it is not clear from the Grid Code exactly what capability is required. This is one of the issues the Grid Code workstream will tackle.

5.5 Stakeholder Engagement

The broad nature and strategic importance of this work means that input and engagement is needed from all relevant industry stakeholders and EirGrid and SONI are working to facilitate open communication and co-ordination at all stages of this process. An Advisory Council has been established to ensure that the views of industry are represented. The purpose of the Advisory Council is to provide a forum to discuss stakeholder views and concerns on those issues which may impact on the implementation of the programme.

To ensure the successful delivery of the DS3 programme, CER, the Utility Regulator NI, EirGrid and SONI will work closely together. The objective of all parties is to ensure that the 2020 40% renewable policy targets are delivered in a cost efficient manner without adversely affecting security of supply of the all-island power system. Further information on the DS3 programme can be found at www.eirgrid.com/renewables.

APPENDICES

APPENDIX 1 DEMAND FORECAST

Median	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2011	27,096	-2.0	9,268	Δ%	36,363	Δ%	4,736	Δ%	1,805	Δ%	6,504	Δ%	4,626	Δ%	1,715	Δ%	6,304	Δ%
2012	27,336	0.9	9,360	1.0	36,696	0.9	4,771	0.7	1,822	1.0	6,556	0.8	4,653	0.6	1,731	1.0	6,348	0.7
2013	27,846	1.9	9,476	1.2	37,323	1.7	4,850	1.7	1,844	1.2	6,657	1.5	4,726	1.6	1,753	1.2	6,441	1.5
2014	28,359	1.8	9,617	1.5	37,977	1.8	4,931	1.7	1,871	1.4	6,763	1.6	4,799	1.5	1,779	1.5	6,540	1.5
2015	28,819	1.6	9,760	1.5	38,579	1.6	5,002	1.5	1,898	1.5	6,861	1.5	4,863	1.3	1,806	1.5	6,630	1.4
2016	29,219	1.4	9,906	1.5	39,125	1.4	5,064	1.2	1,925	1.5	6,950	1.3	4,918	1.1	1,833	1.5	6,711	1.2
2017	29,536	1.1	10,053	1.5	39,589	1.2	5,113	1.0	1,953	1.5	7,027	1.1	4,959	0.8	1,861	1.5	6,780	1.0
2018	29,859	1.1	10,203	1.5	40,061	1.2	5,163	1.0	1,982	1.5	7,105	1.1	5,002	0.9	1,889	1.5	6,851	1.0
2019	30,186	1.1	10,354	1.5	40,541	1.2	5,214	1.0	2,011	1.5	7,184	1.1	5,046	0.9	1,917	1.5	6,922	1.0
2020	30,668	1.6	10,508	1.5	41,176	1.6	5,290	1.4	2,040	1.5	7,288	1.5	5,114	1.4	1,946	1.5	7,019	1.4
2021	31,222	1.8	10,665	1.5	41,887	1.7	5,370	1.5	2,070	1.5	7,398	1.5	5,194	1.6	1,976	1.5	7,128	1.6

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

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	
2011	27,096	-2.0	8,960	Δ%	36,055	Δ%	4,736	Δ%	1,787	Δ%	6,486	Δ%	4,626	Δ%	1,697	Δ%	6,286	Δ%
2012	27,295	0.7	9,023	0.7	36,318	0.7	4,764	0.6	1,786	-0.1	6,513	0.4	4,647	0.4	1,695	-0.1	6,305	0.3
2013	27,764	1.7	9,104	0.9	36,868	1.5	4,835	1.5	1,792	0.4	6,590	1.2	4,711	1.4	1,701	0.4	6,374	1.1
2014	28,234	1.7	9,204	1.1	37,438	1.5	4,907	1.5	1,806	0.8	6,676	1.3	4,775	1.4	1,715	0.8	6,452	1.2
2015	28,649	1.5	9,323	1.3	37,972	1.4	4,970	1.3	1,829	1.3	6,761	1.3	4,831	1.2	1,737	1.3	6,530	1.2
2016	29,018	1.3	9,443	1.3	38,462	1.3	5,026	1.1	1,852	1.3	6,840	1.2	4,880	1.0	1,760	1.3	6,601	1.1
2017	29,304	1.0	9,566	1.3	38,870	1.1	5,069	0.9	1,875	1.3	6,906	1.0	4,916	0.7	1,783	1.3	6,659	0.9
2018	29,595	1.0	9,689	1.3	39,284	1.1	5,114	0.9	1,899	1.3	6,973	1.0	4,952	0.7	1,806	1.3	6,719	0.9
2019	29,890	1.0	9,814	1.3	39,704	1.1	5,158	0.9	1,923	1.3	7,041	1.0	4,990	0.8	1,829	1.3	6,779	0.9
2020	30,337	1.5	9,941	1.3	40,278	1.4	5,227	1.3	1,947	1.3	7,134	1.3	5,051	1.2	1,853	1.3	6,864	1.3
2021	30,855	1.7	10,070	1.3	40,925	1.6	5,300	1.4	1,971	1.3	7,230	1.4	5,124	1.4	1,877	1.3	6,960	1.4

Table A-2 Low Electricity Demand forecast

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	
2011	27,165	Δ%	9,604	Δ%	36,768	Δ%	4,747	Δ%	1,823	Δ%	6,533	Δ%	4,637	Δ%	1,732	Δ%	6,332	Δ%
2012	27,473	1.1	9,728	1.3	37,201	1.2	4,792	1.0	1,851	1.5	6,606	1.1	4,675	0.8	1,760	1.6	6,398	1.0
2013	28,055	2.1	9,891	1.7	37,946	2.0	4,882	1.9	1,881	1.6	6,725	1.8	4,757	1.8	1,790	1.7	6,509	1.7
2014	28,642	2.1	10,058	1.7	38,700	2.0	4,972	1.8	1,912	1.6	6,845	1.8	4,840	1.7	1,821	1.7	6,622	1.7
2015	29,178	1.9	10,227	1.7	39,405	1.8	5,054	1.7	1,944	1.7	6,958	1.7	4,915	1.6	1,852	1.7	6,728	1.6
2016	29,656	1.6	10,399	1.7	40,055	1.7	5,127	1.4	1,976	1.7	7,063	1.5	4,981	1.3	1,884	1.7	6,824	1.4
2017	30,052	1.3	10,574	1.7	40,626	1.4	5,187	1.2	2,009	1.7	7,155	1.3	5,034	1.1	1,916	1.7	6,909	1.2
2018	30,456	1.3	10,752	1.7	41,208	1.4	5,249	1.2	2,042	1.7	7,250	1.3	5,088	1.1	1,949	1.7	6,996	1.3
2019	30,866	1.3	10,933	1.7	41,799	1.4	5,312	1.2	2,076	1.7	7,346	1.3	5,143	1.1	1,982	1.7	7,084	1.3
2020	31,435	1.8	11,118	1.7	42,553	1.8	5,400	1.7	2,110	1.7	7,467	1.7	5,224	1.6	2,016	1.7	7,198	1.6
2021	32,082	2.1	11,305	1.7	43,387	2.0	5,492	1.7	2,145	1.7	7,594	1.7	5,316	1.8	2,051	1.7	7,324	1.8

Table A-3 High Electricity Demand forecast

MEDIAN, One-in-10	TER Peak (MW)	
Year	Ireland	N Ireland
2011	4,901	1,870
2012	4,936	1,887
2013	5,016	1,909
2014	5,096	1,936
2015	5,168	1,963
2016	5,230	1,990
2017	5,279	2,018
2018	5,329	2,047
2019	5,380	2,076
2020	5,455	2,105
2021	5,535	2,135

Table A-4 Median Electricity Demand forecast, with one-in-10 year weather conditions.

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

APPENDIX 2 GENERATION PLANT INFORMATION

Year end:	ID	Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Aghada	AD1	Gas	258	258	258	258	258	258	258	258	258	258
	AT1	Gas/DO	90	90	90	90	90	90	90	90	90	90
	AT2	Gas/DO	90	90	90	90	90	90	90	90	90	90
	AT4	Gas/DO	90	90	90	90	90	90	90	90	90	90
	ADC	Gas/DO	432	432	432	432	432	432	432	432	432	432
Dublin Bay	DB1	Gas/DO	403	401	399	402	400	398	401	399	397	400
Edenderry	ED1	Milled peat/biomass	118	118	118	118	118	118	118	118	118	118
Edenderry OCGT	ED3,5	DO	116	116	116	116	116	116	116	116	116	116
Great Island	GI1	HFO	54	0	0	0	0	0	0	0	0	0
	GI2	HFO	49	0	0	0	0	0	0	0	0	0
	GI3	HFO	109	0	0	0	0	0	0	0	0	0
Huntstown	HN1	Gas/DO	341	341	340	340	339	339	338	338	337	337
	HN2	Gas/DO	399	399	398	398	397	397	396	396	395	395
Indaver Waste	IW1	Waste	15	15	15	15	15	15	15	15	15	15
Lough Ree	LR4	Peat	91	91	91	91	91	91	91	91	91	91
Marina CC	MRT	Gas/DO	85	85	85	85	85	85	85	85	85	85
Moneypoint	MP1	Coal/HFO	282	282	282	282	282	282	282	282	282	282
	MP2	Coal/HFO	283	283	283	283	283	283	283	283	283	283
	MP3	Coal/HFO	282	282	282	282	282	282	282	282	282	282
North Wall CT	NW5	Gas/DO	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
Rhode	RP1	DO	52	52	52	52	52	52	52	52	52	52
	RP2	DO	52	52	52	52	52	52	52	52	52	52
Sealrock	SK3	Gas/DO	80	80	80	80	80	80	80	80	80	80
	SK4	Gas/DO	81	81	81	81	81	81	81	81	81	81
Tarbert	TB1	HFO	54	54	0	0	0	0	0	0	0	0
	TB2	HFO	54	54	0	0	0	0	0	0	0	0
	TB3	HFO	243	243	0	0	0	0	0	0	0	0
	TB4	HFO	243	243	243	243	243	243	243	243	243	0
Tawnaghmore	TP1	DO	52	52	52	52	52	52	52	52	52	52
	TP3	DO	52	52	52	52	52	52	52	52	52	52
Tynagh	TY1	Gas/DO	384	384	384	384	384	384	384	384	384	384
West Offaly	WO4	Peat	137	137	137	137	137	137	137	137	137	137
Whitegate	WG1	Gas/DO	439	438	437	436	435	435	438	437	436	435
Ardnacrusha	AA1-4	Hydro	86	86	86	86	86	86	86	86	86	86
Erne 1	ER1-4	Hydro	65	65	65	65	65	65	65	65	65	65
Lee	LE1-3	Hydro	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
Turlough Hill	TH1-4	Pumped storage	292	292	292	292	292	292	292	292	292	292
EWIC		DC Interconnector		440	440	440	440	440	440	440	440	440
*Extra planned generation**				*459*	*674*	*772*	*870*	*870*	*870*	*870*	*870*	*870*
		Total Dispatchable	**6585**	**7269**	**7128**	**7228**	**7321**	**7319**	**7323**	**7320**	**7315**	**7074**
		Year end:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

Table A-5 Dispatchable generation capacity in Ireland. HFO: Heavy Fuel Oil; DO: Distillate Oil.
**Note- The figures for planned generation are based on assumptions derived from generator information, and do not constitute Eirgrid's formal acceptance of commissioning dates. Some plant capacities include minor degradation over the years.*

Year End:		Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Ballylumford	ST4	Gas* / Heavy Fuel Oil	170	170	170	170	-	-	-	-	-	-
	ST5	Gas* / Heavy Fuel Oil	170	170	170	170	-	-	-	-	-	-
	ST6	Gas* / Heavy Fuel Oil	170	170	170	170	-	-	-	-	-	-
	B10	Gas* / Distillate Oil	97	97	97	97	97	97	97	97	97	97
	B31	Gas* / Distillate Oil	245	245	245	245	245	245	245	245	245	245
	B32	Gas* / Distillate Oil	245	245	245	245	245	245	245	245	245	245
	GT7 (GT1)	Distillate Oil	58	58	58	58	58	58	58	58	58	58
	GT8 (GT2)	Distillate Oil	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
	ST2	Heavy Fuel Oil* / Coal	238	238	238	238	238	238	238	238	238	238
	KGT1	Distillate Oil	29	29	29	29	29	29	29	29	29	29
	KGT2	Distillate Oil	29	29	29	29	29	29	29	29	29	29
	KGT3	Distillate Oil	42	42	42	42	42	42	42	42	42	42
	KGT4	Distillate Oil	42	42	42	42	42	42	42	42	42	42
Coolkeeragh	GT8	Distillate Oil	53	53	53	53	53	53	53	53	53	53
	C30	Gas* / Distillate Oil	402	402	402	402	402	402	402	402	402	402
Moyle Interconnector	Moyle	DC Link #	450	450	450	450	450	450	450	450	450	450
Contour Global (CHP)	CGC3	Gas	3	3	3	3	3	3	3	3	3	3
	CGC4	Gas	3	3	3	3	3	3	3	3	3	3
	CGC5	Gas	3	3	3	3	3	3	3	3	3	3
iPower AGU	AGU	Distillate Oil	26	26	26	26	26	26	26	26	26	26
Total Dispatchable			**2771**	**2771**	**2771**	**2771**	**2261**	**2261**	**2261**	**2261**	**2261**	**2261**

Table A-6 Fully dispatchable plant in Northern Ireland.
** Where dual fuel capability exists, this indicates the fuel type utilised to meet peak demand.*
 # Moyle Interconnector Capacity: 450 MW Nov-Mar & 410MW Apr-Oct

Year end:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wind-Onshore	1629	1847	2065	2284	2502	2720	2939	3157	3375	3593	3812
Wind-Offshore	0	0	0	20	137	137	162	189	281	325	325
Wind-Total	**1629**	**1847**	**2065**	**2303**	**2639**	**2858**	**3101**	**3346**	**3656**	**3918#**	**4137**
Small-scale Hydro	21	21	21	21	21	21	21	21	21	21	21
Waste (50% renewable)	0	15	15	15	77	77	77	77	77	77	77
Biomass/Landfill gas*	56	79	102	125	148	165	181	198	215	231	231
Tidal/Wave	0	0	0	0	0	0	13	25	38	75	125
Industrial	9	9	9	9	9	9	9	9	9	9	9
CHP	141	141	141	141	141	141	141	141	141	141	141
Total	**1856**	**2112**	**2353**	**2614**	**3035**	**3270**	**3543**	**3816**	**4156**	**4472**	**4741**

Table A-7 Partially/non-dispatchable plant in Ireland.
** Includes 150 MW Biomass CHP by 2020, and a 35 MW contribution from Edenderry.*
 # Due to uncertainties associated with wind and other renewable sources, a spread of possible figures for installed wind capacity are estimated between 3500 and 4000 MW to meet the 40% RES target in 2020. The central figure only is indicated in this table.

Partially/Non-Dispatchable Plant in Northern Ireland											
Year end:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Onshore Wind	405	469	532	596	660	723	787	851	914	978	1042
Offshore Wind	0	0	0	0	0	0	0	0	0	300	300
Small Scale Hydro	4	4	4	4	4	4	4	4	4	4	4
Small Scale Biofuels	1	1	1	2	2	2	2	2	2	2	2
Landfill Gas	11	12	13	14	15	17	18	19	21	23	25
Large scale Biomass	0	0	0	0	30	60	90	90	90	90	90
CHP	7	8	9	10	11	12	13	14	15	16	17
Industrial/DSU	0	0	0	0	1	1	2	2	3	3	4
Tidal/Wave	1	1	1	1	1	1	1	1	1	51	51
Total	**429**	**495**	**560**	**627**	**724**	**820**	**917**	**983**	**1050**	**1467**	**1535**

Table A-8 Partially/non-dispatchable plant in Northern Ireland

NI Wind Farm		MEC (MW)
Transmission connected	Slieve Kirk	27.6
Distribution connected	Corkey	5
	Rigged Hill	5
	Elliott's Hill	5
	Bessy Bell	5
	Owenreagh	5.5
	Lendrum's Bridge	5.94
	Lendrum's Bridge2	7.26
	Altahullion	26
	Tappaghan	19.5
	Snugborough	13.5
	Callagheen	16.9
	Lough Hill	7.8
	Bin Mountain	9
	Wolf Bog	10
	Slieve Rushen 2a	27
	Altahullion Extension	11.7
	Bessy Bell 2	9
	Slieve Rushen 2b	27
	Owenreagh Ext	5.1
	Slieve Divena	30
	Garves	15
	Gruig	25
	Tappaghan Ext	9
	Hunters Hill	20
	Crockagarran	15
	Screggagh	20
	Curryfree	15
Total		**397.8**

Table A-9 Existing Windfarms in Northern Ireland, as of 31st October 2011

Wind Farm	Phase	MEC (MW)	Wind Farm	Phase	MEC (MW)
Ballywater	1	31.5	Garvagh	1	26.7
Ballywater	2	10.5	Garvagh	1	31.53
Boggeragh	1	57	Glanlee	1	29.8
Booltiagh	1	19.45	Golagh	1	15
Castledockrell	1	41.4	Kingsmountain	1	23.75
Clahane	1	37.8	Kingsmountain	2	11.05
Coomacheo	1	41.225	Lisheen	1	55
Coomacheo	2	18	Meentycat	1	70.96
Coomagearlahy	1	42.5	Meentycat	2	14
Coomagearlahy	2	30	Mountain Lodge	1	24.8
Coomagearlahy	3	8.5	Mountain Lodge	3	5.82
Derrybrien	1	59.5	Rathrussan/Bindoo	1	48
Dromada	1	28.5			
			Transmission connected total		**782**

Table A-10 Transmission connected windfarms in Ireland as of 1 Oct 2011

Wind Farm	Phase	MEC (MW)	Wind Farm	Phase	MEC (MW)
Altagowlan	1	7.65	Grouse Lodge	1	15
Anarget	1	1.98	Inis Meain	1	0.66
Anarget	2	0.02	Inverin (Knock South)	1	3.3
Arklow Banks	1	25.2	Inverin (Knock South)	2	0.66
Ballincollig Hill	1	15	Kealkil	1	8.5
Ballinlough	1	2.55	Kilbranish (Greenoge)	1	4.9
Ballinveny	1	2.55	Killybegs	1	2.55
Beale	1	1.65	Kilronan	1	5
Beale	2	2.55	Kilvinane	1	4.5
Beallough	1	1.7	Knockastanna	1	7.5
Beam Hill	1	14	Knockawarriga	1	22.5
Beenageeha	1	3.96	Lackan	1	6
Bellacorrick	1	6.45	Lahanaght Hill	1	4.25
Black Banks	1	3.4	Largan Hill	1	5.94
Black Banks	2	6.8	Lenanavea	2	2.55
Burtonport	1	0.66	Lenanavea / Burren	1	2.1
Caranne Hill	1	3.4	Lios na Carraige	1	0.02
Cark	1	15	Loughderryduff	1	7.65
Carnsore	1	11.9	Lurganboy	1	4.99
Carraigcannon	1	20	Mace Upper	1	2.55
Carrig	1	2.55	Meenachullalan	1	11.9
Carrons	1	2.5	Meenadreen	1	3.4
Carrons	2	2.49	Meenakeeragh	1	4.2
Coomatallin	1	5.95	Meenanilta	1	2.55
Corkermore	1	15	Meenanilta	2	2.45
Corneen	1	3	Mienvee	1	0.66
Corrie Mountain	1	4.8	Mienvee	2	0.19
County Crest	1	0.5	Milane Hill	1	5.94
Crocane	1	1.7	Moanmore	1	12.6
Crockahenny	1	5	Moneenatieve	1	3.96
Cronaloght	1	4.98	Mount Eagle	1	5.1
Cronelea	1	4.99	Mount Eagle	2	1.7
Cronelea	2	4.5	Mountain Lodge	1	3
Cronelea Upper	1	2.55	Muingnaminanne	1	15.3
Cronelea Upper	2	1.7	Mullinanalt	1	7.5
Cuillalea	1	3.4	Owenstown	1	0.018
Cuillalea	2	1.59	Raheen Barr	1	18.7
Culliagh	1	11.88	Raheen Barr	2	8.5
Curabwee	1	4.62	Rahora	1	4.25
Curraghgraigue	1	2.55	Rathcahill	1	12.5
Donaghmede Fr Collins Park	1	0.25	Reenascreena	1	4.5
Dromdeeveen	1	10.5	Richfield	1	20.25
Dromdeeveen	2	16.5	Richfield	2	6.75
Drumlough Hill	1	4.8	Shannagh	1	2.55
Drumlough Hill	2	9.99	Skehanagh	1	4.25
Dundalk IT	1	0.5	Slievereagh	1	3
Dunmore	1	1.7	Sonnagh Old	1	7.65
Flughland	2	9.2	Sorne Hill	1	31.5
Gartnaneane	1	10	Sorne Hill	2	7.4
Gartnaneane	2	5	Spion Kop	1	1.2
Geevagh	1	4.95	Taurbeg	1	26
Glackmore	1	0.6	Tournafulla	1	7.5
Glackmore	2	0.3	Tournafulla	2	17.5
Glackmore	3	1.4	Tullow Mushroom Growers Ltd	1	0.133
Glanta Commons	1	19.55	Tullynamoyle	1	9
Glanta Commons	2	8.4	Tursillagh	1	15
Glenough	1	33	Tursillagh	2	6.8
Gneeves	1	9.35	WEDcross	1	4.5
Gortahile	1	21	**Distribution Connected Total**		**811**

Table A-11 Distribution connected windfarms in Ireland as of 1 Oct 2011

APPENDIX 3 METHODOLOGY

GENERATION ADEQUACY & 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-12 Expected Unserved Energy (EUE) for both jurisdictions

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 (LOLE)

AdCal software in 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_{hd} = 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

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

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-13.

	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-13 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.

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-14 Probability table

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.

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 reality this is not always true. In extreme weather, for example, generators are more likely to fail simultaneously. This can lead to supply shortages during periods when the balance of probability would have suggested a supply surplus.

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[61]. 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.

[61] 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 ASSESSMENTS

This section shows the results from the adequacy studies as presented in Section 0.

Median	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	498	466	480	501	240	262	201	178	298	282
	Ireland	958	1261	1115	1268	1304	1295	1291	1316	1283	1131
	All-island	1764	2050	1990	2041	1803	1811	1741	1725	1716	1578

Table A-15 The surplus of plant for 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.*

Low	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	540	516	539	562	304	331	274	256	381	370
	Ireland	964	1273	1133	1294	1334	1330	1331	1361	1335	1185
	All-island	1811	2113	2069	2130	1903	1920	1856	1851	1855	1727

Table A-16 ***Low demand*** *with Base case Availability.*

High	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	419	366	390	404	148	171	95	67	197	178
	Ireland	941	1235	1078	1223	1248	1232	1216	1228	1183	1024
	All-island	1672	1942	1883	1917	1670	1664	1573	1547	1531	1373

Table A-17 ***High demand*** *with Base case Availability.*

	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Northern Ireland	High Availability	498	466	480	501	240	262	201	178	298	282
	Low Availability	129	82	107	115	115	136	74	51	174	158
Ireland	Generator Availability	1064	1393	1356	1488	1544	1532	1525	1559	1515	1369
	Eirgrid Availability	958	1261	1115	1268	1304	1295	1291	1316	1283	1131

Table A-18 Comparison of ***different availability*** *scenarios. Median demand in all cases.*

	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	276	255	261	282	27	44	(11)	(20)	77	64
	Ireland	584	928	737	893	953	951	934	935	902	787
	All-island	1,052	1,357	1,277	1,330	1,103	1,114	1,042	1,015	990	868

*Table A-19 The Base case with one **CCGT removed** from each jurisdiction. Shading indicates deficit of plant.*

	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	(119)	(192)	(160)	(156)	(197)	(185)	(254)	(274)	(162)	(177)
	Ireland	566	902	700	848	897	886	858	847	800	679
	All-island	756	1014	927	967	890	887	790	751	722	579

*Table A-20 High demand, and low availability in Northern Ireland, with one **CCGT removed** from each jurisdiction*

Median	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	127	142	128	139	(130)	(108)	(155)	(178)	(73)	(91)
	Ireland	958	913	746	902	942	935	925	952	915	771
	All-island	1,361	1,332	1,205	1,263	1,022	1,029	964	941	923	793

*Table A-21 The Base Case scenarios, with the two undersea **interconnectors unavailable***

	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Surplus (Deficit)	Northern Ireland	498	466	480	501	240	262	201	178	298	282
	Ireland	958	1,261	1,115	1,268	979	900	794	384	344	430
	All-island	1,764	2,050	1,990	2,041	1,474	1,404	1,237	784	765	869

*Table A-22 The Base Case, with **older plant removed** from 2016*

	Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Northern Ireland	Median	498	466	480	501	240	262	201	178	298	282
	One-in-10	472	452	460	479	209	231	168	158	266	249
Ireland	Median	958	1261	1115	1268	1304	1295	1291	1316	1283	1131
	One-in-10	858	1,164	1,014	1,167	1,201	1,194	1,189	1,211	1,178	1026

*Table A-23 The base case, with **One-in-10 winter** conditions*

EirGrid plc
The Oval
160 Shelbourne Road
Ballsbridge
Dublin 4

Tel: +353 (0)1 6771700
Fax: +353 (0)1 661 5375

www.eirgrid.com

SONI Ltd
Castlereagh House
12 Manse Road
Belfast
BT6 9RT

Tel: +44 (0)28 9079 4336
Fax: +44 (0)28 9070 7560

www.soni.ltd.uk