System Operator for Northern Ireland


All-island Generation Capacity Statement 2011-2020

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

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Front cover image: Ardnacrusha Hydrogeneration plant (courtesy of ESB) and the generation site at Ballylumford (courtesy of AES Ballylumford Limited)

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 2011-2020.

This year, both TSOs have collaborated to produce an all-island report on generation adequacy. 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, reflecting the structure of the Single Electricity Market. This document therefore assesses the generation adequacy situation for the period 2011 to 2020 for both Ireland and Northern Ireland, as well as on an all-island basis.

Both jurisdictions have seen a drop in demand recently due to the economic downturn. This coupled with the connection of new generation and increased interconnection 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 next 10 years will see a large increase in the amount of renewable generation in both Ireland and Northern Ireland. EirGrid and SONI are fully committed to their roles in delivering 40% of electricity generated from renewable sources by 2020. In keeping with this, EirGrid and SONI have released the Facilitation of Renewables report, which shows what needs to be done in order to deal with the operational and system stability issues associated with managing high levels of renewable generation on our power system. We have also published a study which examines generator technologies and plant portfolio options in the longer term to meet the need for secure energy at a competitive price with low carbon emissions, on an all-island basis.

In the past few years, EirGrid, through the GAR publication, highlighted a number of topics relevant to the industry, such as energy efficiency, electric vehicles, and electricity storage. This year, we have included a section in the report which examines the relationship between demand and the weather, in particular temperature. Despite an overall generation surplus, there have been times both last winter and more recently where we have seen periods with very tight margins. These have been due to extremely cold weather causing problems with both generation plant and transmission infrastructure. Section 6 looks at the problems that extreme weather events can cause to TSOs, and shows how SONI and EirGrid correct historical demand peaks to take temperature into account. We will look to develop this methodology further with the regulatory authorities to incorporate extreme weather events appropriately, and I look forward to sharing this with you.

Dermot Byrne

Chief Executive, EirGrid Group

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EXECUTIVE SUMMARY

KEY MESSAGES

All-island

- The all-island generation adequacy situation is positive for all study years, under all scenarios.
- The second high-voltage tie-line between Ireland and Northern Ireland is due to be completed between 2015 and 2017. Adequacy is significantly enhanced by moving to an all-island situation.
- There will be a significant increase in wind generation capacity driven by both Governments' 40% renewables target in 2020 which, combined with the shutdown of older flexible conventional plant, highlights the likely requirement for a more flexible generation plant portfolio to enable both TSOs deal with wind management issues.

Ireland

- The adequacy situation is positive for the next ten years.
- The opening of the East-West Interconnector in 2012 will allow flows of 500 MW in both directions between Ireland and Great Britain.
- Other major portfolio additions assumed for this study include the opening of four new OCGTs, two new Waste-to-Energy Projects, and a pumped storage facility in Cork.
- The oil units at Tarbert and Great Island are due to close over the next 5 years.
- It is estimated that Ireland will need a total installed wind capacity of 4,350 MW in 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.
- Without additional interconnection capacity between Northern Ireland and Ireland, surpluses in Northern Ireland are reduced to modest levels of circa 300MW.
- 510 MW of conventional plant will be decommissioned from Ballylumford by 2016.
- An additional more onerous scenario based on the assumption of a prolonged major outage of a large CCGT plant in Northern Ireland could result a deficit position for Northern Ireland.
- A number of demand forecast scenarios have been assessed to consider varying recession and recovery possibilities. It is likely that we will not return to 2008 demand levels until 2013.

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 2011-2020, the likely production capacity that will be in place to meet this demand, and assesses the adequacy of generation in terms of the overall supply/demand balance. This is carried out on both a regional and all-island basis.

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 EirGrid's previous Generation Adequacy Report 2010-2016 and SONI's previous Seven Year Generation Capacity Statement 2010-2016.

METHODOLOGY

Generation adequacy is essentially determined by comparing electricity supply 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 electricity supply 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, the anticipated commissioning of additional interconnection capacity between the two jurisdictions will enable demand and supply analysis for Ireland and Northern Ireland to be consolidated into a single all-island assessment. This all-island assessment is carried out against an agreed all-island security standard of 8 hours LOLE per year as agreed with the Regulatory Authorities.

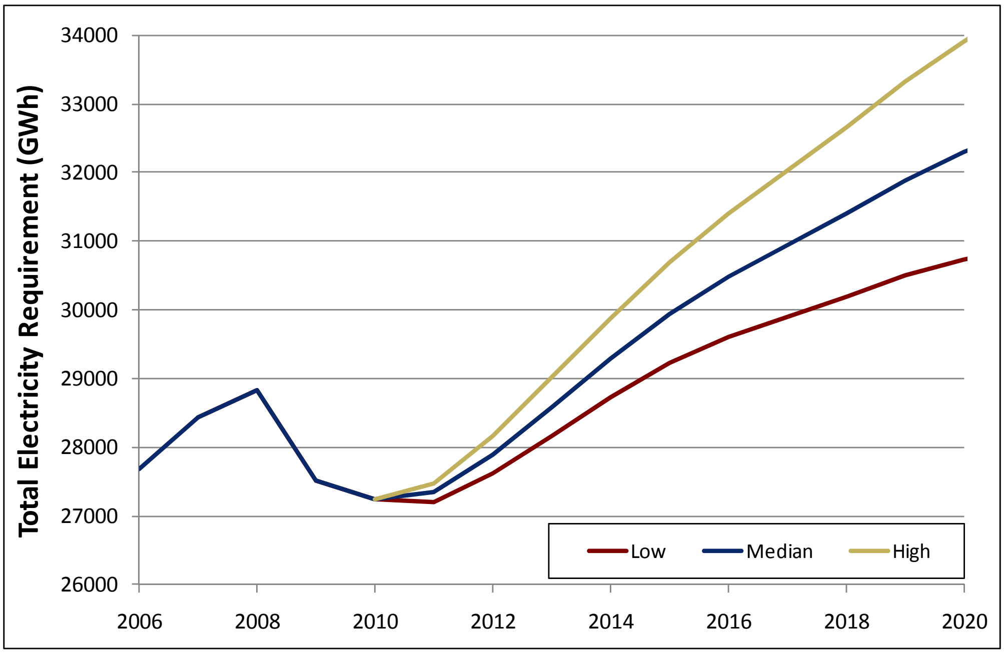
Given the uncertainty that surrounds any forecast of electricity supply and demand, the report examines a number of different scenarios. It is intended that the results from these scenarios would provide the reader with enough information to draw their own conclusions regarding future adequacy.

A key factor in the analysis is the treatment of 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.

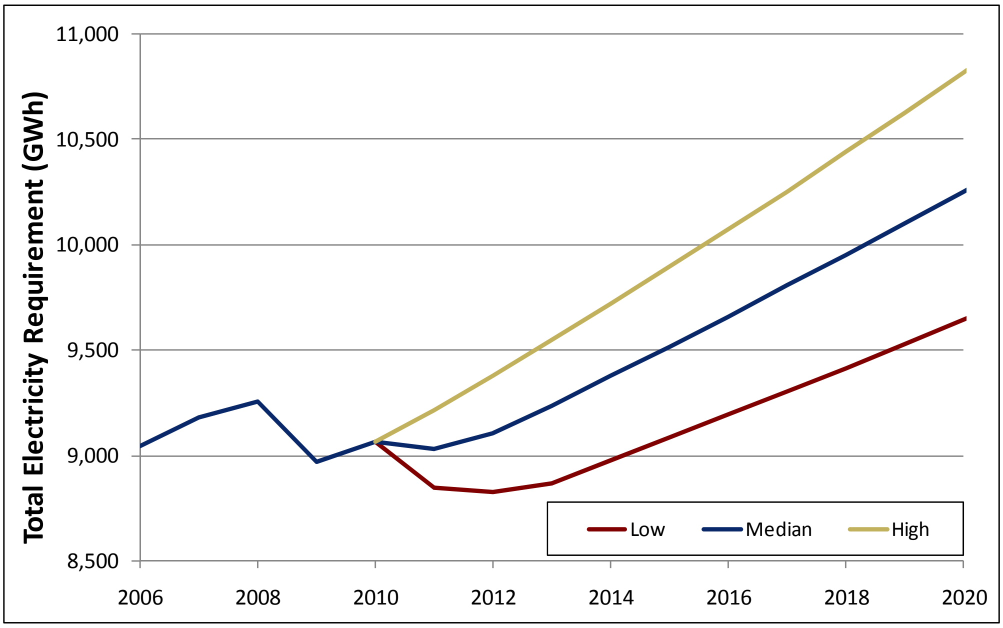
DEMAND FORECAST

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



Demand forecasts for Ireland.

The forecast 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 2007 levels until 2013 in the median forecast.



Demand forecasts for Northern Ireland.

Northern Ireland's forecast (see above), follows a similar pattern. Demand levels in 2010 have seen a rise mainly due to the extremely cold weather in the first 4 months of the year.

However, with the ongoing economic recession and Government austerity measures, it is anticipated that the demand levels will fall again in 2011 before gradually returning to the normal steady growth rate of 1.5% in 2013. It will be 2013 before 2008 levels would be reached in the median forecast.

CONVENTIONAL GENERATION

The assumptions for the generation portfolio are based on responses from the generators and connection agreements in place at the data freeze (31st October 2010). A variety of scenarios have been studied, looking at different supply, demands, and availabilities.

Ireland

The East-West Interconnector is due to commission in the summer of 2012. It is the second transmission cable connecting the island of Ireland to Great Britain, and will be able to import and export 500 MW at any given moment. We have assumed that it adds the equivalent of 440 MW additional generation capacity.

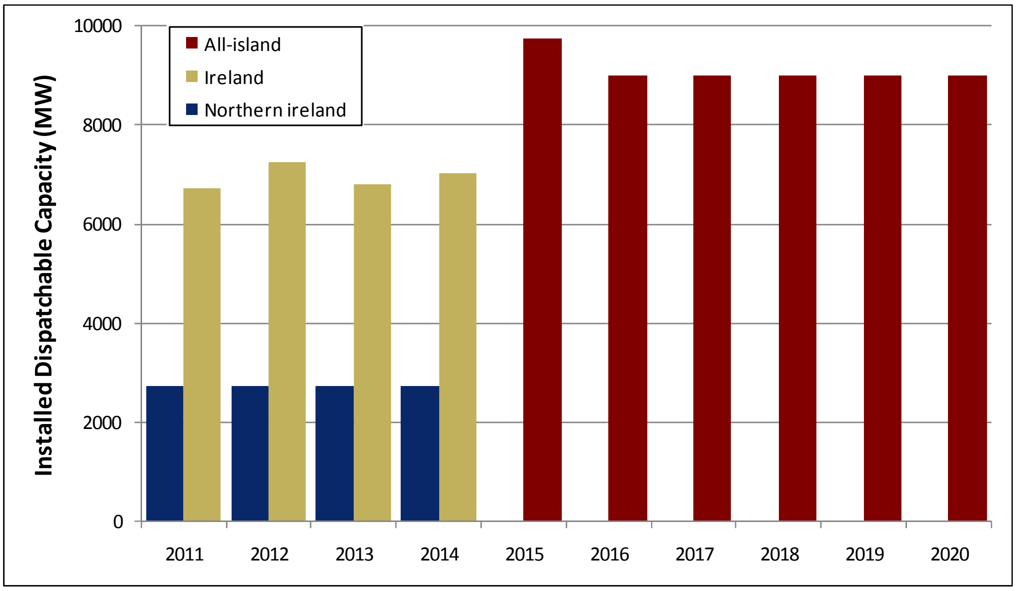
The past year has already seen the addition of two large CCGT plants in Cork, and two new OCGT units at Edenderry, adding almost 1,000 MW to Ireland's generation capacity. Four new OCGTs are due to connect to the system over the next 4 years, adding a generation capacity of 349 MW. A new 70 MW pumped storage unit is due to commission in Cork in 2014.

Generators powered by heavy fuel oil (HFO) are steadily disappearing from Ireland. This year saw the removal of 219 MW of oil generation with the closure of Poolbeg Units 1 & 2. In 2013, 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 2015, removing 241 MW from the system.

Northern Ireland

Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by 2016. This is due to environmental constraints introduced by the Heavy Fuel Oil Directive and will give a reduction of 510 MW in capacity. The proposed Kilroot 400 MW CCGT that was assumed to be available from 2015 onwards in the SONI Seven Year Statement 2010-16 has been removed from the analysis and studies[1]. The graph below outlines the dispatchable capacity on the island over the next 10 years.

[1] *Although AES still hold a formal connection offer for additional generation capacity, they have indicated that it is not possible at this stage to provide a date when this generation capacity would commissioned. It should be noted that this in no way affects the connection offer held by Kilroot, and that they can still act upon the offer up to 2012.*



Dispatchable Capacity figures for the next 10 years

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 by the most part be achieved through wind generation, though other renewables will play a role.

Ireland

Using our median demand forecast, we have calculated that ~4,350 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, we have assumed that a modest amount of marine generation will appear in Ireland from 2017. There are also 89 MW of Waste to Energy projects due to connect over the next few years. In addition, a small, steady growth in bioenergy is assumed.

Northern Ireland

A number of renewable generation projects are assumed to be commissioned by 2020 giving a total renewable generation capacity of 2112 MW in Northern Ireland. This includes onshore wind (1012 MW), offshore wind (600 MW), tidal (300 MW) and large scale biomass (200 MW).

These have been included using assumptions made based on the Strategic Environmental Assessment (SEA) and the Strategic Energy Framework produced by the Department of Enterprise, Trade and Investment.

This level of installed renewable generation capacity will enable Northern Ireland to be well in excess of the 40% target of electricity energy consumed being produced by renewable generation resources.

ADEQUACY ASSESSMENTS

In determining future system adequacy, the impact of varying demand growth and availability was examined. We examined the potential effects of losing a CCGT in both Ireland and Northern Ireland, and also phased closure of older plant in Ireland.

Ireland

Generation Adequacy in Ireland is positive in almost all scenarios across all years. The only exception occurs in the scenario examining the removal of older plant. This shows a deficit in Ireland in 2020 when the high demand forecast is assumed. However, as we should have moved to an all-island adequacy assessment by then, there should not be an adequacy issue were this scenario to arise.

Northern Ireland

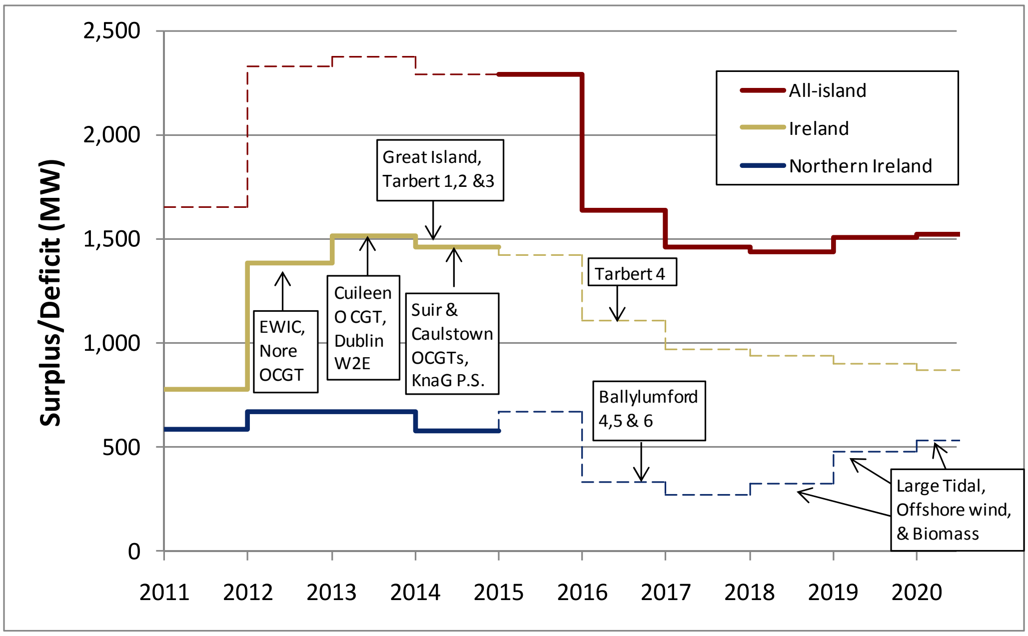
Without the introduction of additional interconnection, and following the decommissioning of older plant in Northern Ireland, by 2016 surpluses in Northern Ireland are reduced to circa 300 MW even with increasing levels of renewable generation capacity. The analysis has considered another more onerous scenario for the loss of a large CCGT in Northern Ireland. This resulted in a deficit position for Northern Ireland when the high demand forecast or low availability forecast were assumed.

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

All-Island

Following the introduction of further interconnection, the benefits are highlighted in the All-Island analysis, where surpluses of circa 1500MW are possible.

The results from our base case studies are shown below, with significant changes to the portfolio indicated.



Adequacy results for the base scenario, shown for Ireland, Northern Ireland, and on an all-island basis. Major changes in the portfolio have been indicated.

It should also be noted that by 2012, it is assumed that interconnection with the BETTA market in Britain will provide 890 MW of capacity. However, flows on the interconnectors are dependent on market interactions. There have already been occasions when energy has not been available from the Moyle Interconnector during a capacity shortfall either for balancing trades or emergency assistance. A 890 MW import capability tends to project a healthy position with respect to capacity adequacy. However this capacity comes with a large degree of operational complexity and uncertainty in the commercial markets. As flows are difficult to predict, margins can be complex to manage in operational timescales.

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 2020[2]. Generation adequacy is a measure of the capability of electricity supply to meet the electricity demand on the system. The development of new generation capacity and connection to the transmission or distribution systems involves 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 previous EirGrid's Generation Adequacy Report 2010-2016 published in November 2009, and also SONI's previous Seven Year Generation Capacity Statement 2010-2016 published December 2009.

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 production. Adequacy assessments are presented in Section 4. The report concludes with Section 5, which examines the interaction between system adequacy and the weather. Appendices which provide further detail of the data, results and methodology used in this study are included at the end of this report.

[2] *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 Adequacy Report.*

2 Demand Forecast

2 DEMAND FORECAST

2.1 INTRODUCTION

A forecast of how much electricity will be needed in the future is essential for determining generation adequacy. EirGrid and SONI use models based on economic forecasts and historical trends 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.

The results obtained are compared with previous forecasts, and 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. In previous SONI Generation Capacity Statements TER was referred to as Generated Energy Sent-Out (MWh) and TER Peak was referred to as Sent-Out Peak (MW).

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 GDP[3] and PCGS[4]. 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[5] of this quantity is added to the energy which must be exported by generators to meet sales. The resultant energy is known as the Total Electricity Requirement (TER). As all generation sources are considered in the analysis, it is this TER that is utilised for generation adequacy calculations.

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

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

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

2.2(b) Training the forecast model

The electricity model is trained using historical data. For the forecast presented here, the most recent figures at the time of the data freeze were used; economic data from the Economic and Social Research Institute (ESRI), as well as demand data supplied by the Distribution System Operator and ESB Public Electricity Supply.

2.2(c) Forecasting causal inputs

In order for the trained energy model to make predictions, it needs forecasts of GDP[2] and PCGS[3]. These forecasts are based on publications by the ESRI, who have expertise in modelling the Irish economy and were consulted during the modelling process.

The forecast for 2011 was based on the latest Quarterly Economic Commentary published by the ESRI in October 2010. To model growth for 2012 and beyond, we have used GDP predictions from the 'Recovery Scenarios for Ireland: An Update' report[6] published by the ESRI in July 2010. The growth rates for the economic forecast are outlined in Table 2-A.

	GDP (volume)	Personal Consumption
2011	2.25%	1.00%
2012-2015	4.60%	2.30%

Table 2-A The economic growth rates for Ireland used to build median demand figures.

Figures for 2010 demand were based on real data available to EirGrid through our National Control Centre. As only figures up until October were available by the data freeze date, estimates were made for the remaining 2 months.

2.2(d) Growth rates post 2015

Demand growth rates after 2015 were based on figures provided by the ESRI. These were calculated in conjunction with the Sustainable Energy Authority of Ireland (SEAI) using ESRI's HERMES model. HERMES is a macro-economic model, using a bottom up approach to forecast growth in all the different sectors of Ireland's economy. The average electricity demand growth rates were 1.5% from 2016-2020.

2.2(e) Low and High Demand Scenarios

We have developed both a low and a high demand scenario to give a range in our future predictions. To build these, we first built the median demand scenario as described above. We then shifted the growth rates for each year by -0.5% and +0.5% to create low and high demand forecasts respectively.

2.3 NORTHERN IRELAND ANNUAL ELECTRICITY DEMAND FORECAST MODEL

2.3(a) Historic Northern Ireland Methodology

Until recently 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 prediction.

[6] http://www.esri.ie/UserFiles/publications/RecoveryScenarios/QEC2010SumSA_Recovery%20Scenarios.pdf

2.3(b) Current Northern Ireland Methodology

The above procedure has been reasonably accurate and produced values close to the observed values. Since 2008, however, there has been an increase in the difference between the predicted values and the observed values. This is explained by the drastic downturn in the global economy that began during the second half of 2008. This economic crisis has had a major affect on both peak demand and energy 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 also. It is for this reason the traditional forecasting approaches have been modified to increase accuracy in the short term.

Given the high degree of uncertainty over the future, the best approach is to consider three alternative scenarios for the economy and for each of these derive an estimate energy production. The three scenarios will consist of a Pessimistic, Realistic and Optimistic view with adjustments that take account of current economic outlook predictions.

In June 2010, SONI published a document called 2010 Forecast of Northern Ireland Peak Demand & Energy Production[7] outlining this forecast. This has been discussed with the Utility Regulator for Northern Ireland who have agreed with the rationale and methodolgy used in compiling the forecasts.

It should be noted that unlike Peak Demand the temperature has a lesser impact on annual electricity Energy demand where the effect is found to generally balance over the course of a year.

2.4 RESULTS OF ANNUAL ELECTRICITY DEMAND FORECAST

The energy demand models forecast the TER for each region over the next 10 years. Figure 2-1 and Figure 2-2 show the forecasts for the Ireland and Northern Ireland respectively.

The forecast for Ireland 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 2007 levels until 2013 in the median forecast. Smoothing has been applied to the data for Ireland in order to avoid a sudden change in growth rates.

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[7] *2010 Forecast Of NI Peak Demand And Energy Production - June 2010: http://www.soni.ltd.uk/upload/2010%20Forecast%20Of%20NI%20Peak%20Demand%20And%20Energy%20Production%20-%20June%202010.pdf*

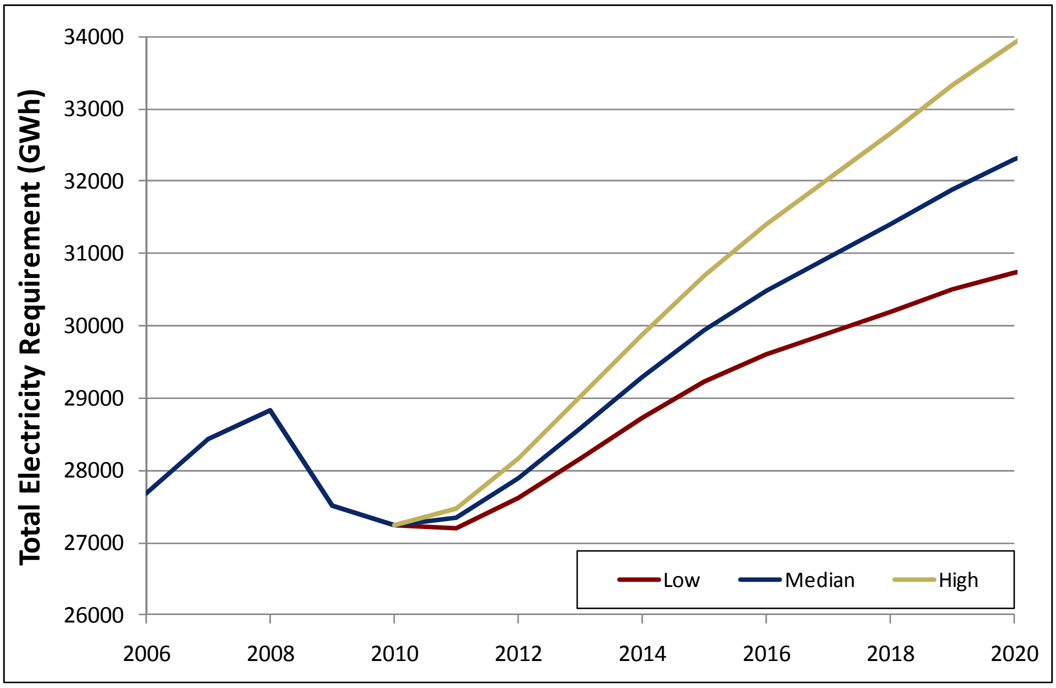

Figure 2-1 TER forecasts for Ireland.

Northern Ireland's forecast (see below), follows a similar pattern to that of Ireland's. Demand levels in 2010 have seen a small rise, mainly due to the extreme inclement winter that affected the first 4 months of the year. However, with the ongoing economic recession and Government austerity measures, it is anticipated that the demand levels will fall again in 2011 gradually returning to a steady growth rate of 1.5% in 2013. It will be 2013 before the pre-recessionary 2008 levels would be reached in the median forecast.

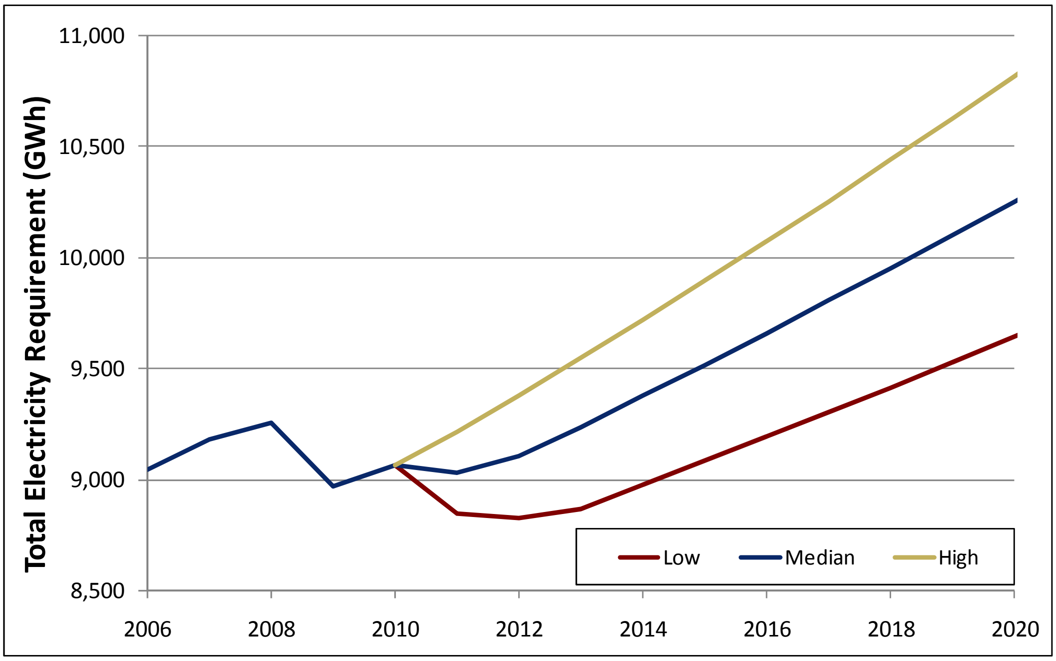

Figure 2-2 TER forecasts for Northern Ireland.

EirGrid, SONI and Northern Ireland Electricity (NIE) are currently working together to strengthen interconnection between the two regions through the North-South

Interconnection Project. A consolidation of the Ireland and Northern Ireland models can then take place creating a single all-island model on which system adequacy studies can be performed. This will then reflect the Single Electricity Market model. The combined demand for the two regions is shown in Figure 2-3.

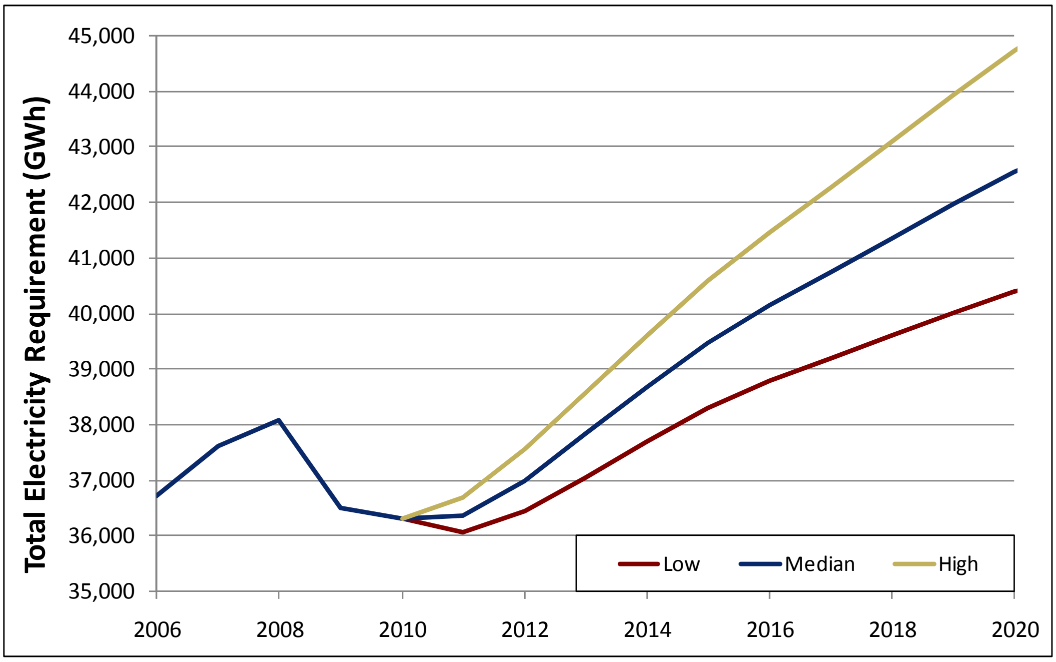

Figure 2-3 TER forecasts for the island of Ireland.

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

2.5 PEAK DEMAND FORECASTING

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

Historically, the winter peak is somewhat erratic and difficult to model as it is subject to many disparate influences, including

- temperature and weather conditions
- changing electricity usage patterns
- Demand-Side Management (DSM) schemes and Customer Private Generation (CPG)[8]

Of all the meteorological elements it has been found that temperature has the greatest effect on the demand for electricity. For this reason, demand data is adjusted to a temperature standard known as Average Cold Spell (ACS). 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.

[8] *Some customers are given a financial incentive to reduce their demand at peak hours, thus lessening the actual peak that needs to be supplied.*

Analysis is carried out over historical temperature data. The effective mean temperatures for each winter are assessed to determine the average cold spell effective mean temperature. 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 relationship between demand and temperature is discussed further in section 5.1 as a special topic in this year's statement.

2.5(a) Ireland peak forecast

Demand side management (DSM) schemes in Ireland have a notable affect on the shape of the annual demand profile. The effects of DSM are estimated and corrected for within our peak model. The amount of peak load reduction achieved by the Winter Peak Demand Reduction Scheme has been estimated at 138 MW for future years, based on historic data. Were the incentives removed in the future, the peak load should increase by approximately this amount.

Figure 2-4 shows the recorded and ACS-adjusted transmission peaks in Ireland since the winter of 1997/98. There is a significant gap between the two curves for last winter, where the recorded peak was higher than the ACS peak by over 230 MW. This is due to the extremely cold temperatures experienced at the time.

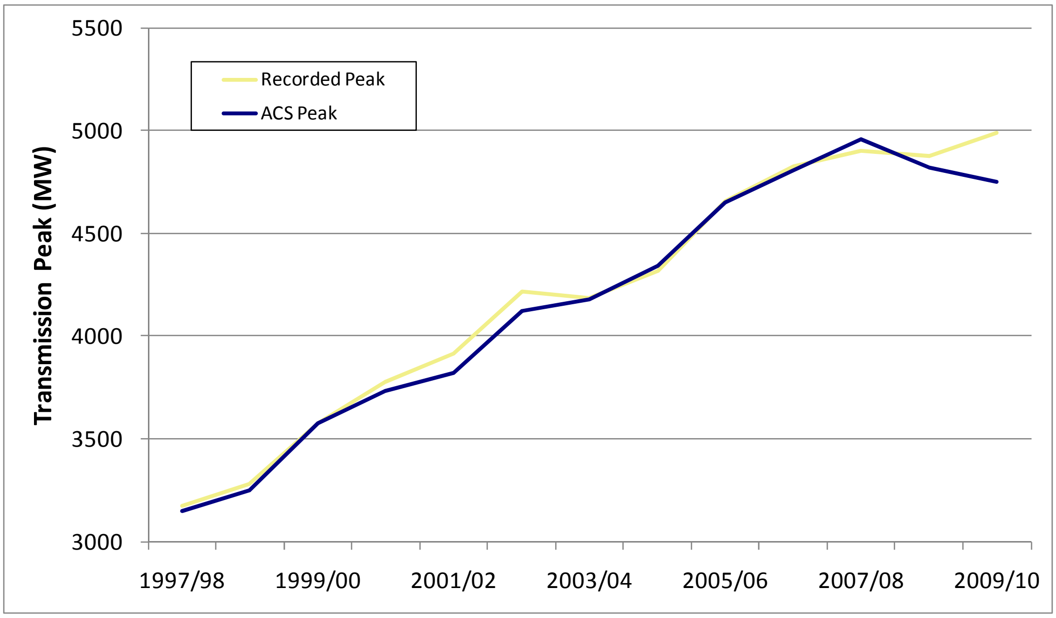

Figure 2-4 Actual and ACS-adjusted transmission peaks for Ireland.

2.5(b) Northern Ireland peak forecast

The Northern Ireland demand data used is on a sent out basis i.e. net of power station auxiliary load. It is the power directly injected onto the 275/110kV transmission network to meet the demand by centrally dispatched generating plant.

The demand peaks over the last decade reflect CPG, consisting of customers running private embedded diesel generation to avoid the higher winter peak use of system tariff charges.

Analysis was carried out over the 09/10 winter period to calculate the amount of private generation that was actually running and was found to be 44MW. This has the effect of suppressing the peak and is assumed to continue over the ten years of this report.

As discussed above, Northern Ireland data is corrected to account for temperature, giving the ACS peak. The 2009/10 winter peak which occurred on 12th January 2010 @ 17:30 consisted of the following data:

CDGU + Interconnectors = 1547 MW
Renewable + Small Scale = 275 MW
Customer Private Generation = 44 MW
TOTAL GENERATED PEAK =1866 MW

When average cold spell temperature correction (ACS) is applied using the methodology as described above the figure of 1866 MW is corrected down by 70MW, providing an ACS corrected figure of 1796 MW for the 2009/10 winter period.

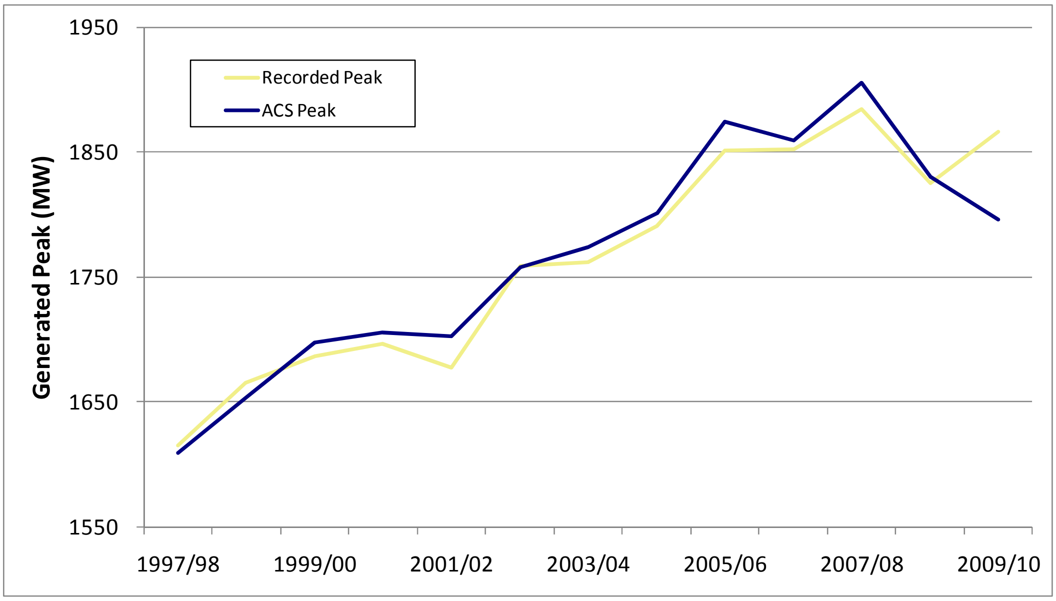

Figure 2-5 Actual and ACS-adjusted generated peaks for Northern Ireland.

Peak demand in Northern Ireland has generally seen steady incremental growth over the last fifteen years. It should be noted however that since the 2008/09 winter the peak demand fell significantly due to the onset of the economic downturn.

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 generation sent out (exported, net of house loads) terms. 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.

2.6 PEAK DEMAND FORECAST RESULTS

Peak demands have been forecasted on an Ireland, Northern Ireland and all-island basis. The winter TER peaks for the next ten years were calculated for all three demand scenarios using the forecast electricity demand values and the DSM and CPG assumptions in the peak demand model. The TER peak consists of the peak exported power plus an estimate of self consumption[9] (for Northern Ireland, this is accounted for in the CPG figure).

The forecasted winter peaks are given in Figure 2-6 and Figure 2-7 for Ireland and Northern Ireland. The peaks forecasted here are for a typical winter – in reality peaks may be higher or lower depending on the weather conditions. Historical values shown in these graphs consist of actual measured peaks and have not been corrected for temperature.

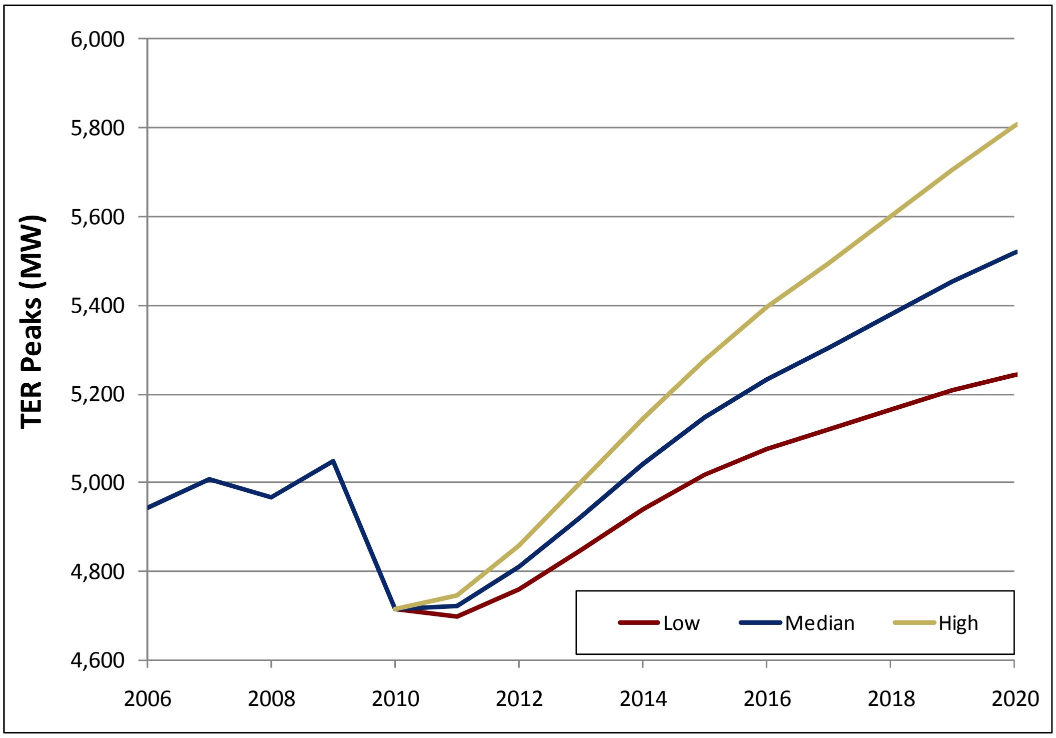

Figure 2-6 TER Peak forecasts for Ireland.

[9] *Electricity which is generated at the location where it is consumed This does not include house-load, which is power consumed by generators during the process of generation.*

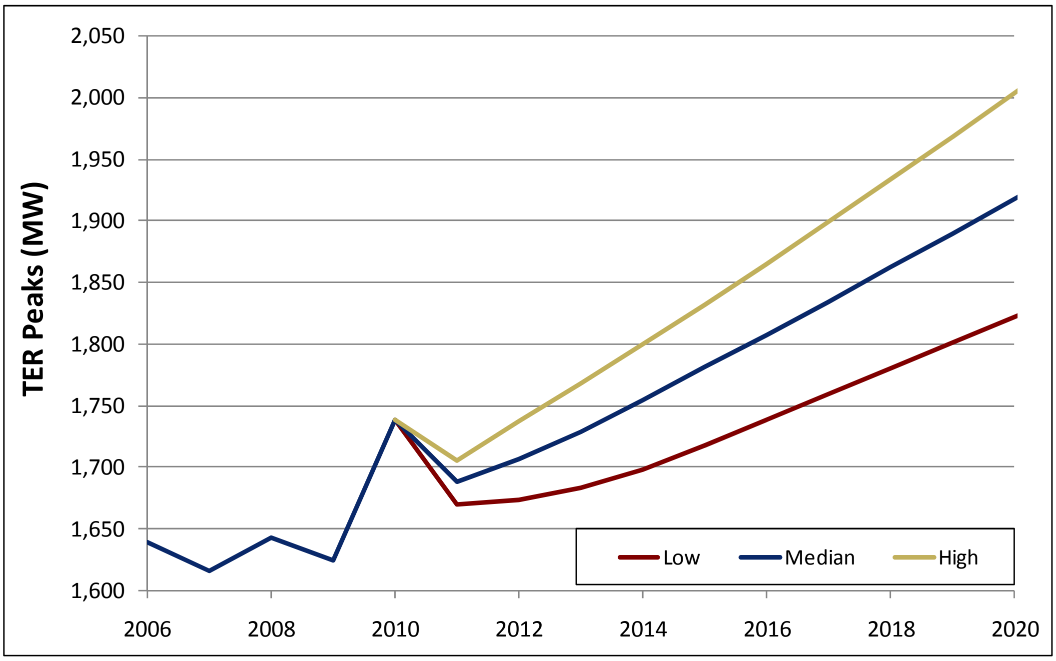

Figure 2-7 TER Peak forecasts for Northern Ireland.

The annual peaks for Ireland and Northern Ireland do not generally coincide. In Northern Ireland, annual peaks tend to occur at the start of the year, whereas in Ireland peaks tend to occur in December. Also, peaks in Northern Ireland usually occur later in the evening than those in Ireland. To create all-island peaks, we have built future demand profiles 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.

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

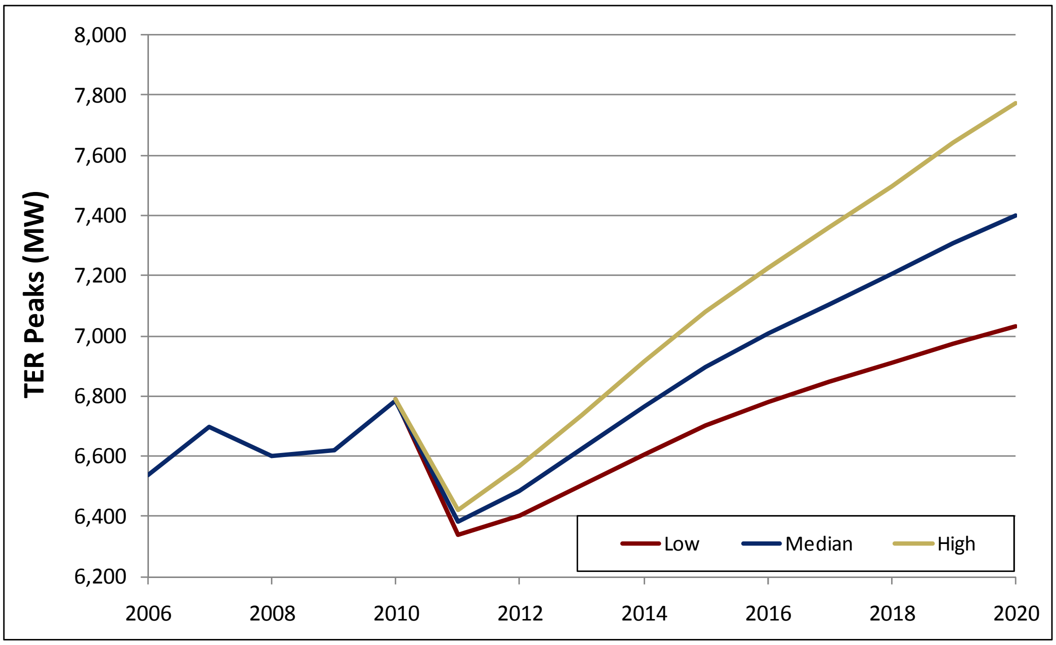

Figure 2-8 The all-island TER peak forecast.

2.7 ANNUAL LOAD SHAPE & 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 demand profile has been deemed as abnormal as the recession continued to affect both demand profiles.

In previous reports the Northern Ireland methodology subtracted the estimated wind generation profile from the total demand profile. The generation capacity adequacy was then determined based on the ability of conventional centrally despatched generation plant to meet the resulting demand profile.

However, as the capacity of installed wind reaches higher levels both in Ireland and Northern Ireland and continues to rise rapidly, another way of analysing the contribution of wind will be used in this report and all future reports for Northern Ireland. This new methodology will be in line with the methodology used by Eirgrid (see section 3.7(c)).

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 winter weekday in 2009. Many factors impact on this electricity usage pattern throughout the year. Examples include weather, sporting or social events, holidays, and customer demand management.

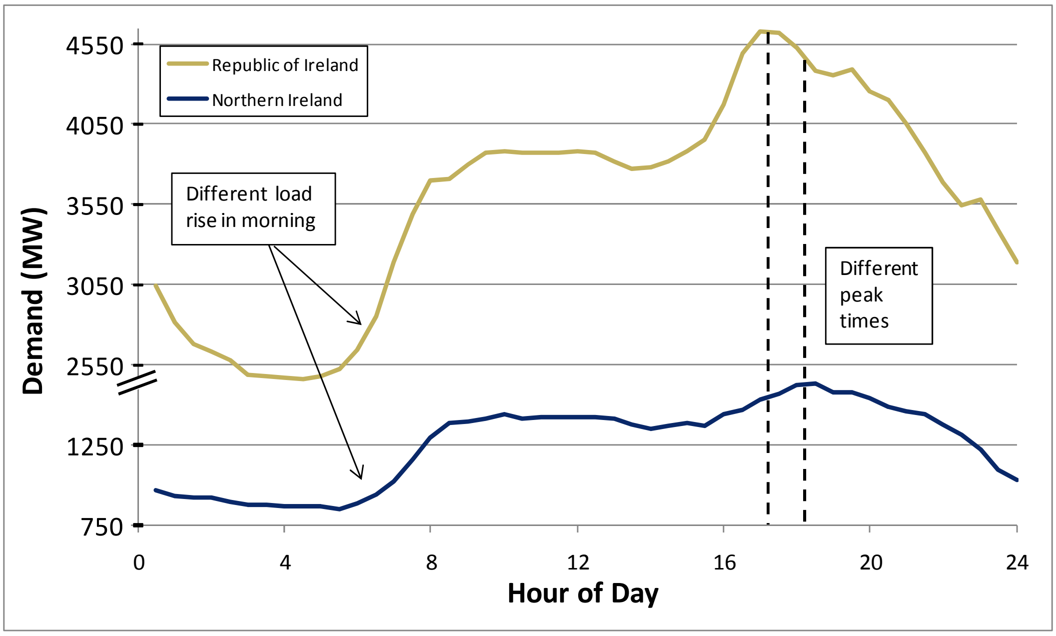

Figure 2-9 Typical demand patterns for a winter day in 2009. The differences between the profiles for Ireland and Northern Ireland lead to a benefit when the demands are combined.

2.8 CHANGES IN FUTURE DEMAND PATTERNS

The Government in 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[10]. 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[11].

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[12]. They envisage 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 Invest NI[13] to help businesses identify and implement significant energy efficiencies.

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[10] *http://www.seai.ie/Grants/Home_Energy_Saving_Scheme/*, *http://www.seai.ie/Grants/Warmer_Homes_Scheme/*
[11] *See for e.g. GAR 2009-2015, GAR 2008-2014*
[12] *http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf*
[13] *http://www.investni.com/index/grow/technology_and_process_development/energy.htm*

3 Electricity Supply

3 ELECTRICITY SUPPLY

3.1 INTRODUCTION

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

Predicting the future of electricity supply in Ireland and Northern Ireland will never be fully accurate. EirGrid and SONI have endeavoured to use the most up-to-date information available at the time of the data freeze for this report. The data freeze date for this report was set as the 31st October 2010.

Interconnection will play an important role in future 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.

The second major North-South Interconnector (NSIC) connecting Northern Ireland and Ireland will enable a consolidation of the two system's demand and supply for assessing system adequacy. This will lead to a more secure, stable, and efficient system. The NSIC is expected to be completed between 2015 and 2017.

Table 3-A shows the changes to the total island capacity over the next 10 years. These are tabulated in further detail in Appendix 2.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity added (Ireland)[14]		98	98	223						
Capacity Removed (Ireland)			-561			-253				
Capacity Removed (NI)						-510				
EWIC		440								
Minor Degradation		-3	-1	-3	-1	-3	-1	-3	-1	-3
Net Impact	**0**	**535**	**-464**	**220**	**-1**	**-756**	**-1**	**-3**	**-1**	**-3**
Change from 2010	0	535	71	291	290	-466	-467	-470	-471	-474
Total Dispatchable capacity	**9,498**	**10,033**	**9,569**	**9,789**	**9,788**	**9,032**	**9,031**	**9,028**	**9,027**	**9,024**

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

[14] *There is no new generation currently planned for NI over the next 10 years. The proposed Kilroot 400 MW CCGT that was assumed to be available from 2015 onwards in the SONI Seven Year Statement 2010-16 has been removed from the analysis and studies (see section 3.5(a))*

3.2 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 new distribution-level Combined Heat and Power (CHP) plant will be opening in Dublin. This Waste-to-Energy converter, located at Ringsend, will be able to supply 72 MW. Current estimates put the commissioning date before 2013. A smaller 17 MW Waste-to-Energy converter will be commissioning in Meath in 2011.
- A new pumped storage unit at Knocknagreenagh in Co. Cork is due to commission in 2014, with a capacity of 70 MW.
- All Great Island units will be decommissioned by the end of 2013. This will give a reduction of 212 MW in capacity.
- Tarbert Units 1, 2, and 3 will be decommissioned in 2013, reducing capacity by 349 MW. Tarbert Unit 4 will decommission by the end of 2016, reducing capacity by 243 MW.
- There will be a large amount of wind generation installed in Ireland over the next seven years. While the exact amount is as yet uncertain, it is assumed to be in the region of an additional 3,000 MW.

3.3 PORTFOLIO CHANGES IN NORTHERN IRELAND

- Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by 2016. This is due to environmental constraints introduced by the Heavy Fuel Oil Directive and will give a reduction of 510 MW in capacity.
- A number of renewable generation projects are assumed to be commissioned by 2020 in Northern Ireland. This includes offshore wind (600 MW), tidal (300 MW) and large scale biomass (200 MW). These have been included using assumptions made based on the Strategic Environmental Assessment (SEA)[15] and the Strategic Energy Framework[16] produced by the Department of Enterprise, Trade and Investment.
- There will be a large amount of onshore wind generation added to the Northern Ireland system over the next number of years. While the exact amount is as yet uncertain it is assumed that by 2020 there will be an installed capacity of 1012 MW. The figures for the amount of wind in each study year have been derived from information provided on wind farm connections by Northern Ireland Electricity, information available from the Northern Ireland Planning Service[17] and assumptions made on what amount of wind capacity actually will receive the planning permission required.

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 centre. 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.

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[15] www.offshorenergyni.co.uk
[16] *Strategic Energy Framework (www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf)*
[17] http://www.planningni.gov.uk/index/advice/advice_apply/advice_renewable_energy/renewable_wind_farms.htm

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 CHP units operated by Contour Global, and a 22 MW Aggregated Generating Unit operated by Energia.

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. However, their output can be reduced by EirGrid or SONI when required, and they are therefore categorised as being partially dispatchable. In accordance with the EirGrid Grid Code[18] and the Distribution Code[19] in Ireland, wind farms with an installed capacity greater than 5 MW must be partially dispatchable.

In accordance with the SONI Grid Code[20] and the Distribution Code[21] 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 CWFPS 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[22] 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-B lists thermal generators that have signed agreements to connect to the island over the next few years. These generators are all due to connect in Ireland only.

Plant	Date	Capacity (MW)
Meath Waste to Energy	Feb 2011	17
Nore Power	Apr 2012	98
Dublin Waste to Energy	Dec 2012	72
Cuilleen OCGT	Jan 2013	98
Suir OCGT	Jan 2014	98
Caulstown GT	Apr 2014	55
Knocknagreenan Pumped Storage	Jun 2014	70

Table 3-B Confirmed new conventional generation capacity for the island.

[18] www.eirgrid.com/operations/gridcode/
[19] www.esb.ie/esbnetworks/en/about-us/our_networks/distribution_code.jsp
[20] www.soni.ltd.uk/gridcode.asp
[21] www.nie.co.uk/suppliers/distribution.htm
[22] *i.e. a signed Connection Offer has been accepted and any conditions precedent fulfilled.*

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

Endesa have plans to commission new plant immediately after the closure of the existing units at Great Island and Tarbert (see section 3.5(a)). However, as no official connection agreement has yet been signed, we are assuming that no new plant is built at these locations in our base case scenario.

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 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.

It is for this reason that at Ballylumford only two units from Unit 4, Unit 5 or Unit 6 are included in the adequacy analysis each year. In each year the predicted Forced Outage Probability (FOP) used in the study for the two units included have been reduced 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.

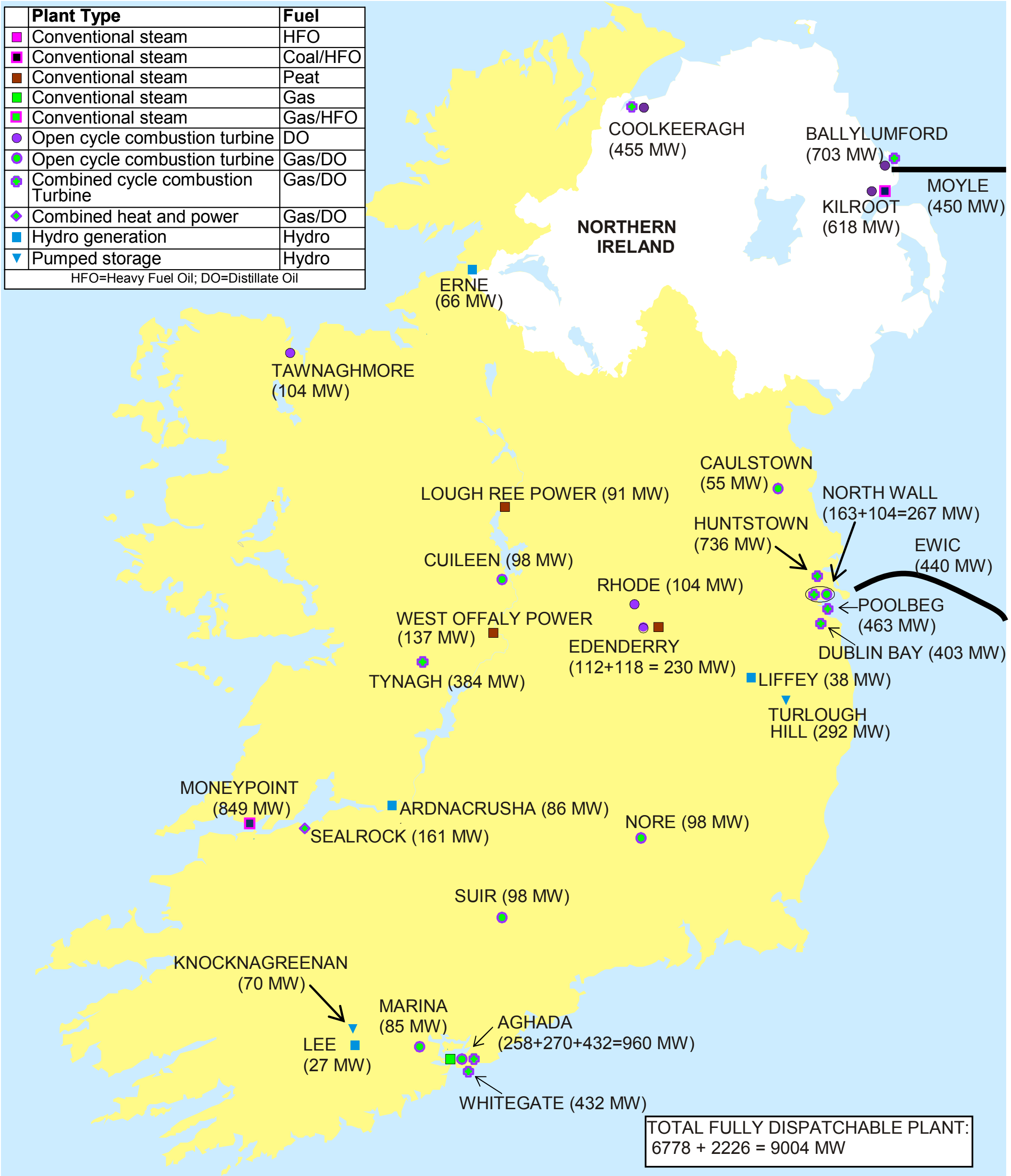

Figure 3-1 Fully dispatchable plant installed in 2017, at exported capacities. All figures shown are maximum export capacities – generators may often operate at a lower export capacity.

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 7 years. Confirmed decommissionings are shown in Table 3-C.

Plant	Date	Capacity (MW)
Tarbert Units 1,2 and 3	June 2013	349
Great Island	Sept 2013	212
Tarbert 4	Dec 2015	241
Ballylumford Units 4,5 & 6	Dec 2015	510

Table 3-C Confirmed closures of conventional generators.

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 around the end of next year. This will remove 85 MW from the island's generation capacity. As ESB have the option to upgrade the plant, we have not removed it from our base case studies.

3.6 INTERCONNECTION

Interconnection allows the transport of electrical power between two transmission systems. EirGrid and SONI are due to complete two large interconnection projects over the next few years.

3.6(a) North-South Interconnection

The completion of the second high capacity transmission link between Ireland and Northern Ireland will allow the consolidation of demand and supply on an all-island basis for assessment of system adequacy. Therefore, from 2015 onward, an all-island generation adequacy assessment has been carried out. In this all-island assessment, the demand and generation portfolios for Northern Ireland and Ireland are aggregated.

Prior to the completion of this 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. It has been agreed that each TSO will apply a No Load Loss Sharing (NLLS) policy, where each system is obliged to help the other only to the extent of any surplus it may have at the time. The TSOs have developed a 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 the importing party as a final step to maintain system integrity.

To define the capacity benefit of the current NLLS policy, each TSO undertakes adequacy assessments in each system with a formal degree of capacity interdependence. This will lead to capacity benefits on the island. 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-D .

	North to South	South to North
Transfer Capacity	450 MW	400 MW
Capacity Reliance	200 MW	100 MW

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

3.6(b) Moyle Interconnector between Northern Ireland and Scotland

The Moyle Interconnector is a dual monopole HVDC link with 2 coaxial under sea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The total installed capacity of the link is 500MW but the transfer capability is curtailed by certain network limitations on both sides.

The available Net Transfer Capacity (NTC) is 450MW during the winter and 410MW from April to October inclusive. However, it should be noted that this NTC figure may change in the future due to EU legislation. An emergency flow of up to 50MW is available should the frequency in Ireland reach 49.6Hz and a further 25MW available at 49.5Hz. All interconnector capacity is auctioned by the Transmission System Operator (TSO) in NI on behalf of Northern

Ireland Energy Holdings[23]. 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 450MW.

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 78.5 GW of installed generation 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 450MW 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.

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 can 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, EirGrid has estimated the capacity value of the interconnector to be 440MW for our studies.

3.7 WIND CAPACITY & RENEWABLES TARGETS

In both Ireland and Northern Ireland, there is existing government policy relating to the amount of electricity sourced from renewables. Biofuels and marine energy will make an important contribution to these targets (see sections 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 3-7 shows the location of existing and planned wind generation on the island.

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 over 1,400 MW at the time of writing. This value is set to increase rapidly 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. We estimate that an installed wind capacity of around **4,350 MW** will be enough to achieve the 40% figure. A certain amount of this contribution is from offshore wind generation, as set out in Ireland's National Renewable Energy Action Plan (NREAP[10]).

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[23] www.nienergyholdings.com/The_Moyle_Interconnector/Index.php

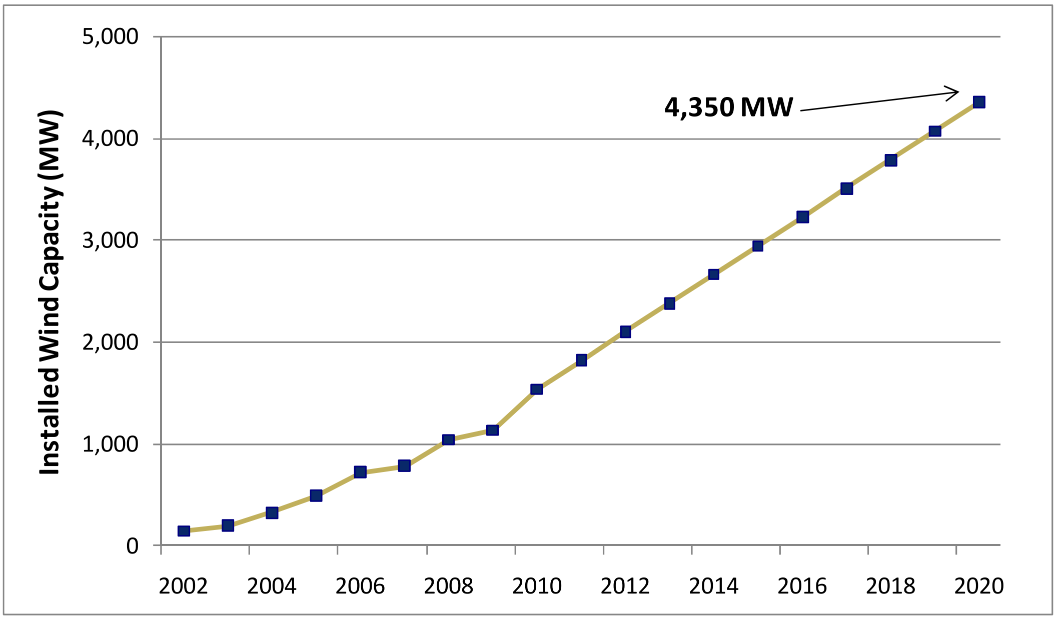

Figure 3-2 Wind levels for Ireland assumed for this report, determined using a linear projection of installed wind capacity required to meet 2020 targets.

The assumptions for the above figure take into account the contribution of other renewables (see section 3.8). It is assumed that onshore wind has a capacity factor of 30.8%, and offshore 37%. It is also assumed that a small percentage of wind generation cannot be used due to constraints or curtailment.

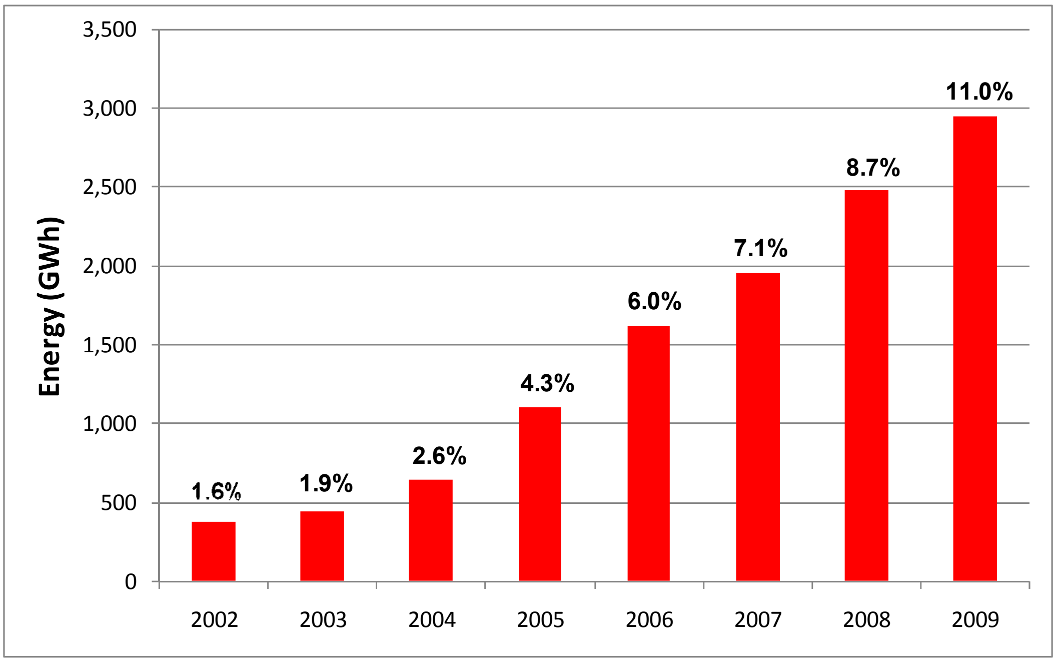

Figure 3-3 Historical wind generation in annual energy terms for Ireland, also given as a percentage of total electrical energy produced that year.

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. Historical 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. An average capacity factor of 30.8% was used for future wind years for calculations in this report.

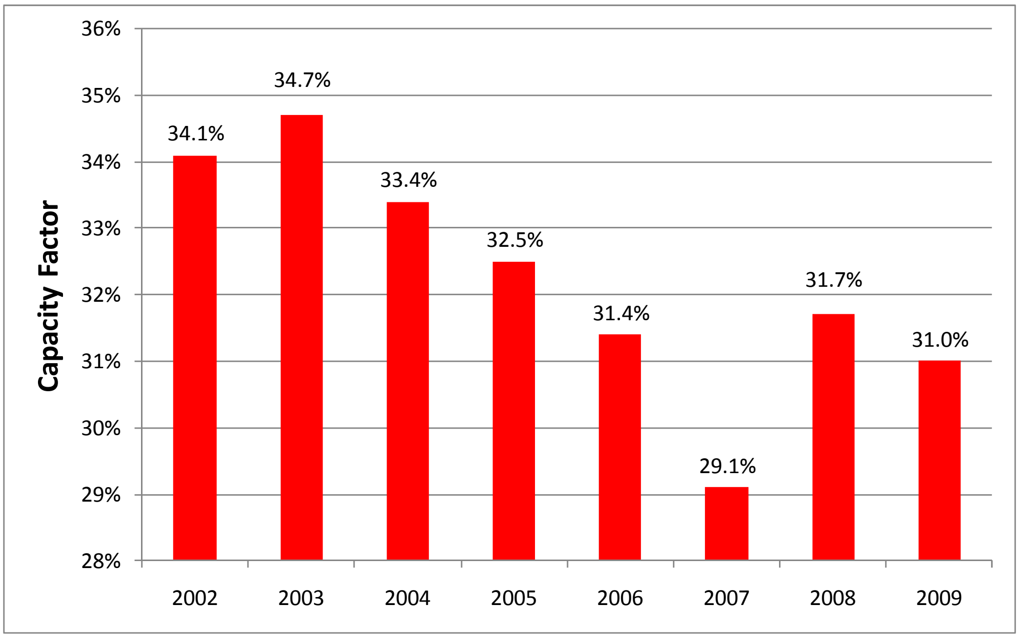

Figure 3-4 Historical wind capacity factors for Ireland.

The Government's White Paper on renewable energy[24] declares that 15% of electricity should be produced from renewable sources by 2010. Ireland currently has enough wind generation to achieve this target on a typical wind year. However, the wind capacity factor for 2010 has been very disappointing so far, and may turn out to be the worst year on record. An estimate of the monthly capacity factors to date is shown in Figure 3-5. This low wind yield to date will make it harder to achieve the 15% target for 2010.

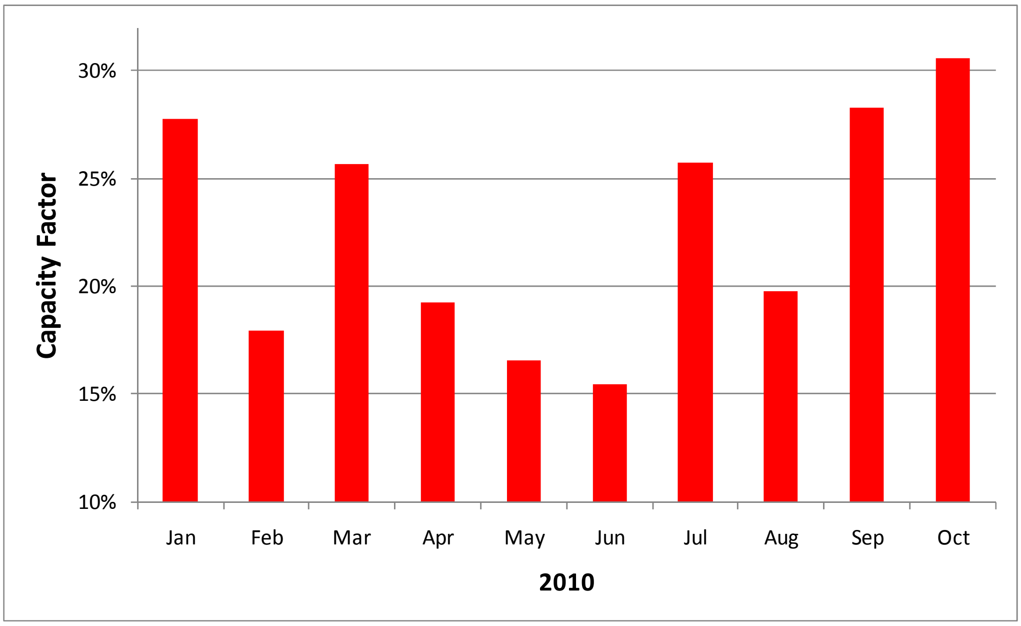

Figure 3-5 Monthly wind capacity factors in Ireland for 2010.

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

3.7(b) Northern Ireland

In September 2010 DETI published the Strategic Energy Framework for Northern Ireland[25]. This restated the current target of 12% of electricity consumption from renewable resources by 2012 and confirmed a new additional target of 40% of electricity consumption from renewable resources by 2020.

Installed capacity of wind generation has grown from 37 MW in 2002 to over 335 MW at the time of writing (see APPENDIX 2). This is set to increase rapidly over the next years as increasing levels of planning applications[26] 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.

Using the current median load forecast, it is estimated at this stage that to reach the 40% target by 2020, circa 1,100 MW of installed onshore and offshore wind capacity in Northern Ireland would be required. This also takes into account the contribution of other renewables as outlined in section 3.5. This assumes that wind has a capacity factor of 33%, 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 3-7 below illustrates the wind levels in Northern Ireland assumed for this report. Most of this wind will be built on the west of Northern Ireland, and transmission reinforcements will be required to transport it to the east, where demand is highest. To avoid considerable 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 3-7 are dependent on a number of key transmission corridors being reinforced by the asset owner, Northern Ireland Electricity.

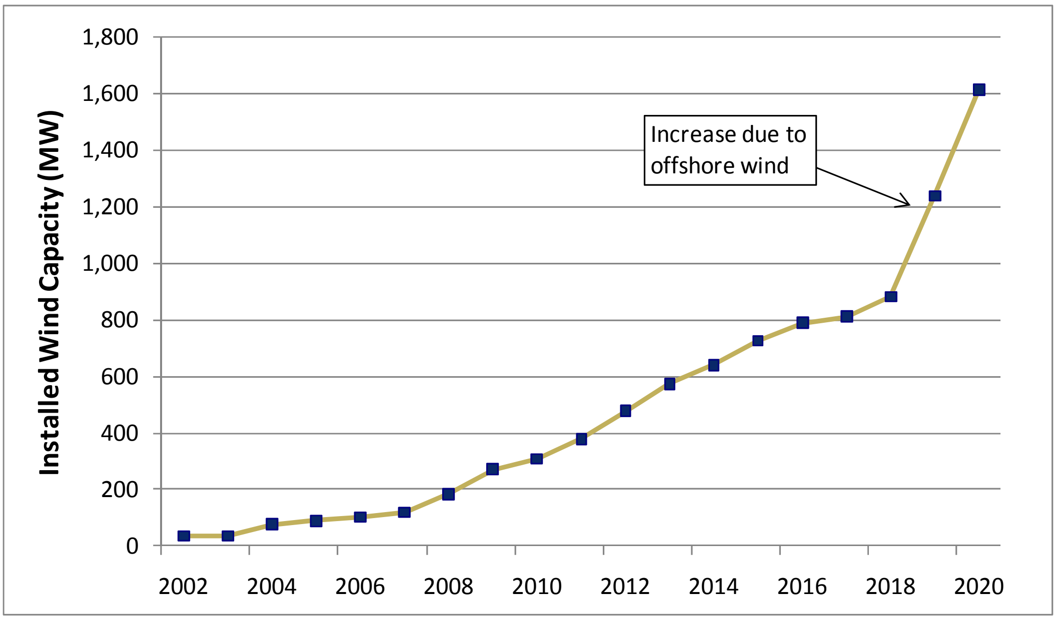

Figure 3-7 Northern Ireland wind levels assumed for this report

[25] *Strategic Energy Framework (www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf)*
[26] *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*

Figure 3-8 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.

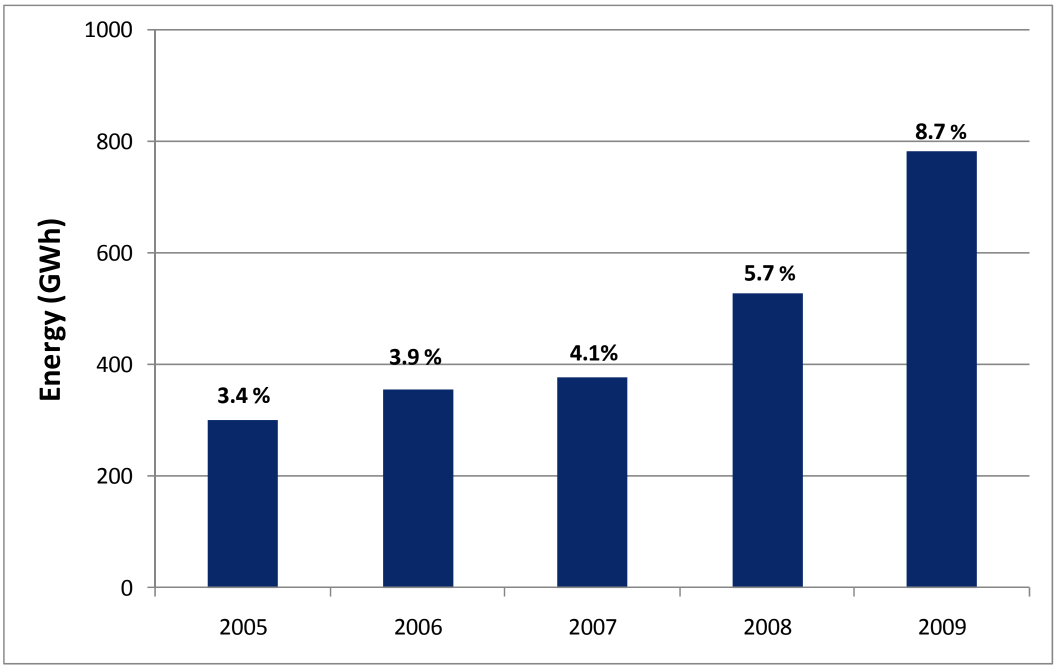

Figure 3-8 Historical wind generation in annual energy terms for Northern Ireland, also given as a percentage of total electrical energy produced that year.

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. Historical capacity factors for Northern Ireland are shown in Figure 3-9. The average wind capacity factor for the last 5 years is 33.1%.

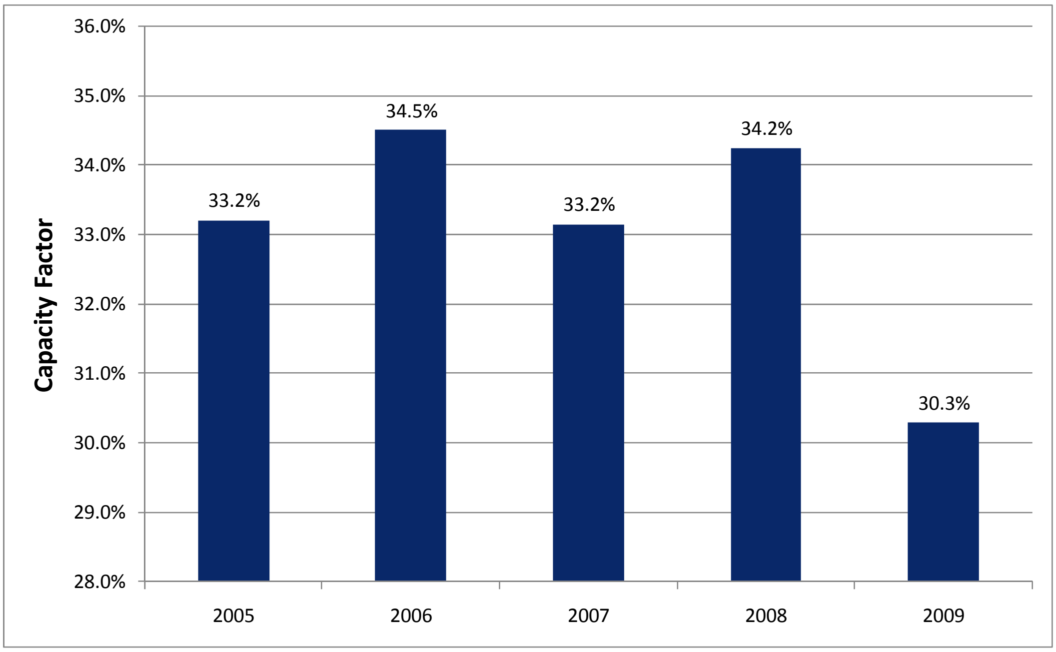

Figure 3-9 Historical wind capacity factors for Northern Ireland.

3.7(c) *Wind Capacity Credit*

Due to Ireland's small geographical size, wind levels are strongly correlated across the country. Wind generation across Ireland 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 MWs 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. Our analysis showed the behaviour of the 2009 profile to be close to average in terms of capacity credit.

It can be seen in Figure 3-6 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.

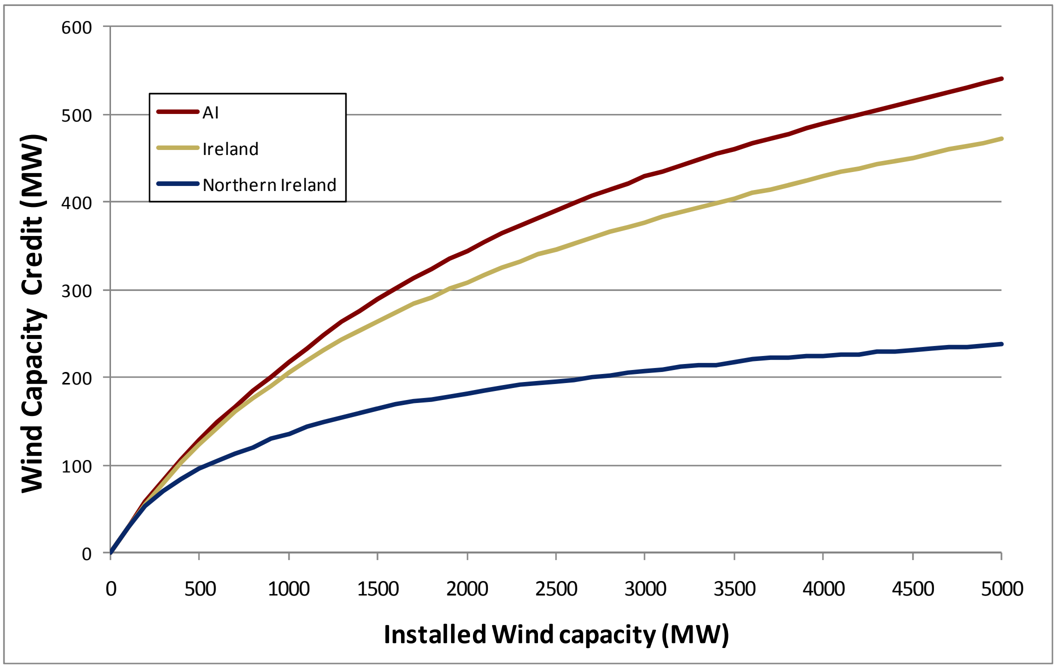

Figure 3-6 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation. The wind profiles were taken from 2009.

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.

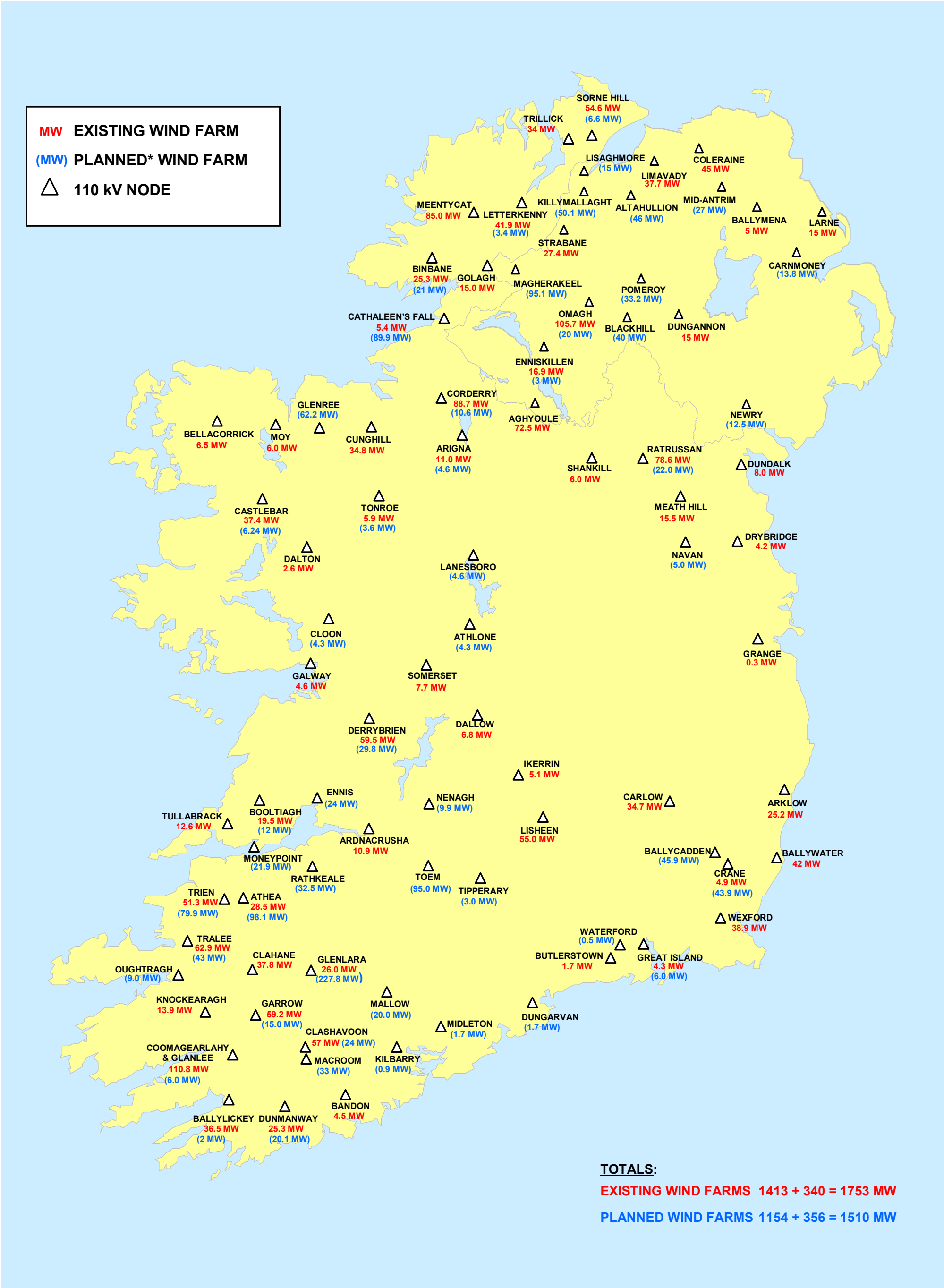

Figure 3-7 Existing and planned wind farms, as of the data freeze date. 'Planned' refers to wind farms that have signed a connection agreement with EirGrid in Ireland, or that have received planning approval in Northern Ireland.

3.8 CHANGES IN SMALL SCALE GENERATION & MARINE ENERGY

This section discusses expected developments in CHP, demand side generation, small scale hydro, biofuels and marine energy over the next 10 years. All assumptions regarding small-scale generation and are tabulated in APPENDIX 2.

3.8(a) Biomass & Biogas

In Ireland, there is currently an estimated 11 MW of solid biofuels and 35 MW of landfill gas powered generation. This excludes the biomass contribution from peat plant at Edenderry, which aims to power 30% of its output using biomass by 2015. For the purpose of this report it has been assumed that installed biomass & biogas capacity will rise steadily to a total of 74 MW by 2020.

Currently in Northern Ireland, there is an estimated 1 MW of solid biofuels and 13 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 2020 solid biomass capacity will rise to 2 MW while landfill gas powered generation capacity will reach 27 MW. It should be noted that DETI has recently revised the Northern Ireland Renewable Obligation (NIRO)[27] to increase support to less developed technologies such as bioenergy.

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 of roughly 130 MW in Ireland (not including the 161 MW centrally dispatched CHP plant operated by Aughinish Alumina).

As an indication of current activity by developers of CHP, there are 70 MW of projects applying to connect to the grid in Ireland. A 72 MW Waste-to-Energy plant due to commission by 2013 will also produce usable heat. The base case assumption for this report is that 5 MW of CHP will be added each year in Ireland over the next ten years.

In Ireland, the Government targets[28] for CHP are for 400 MW by 2010 and 800 MW by 2020. Given the current amount of CHP applications in the queue, it is evident that there is a need for a significant increase in CHP development to meet these targets.

In Northern Ireland, there is currently an estimated 8 MW of small scale CHP connected to the distribution system. This does not include the three 3 MW centrally dispatched units that is operated by Contour Global. Without detailed public information an assumption has been made that for the purposes of this statement, the estimated 8 MW in 2010 will rise to 19 MW by 2017 and to 22 MW by 2020 in Northern Ireland.

Currently CHP is promoted in accordance with the European Directive 2004/8/EC. The Strategic Energy Framework[29] for Northern Ireland acknowledges that the uptake of CHP in the region has been limited and therefore DETI have decided to encourage greater scope for combined heat and power in Northern Ireland.

3.8(c) 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 at 1 MW from 2015, rising to 3 MW in 2020.

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[27] *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*

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

[29] *www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf*

3.8(d) Small-scale hydro

It is estimated that there is currently 22 MW of small-scale hydro capacity installed in rivers and streams across Ireland, with a further 3 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

In Northern Ireland the marine energy assumptions for the purposes of this report are based on the Strategic Environmental Assessment (SEA)[30]. This proposes a target of 300 MW from tidal generation by 2020. It is unclear at this stage as to which tidal technology will be used to achieve this, however, for the purposes of this report it is assumed that this tidal generation capacity will be phased in from 2018 to 2020.

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.

3.9 PLANT AVAILABILITY

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

The base case availability scenario used in this report combines availability figures calculated by EirGrid (see section 3.9(a)) for Ireland, and SONI's high availability forecast for Northern Ireland. While this is considered to be the most likely scenario, other availability scenarios have been examined to prepare for a range of possible outcomes.

3.9(a) Ireland

Figure 3-8 shows the forced-outage rates (FOR)[31] 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 bringing in 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[32] will likely lead to poorer availability in 2010 and 2011.

The operators of fully-dispatchable generators have provided forecasts of their availability performance for the seven year period 2011 to 2017. To create a 10 year adequacy assessment, we have extrapolated these figures. 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.

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[30] *http://www.offshorenergyni.co.uk/Data/NTS_FINAL_DEC_09.pdf*

[31] *FORs are simply the percentage of generation over a year that is unavailable due to forced outages.*

[32] *Both Turlough Hill and North Wall CC are currently experiencing major outages which may last several months*

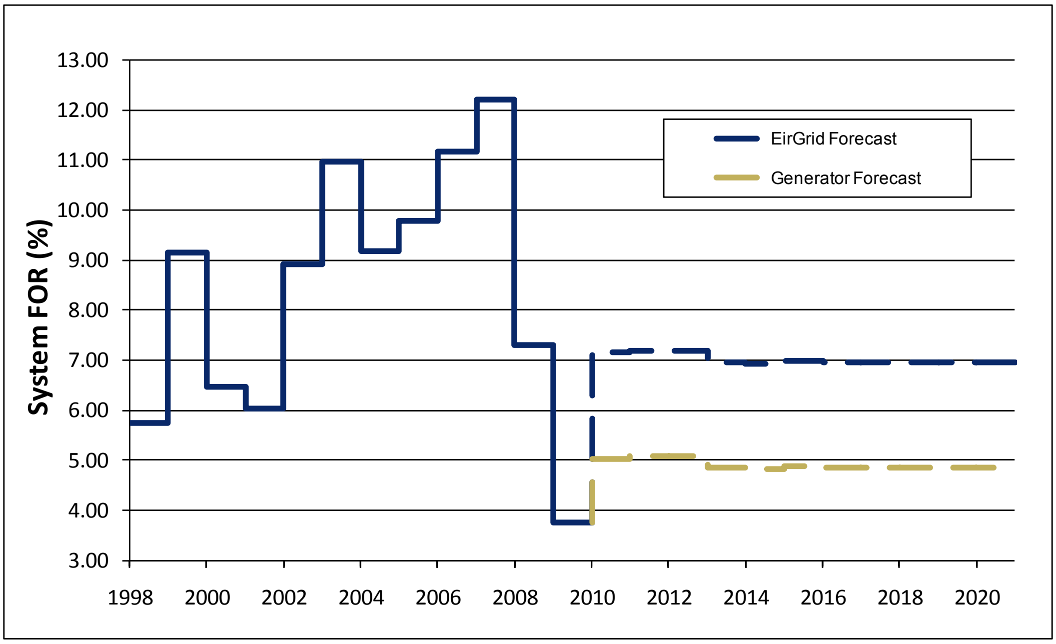

Figure 3-8 Historic and predicted Forced Outage Rates for Ireland. Future rates as predicted by both EirGrid and the generators are shown. Due to its atypical outage rates, Poolbeg Unit 3 has been excluded from historic calculations.

HILP events are unforeseen events that don't often transpire but, when they do occur, will have a significant adverse impact on a generator's availability performance, taking it out of commission for several weeks. The probability of this occurring to an individual generator is low. However, when dealing with the system as a whole, there is a reasonable chance that at least one generator is undergoing such an event at any given time. EirGrid studies[33] 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 our studies.

3.9(b) Northern Ireland

Generators are obligated to provide SONI with planned outage information in accordance with the Grid Code (OC2). 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 do have a concern that these patterns may change as a result of increased two shifting. Two shifting is where a generator is taken off overnight or at min load times. This will occur more frequently with increased penetration of wind generation, and will result in the requirement for additional maintenance and increased SODs. SONI will continue to monitor the operation of plant and the impact of this on availability.

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

[33] *see GAR 2009-2015*

Figure 3-9 shows the system forced-outage rates (FOR) for Northern Ireland since 2003, as well as predicted values for the study period of this report. 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 economic downturn, which means older peaking units are called on less often, giving them less of an opportunity to fail.

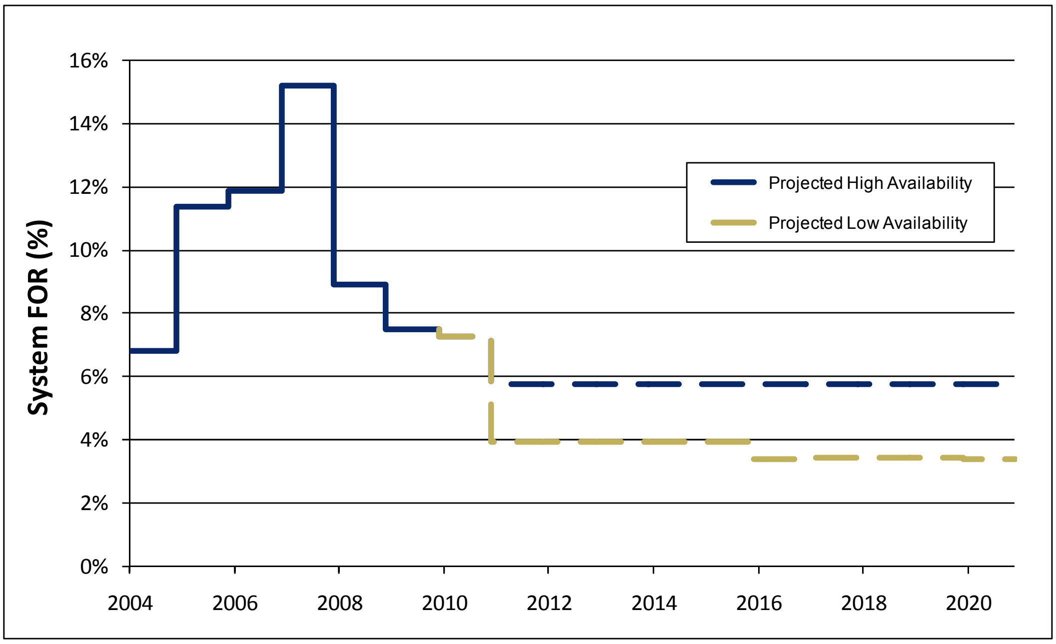

Figure 3-9 Historic and predicted Forced Outage Rates for Northern Ireland.

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 3-10 show the historic availabilities in Northern Ireland along with the projected high and low availabilities. The average high availability over the 10-year period is 91.1% and the low availability figure is 89.0%. This analysis is focused on conventional generation plant and does not include the Moyle Interconnector. The availability of Moyle has been much higher than conventional generation as one would expect from a modern HVDC link.

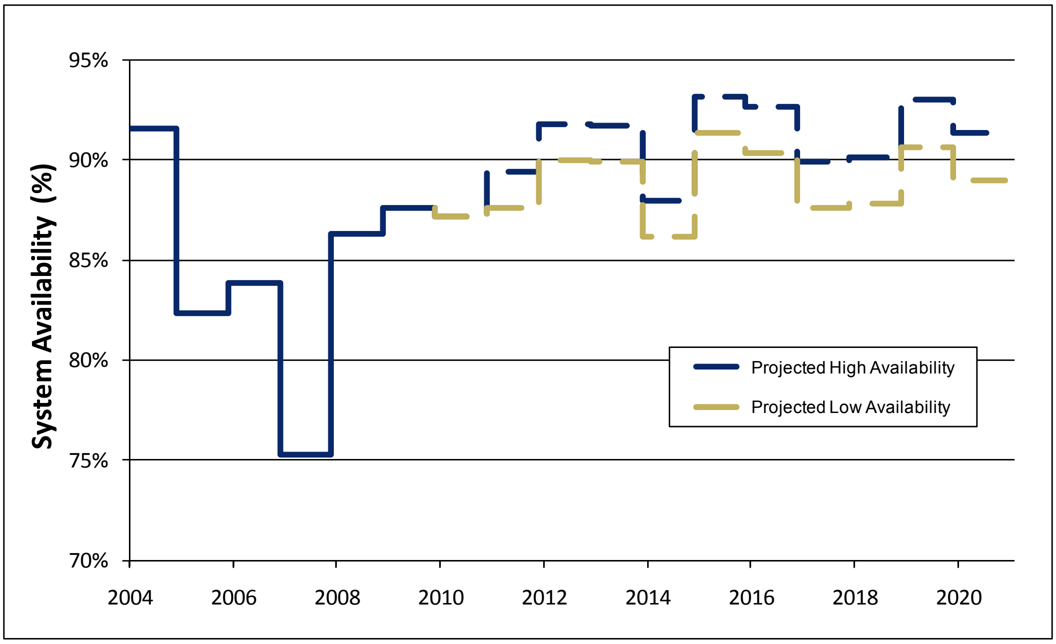

Figure 3-10 Historic and predicted Plant Availabilities in Northern Ireland.

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 are considered good. The low availability has been calculated with a pessimistic view of FOPs, where the performance of all generators drops to a level corresponding to the worst performing unit on the system.

4 Adequacy Assessments

4 ADEQUACY ASSESSMENTS

4.1 INTRODUCTION

In this section, we present the results from our adequacy studies. We give these results in terms of the resulting plant surplus or deficit (see APPENDIX 3 for information on the methodology used). Results are shown on an Ireland, Northern Ireland, and all-island basis. The completion of the North-South Interconnector allows us to treat adequacy on an all-island basis.

We examine different demand growth and plant availability scenarios and their effect on adequacy. We also consider the effects of the loss of a CCGT in each jurisdiction, and also the loss of aging plant in Ireland. All results are presented in full in APPENDIX 4.

4.2 BASE CASE

The results from our base case scenario out to 2020 are shown in Figure 4-1. The base case assumes median demand growth, the EirGrid calculated availability for the generation portfolio in Ireland, and the high availability (based on historic performance) for the Northern Ireland generation portfolio. We have indicated any significant changes to the generation portfolio. In addition to these, demand growth 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.

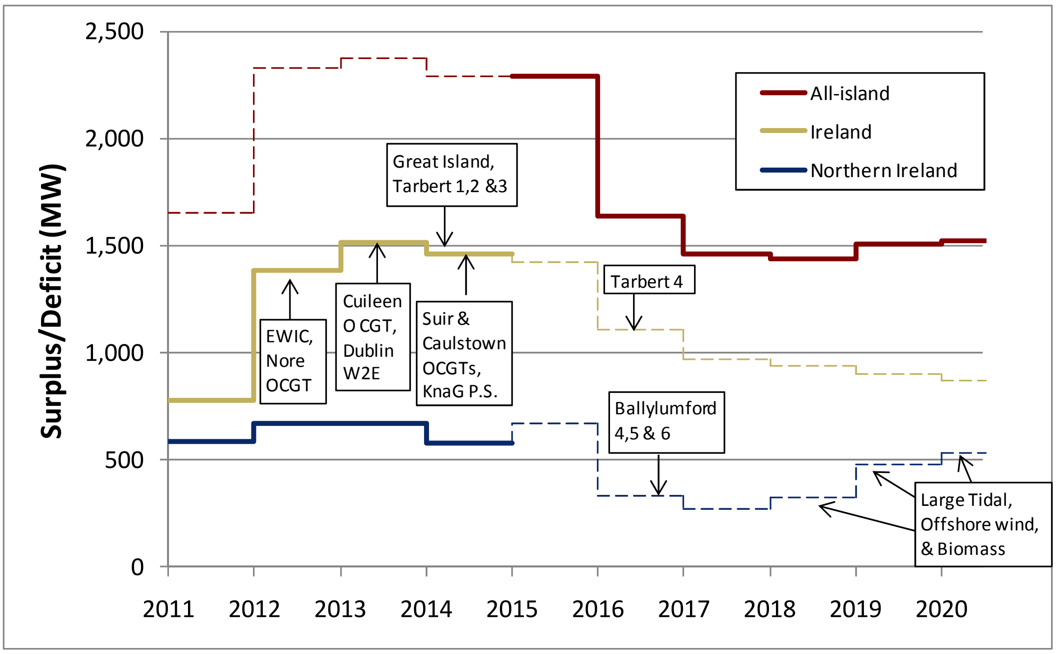

Figure 4-1 Adequacy results for the base scenario, shown for Ireland, Northern Ireland, and on an all-island basis. Major changes in the portfolio have been indicated.

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 particularly large over the next 5 years, with the closure of old plant more than compensated for by additional interconnection and new plant joining the island.

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 300MW 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.

4.3 IMPACT OF DEMAND GROWTH

Changing demand will have an obvious impact on generation adequacy. The effect of different demand forecasts on the adequacy situation is illustrated in Figure 4-2 and Figure 4-3, 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 low demand scenario leads to increased adequacy when compared with the base case, and the high demand to reduced adequacy. In Ireland, even the high demand scenario consistently shows positive adequacy, with a generation surplus of at least 600 MW for all years.

In Northern Ireland the lowest surplus for the high demand scenario is circa 200 MW, occurring in 2017, again highlighting the importance of additional interconnection capacity to enable SONI to maintain generation security standards in Northern Ireland.

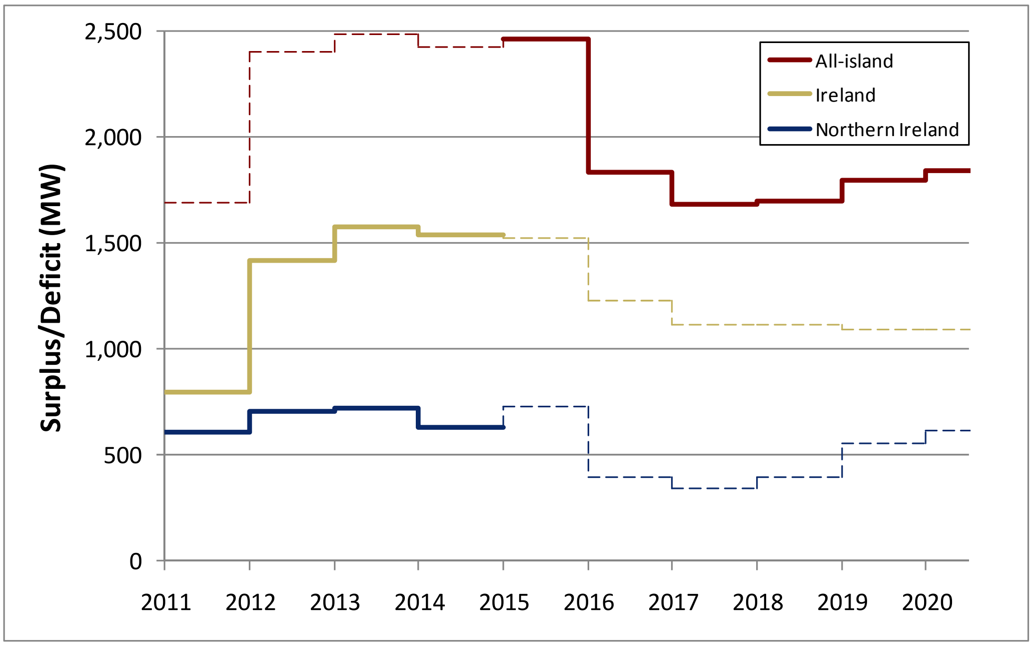

Figure 4-2 Adequacy results for the low demand scenario, using the base case availability forecast.

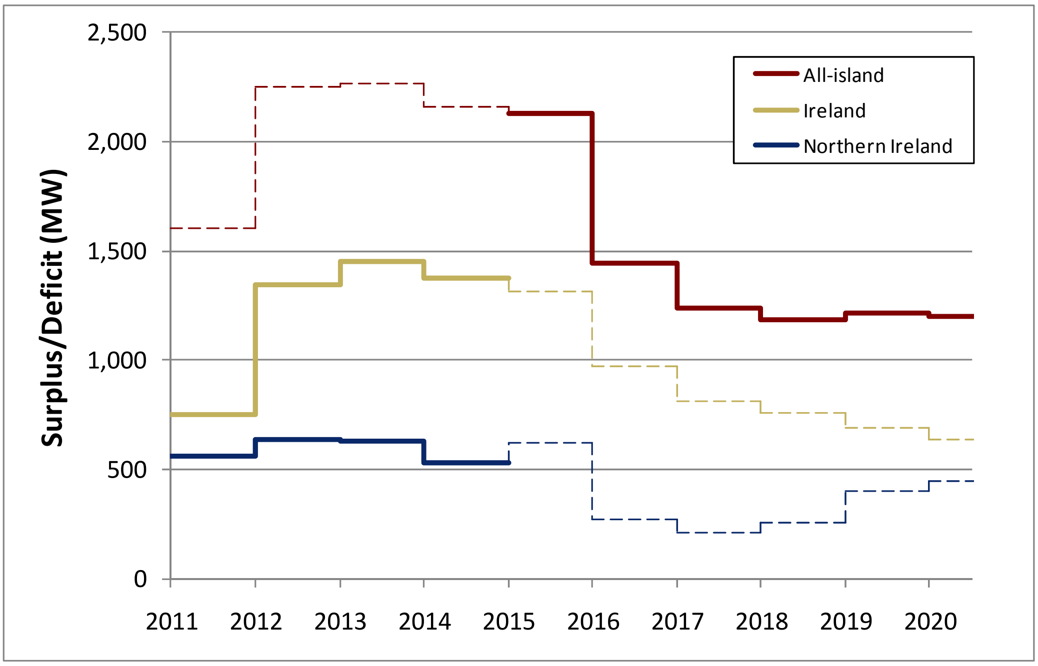

Figure 4-3 Adequacy results for the high demand scenario, using the base case availability forecast.

4.4 IMPACT OF PLANT AVAILABILITY

The effect of different plant availability scenarios are illustrated for Ireland in Figure 4-4 and for Northern Ireland in Figure 4-5, with demand at the median growth level.

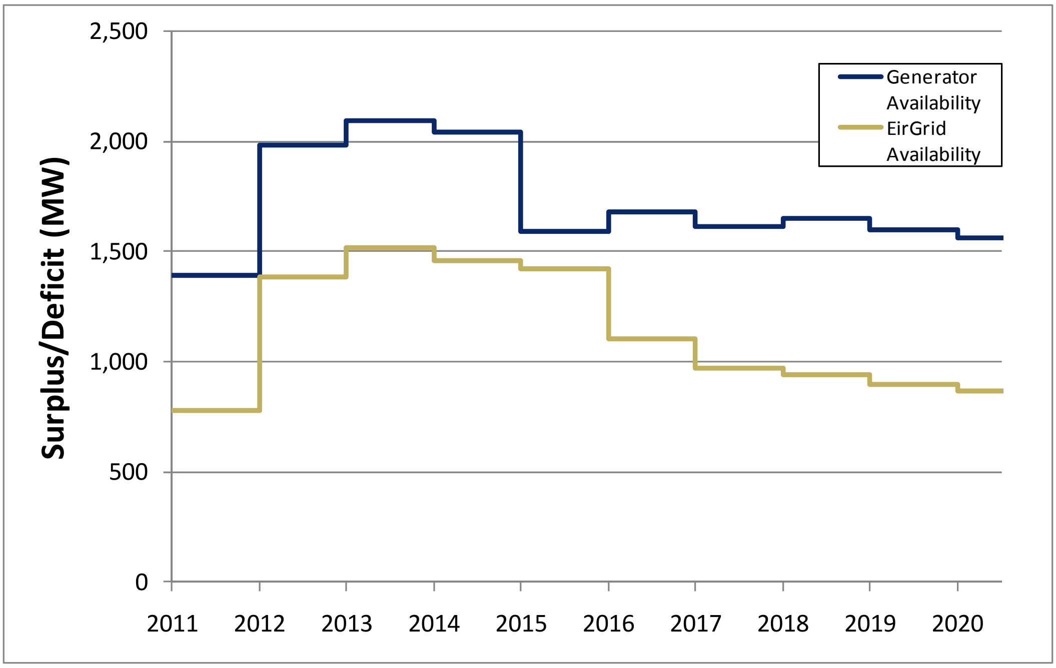

Figure 4-4 Adequacy results for Ireland, calculated using EirGrid's availability estimates and the availabilities as provided by the generators. The median demand forecast is assumed.

EirGrid obtain availability figures for Ireland directly from the generators, however historically these have not given a good forecast of overall system availability. As a result, EirGrid carry out there own system availability forecast - see section 3.9(a). For both availability scenarios, the system shows surplus availability over the study period. However the surplus is much larger in the generator availability scenario. There is an average surplus difference of 580 MW between using the generators availability forecast and EirGrid's prediction of availability.

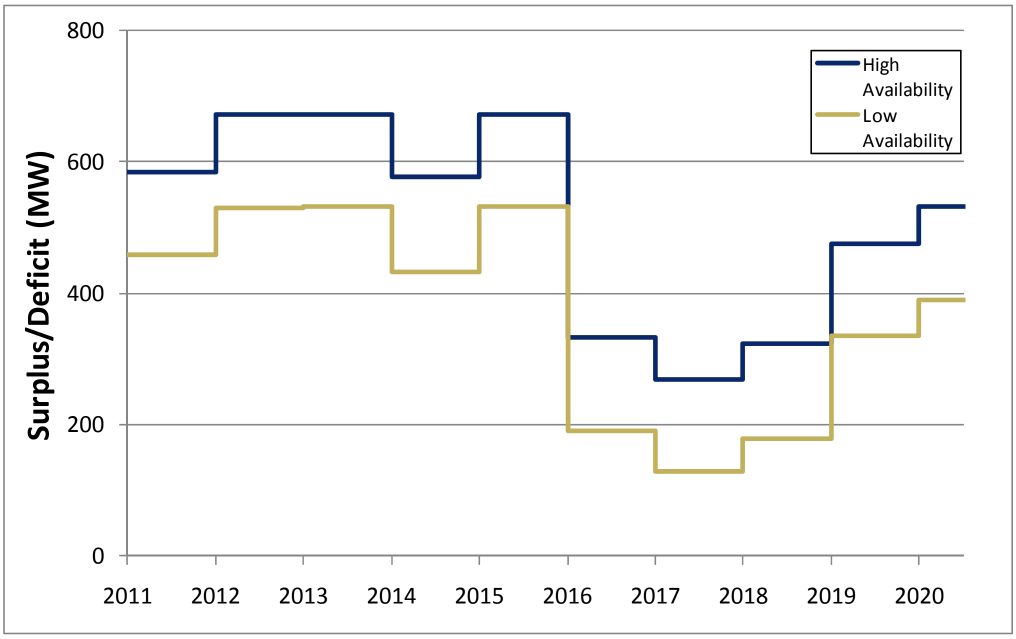

Figure 4-5 Adequacy results for Northern Ireland, calculated using the low and high availability estimates. The median demand forecast is assumed.

For Northern Ireland, the future availability predictions are based on the historic performance of generators and where data is unavailable, for example newly commissioned plants, by making comparisons with similar units, with the values used being discussed with the generators where possible. Historic performance is also used to determine future availability for the Moyle Interconnector.

The high availability scenario is based on this actual historic performance of generators in Northern Ireland, which are considered good. The low availability has been calculated with a pessimistic view of availability, where the performance of all generators drops to a level corresponding to the worst performing unit on the system. There is an average surplus difference of 140 MW between using the low and high availability scenarios in Northern Ireland.

4.5 SCENARIO: LOSS OF 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. We have considered a scenario where a major combined cycle generator is out of action in both Northern Ireland and Ireland. The results of this study are shown in Figure 4-6, where demand and availability assumptions are as per the base case.

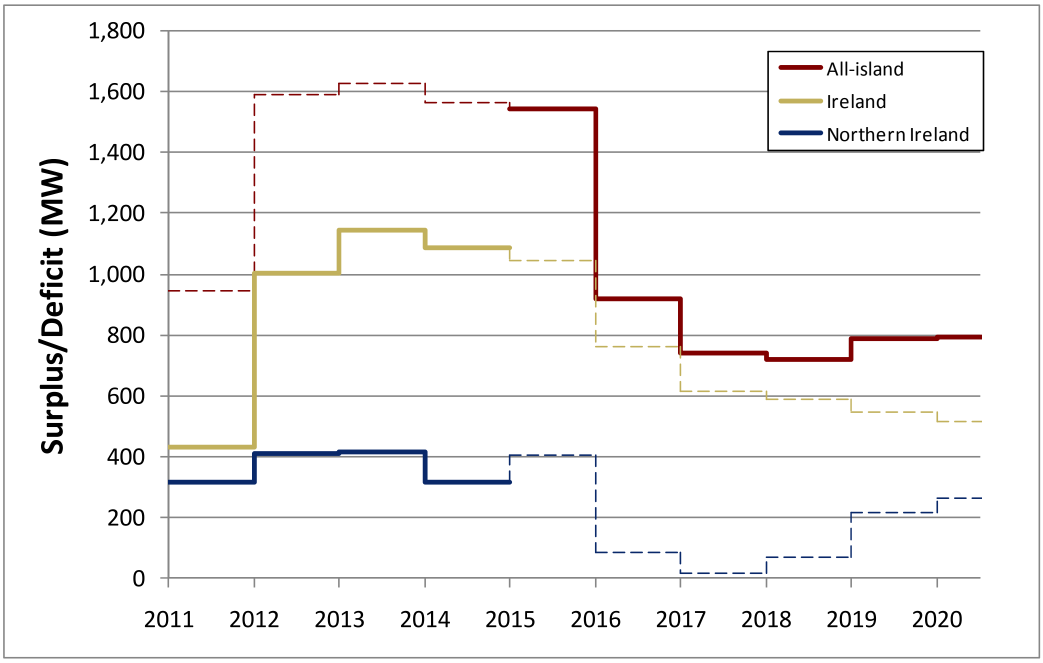

Figure 4-6 Adequacy results for scenario showing the loss of a major CCGT in each of the jurisdictions. The base-case availability and medium demand scenarios are assumed.

In Ireland, a positive adequacy position is seen across all years for this scenario. In Northern Ireland, there is only just a positive adequacy position, when the surplus is reduced to circa 20 MW in 2017. This would leave SONI in a potentially difficult situation in terms of maintaining the generation security standards in Northern Ireland.

Figure 4-7 shows results from the same study, using the low availability assumption was used for Northern Ireland.

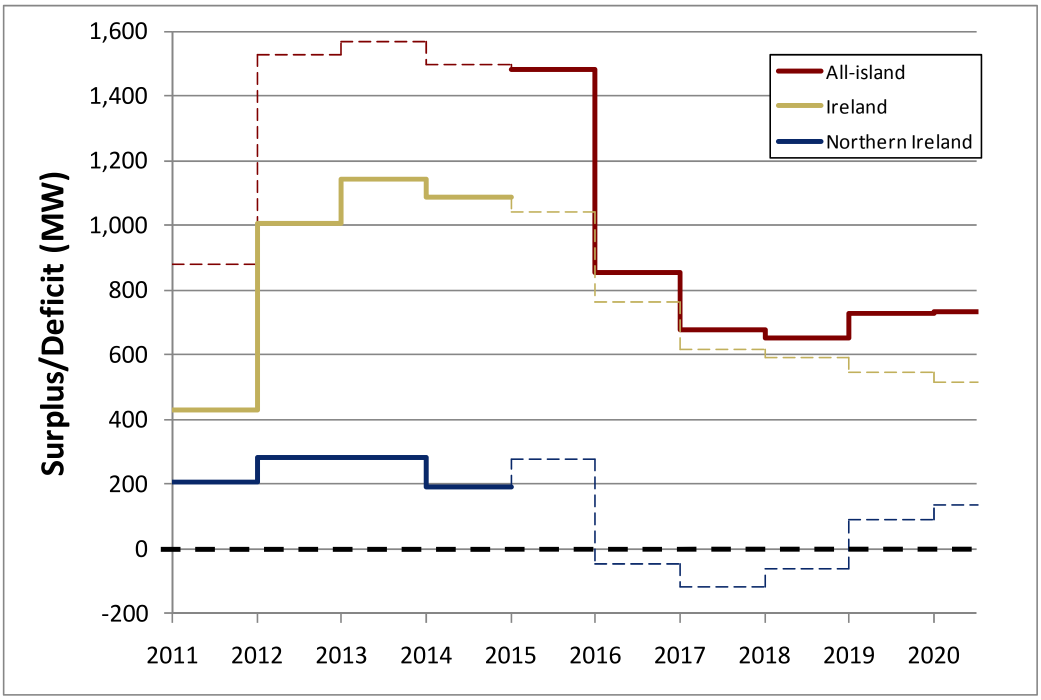

Figure 4-7 Adequacy results for scenario showing the loss of a major CCGT in each of the jurisdictions. The low availability and medium demand scenarios are assumed for both regions.

In Ireland, a positive adequacy position is once again seen across all years for this scenario.

In Northern Ireland the results show that the loss of a major CCGT would lead to a deficit from 2016 through to 2019 with the highest deficit being circa 100 MW in 2017. This deficit is accentuated if the high demand and low availability scenario is assumed, as shown in Figure 4-8.

This more onerous scenario indicates an even greater deficit position, with the highest deficit being circa 200 MW in 2017. This analysis highlights the importance of additional interconnection capacity to enable SONI to maintain generation security standards in Northern Ireland. It should be noted that if the additional North-South Interconnector should not be in place until 2017, then this would leave Northern Ireland below the 4.9 hours/year LOLE standard and in a capacity deficit under this scenario.

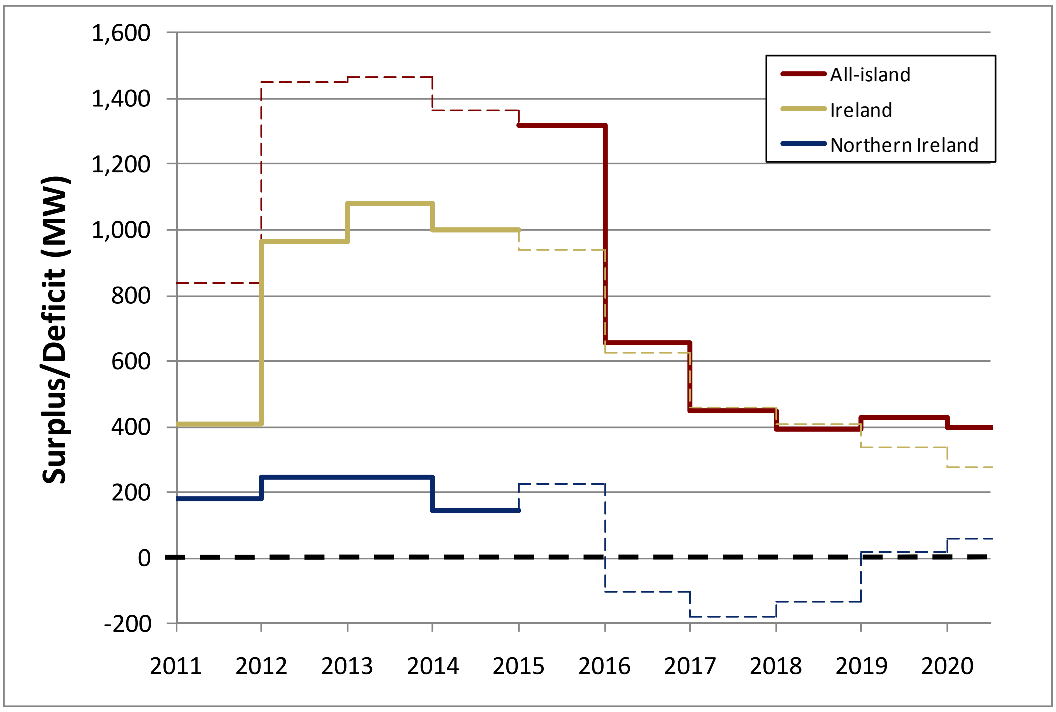

Figure 4-8 Adequacy results for scenario showing the loss of a major CCGT in each of the jurisdictions. The low availability and high demand scenarios are assumed for both regions.

4.6 SCENARIO: CLOSURE OF OLD PLANT IN IRELAND

The introduction of European legislation[34] means that generators must adhere to strict emission limits. Recently, further legislation[35] has made these emission limits even more stringent. Ireland has National Emissions Reduction Plan which control the maximum emissions from older generators until 2016. After this, some of these generators must either be improved to reduce their emissions, or shut down.

We have developed a scenario in which these older generators are phased out of commission. While ESB have not notified EirGrid of any plant decommissionings, EirGrid must prepare against uncertainties which may have severe consequences on security of

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

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

supply. For this scenario, EirGrid have therefore made our own best estimation on which generators to phase out and when.

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 4-9 shows the results from this study, using the same demand and availability assumptions as the base case. While a sharp drop in surplus generation is seen post 2016, none of the systems show an adequacy deficit over the study period.

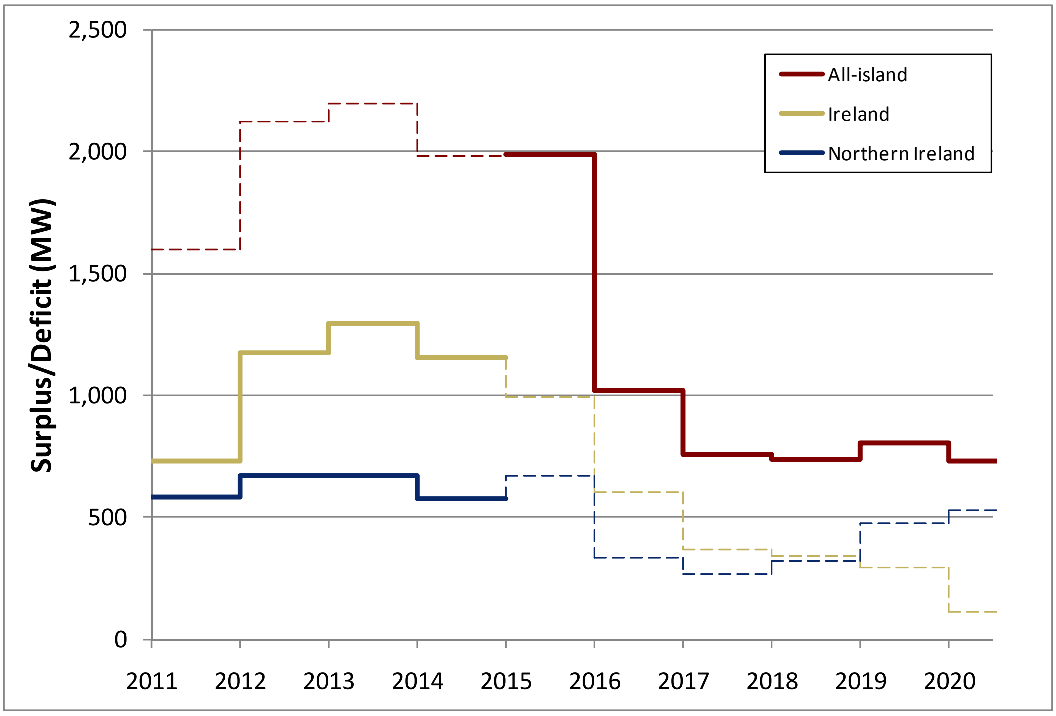

Figure 4-9 Adequacy results for scenario showing the removal of older plant from Ireland's portfolio. The base case availability and medium demand scenarios are assumed for both regions.

Figure 4-10 shows the results from the same study, except the high demand scenario has been used for both regions. This scenario shows the Ireland system to be in deficit by 2020. However, the all-island system is in adequacy for all years. As the second North-South tie-line is due to be completed well before 2020, there should not be any adequacy issues.

In Northern Ireland, under this scenario, a positive adequacy position is seen across all years in line with the Northern Ireland base case scenario

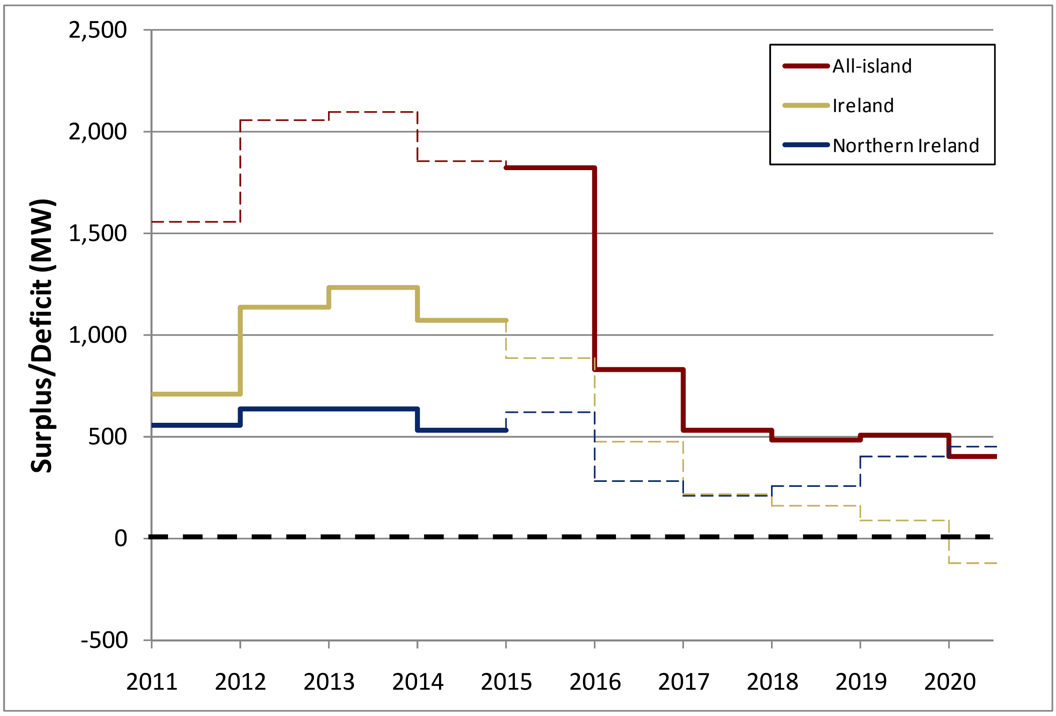

Figure 4-10 Adequacy results for scenario showing the decommissioning of older plant from Ireland portfolio. The base case availability and high demand scenarios are assumed for both regions.

5 Adequacy & the Weather

5 ADEQUACY & THE WEATHER

Generation adequacy can by and large be ensured by a mixture of appropriate government policy, suitable market signals, and intelligent regulation and planning. However, there is one factor which can have a significant effect on the security of electricity supply, and it is one which is difficult to predict and impossible to control – the weather.

Severe cold spells in Northern Europe can have a detrimental effect on electricity supplies. Demand spikes occur in cold weather, due to for example electric heating, and can coincide with damage to power lines due to ice loading. Cold weather can increase the likelihood of failure when starting up thermal plants, and the high pressure weather systems that bring freezing conditions often mean a low capacity factor for wind.

In this section we look at the risk extreme weather events bring to the transmission systems in Ireland and Northern Ireland. We discuss this in the context of the unusually cold winter of 2009/10.

5.1 PEAK DEMAND & TEMPERATURE

High demand puts security of supply under pressure. For most countries in Northern Europe, highest demand occurs during the winter peak, which typically takes place during the coldest week of the year[36]. Our forecasts for future peaks are based on trends in historical annual peaks. However, these historical peaks must be corrected, as an unusually cold or mild winter will affect the data.

Previous studies[37] have examined the relationship between demand and temperature in Ireland. These studies show demand increasing as temperatures drop, with a sharper rate of demand increase the cooler it gets. This relationship is outlined in Figure 5-1. In warmer countries, a similar pattern occurs as you increase temperatures above 25° C or so, and air-conditioning and refrigeration units are forced to work harder, drawing more power. Temperatures in Ireland are rarely high enough for this effect to be noticeable.

[36] *There are exceptions to this, e.g. if coldest week occurs during the Christmas season*

[37] *Fay, Damien and Ringwood, John V. and Condon, Marissa and Kelly, Michael (2002), Proceedings of the 22nd International Symposium on Forecasting, June 23-26 2002, Dublin.* http://eprints.nuim.ie/1968/1/JR_C81dfisf.pdf

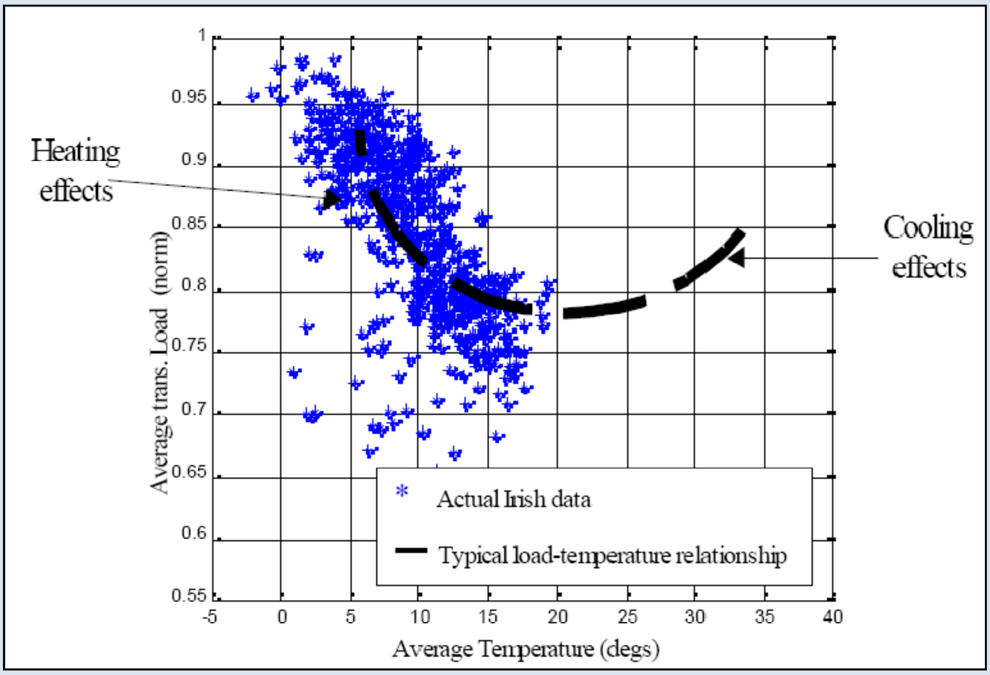

Figure 5-1 Normalised load as a function of temperature. The blue markers show actual data from Ireland. The line shows a typical load-temperature relationship. Taken from[37].

In both Ireland and Northern Ireland, the peak data is adjusted to a temperature standard known as Average Cold Spell (ACS). To calculate the ACS for a given year, we must first look at the effective mean temperature for each day. This is obtained by taking the mean temperature on that day, and averaging it with the effective mean on the previous day. The logic behind this is that changes in temperature take some time to produce their full effect on demand.

The ACS temperature for a particular year is then given as the lowest effective mean for that year, excluding weekends. The ACS values for Ireland and Northern Ireland are shown in Figure 5-2. Northern Ireland ACS values are slightly lower (0.1 °C) on average.

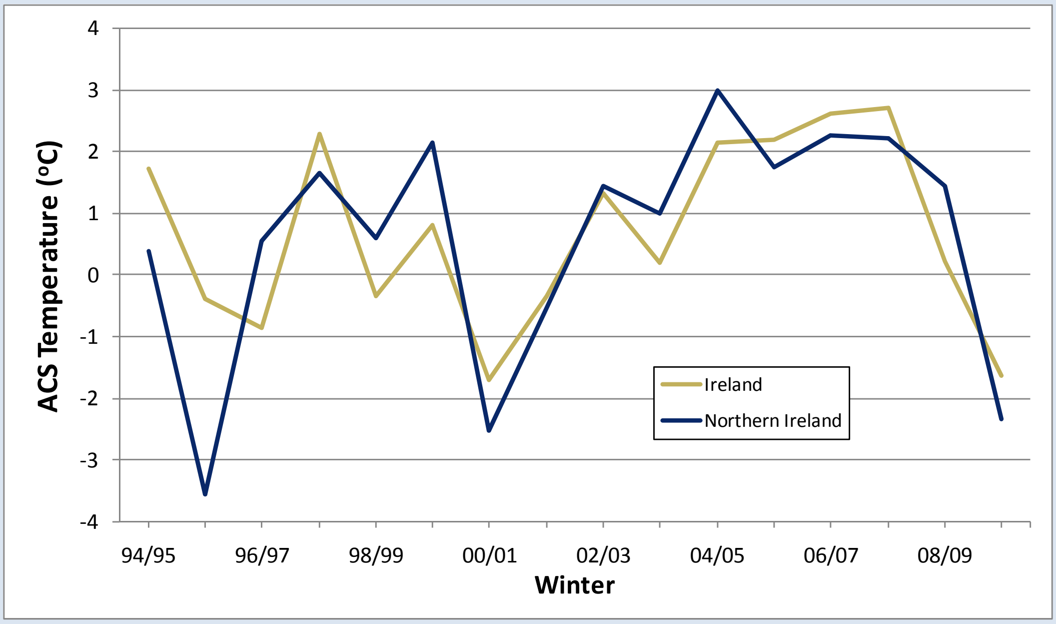

Figure 5-2 Historical ACS values for Ireland and Northern Ireland.

The ACS Effective Mean temperature is determined by calculating the median value of the ACS temperatures over a number of historic years. The ACS analysis produces a peak demand for a given year which has been adjusted to the ACS effective mean temperature. It results in a peak demand which would have occurred had conditions been averagely cold for the time of year. It therefore eliminates temperature effects and gives a better indication of the underlying pattern of annual peak demand, in line with international practice[38].

Last winter was particularly cold. Despite the drop in overall demand in 2009 due to the economic downturn, the winter peak was the highest in record. On the peak demand day in Ireland (7th January 2010), one weather station recorded the country's coldest air temperature in over 30 years. In Northern Ireland, Met Office figures[39] show that in January 2010 when the winter peak occurred, the temperature was 2.3°C lower that the 1971-2000 average temperature for January.

This lead to the peak in Ireland being over 230 MW higher than it would have been had temperatures been normal, with a 70 MW shift in Northern Ireland. The historical ACS peaks are shown in section 2.5. Figure 2-4 and Figure 2-5 show the ACS peaks compared to the actual recorded peaks.

As this document is being written, we are experiencing similarly harsh conditions. This may lead to atypical peaks which are higher than those predicted in the peak forecast. However, we maintain that such weather conditions are a very rare event.

5.2 WINTER PEAKS & WIND GENERATION

Wind generation is intermittent. It is impossible to predict in advance what the generation from wind during future annual demand peaks will be. This makes the value of wind capacity in terms of adequacy hard to define – see section 3.7(c) for a more in depth discussion.

Figure 5-3 shows the historical capacity factors of wind farms during winter peaks over the last 8 years. Wind capacity factors have been less than 10% during three of the last four annual peaks in Ireland. This is due to the fact that the high pressure systems which bring cold weather during winter also tend to bring calm weather and low wind speeds. The combination of cold weather and high winds brings its own problems, as it leads to an increased risk of ice-loading on power lines.

It is noticeable over the last 6 years that capacity factors are higher in Northern Ireland as the wind has tended to blow on cold days. In 4 out of the last 6 years, capacity factors have exceeded 50%.

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[38] *E.g. see UK National Grids 7-year statement http://www.nationalgrid.com/uk/Electricity/SYS/ and France's GAR http://clients.rte-france.com/htm/an/mediatheque/telecharge/generation_adequacy_report_2009.pdf*

[39] *http://www.metoffice.gov.uk/climate/uk/anomalygraphs/2010/2010_MeanTemp_Anomaly_1971-2000.gif*

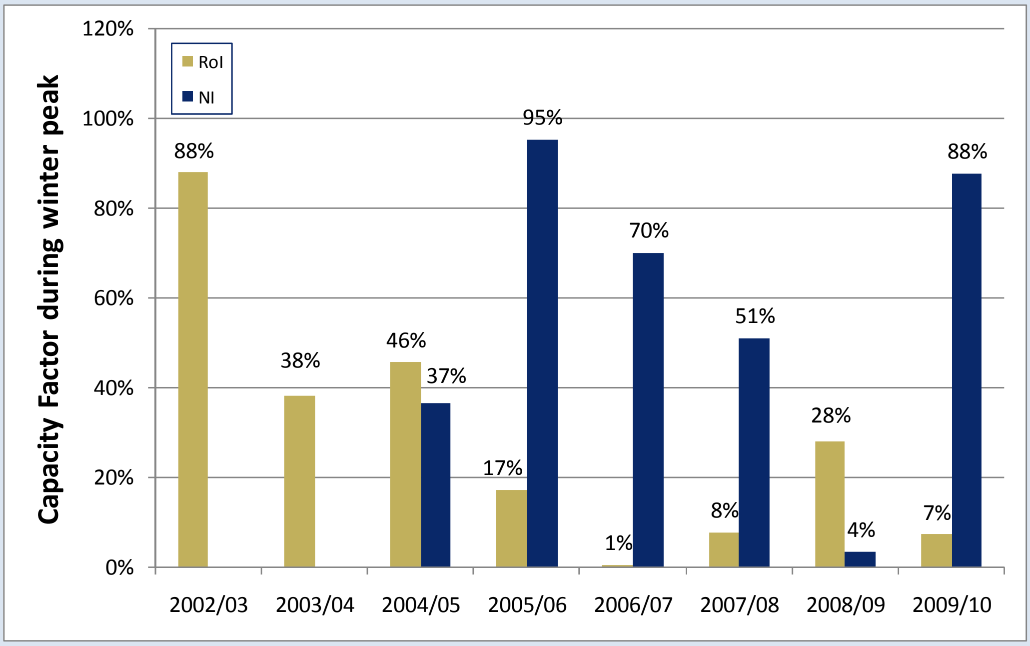

Figure 5-3 Historical capacity factor of wind during winter peak for Ireland and Northern Ireland. Winter peaks do not necessarily coincide for both regions.

5.3 GENERATOR & TRANSMISSION NETWORK OUTAGES

Periods of cold weather can make it very difficult for TSOs to operate a power system. Ice can form on power lines, creating considerable additional weight and causing the lines to sag and sometimes break. The contraction of materials due to cold temperatures, often followed by rapid expansion as they are heated by electrical currents, puts a lot of strain on electrical equipment.

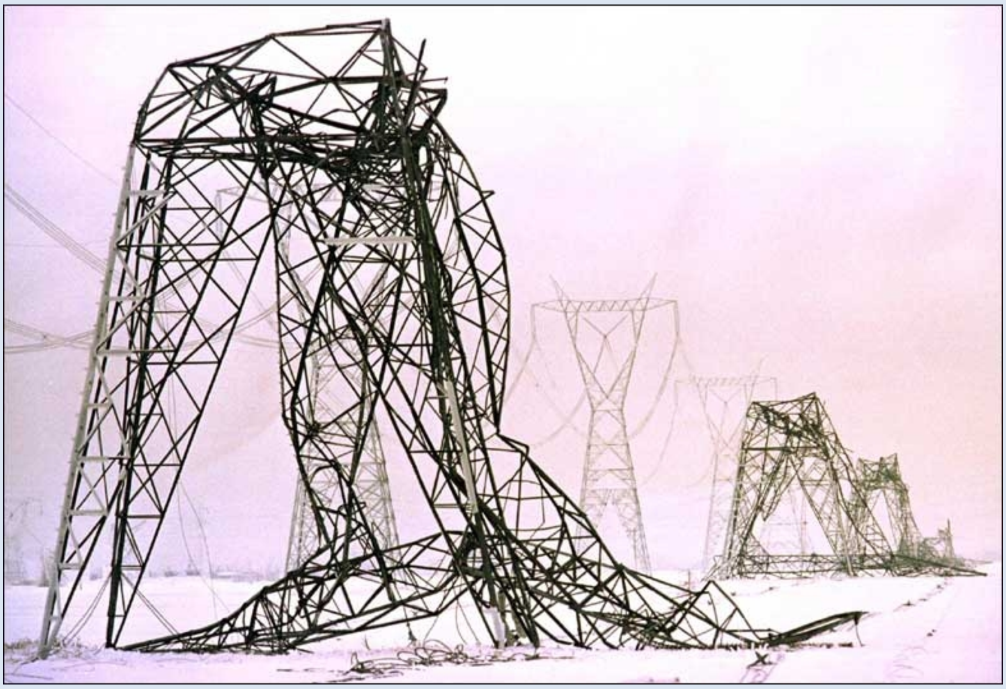

Figure 5-4 Cold weather can have a devastating effect on transmission systems. Image of pylons collapsed due to ice in Canada courtesy of the British Broadcasting Corporation.

Ireland experienced extremely cold weather between the 7th and 9th January 2010. Over this period, 23 generator trips[40] and several transmission faults occurred. This resulted in, at one stage on January 9th, over 1,700 MW of conventional generation forced out. This, combined with the unusually high demand, forced EirGrid to issue an alert at its National Control Centre, indicating a high risk of load-shedding.

Over the entire day, SONI helped meet the generation balance in Ireland with a higher than normal export to the EirGrid system. Also, a new generator, which was under testing at the time, was used to export its maximum generation onto the system. Support from SONI, the timely return of one of the tripped units before the evening peak, and this test unit undoubtedly helped to avoid load shedding on this day.

In 2010 the Northern Ireland system was severely affected by heavy ice storms during the period March 29th – March 31st. This resulted in faults in both the Transmission and Distribution systems. Weather conditions resulted in significant damage to 125km of overhead line, with around 138,000 customers experiencing a disruption to their electricity supply. From approximately 1900 on 30th March to 1200 on 31st March the system experienced over 100 voltages dips due to faults on the Northern Ireland system.

Figure 5-5 Example of damage during the March ice storm. Image courtesy of NIE.

85% of all pole damages were associated with conductor damage. This was primarily due to the conductor undergoing excessive stress loading beyond its design limits resulting from effects of the storm winds and wet snow accretion causing the pole support and conductor to break.

The transmission network experienced an unprecedented number of faults, with 139 circuit trips in 15 hours, equating to 400 circuit breaker trip operations. Visual evidence from fault patrols confirmed a heavy cylindrical accumulation of wet snow (up to 100mm diameter) accreted around conductors and on some spans weighing the middle conductors down to within 300mm of the bottom conductors.

There was a significant number of faults on the transmission system caused by these multiple transmissionand generation trips due to disconnection of distribution connected

[40] *i.e. were either forced to shut down or failed to start properly*

customers. It should be noted that none of the transmission faults resulted in loss of supplies to customers. Further information on this storm can be found in a report published by Northern Ireland Electricity.[41]

In our adequacy studies, it is assumed that forced outages of generators occur independently. We presume that the forced outage probability is the same at all times and not linked to the outages of other generators. In reality this is not entirely true, as extreme weather events make the simultaneous failure of generators more probable. This may lead to us overestimating system adequacy somewhat, especially since these failures are likely to coincide with periods of high demand.

[41] http://www.nie.co.uk/customerinformation/SevereWeatherResponse.htm

Appendices

APPENDIX 1 DEMAND FORECAST

	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2010	27,249	Δ%	9,067	Δ%	36,316	Δ%	4,715	Δ%	1,738	Δ%	6,421	Δ%	4,602	Δ%	1,738	Δ%	6,308	Δ%
2011	27,345	0.4	9,029	-0.4	36,374	0.2	4,722	0.1	1,688	-2.9	6,380	-0.6	4,604	0.0	1,688	-2.9	6,262	-0.7
2012	27,897	2.0	9,103	0.8	37,000	1.7	4,810	1.9	1,707	1.1	6,486	1.7	4,687	1.8	1,707	1.1	6,363	1.6
2013	28,589	2.5	9,239	1.5	37,828	2.2	4,924	2.4	1,729	1.3	6,622	2.1	4,796	2.3	1,729	1.3	6,494	2.1
2014	29,302	2.5	9,378	1.5	38,680	2.3	5,041	2.4	1,755	1.5	6,764	2.1	4,908	2.3	1,755	1.5	6,631	2.1
2015	29,946	2.2	9,518	1.5	39,464	2.0	5,146	2.1	1,781	1.5	6,895	1.9	5,008	2.0	1,781	1.5	6,757	1.9
2016	30,485	1.8	9,661	1.5	40,146	1.7	5,233	1.7	1,807	1.5	7,007	1.6	5,089	1.6	1,807	1.5	6,864	1.6
2017	30,942	1.5	9,806	1.5	40,748	1.5	5,305	1.4	1,834	1.5	7,106	1.4	5,156	1.3	1,834	1.5	6,957	1.4
2018	31,407	1.5	9,953	1.5	41,360	1.5	5,378	1.4	1,862	1.5	7,206	1.4	5,224	1.3	1,862	1.5	7,052	1.4
2019	31,878	1.5	10,102	1.5	41,980	1.5	5,453	1.4	1,889	1.5	7,308	1.4	5,293	1.3	1,889	1.5	7,149	1.4
2020	32,292	1.3	10,254	1.5	42,546	1.3	5,517	1.2	1,917	1.5	7,399	1.2	5,353	1.1	1,917	1.5	7,235	1.2

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

	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2010	27,249	Δ%	9,067	Δ%	36,316	Δ%	4,715	Δ%	1,738	Δ%	6,421	Δ%	4,580	Δ%	1,738	Δ%	6,308	Δ%
2011	27,209	-0.1	8,846	-2.4	36,055	-0.7	4,697	-0.4	1,670	-3.9	6,336	-1.3	4,638	1.3	1,670	-3.9	6,218	-1.4
2012	27,621	1.5	8,828	-0.2	36,449	1.1	4,761	1.4	1,674	0.2	6,403	1.1	4,721	1.8	1,674	0.2	6,280	1.0
2013	28,169	2.0	8,870	0.5	37,039	1.6	4,849	1.8	1,684	0.6	6,501	1.5	4,806	1.8	1,684	0.6	6,373	1.5
2014	28,730	2.0	8,977	1.2	37,707	1.8	4,940	1.9	1,698	0.8	6,606	1.6	4,879	1.5	1,698	0.8	6,473	1.6
2015	29,219	1.7	9,084	1.2	38,303	1.6	5,017	1.6	1,718	1.2	6,703	1.5	4,932	1.1	1,718	1.2	6,565	1.4
2016	29,598	1.3	9,193	1.2	38,791	1.3	5,075	1.2	1,738	1.2	6,780	1.1	4,970	0.8	1,738	1.2	6,637	1.1
2017	29,894	1.0	9,304	1.2	39,198	1.0	5,119	0.9	1,759	1.2	6,845	1.0	5,009	0.8	1,759	1.2	6,696	0.9
2018	30,193	1.0	9,415	1.2	39,608	1.0	5,163	0.9	1,780	1.2	6,910	0.9	5,049	0.8	1,780	1.2	6,756	0.9
2019	30,495	1.0	9,528	1.2	40,023	1.0	5,208	0.9	1,801	1.2	6,975	0.9	5,079	0.6	1,801	1.2	6,816	0.9
2020	30,739	0.8	9,643	1.2	40,382	0.9	5,243	0.7	1,822	1.2	7,031	0.8	5,092	0.3	1,822	1.2	6,867	0.7

Table A-2 Low demand forecast – all figures are for a 52 week year.

	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2010	27,249	Δ%	9,067	Δ%	36,316	Δ%	4,715	Δ%	1,738	Δ%	6,421	Δ%	4,628	Δ%	1,738	Δ%	6,308	Δ%
2011	27,481	0.9	9,213	1.6	36,694	1.0	4,746	0.7	1,705	-1.9	6,421	0.0	4,737	2.3	1,705	-1.9	6,303	-0.1
2012	28,173	2.5	9,379	1.8	37,552	2.3	4,860	2.4	1,737	1.9	6,567	2.3	4,871	2.8	1,737	1.9	6,444	2.2
2013	29,013	3.0	9,548	1.8	38,561	2.7	5,000	2.9	1,768	1.8	6,737	2.6	5,011	2.9	1,768	1.8	6,609	2.6
2014	29,881	3.0	9,720	1.8	39,601	2.7	5,145	2.9	1,800	1.8	6,914	2.6	5,140	2.6	1,800	1.8	6,781	2.6
2015	30,688	2.7	9,895	1.8	40,583	2.5	5,278	2.6	1,832	1.8	7,078	2.4	5,251	2.2	1,832	1.8	6,940	2.3
2016	31,394	2.3	10,073	1.8	41,467	2.2	5,394	2.2	1,865	1.8	7,226	2.1	5,347	1.8	1,865	1.8	7,083	2.1
2017	32,022	2.0	10,254	1.8	42,276	2.0	5,496	1.9	1,899	1.8	7,362	1.9	5,446	1.9	1,899	1.8	7,213	1.8
2018	32,662	2.0	10,439	1.8	43,101	2.0	5,600	1.9	1,933	1.8	7,499	1.9	5,548	1.9	1,933	1.8	7,345	1.8
2019	33,315	2.0	10,627	1.8	43,942	2.0	5,707	1.9	1,968	1.8	7,641	1.9	5,640	1.7	1,968	1.8	7,482	1.9
2020	33,915	1.8	10,818	1.8	44,733	1.8	5,804	1.7	2,003	1.8	7,772	1.7	5,716	1.3	2,003	1.8	7,608	1.7

Table A-2 High demand forecast – all figures are for a 52 week year.

Notes: In Ireland, total electricity sales are measured at the customer level, for a 52-week year. To convert this to TER, it is brought to exported level by applying the loss factor (8.3%) and adding on an estimate of self-consumption.

The transmission peak (or exported peak) is the maximum demand met by centrally-dispatched generation (including wind), measured at exported level by the National Control Centre. To calculate the TER Peak, an estimation of the contribution from small scale hydro, biomass and CHP (both exporting and self-consuming CHP) are added to the Transmission peak.

APPENDIX 2 GENERATION PLANT INFORMATION

Fully Dispatchable Plant (Ireland)												
Year end:		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Aghada	AD1	258	258	258	258	258	258	258	258	258	258	258
	AT1	90	90	90	90	90	90	90	90	90	90	90
	AT2	90	90	90	90	90	90	90	90	90	90	90
	AT4	90	90	90	90	90	90	90	90	90	90	90
	ADC	432	432	432	432	432	432	432	432	432	432	432
Cahir OCGT						98	98	98	98	98	98	98
Cuilleen OCGT				98	98	98	98	98	98	98	98	98
Dublin Bay	DB1	403	403	403	403	403	403	403	403	403	403	403
Dublin Waste-to-Energy				72	72	72	72	72	72	72	72	72
Edenderry	ED1	117.6	117.6	117.6	117.6	117.6	117.6	117.6	117.6	117.6	117.6	117.6
Edenderry OCGT	ED3	55	55	55	55	55	55	55	55	55	55	55
	ED5	55	55	55	55	55	55	55	55	55	55	55
Great Island	GI1	54	54	54	0	0	0	0	0	0	0	0
	GI2	54	54	54	0	0	0	0	0	0	0	0
	GI3	108	108	108	0	0	0	0	0	0	0	0
Huntstown	HN1	342	342	341	341	340	340	339	339	338	338	337
	HN2	400	400	399	399	398	398	397	397	396	396	395
Knocknagreenan						70	70	70	70	70	70	70
Lough Ree Power	LR4	91	91	91	91	91	91	91	91	91	91	91
Marina	MRT	85	85	85	85	85	85	85	85	85	85	85
Meath Waste-to-Energy			17	17	17	17	17	17	17	17	17	17
Moneypoint	MP1	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5
	MP2	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5
	MP3	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5	282.5
Nore Power				98	98	98	98	98	98	98	98	98
North Wall	NW4	163	163	163	163	163	163	163	163	163	163	163
	NW5	104	104	104	104	104	104	104	104	104	104	104
Poolbeg CCGT	PBC	463	463	463	463	463	463	463	463	463	463	463
Rhode	RP1	52	52	52	52	52	52	52	52	52	52	52
	RP2	52	52	52	52	52	52	52	52	52	52	52
Sealrock	SK3	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5
	SK4	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5
Tarbert	TB1	54	54	54	0	0	0	0	0	0	0	0
	TB2	54	54	54	0	0	0	0	0	0	0	0
	TB3	241	241	241	0	0	0	0	0	0	0	0
	TB4	241	241	241	0	0	0	0	0	0	0	0
Tawnaghmore	TP1	52	52	52	52	52	52	52	52	52	52	52
	TP3	52	52	52	52	52	52	52	52	52	52	52
Tynagh	TY1	384	384	384	384	384	384	384	384	384	384	384
West Offaly Power	WO4	137	137	137	137	137	137	137	137	137	137	137
Whitegate	WG1	437	436	435	434	433	432	431	430	429	428	427
Ardnacrusha Hydro	AA1-4	86	86	86	86	86	86	86	86	86	86	86
Erne Hydro	ER1-4	65	65	65	65	65	65	65	65	65	65	65
Lee Hydro	LE1-3	27	27	27	27	27	27	27	27	27	27	27
Liffey Hydro	LI1,2,4,5	38	38	38	38	38	38	38	38	38	38	38
Turlough Hill	TH1-4	292	292	292	292	292	292	292	292	292	292	292
EWIC				440	440	440	440	440	440	440	440	440
Total Dispatchable		**6,727**	**6,743**	**7,448**	**6,641**	**6,806**	**6,805**	**6,802**	**6,801**	**6,798**	**6,797**	**6,794**

Table A-3 Dispatchable generation capacity in Ireland, for the base case assumptions. Please note that these figures are indicative only.

Fully Dispatchable Plant (Northern Ireland)												
Year end:		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Ballylumford Steam Turbines	ST4	170	170	170	170	170	170					
	ST5	170	170	170	170	170	170					
	ST6	170	170	170	170	170	170					
Ballylumford CCGT	B10	97	97	97	97	97	97	97	97	97	97	97
	B31	245	245	245	245	245	245	245	245	245	245	245
	B32	245	245	245	245	245	245	245	245	245	245	245
Ballylumford Gas Turbines	GT7	58	58	58	58	58	58	58	58	58	58	58
	GT8	58	58	58	58	58	58	58	58	58	58	58
Kilroot Steam Turbines	ST1	238	238	238	238	238	238	238	238	238	238	238
	ST2	238	238	238	238	238	238	238	238	238	238	238
Kilroot Gas Turbines	KGT1	29	29	29	29	29	29	29	29	29	29	29
	KGT2	29	29	29	29	29	29	29	29	29	29	29
	KGT3	42	42	42	42	42	42	42	42	42	42	42
	KGT4	42	42	42	42	42	42	42	42	42	42	42
Coolkearagh Gas	GT8	53	53	53	53	53	53	53	53	53	53	53
Coolkearagh CCGT	C30	402	402	402	402	402	402	402	402	402	402	402
Moyle Interconnector	Moyle	450	450	450	450	450	450	450	450	450	450	450
Contour Global (CHP)	CGC3	3	3	3	3	3	3	3	3	3	3	3
	CGC4	3	3	3	3	3	3	3	3	3	3	3
	CGC5	3	3	3	3	3	3	3	3	3	3	3
Energia AGU	AGU	22	22	22	22	22	22	22	22	22	22	22
Total Dispatchable		**2,767**	**2,767**	**2,767**	**2,767**	**2,767**	**2,767**	**2,257**	**2,257**	**2,257**	**2,257**	**2,257**

Table A-4 Dispatchable generation plant capacity in Northern Ireland. These figures are indicative only, and may not reflect what is in the generators' connection agreements.

Partially/Non-Dispatchable Plant in Ireland											
Year end:	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Onshore Wind (MW)	1538	1764	1990	2215	2441	2667	2893	3118	3344	3570	3796
Offshore Wind (MW)	0	36	36	252	252	252	252	416	529	533	555
Small Scale Hydro (MW)	22	22	22	22	22	22	22	22	22	22	22
Solid Biofuels (MW) [42]	13	21	29	38	46	55	57	59	61	63	65
Landfill Gas (MW) [43]	35	35	45	46	47	84	85	86	87	88	89
CHP (MW)	129	134	139	144	149	154	159	164	169	174	179
Industrial / DSU (MW)	9	9	9	9	9	9	9	9	9	9	9
Tidal/Wave (MW)	0	0	0	0	0	0	0	13	25	38	75
Total	**1,746**	**2,021**	**2,270**	**2,726**	**2,966**	**3,243**	**3,477**	**3,887**	**4,246**	**4,497**	**4,790**

Table A-5 Partially and non-dispatchable plant capacity for Ireland.

[42] *Includes contribution from cofiring of the Edenderry Peat Generator*
[43] *Includes contribution from waste-to-energy generators*

Partially/Non-Dispatchable Plant in Northern Ireland											
Year end:	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Onshore Wind (MW)	380	478	573	640	725	788	811	881	937	1012	1030
Offshore Wind (MW)	0	0	0	0	0	0	0	0	300	600	600
Small Scale Hydro (MW)	3	3	3	3	3	3	3	3	3	3	3
Solid Biofuels (MW)	1	1	1	2	2	2	2	2	100	200	200
Landfill Gas (MW)	10	13	15	17	19	21	21	23	25	27	27
CHP (MW)	8	14	18	22	26	30	34	38	42	46	50
Industrial / DSU (MW)	0	0	0	0	0	1	1	2	2	3	3
Tidal/Wave (MW)	1	1	1	1	1	1	1	1	150	300	300
Total	**403**	**510**	**611**	**685**	**776**	**846**	**873**	**950**	**1559**	**2191**	**2213**

Table A-6 Partially and non-dispatchable plant capacity at end of each year for Northern Ireland.

	Windfarm Name	MEC (MW)
Distribution connected	Corkey	5
	Rigged Hill	5
	Elliott's Hill	5
	Bessy Bell	5
	Slieve Rushen	5
	Owenreagh	5.5
	Lendrum's Bridge	5.94
	Lendrum's Bridge 2	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	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
Total		**340**

Table A-7 Existing wind farms in Northern Ireland, as of 1 November 2010

	Windfarm Name	MEC (MW)
Transmission Connected	Ballywater 1	31.5
	Ballywater 2	10.5
	Boggeragh 1	57
	Booltiagh 1	19.45
	Clahane 1	37.8
	Coomacheo 1	59.225
	Coomagearlahy 1	42.5
	Coomagearlahy 2	8.5
	Coomagearlahy 3	30
	Derrybrien 1	59.5
	Dromada 1	28.5
	Garvagh 1	58.225
	Glanlee 1	29.8
	Golagh 1	15
	Kingsmountain 1	23.75
	Kingsmountain 2	11.05
	Lisheen 1	55
	Meentycat 1	70.96
	Meentycat 2	14
	Mountain Lodge 1	24.8
	Mountain Lodge 3	5.82
	Ratrussan 1	48
Distribution Connected	Altagowlan 1	7.65
	Anarget 1	1.98
	Anarget 2	0.02
	Arklow Banks 1	25.2
	Ballincollig Hill 1	15
	Ballinlough 1	2.55
	Ballinveny 1	2.55
	Beale 2	2.55
	Beale Hill 1	1.65
	Beallough 1	1.7
	Beam Hill 1	14
	Beenageeha 1	3.96
	Bellacorick 1	6.45
	Black Banks 1	3.4
	Black Banks 2	6.8
	Burtonport Harbour 1	0.66
	Caranne Hill 1	3.4
	Cark 1	15
	Carnsore 1	11.9
	Carrig 1	2.55
	Coomatallin 1	5.95
	Corneen 1	3
	Corrie Mountain 1	4.8
	Crockahenny 1	5
	Cronalaght 1	4.98
	Cronelea 1	4.99
	Cronelea 2	4.5
	Cronelea Upper 1	2.55
	Cronelea Upper 2	1.7
	Cuillalea 1	3.4
	Culliagh 1	11.88
	Currabwee 1	4.62
	Curraghgraigue 1	2.55
	Donaghmede Fr Collins	0.25
	Drumlough Hill 1	4.8
	Drumlough Hill 2	9.99
	Dundalk IT 1	0.5
	Dunmore 1	1.7
	Dunmore 2	2.5
Distribution Connected	Flughland 1	9.2
	Gartnaneane I & II	15
	Geevagh 1	4.95
	Glackmore Hill 1	0.6
	Glackmore Hill 2	1.4
	Glackmore Hill 3	0.3
	Glanta Commons 1	19.55
	Glanta Commons 2	8.4
	Gneeves 1	9.35
	Gortahile 1	21
	Greenoge 1	4.9
	Inis Mean 1	0.675
	Inverin Knock South 1	3.3
	Inverin Knock South 2	0.66
	Kealkil Curraglass 1	8.5
	Killybegs 1	2.55
	Kilronan 1	5
	Kilvinane 1	4.5
	Knockastanna 1	7.5
	Knockawarriga 1	22.5
	Lackan 1	6
	Lahanaght Hill 1	4.25
	Largan Hill 1	5.94
	Loughderryduff 1	7.65
	Lurganboy 1	4.99
	Mace Upper 1	2.55
	Meenachullalan 1	11.9
	Meenadreen 1	3.4
	Meenanilta 1	2.55
	Meenanilta 2	2.45
	Meenkeeragh 1	4.2
	Mienvee 1	0.66
	Mienvee 2	0.19
	Milane Hill 1	5.94
	Moanmore 1	12.6
	Moneenatieve 1	3.96
	Moneenatieve 2	0.29
	Mount Eagle 1	5.1
	Mount Eagle 2	1.7
	Mountain Lodge 2	3
	Muingnaminnane 1	15.3
	Mullananalt 1	7.5
	Raheen Barr 1	18.7
	Raheen Barr 2	15.3
	Rahora 1	4.25
	Reenascreena 1	4.5
	Richfield 1	20.25
	Richfield 2	6.75
	Shannagh 1	2.55
	Skehanagh 1	4.25
	Slievereagh 1	3
	Sonnagh Old 1	7.65
	Sorne Hill 1	31.5
	Sorne Hill 2	7.4
	Spion Kop 1	1.2
	Taurbeg 1	26
	Tournafulla 1	7.5
	Tournafulla 2	17.1
	Tursillagh 1	15
	Tursillagh 2	6.8
	WEDcross 1	4.5
	Total	**1,416**

Table A-8 Existing wind farms in Ireland, as of 1 November 2010

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 4.9 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-9 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.

We assume 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)

We use AdCal software 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

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

then the annual LOLE is given by

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

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-10.

	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-10 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) State	1) Units in service	2) Capacity in service (MW)	3) Probability for (A*B*C)	3) Probability	4) Ability to meet 55 MW demand	4) 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-11 Probability table

Only states 1, 2 and 3 are providing enough generation to meet the demand of 55 MW. The probabilities for these five 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[44]. 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.

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

APPENDIX 4 ADEQUACY ASSESSMENT RESULTS

This section shows the results from the adequacy calculations presented in section 4.

Median	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	583	671	671	576	671	334	269	324	476	531
	Ireland	776	1,383	1,516	1,460	1,422	1,106	968	941	900	870
	All-island	1,650	2,330	2,374	2,289	2,292	1,636	1,459	1,441	1,510	1,524

Table A-12 The surplus of plant for each year resulting from the base-case scenario. All figures are given in MW of perfect plant. See section 4.2 for details on the assumptions used.

Low	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	612	707	720	629	729	398	345	400	555	614
	Ireland	796	1,422	1,577	1,544	1,526	1,233	1,117	1,113	1,096	1,091
	All-island	1,694	2,406	2,485	2,428	2,461	1,834	1,685	1,696	1,798	1,841

Table A-13 The surplus of plant for each year resulting from the low demand scenario. All figures are given in MW of perfect plant. See section 4.3 for details on the assumptions used

High	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	559	635	632	529	622	277	212	258	401	449
	Ireland	756	1,343	1,453	1,375	1,314	976	814	762	694	637
	All-island	1,606	2,253	2,269	2,158	2,128	1,443	1,238	1,186	1,217	1,199

Table A-14 The surplus of plant for each year resulting from the high demand scenario. All figures are given in MW of perfect plant. See section 4.3 for details on the assumptions used

	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Ireland	Generator Availability	1,394	1,984	2,092	2,041	1,594	1,678	1,612	1,652	1,600	1,564
	EirGrid Availability	776	1,383	1,516	1,460	1,422	1,106	968	941	900	870
Northern Ireland	High Availability	583	671	671	576	671	334	269	324	476	531
	Low Availability	458	530	531	433	531	190	130	179	335	390

Table A-15 The surplus of plant for each year using different availability scenarios. All figures are given in MW of perfect plant. Median demand was assumed, see section 4.4 for more details

	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	318	413	418	315	404	84	19	69	218	265
	Ireland	430	1,004	1,145	1,085	1,043	762	618	589	547	515
	All-island	943	1,590	1,629	1,563	1,545	917	741	720	789	794

Table A-16 The surplus of plant for each year, with a large CCGT removed from each jurisdiction. All figures are given in MW of perfect plant. Median demand and base-case availability have been used. See section 4.5 for more details.

	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	206	281	285	191	276	(47)	(119)	(62)	92	138
	Ireland	430	1,004	1,145	1,085	1,043	762	618	589	547	515
	All-island	882	1,527	1,568	1,496	1,482	853	675	654	728	732

Table A-17 The surplus/deficit of plant for each year, with a large CCGT removed from each jurisdiction. All figures are given in MW of perfect plant. Median demand and low availability have been used. A deficit is seen in Northern Ireland for 2016-2018. See section 4.5 for more details.

	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	182	248	248	143	228	(104)	(178)	(131)	19	60
	Ireland	410	964	1,081	999	937	628	461	406	337	278
	All-island	839	1,451	1,463	1,364	1,317	656	449	395	430	400

Table A-18 The surplus/deficit of plant for each year, with a large CCGT removed from each jurisdiction. All figures are given in MW of perfect plant. High demand and low availability have been used. A deficit is seen in Northern Ireland for 2016-2018. See section 4.5 for more details.

Median	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	583	671	671	576	671	334	269	324	476	531
	Ireland	729	1,176	1,299	1,155	991	601	368	340	297	115
	All-island	1,597	2,126	2,199	1,984	1,986	1,021	756	738	802	730

Table A-19 The surplus of plant for each year, with older generation removed from Ireland. All figures are given in MW of perfect plant. Median demand and base-case availability have been used. See section 4.6 for more details.

Median	Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Surplus (Deficit)	Northern Ireland	559	635	632	529	622	277	212	258	401	449
	Ireland	708	1,136	1,235	1,069	883	473	213	159	90	(125)
	All-island	1,555	2,052	2,095	1,854	1,823	826	534	481	509	398

Table A-20 The surplus/deficit of plant for each year, with older generation removed from Ireland. All figures are given in MW of perfect plant. Median demand and low availability have been used. A deficit is seen in Ireland in 2020. See section 4.6 for more details.