SONI System Operator for Northern Ireland

EirGrid

All-Island Generation Capacity Statement
2013-2022

www.soni.ltd.uk

www.eirgrid.com

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

The general form and content of the document has been approved by the Commission for Energy Regulation (CER) and the Utility Regulator for Northern Ireland (URegNI). This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2012-2021.

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

DISCLAIMER

COPYRIGHT NOTICE

Front cover images:

- Servers in a Data Centre, one of the new types of substantial load customers on the system. See Section 5 for a report on their impact on the power system.
- Ireland at night, courtesy of NASA Earth Observatory/NOAA NGDC.

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 2013-2022.

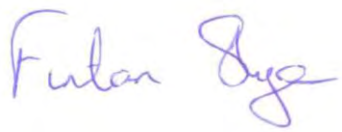
This statement outlines the expected electricity demand and the level of generation capacity available over the next 10 years, together with an analysis of generation adequacy for a number of realistic scenarios. In summary, there is a considerable surplus of generation in Ireland. However, current transmission limitations restrict the amount of generation in Ireland that can be transferred to Northern Ireland. For Northern Ireland, with this limited support, the margin becomes tight after 2015 and will be in deficit from 2021. However, the second North-South tie line, which is planned to be in service in 2017, will ensure that both jurisdictions have a generation supply sufficient to meet demand reliably in accordance with the adequacy standard.

Both governments in Ireland and Northern Ireland have set a 40% target for renewable energy sources by 2020. Much of this will come from wind power. In fact, Ireland and Northern Ireland are leading the world in maximising the proportion of wind generation on their power systems. Greater demands will be put on the flexibility of the conventional generation and their ability to provide system support and balancing services. EirGrid and SONI, together with industry stakeholders, are working together in the DS3 programme (Delivering a Secure Sustainable Electricity System) to address the issues arising from additional renewable generation and to develop innovative solutions that will ensure that the power system can be operated safely and securely with high penetrations of renewable generation.

Smart Grid developments are an important component of an overall solution for the integration of renewable generation. EirGrid and SONI, in collaboration with NDRC (National Digital Research Centre), have recently launched the Smart Grid Innovation Hub which will promote the development of innovative Smart Grid solutions, with the focus on entrepreneurial initiatives by companies, academics and entrepreneurs.

While the last few years have seen a reduction in electricity demand, Data Centres have become a significant new category of demand. There is currently over 175 MW of Data Centre demand on the power system and we expect this to at least double over the rest of this decade. We have recently completed a study of Data Centres, their impact on the power system, and how we see them evolving and developing over the next years. We have found that Data Centre demand profile has a benign impact on the power system in general, and, in particular seems to match well with renewable generation. You can read more about this in Section 5.

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



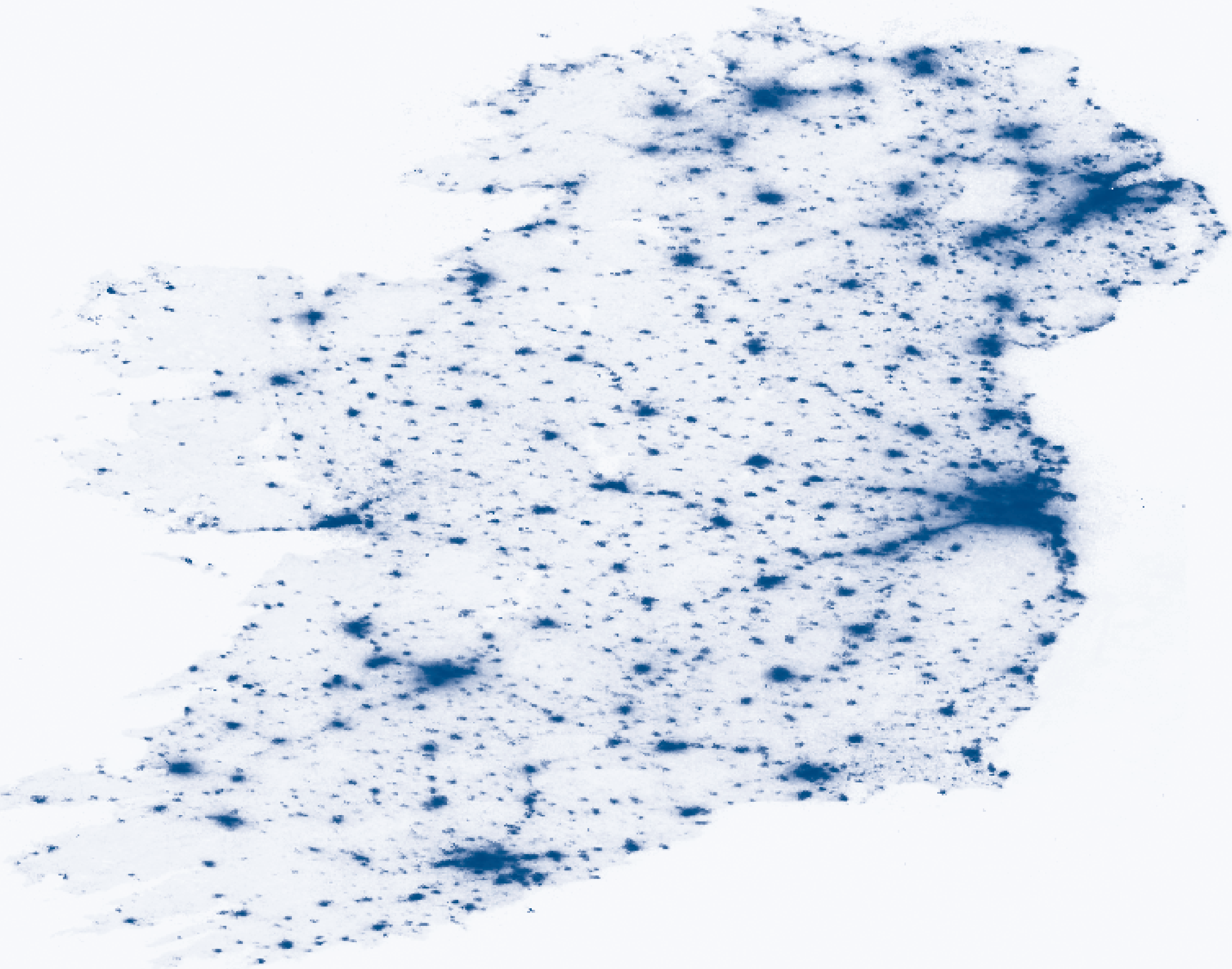
Fintan Slye
Chief Executive, EirGrid Group.

January 2013

Table of Contents

Table of Figures

EXECUTIVE SUMMARY



EXECUTIVE SUMMARY

KEY MESSAGES

All-Island

- Once the additional North-South tie line is completed, the combined systems of Ireland and Northern Ireland can be assessed as a single system. Combined studies confirm that the all-island generation standard is met for all years, for all scenarios.
- The addition of the second high-voltage tie line between Ireland and Northern Ireland improves security in both jurisdictions. This is planned to be operational by 2017.
- In both jurisdictions, demand has fallen, with growth mainly dependent on economic recovery.
- There will be a significant increase in wind generation (to reach between 4,800 and 5,300 MW of installed wind capacity in total), driven by both Governments' 40% renewables target in 2020. This, combined with the shutdown of older flexible conventional plant, highlights the likely requirement for a more flexible generation plant portfolio to enable both TSOs to deal with wind management issues.

Northern Ireland

- In the base case scenario the Northern Ireland Generation Security Standard is met until 2020. Thereafter, Northern Ireland will be in deficit. With the additional North-South tie line in place, these deficits are avoided.
- Northern Ireland is at risk of deficits from 2016 onwards in the event of a prolonged outage of a large generation plant or of the Moyle Interconnector.
- No new generation is expected to connect out to 2022 other than renewables.
- 510 MW of conventional plant in Ballylumford will close by 2016. From 2021, the output from 476 MW of plant at Kilroot is projected to be severely restricted because of limited running hours due to the Industrial Emissions Directive (IED). The effect of this is that the Northern Ireland Generation Security Standard is not met in 2021 and 2022.
- The Moyle Interconnector has been modelled at an import capacity of 250 MW due to uncertainty as to when the current ongoing fault on one cable will be repaired.

Ireland

- The adequacy situation is positive for the next ten years, i.e. the adequacy standard is satisfied. There is a considerable generation surplus forecast in Ireland. Present network limitations mean that all of this surplus cannot be utilised in Northern Ireland.
- The major portfolio additions assumed include a Combined Cycle Gas Turbine (CCGT) at Great Island, Dublin Waste-to-Energy project, up to 150 MW of biomass CHP, as well as wind generation to meet Ireland's 2020 RES-E targets. While there are connection agreements in place for four new Open Cycle Gas Turbines (OCGT), it has been assumed that only three will connect. Given the generation surplus forecast, even this might be an optimistic assumption.

- The oil units at Tarbert and Great Island are due to close over the next ten years. EirGrid has not been notified of other generation closures. However, it has been assumed in the base case that some older plant will experience higher outage rates and/or close over the study period.

INTRODUCTION

This statement sets out estimates of the demand for electricity in the period 2013-2022 and the likely generation capacity that will be in place to meet this demand. This is then assessed against the generation adequacy standards for Ireland, Northern Ireland and on an all-island basis in terms of the overall supply/demand balance.

METHODOLOGY

Generation adequacy is essentially determined by comparing generation capacity with demand. To measure the imbalance between them, a statistical indicator called the Loss of Load Expectation (LOLE) is used. When this indicator is at an appropriate level, called the generation adequacy standard, the supply/demand balance is judged to be acceptable. The generation adequacy standard for Ireland is 8 hours LOLE per year, 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 Authority in each respective jurisdiction.

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

Currently, limited interconnection capacity between Ireland and Northern Ireland means that Ireland has an assumed capacity reliance of 100 MW on Northern Ireland. Similarly, Northern Ireland has an assumed capacity reliance of 200 MW on Ireland. However, with the commissioning of an additional tie line between the two jurisdictions, adequacy will improve further.

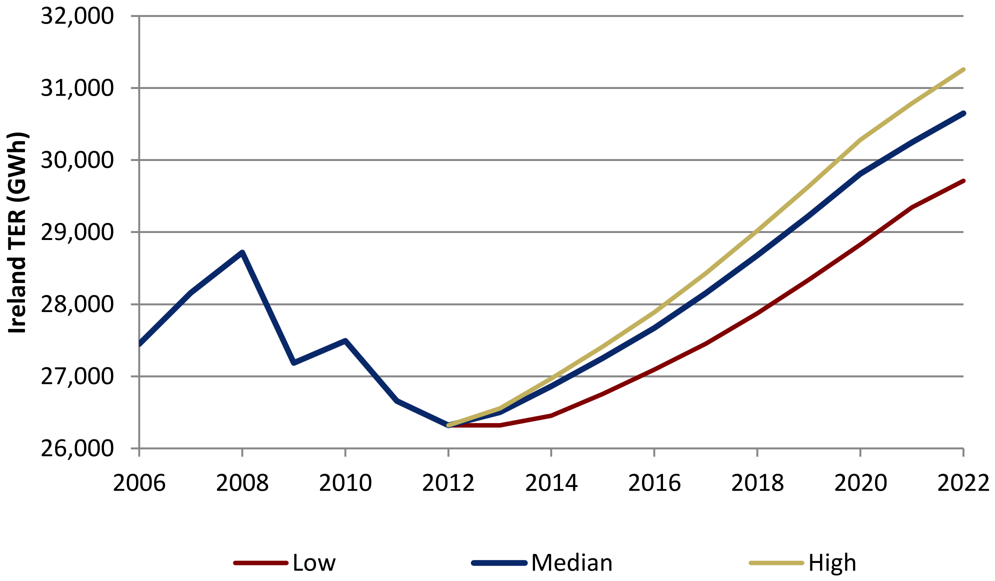
Given the uncertainty that surrounds any forecast of generation and demand, the report examines a number of different scenarios. It is intended that the results from these scenarios would provide the reader with enough information to draw their own conclusions regarding future adequacy.

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

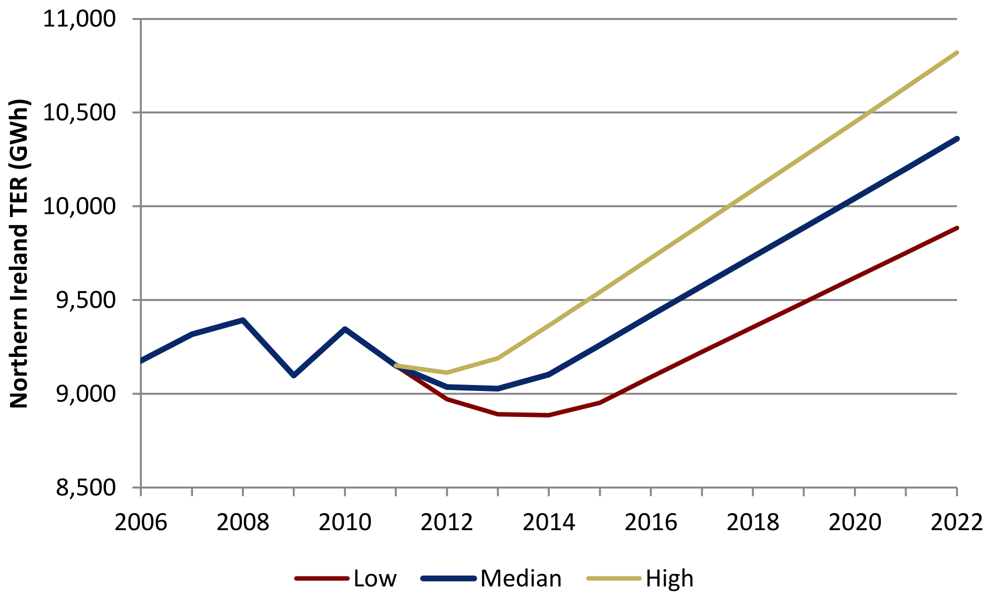
Wind generation requires a special modelling approach to capture the effect of its variable nature. The approach used in this study bases estimated future wind performance on historical records of actual wind power output.

DEMAND FORECAST

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



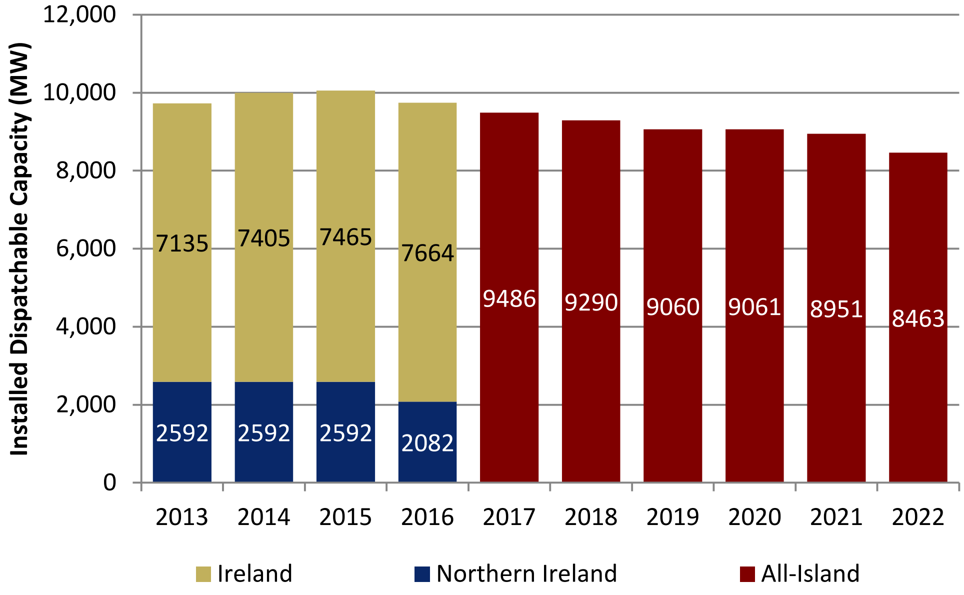
The forecast of Total Electricity Requirement (TER) for Ireland (see above) shows a relatively slow recovery compared to the growth rates seen over the last two decades. It is expected that demand will not return to 2008 levels until 2018 in the median forecast.



Northern Ireland's forecast (above) follows a similar pattern to that of Ireland's. With the ongoing economic difficulties, it is anticipated that the demand levels in 2012 will fall and it will be 2015 before demand levels gradually return to a steady growth rate of 1.5%.

CONVENTIONAL GENERATION

The assumptions for the generation portfolio are based on information received from the generators and connection agreements in place at the data freeze (October 2012). A variety of scenarios have been studied, looking at different supply and availabilities. The graph below outlines the dispatchable capacity assumed on the island over the next 10 years.



Ireland

The East-West Interconnector is the second transmission cable connecting the island of Ireland to Great Britain, and is expected to be capable of importing or exporting 500 MW at any given moment. Based on the Interconnector Feasibility Report, this interconnector is assumed to add the equivalent of 440 MW additional generation capacity.

A new CCGT is due to connect at Great Island in 2014.

Four new OCGTs and one waste-to-energy unit have connection agreements, which if realised, would add 411 MW of generation capacity.

Generators powered by heavy fuel oil (HFO) are steadily disappearing from Ireland. Over the next 9 years, all the units at Great Island and Tarbert are due to close, leading to a reduction in capacity of 802 MW.

For these adequacy assessments, EirGrid is taking the prudent approach that some of the older plant on the system will, in effect, shut down over the time period covered by this report, and that not all of the contracted plant will be commissioned.

Northern Ireland

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

Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by 2016. This is due to environmental constraints introduced by the Large Combustion Plant Directive[1] and will result in a reduction of 510 MW in capacity.

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

There is some uncertainty over the future running regime of the larger units at Kilroot due to emissions restrictions imposed by the Industrial Emissions Directive (IED)[2]. In preparing this document, SONI discussed this uncertainty with AES Kilroot and has made assumptions according to the best information available to both AES Kilroot and SONI about how the IED will affect the running regime of these units.

RENEWABLE ENERGY

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

Ireland

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

Also, there are 77 MW of Waste-to-Energy projects connected or due to connect over the next few years. In addition, a significant growth in bioenergy is assumed.

Northern Ireland

A number of renewable generation projects are assumed to be commissioned over the 10 years that this report covers, equating to a total renewable generation capacity of 2175 MW in Northern Ireland by 2022. This includes onshore wind (1097 MW), offshore wind (600 MW), tidal (200 MW) and large scale biomass (45 MW).

These assumptions have been derived from a number of sources, including Strategic Environmental Assessment (SEA)[3], the Onshore Renewable Electricity Action Plan (OREAP)[4] and the Strategic Energy Framework[5] (SEF) produced by the Department of Enterprise, Trade and Investment (DETI).

The assumptions also incorporate the recent announcements by the Crown Estates[6] who have now awarded development rights for three offshore renewable energy sites in Northern Ireland's coastal waters including a 600 MW offshore wind farm, and two 100 MW Tidal sites.

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

---

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

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

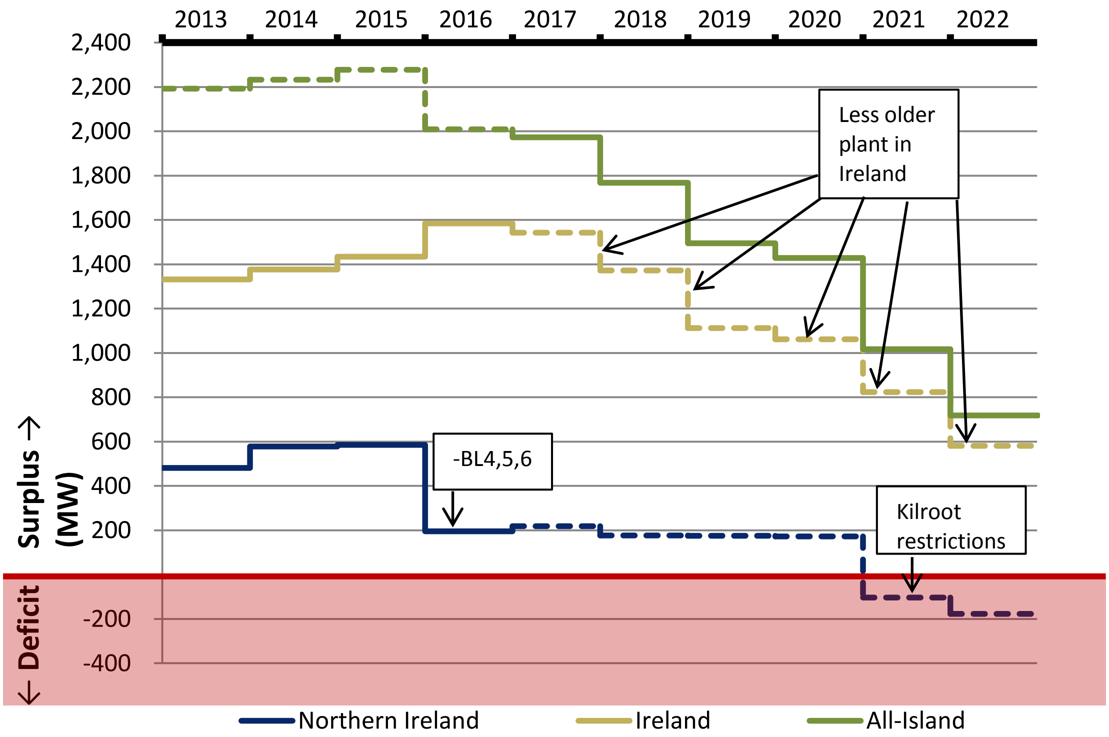
[4] Onshore Renewable Electricity Action Plan (OREAP) (www.onshorerenewablesni.co.uk)

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

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

GENERATION ADEQUACY ASSESSMENTS

In determining future generation adequacy, the base case portrays the most likely situation with the current information available to EirGrid and SONI. More onerous scenarios were also investigated, which studied the loss of a CCGT in each jurisdiction and the unavailability of energy flow over the interconnectors to Great Britain. Also, the consequences of varying demand growth and plant availabilities were examined.



Northern Ireland

Individual jurisdictional studies show that on its own, Northern Ireland is in surplus up to the end of 2015. Following the closure of plant at Ballylumford at the end of 2015 and the introduction of emissions restrictions on plant at Kilroot at the start of 2016, the Northern Ireland adequacy position is tight with surpluses reduced to modest levels of circa 200 MW. This means Northern Ireland is at risk in the event of a prolonged outage of a large generation plant or the Moyle Interconnector, even with a 200 MW reliance on Ireland being available to Northern Ireland.

From 2021, further emissions restrictions on plant at Kilroot have a large effect on system adequacy, and push the jurisdiction into deficit. This deficit could be alleviated if the additional North-South tie line was in place, as can been seen from the solid green line above which portrays the combined, all-island system study.

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

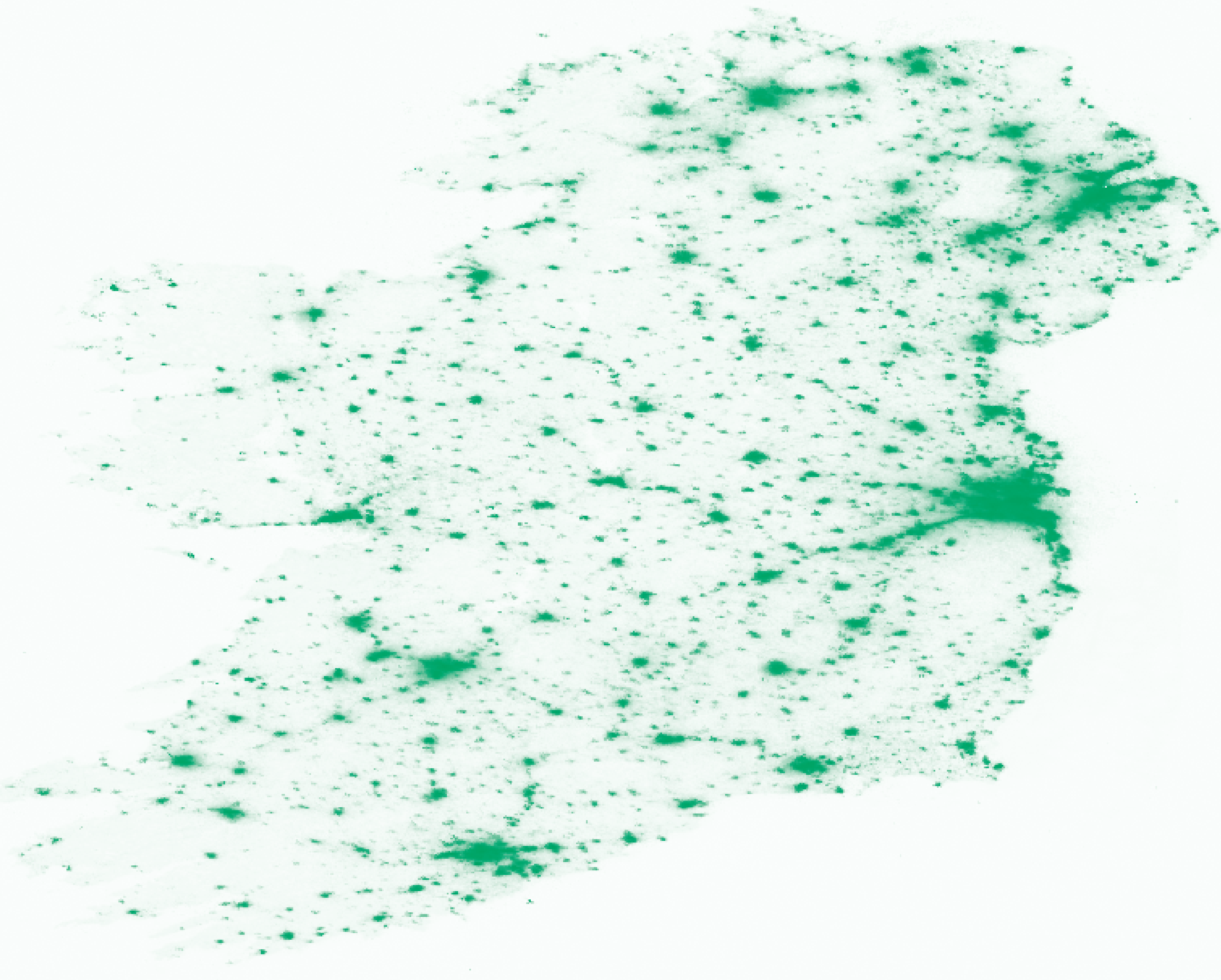
Ireland

Generation Adequacy in Ireland is positive in all scenarios across all years, though with the loss of older plant, the surplus reduces from a peak of nearly 1600 MW to 600 MW by 2022.

All-Island

Following the introduction of the additional tie line, the benefits are highlighted in the all-island analysis, where surpluses of over 700 MW are possible even at the end of the study period.

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 2022[7]. Generation adequacy is a measure of the capability of the electricity supply to meet the electricity demand on the system. The development, planning and connection of new generation capacity to the transmission or distribution systems can involve long lead times and high capital investment. Consequently, this report provides information covering a ten-year timeframe.

EirGrid, the Transmission System Operator (TSO) in Ireland, is required to publish forecast information about the power system, (as set out in Section 38 of the Electricity Regulation Act 1999 and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations). Similarly, SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement, in accordance with Condition 35 of the Licence to participate in the Transmission of Electricity granted to SONI Ltd by the Department of Enterprise Trade and Investment.

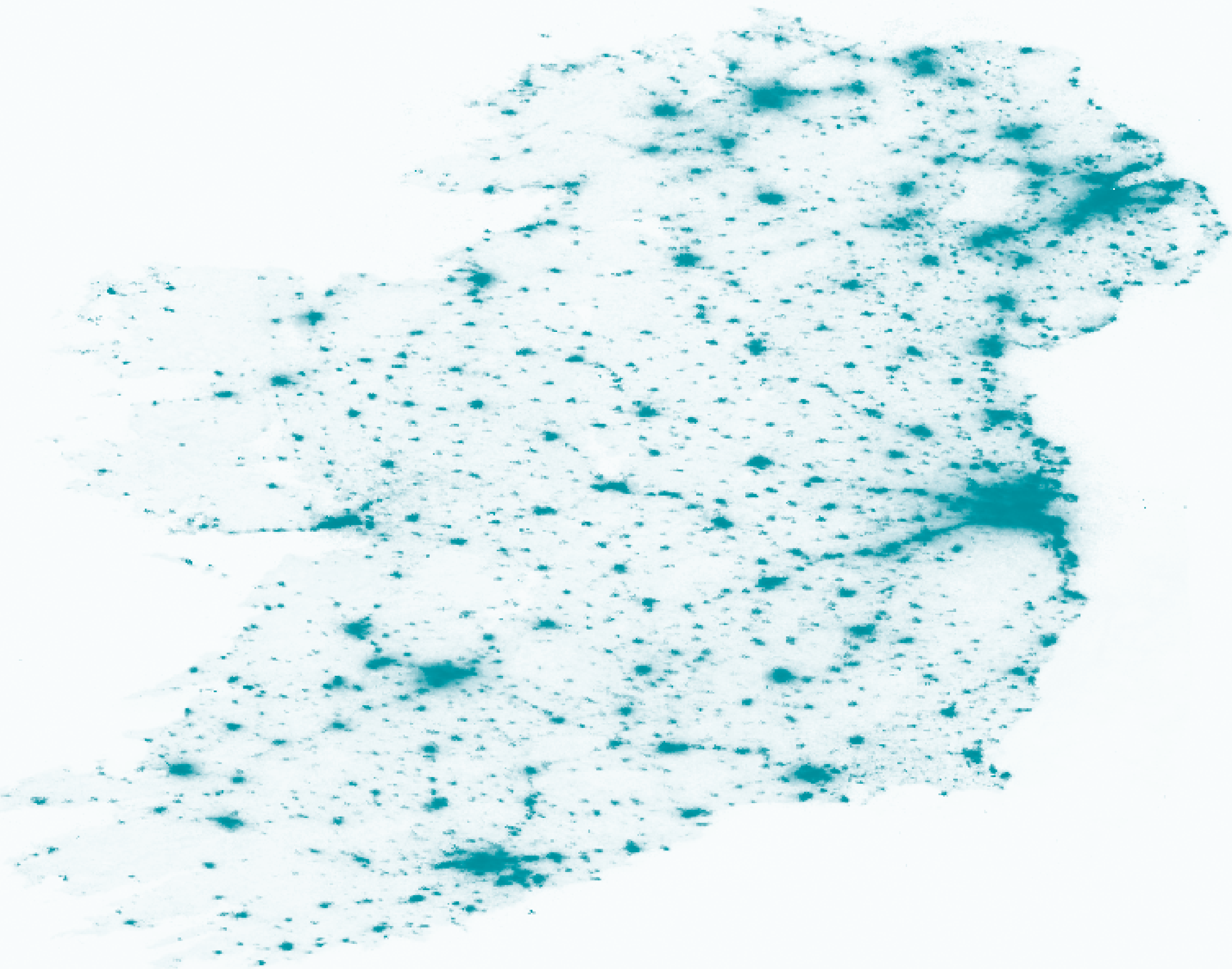
This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2012-2021, published in December 2011.

This report is structured as follows:

- Section 2 outlines the demand forecast methodology, and presents estimates of demand over the next ten years.
- Section 3 describes the assumptions in relation to electricity generation.
- Adequacy assessments are presented in Section 4.
- The report concludes with Section 5, which reports on Data Centres, a growing sector of electricity customers on the island.
- Appendices which provide further detail on the data, results and methodology used in this study are included at the end of this report.

[7] EirGrid and SONI also publish a Winter Outlook Report which is focused on the following winter period, thus concentrating on the known, short-term plant position rather than the long-term outlook presented in the Generation Capacity Statement. (www.eirgrid.com/media/EirGrid%20Winter%20Outlook%202012-2013.pdf)

2 DEMAND FORECAST



2 DEMAND FORECAST

2.1 Introduction

The forecasting of electricity demand is an essential aspect of assessing generation adequacy. This task has become more complicated in recent years with the changing economic climate. Some sectors have been affected more than others.

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

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

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

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

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

2.2 Temperature Correction of Demand Peaks

Of all the meteorological elements it has been found that temperature has the greatest effect on the demand for electricity in both Northern Ireland and Ireland. For this reason, historical demand peak data is adjusted to Average Cold Spell (ACS) temperatures. 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 seeks to remove any sudden changes caused by extremely cold or unusually mild weather conditions. Over each winter period of November through to February, temperature and demand data is collated to enable the annual winter calculation of the ACS effective mean temperature which represents the temperature conditions that prevailed during that particular winter.

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

Statistical analysis is carried out to determine the relationship between demand, temperature and day of the week using multivariate regression analysis over the winter periods. The resultant relationships are then applied to the current winter data to establish the adjusted ACS winter demand.

2.3 Demand Forecast for Northern Ireland

2.3(a) Historical Northern Ireland Methodology

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

2.3(b) Current Northern Ireland Methodology

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

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

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

2.3(c) Temperature and Demand

It is important to consider the effect of temperature on energy demand given the significant impact that the recent severe winters have had. SONI have studied the effect of temperature in the forecasting process. These studies have revealed a significant correlation between temperature and energy demand throughout the year and this has been used to forecast ahead based on average temperature years (ACS).[8] It also allows for average low temperature years and average high temperature years to be taken into consideration.

2.3(d) Demand Scenarios

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

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

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

---

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

2.3(e) Self Consumption and TER

Some industrial customers produce and consume electricity on site at varying times throughout the year[9]. As well as this, a growing amount of small scale embedded generation is appearing on the Northern Ireland system which also produces and consumes electricity on site. These include technologies such as small scale wind turbines, photo-voltaic and biofuels which serve domestic dwellings, community centres, farms, etc. This electricity consumption, known as self consumption, is not included in the SONI Sent-Out[10] annual energy.

In isolation each individual small scale embedded generator of this type does not have a significant effect on the demand profile; however they do become significant on a cumulative basis. SONI have been working closely with Northern Ireland Electricity (NIE) and referencing the Renewable Obligation Certificate Register (ROC Register)[11] to establish the amount of this embedded generation that is currently connected on the Northern Ireland system as well as referencing Northern Ireland Planning Service[12] data to try and establish what amounts will be connecting in the future.

This has enabled SONI to make an informed estimate of the amount of energy contributed to the total demand by self consumption which is then added to the energy which must be exported by generators to meet all demand, including this self consumption. The resultant energy is known as the Total Energy Requirement (TER). It is this TER that is utilised for generation adequacy calculations as the analysis needs to consider the ability to meet this total annual energy.[13]

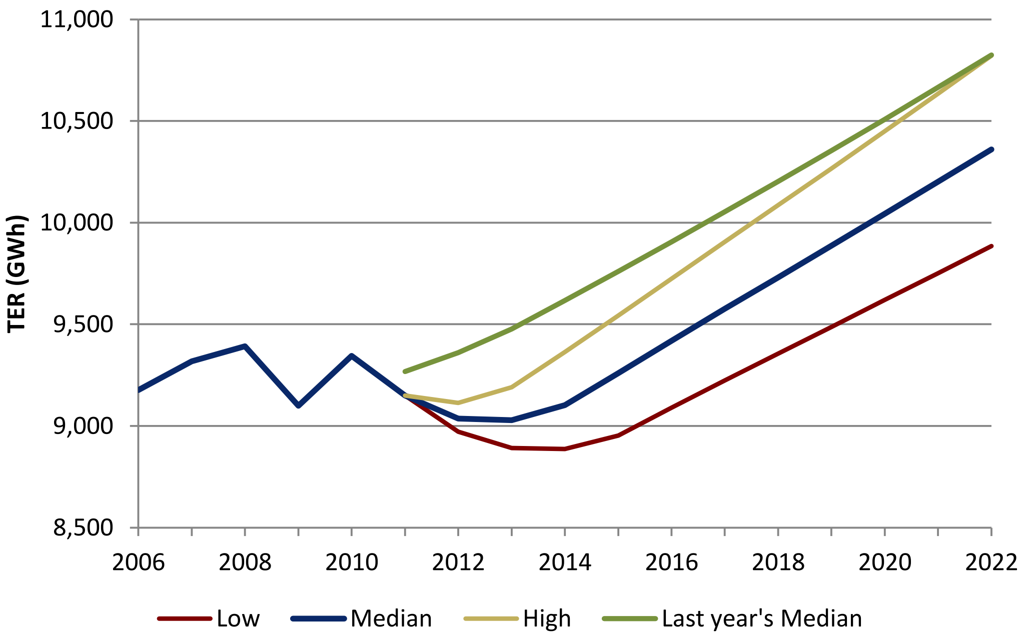


Figure 2-1 Northern Ireland TER Forecast

The resulting forecast for Northern Ireland (Figure 2-1) indicates that it could be 2015 before demand returns to pre-recessionary values.

---

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

[10] Exported = Net of Generator House Loads

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

[12] www.planningni.gov.uk

[13] Self-consumption in Northern Ireland currently represents approximately 1.6% of TER and this grows to approximately 2.5% by the final year of the study.

2.3(f) Peak Demand Forecasting

The Northern Ireland peak demand forecast is carried out using similar methodology as the Ireland peak forecast described in Section 2.4.

The demand peaks over the last decade reflect Customer Private Generation (CPG)[14], consisting of customers running private embedded diesel generation. Analysis was carried out over the 2011/12 winter period to calculate the amount of CPG that was actually running and was found to be 40 MW. This has the effect of suppressing the peak (in effect, this is Demand-Side Management) and is assumed to continue over the ten years of this report.

The Northern Ireland 2011/12 generated winter peak, which occurred on 13th December 2011 @ 17:30, consisted of the following data:

CDGUs[15] + Interconnectors	= 1581 MW
Renewable + Small Scale	= 262 MW
Customer Private Generation	= 40 MW
TOTAL GENERATED PEAK	**= 1883 MW**

When average cold spell temperature correction (ACS) is applied using the methodology as described above, the figure of 1883 MW is corrected down by 12 MW, providing an ACS corrected figure of 1871 MW for the 2011/12 winter period, see Figure 2-2.

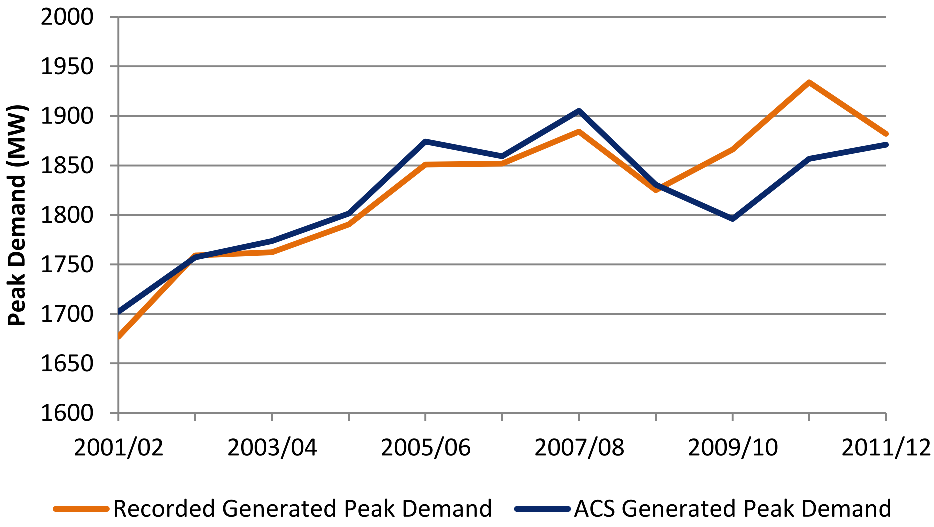


Figure 2-2 Recorded and ACS-corrected peaks (generated level) for Northern Ireland. The most significant corrections are for 2009/10 and 2010/11, when the temperature deviated most from normal.

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(d), 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.

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

[15] Centrally Dispatched Generating Units

It should be noted that the generation adequacy assessment is based on the generation sent out (exported, net of house loads). In Northern Ireland the analysis for the peak demand forecast is carried out using Generated Peak Demand. Therefore a statistically derived conversion factor of 0.953 is applied to the generated peak demand forecasts to convert them to generated peak demand in sent out terms and is the equivalent to the Transmission Peak.

The TER Peak is then derived by adding a further estimation of the contribution to peak demand that the self consuming small scale generation makes as described in section 2.3(e) . On average over the 10 years of the study this has the effect of adding approximately 52 MW to the Transmission Peak.

Figure 2-3 shows the TER peak forecast for Northern Ireland. It indicates that the normal 1.5%[16] growth rate will not return until winter 2015/16.

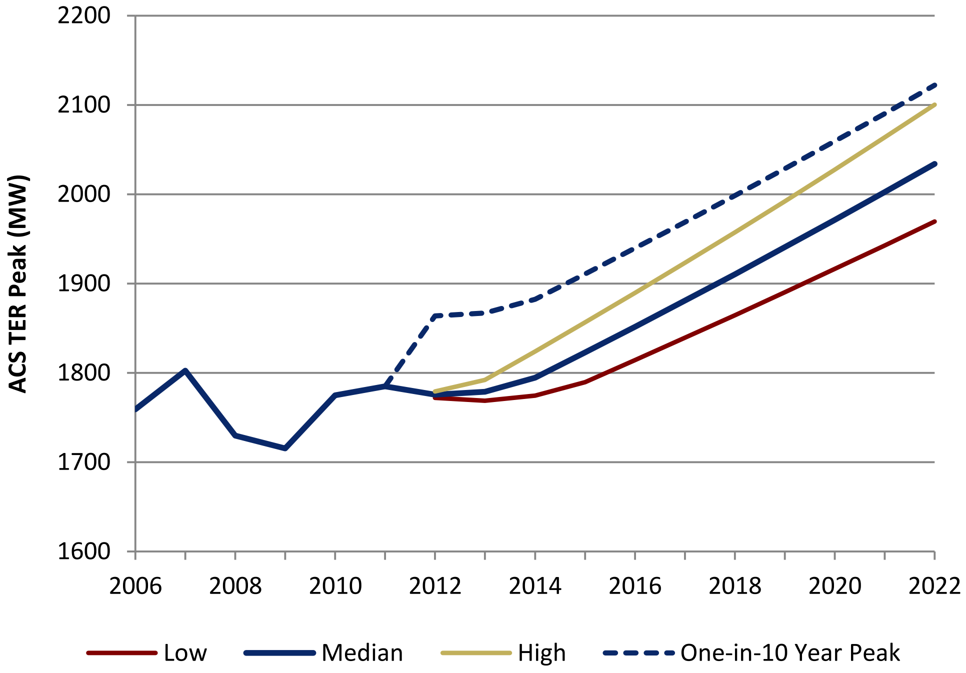


Figure 2-3 ACS TER Peak forecasts for Northern Ireland

2.4 Demand Forecast for Ireland

2.4(a) Structure of the Annual Electricity Demand Forecast Model

The energy forecast model for Ireland is a multiple linear regression model which predicts electricity sales based on changes in the economic parameters of GDP[17] and PCGS[18]. However, before the econometric model is applied, the historical energy figures are corrected for the effect of temperature. Three electricity sales forecasts (high, median and low) are produced for Ireland for the next ten years.

Transporting electricity from the supplier to the customer invariably leads to losses. These losses must be added to the forecasted sales figures to give the amount of electricity needed to be generated. Based on the comparison of sales to exported energy, it is estimated that between 7 and 8% of power produced is lost as it passes through the electricity transmission and distribution systems.

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

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

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

Some large-scale industrial customers produce and consume electricity on site, many with the facility of Combined Heat and Power (CHP). This electricity consumption, known as *self-consumption*, is not included in sales or transported across the network. Consequently, an estimate[19] of this quantity is added to the energy which must be exported by generators to meet sales. The resultant energy is known as the Total Electricity Requirement (TER). As all generation sources (including an estimate of self-consumers) are considered in the analysis, it is this TER that is utilised for generation adequacy calculations.

2.4(b) Training the forecast model

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

Past economic data is sourced from the most recent Quarterly National Accounts of the Central Statistics Office. Data from the past 17 years is analysed to capture the most recent trends relating the economic parameters to demand patterns.

2.4(c) Forecasting causal inputs

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

The short-term data comes from the Quarterly Economic Commentary published by the ESRI in September 2012. Longer-term trends arise out of recent analysis by ESRI. These trends compared well with predictions from other institutions including the Department of Finance, the European Commission[20], the Central Bank and the International Monetary Fund.

	GDP (volume)	Personal Consumption
2013	2.2%	-0.5%
2014-2015	3.0%	0.2%
2016-2022	2.8%	2.2%

2.4(d) Uncertainty around the median forecast

The median demand forecast is the best estimate of what might happen in the future. However, in an effort to capture the uncertainty involved in any forecasting exercise, higher and lower forecasts have been made to bracket the median demand. Growth in the lower forecast is delayed by about two years in comparison to the median. For the higher forecast, growth is accelerated by about one year.

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

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

---

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

[20] Directorate General for Economic and Financial Affairs (DG ECFIN)

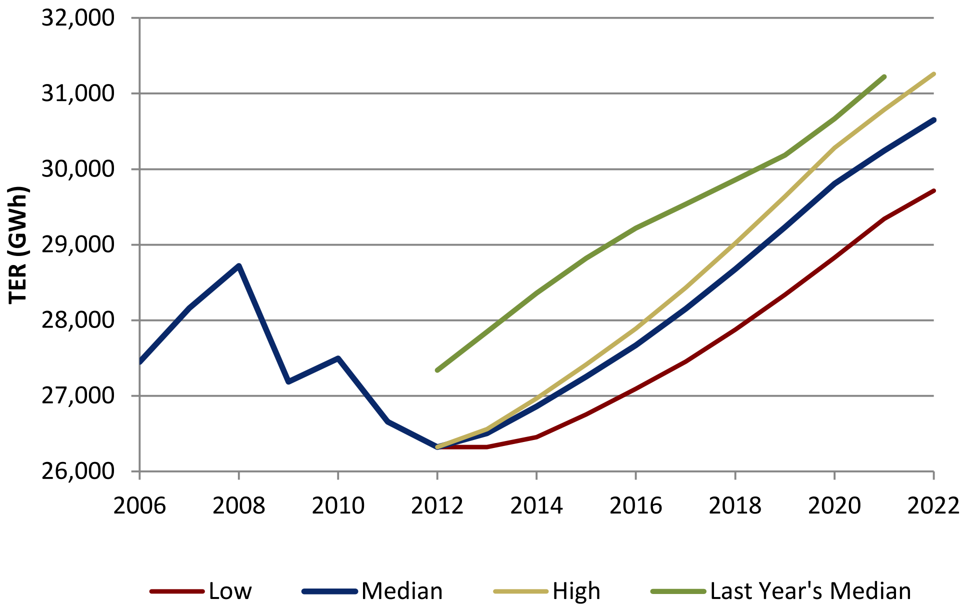


Figure 2-4 TER Forecasts for Ireland. The figure for 2012 is based on real data available at EirGrid's National Control Centre up to October, and so estimates are made for the remaining months.

2.4(e) Peak Demand Forecasting

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

Before applying this model, it is necessary to assess the other disparate factors which can affect the somewhat erratic winter peak, including

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

The current DSM scheme (Winter Peak Demand Reduction Scheme (WPDRS)) results in a lowering of the winter peak. This effect has been estimated and allowed for in the past. While this particular scheme is being phased out, it is likely that there will still be a similar amount of peak reduction – some of this could be due to customers reacting to the price differences on their smart meters. More peak reduction should be available when called from the new Demand Side Units (DSU), such as Activation Energy and DAE.

This situation merits careful monitoring into the future, so that any adjustments to the modelling procedure can be assessed.

As discussed already, Temperature has a most significant effect on electricity demand, as was particularly evident over the two severe winters of 2010 and 2011, when temperatures plunged and demand rose.

ACS correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences, see Figure 2-5.

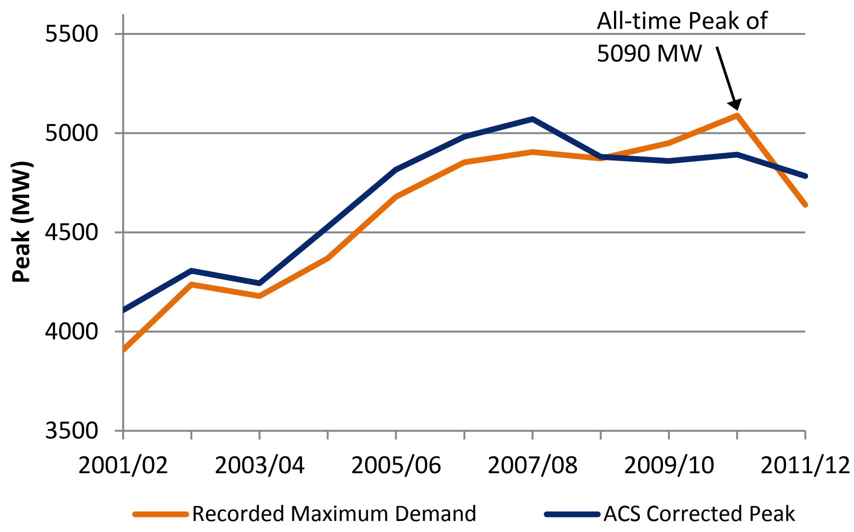


Figure 2-5 Past values of recorded maximum demand in Ireland, and the ACS corrected values.

The temperature-corrected peak curve is used in the ALF model which can then be forecast forwards using the previously-determined energy forecasts, see Figure 2-6.

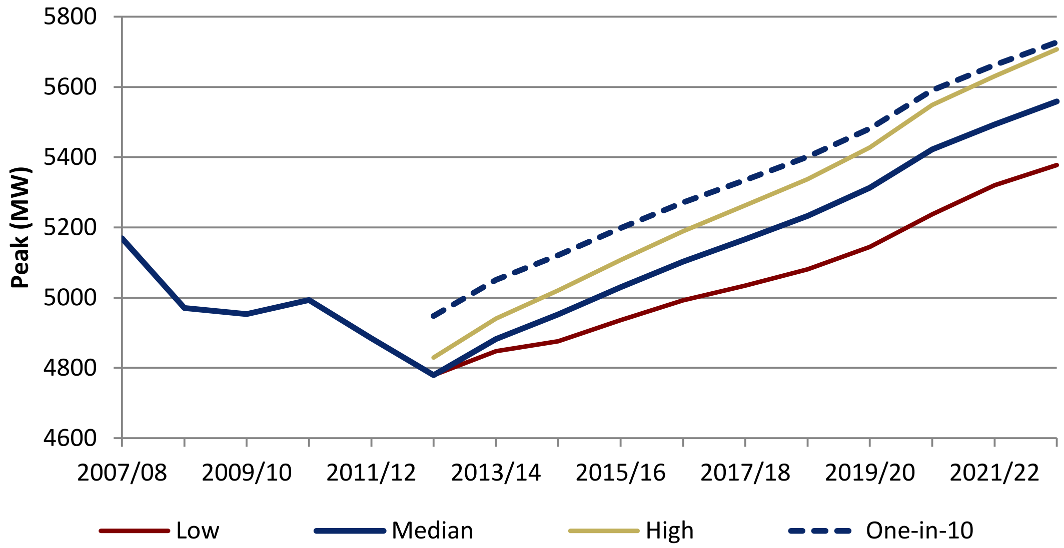


Figure 2-6 Forecast of TER Peak for Average Cold Spell conditions, for high, median and low scenarios in Ireland. Also included are the peaks that could result if the weather were not average, but as severe as the coldest in 10 winters.

2.5 All–Island Forecasts

2.5(a) Annual Electricity Demand

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

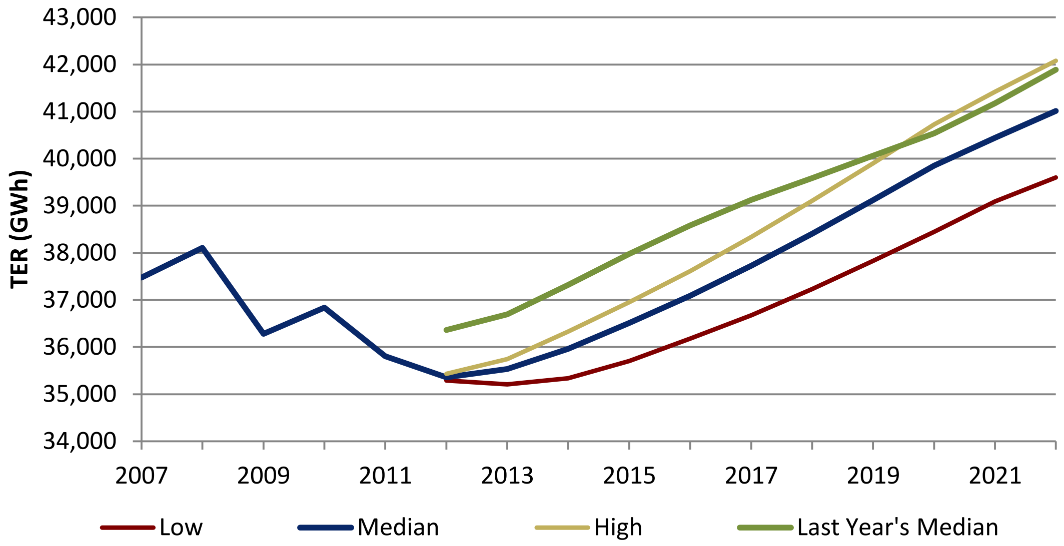


Figure 2-7 Combined all-island TER forecast

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

2.5(b) All-Island Peak Forecast

The annual peaks for Ireland and Northern Ireland do not generally coincide. In Northern Ireland, annual peaks may occur at the start or at the end of the year, whereas in Ireland peaks tend to occur in December. To create all-island peaks, future demand profiles have been built for both regions based on the actual 2011 demand shape. This gives yearly all-island peaks which are less than the sum of the equivalent peaks for each region – just one of the benefits of switching to an all-island system. The forecasted all-island peaks are shown in Figure 2-8, where ACS conditions are assumed for the future.

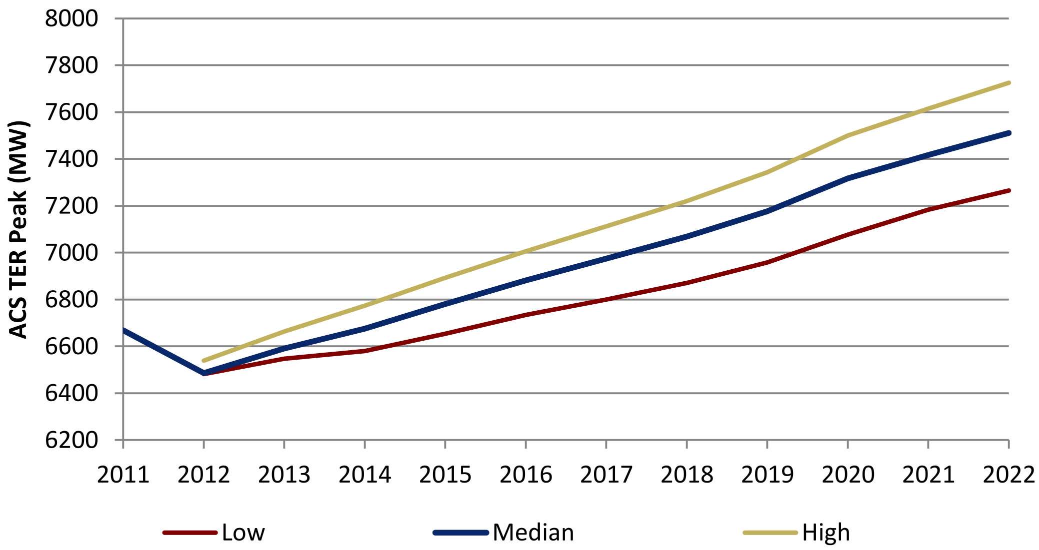


Figure 2-8 The all-island TER Peak Forecast

2.6 Annual Load Shape and Demand Profiles

To create future demand profiles for the adequacy studies, it is necessary to use an appropriate base year profile which provides a representative demand profile of both jurisdictions. This profile is then progressively scaled up using forecasts of energy peak and demand. The base year chosen for the profile creation was 2011 for both jurisdictions.

2011 was chosen because it was the most recent profile available, and it was deemed to be a year representative of contemporary demand patterns. The choice of a typical year for load profiling is a matter for continual review.

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

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

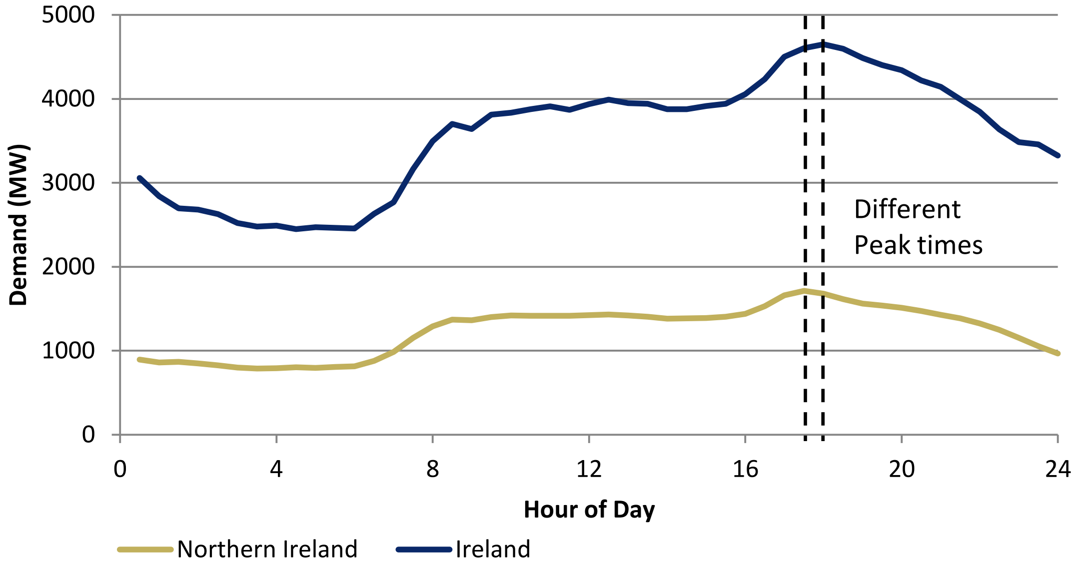


Figure 2-9 Typical winter day profile

2.7 Changes in Future Demand Patterns

The Government of Ireland has a plan to increase energy efficiency by 20% by 2020. This includes such actions as replacing existing lighting with energy efficient sources, and increasing the thermal insulation standards for newly built housing, as well as government grants for retrofitting existing houses to improve their efficiency[21].

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[22].

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

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

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

target for the UK as set out in the Strategic Framework for Northern Ireland[23]. It is envisaged that they will be able to achieve this through a number of different schemes. These include for example, the introduction of Energy Performance Certificates, amending building regulations to progressively improve the thermal performance of buildings, and providing services through the Government's regional business development agency (Invest NI[24]) to help businesses identify and implement significant energy efficiencies.

There are also moves by the Northern Ireland Executive to encourage a higher uptake of electric vehicles, by the introduction of a number of free car charging points throughout Northern Ireland through the ECAR project[25]. At present there are approximately 40 charging points installed with an additional 130 to be installed in 2013. However, to date there has been a very low usage of these charging points with almost half of them never being used at all. It is therefore hard to predict at this stage as to whether or not electric vehicles will have a significant effect on the Northern Ireland demand profile in the future.

Trials are currently ongoing to evaluate the effect of the use of smart metering in Northern Ireland,[26] which could also have a significant effect on the demand profile. SONI will monitor the results of this trial to take account of any significant effects that smart metering may have on the future demand profiles.

---

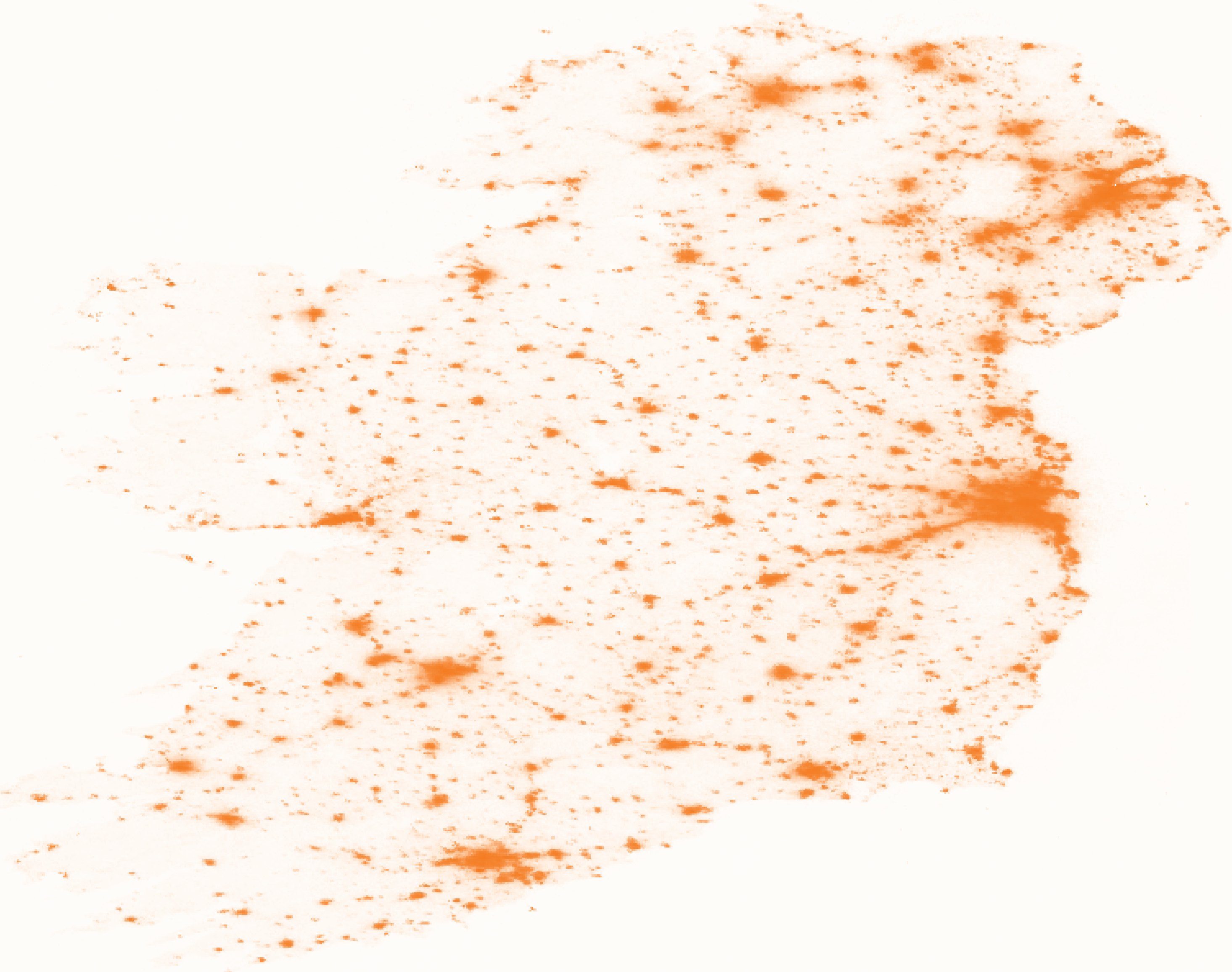
23 http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf

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

25 www.nidirect.gov.uk/index/information-and-services/travel-transport-and-roads/northern-ireland-e-car-project.htm

26 www.nie.co.uk/Network/Future-networks/Smart-meters

3 ELECTRICITY GENERATION



3 ELECTRICITY GENERATION

3.1 Introduction

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

In predicting the future of electricity generation supply in Ireland and Northern Ireland, EirGrid and SONI have endeavoured to use the most up-to-date information available at the time of the data freeze for this report (October 2012). EirGrid have taken the prudent approach of assuming that not all of the contracted plant will be commissioned, and that some of the older plant in Ireland will, in effect, shut down over the course of the study period.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capacity Removed (Northern Ireland)				-510						
Capacity added (Ireland) [27]		486	62	196						
Capacity Removed (Ireland)		-212							-592	
Minor degradation		-4	-2	3	-2	-4	-2	1	-2	-4
Net Impact		270	60	-311	-2	-4	-2	1	-594	-4
Total Dispatchable capacity	**9727**	**9997**	**10057**	**9746**	**9744**	**9740**	**9738**	**9739**	**9145**	**9141**

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

Interconnection will continue to play an important role in future generation supply security. The East-West Interconnector has connected the transmission systems of Ireland and Wales, and is expected to transmit 500 MW in either direction. Along with the existing Moyle Interconnector[28] that connects the transmission systems of Northern Ireland and Scotland, this has significantly enhanced the overall interconnection between the island of Ireland and Great Britain.

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

[27] There is no new conventional generation currently planned for Northern Ireland over the next 10 years.

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

3.2 Plant Types

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

Although fully-dispatchable plant normally consists of the larger units on the system, smaller units can also be fully-dispatchable if they wish to take part in the market, for example, in Northern Ireland there are now three 3 MW gas units operated by Contour Global, and a 47 MW Aggregated Generating Unit operated by iPower. Also there are some new Demand Side Units in Ireland which take part in the market and are fully dispatchable.

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

Large wind farms fall into a different category. Since the maximum output from wind farms is determined by wind strength, they are not fully controllable, i.e. they may not be dispatched up to their maximum registered capacity if the wind strength is too low to allow this. However, their output can be reduced by EirGrid or SONI if required (for example, due to transmission constraints), and they are therefore categorised as being partially dispatchable. In accordance with the EirGrid Grid Code[29] and the Distribution Code[30] in Ireland, wind farms with an installed capacity greater than 5 MW must be partially dispatchable.

In accordance with the SONI Grid Code[31] and the Distribution Code[32] in Northern Ireland, a wind farm with a registered capacity of 5 MW or more must be controllable by the TSO and is defined as a "Controllable Wind Farm Power Station" (CWFPS). A "Dispatchable Wind Farm Power Station" is further defined as a DWFPS which must have a control facility in order to be dispatched via an electronic interface by the TSO. In both cases these would be categorised as being partially dispatchable.

3.3 Changes in Conventional Generation in Ireland

This section describes the changes in fully dispatchable plant capacities which are forecast to occur over the next ten years. Plant closures and additions are documented. In Ireland, the only new generators that are documented here are those which have a signed connection agreement with EirGrid[33] or the DSO (Distribution System Operator), and have indicated a commissioning date to EirGrid by the data freeze date.

3.3(a) Plant Commissionings

- Endesa plans to commission a new Combined-Cycle Gas Turbine (CCGT) plant immediately after the closure of the existing units at Great Island (see section 3.3(b)). The Firm Access Quantity (FAQ) at this site is assumed to be initially 216 MW, until an additional FAQ of 215 MW is assigned in 2021. SSE has agreed to purchase the Endesa generators.

---

29 www.eirgrid.com/operations/gridcode/

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

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

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

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

- A Waste-to-Energy converter, located in Dublin, should be able to supply 62 MW.
- Four new open cycle gas turbine (OCGT) power stations have signed to connect to the system, giving an additional capacity of 349 MW.
- Two Demand Side Units have entered the SEM: Activation Energy has a dispatchable capacity of 12 MW and DAE Virtual Power has 29 MW.

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

Plant	Maximum Export Capacity (MW)
Great Island CCGT	431
Caulstown OCGT	55
Nore OCGT	98
Dublin Waste to Energy	62
Cuilleen OCGT	98
Suir OCGT	98

Table 3-2 Confirmed contracted generation capacity for Ireland to 2022

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

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

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

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

3.3(b) Plant Decommissionings

Some older generators will come to the end of their lifetimes over the next ten years. Confirmed decommissionings are shown in Table 3-3.

Plant	Export Capacity (MW)
Great Island 1,2,3	212
Tarbert 1, 2, 3, 4	592

Table 3-3 Confirmed closures of conventional generators in Ireland

3.3(c) Ireland's Base Case

Other than the generators listed in Table 3.3, EirGrid has received no other notification of plant closures. However, EirGrid has assumed that some older generators will shut towards the latter end of the 10 year period. An alternative approach could be to model these units with higher forced outage rates, which would have the same effect as closure.

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

Plant Type	Fuel
Conventional steam	HFO
Conventional steam	Coal/HFO
Conventional steam	Peat
Conventional steam	Gas
Conventional steam	Gas/HFO
Open cycle combustion turbine	DO
Open cycle combustion turbine	Gas/DO
Combined cycle combustion Turbine	Gas/DO
Combined heat and power	Gas/DO
Hydro generation	Hydro
Pumped storage	Hydro
Open cycle combustion turbine	Waste

HFO=Heavy Fuel Oil; DO=Distillate Oil

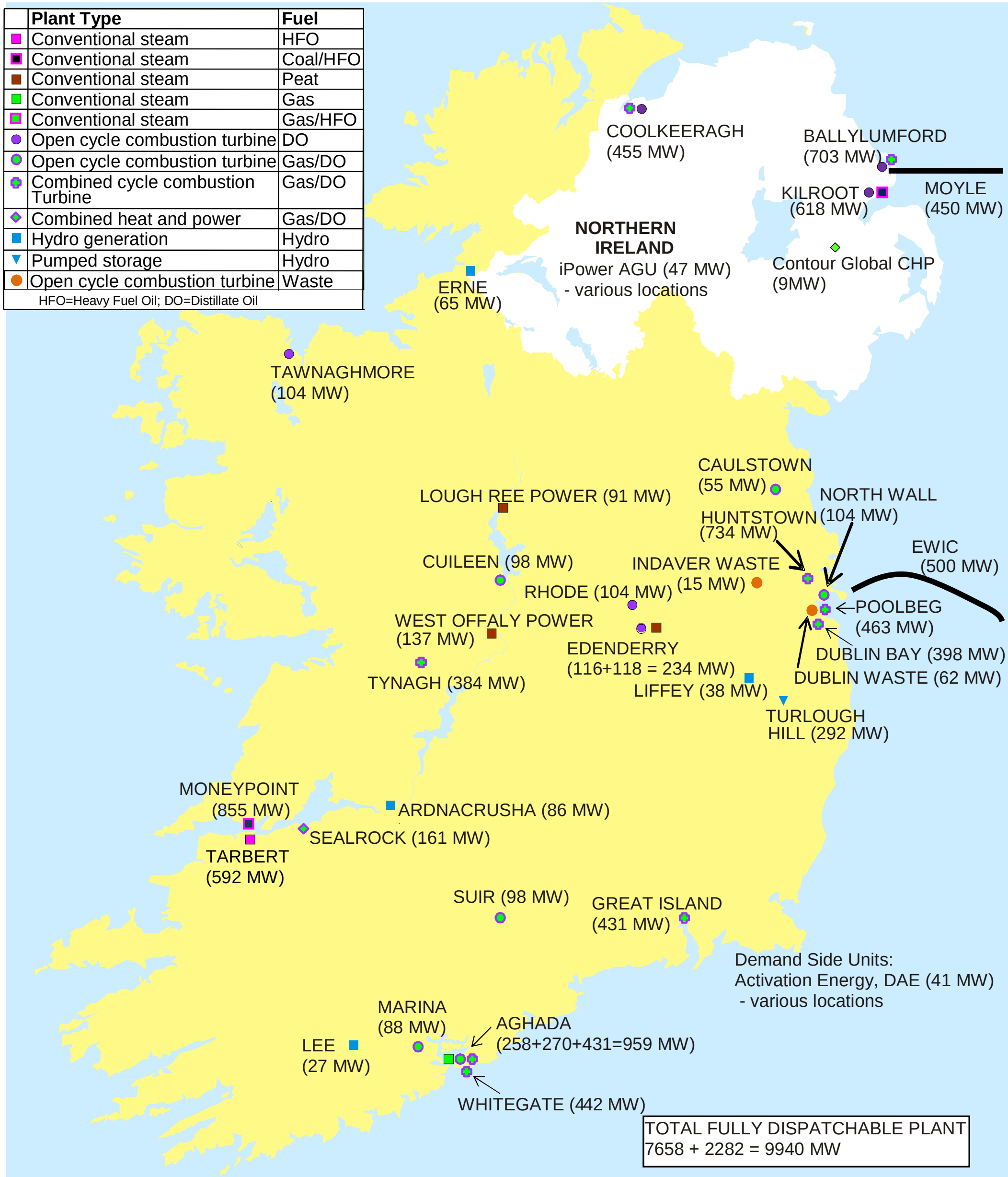


Figure 3-1 Fully dispatchable plant and interconnectors installed in 2018, at exported capacities. All figures shown are Registered Capacities (except new plant which are at the planned Maximum Export Capacity) – generators and interconnectors may often operate at a lower capacity.

3.4 Changes in Conventional Generation in Northern Ireland

- There is no new conventional generation currently planned for Northern Ireland over the next 10 years.
- Ballylumford Gas/HFO ST4, ST5 and ST6 are to be decommissioned by 2016. This is due to environmental constraints introduced by the Large Combustion Plants Directive[34] and will give a reduction of 510 MW in capacity.
- From 2016, KPS1 & KPS2 at Kilroot will have to comply with the Industrial Emissions Directive (IED)[35]. SONI have discussed with AES Kilroot how the workings of the IED will affect KPS1 and KPS2 running regimes.

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

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

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

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

3.5 Interconnection

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

3.5(a) North-South Tie Line

With the completion of the second high capacity transmission link between Ireland and Northern Ireland, an all-island generation adequacy assessment has been carried out from 2017 onward. In this all-island assessment, the demand and generation portfolios for Northern Ireland and Ireland are aggregated.

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

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

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

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

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

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

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

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

3.5(b) Moyle Interconnector between Northern Ireland and Scotland

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

However, due to the uncertainty as to if or when the ongoing cable fault on Pole 1 of the Moyle Interconnector will be repaired and available for service again, the Moyle's [36] import (and export) capacity is assumed to be limited to 250 MW.

All interconnector capacity is auctioned by SONI on behalf of Mutual Energy Limited[37]. This capacity is purchased by market participants. In the SEM the unused capacity can, in emergency situations, be used solely to meet peak demand. Therefore this capacity assessment assumes the capacity of the Moyle Interconnector as a maximum of 250 MW.

In Ofgem's recent Electricity Capacity Assessment[38], even though there are warnings about power shortage risks in Great Britain by 2015, their base case is still treating the interconnectors to Northern Ireland and Ireland as negative generation which is in line with SONI's assumptions for the Moyle Interconnector. National Grid's most recent Seven Year Statement[39] also treats the Moyle as negative generation.

At the time of writing this report, one cable of the Moyle Interconnector was on a prolonged forced outage due to an undersea cable fault and is unlikely to be repaired for the foreseeable future. This follows previous prolonged faults on both cables in 2011 and on one of the two cables in 2010. As such, the Forced Outage Probability[40] (FOP) used in adequacy assessments for the Moyle has been adjusted to reflect the recent outages.

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

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

[37] www.mutual-energy.com

[38] Ofgem Electricity Capacity Assessment: www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

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

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

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

The East-West interconnector (EWIC) connects the transmission systems of Ireland and Wales with a capacity of 500 MW in either direction. However, it is not easy to predict whether or not imports for the full 500 MW will be available at all times. Based on analysis[41], EirGrid has estimated the capacity value of the interconnector to be 440 MW for these generation adequacy studies. Similar to the Moyle, EWIC is treated as negative generation by National Grid.

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

3.6 Wind Capacity & Renewables Targets

In both Ireland and Northern Ireland, there are government policies which make targets for the amount of electricity sourced from renewables. Biofuels, hydro and marine energy will make an important contribution to these targets. However, it is assumed that these renewable targets will be achieved largely through the deployment of additional wind powered generation. Table 3-5 shows the existing and planned wind generation on the island.

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

County	Connected (MW)	Contracted (MW)	County	Connected (MW)	Contracted (MW)
Cork	284	208	Wicklow	34	40
Donegal	276	103	Clare	32	58
Kerry	269	213	Roscommon	23	0
Tyrone	221	283	Laois	21	0
Wexford	122	62	Kilkenny	10	0
Cavan	107	0.02	Carlow	10	3
Limerick	99	84	Offaly	5	79
Leitrim	88	5	Meath	3	0
Tipperary	87	226	Louth	2	2
Londonderry	85	170	Waterford	2	0
Fermanagh	84	18	Dublin	1	0
Galway	72	244	Kildare	0.02	0
Antrim	60	78	Down	0	13
Sligo	49	8	Westmeath	0	9
Mayo	46	212	Armagh	0	0
			Total	**2093**	**2116**

Table 3-5 Existing (connected) and planned (contracted) wind farms, as of October 2012, in order of county by the capacity (MW) of connected wind farms. Planned refers to wind farms that have signed a connection agreement in Ireland, or that have received planning approval in Northern Ireland.

3.6(a) Wind Power in 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 1,600 MW at the time of writing. This value is set to increase over the next few years as Ireland endeavours to meet

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

its renewables target in 2020. The actual amount of renewable energy this requires will depend on the demand in future years (the forecast of which has decreased due to the economic downturn). Also, the assumptions made for other renewable generation will have a bearing on how much wind energy will need to be generated to reach the 40% target. Lastly, a small amount of available energy from wind cannot be used due to transmission constraints or system curtailment – the exact amount has to be estimated, and is therefore another source of potential error.

With these uncertainties in mind, not one figure but a band of possible outcomes has been estimated for wind capacity in 2020. Figure 3-2 indicates these targets between about 3500 MW and 4000 MW.

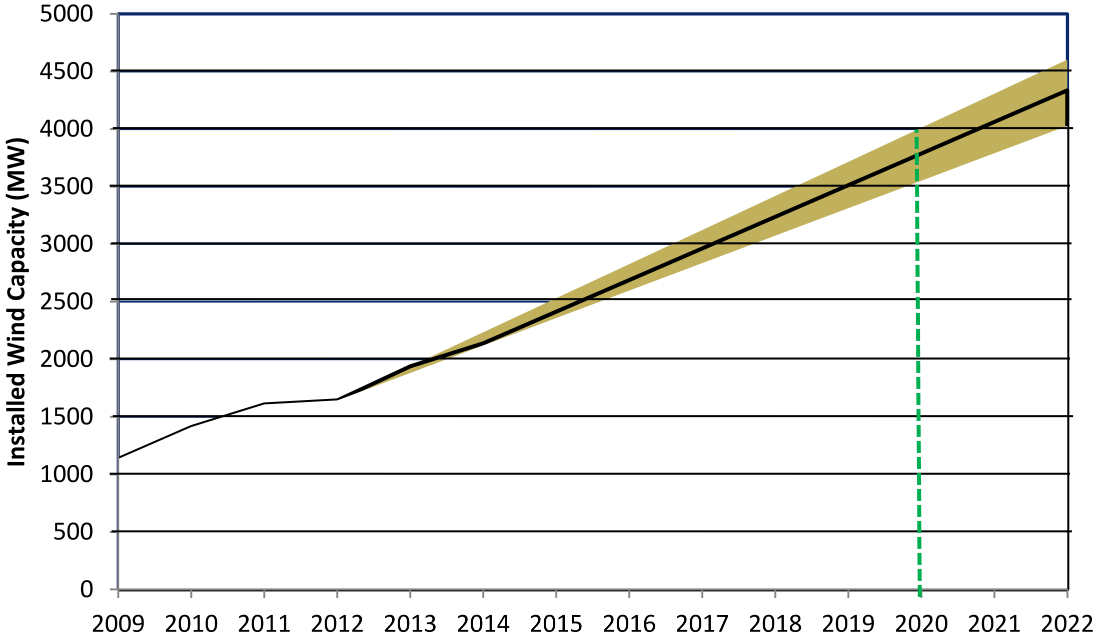


Figure 3-2 Band of predictions for wind capacity levels in Ireland assumed for this report, determined using a linear projection of installed wind capacity required to meet 2020 targets.

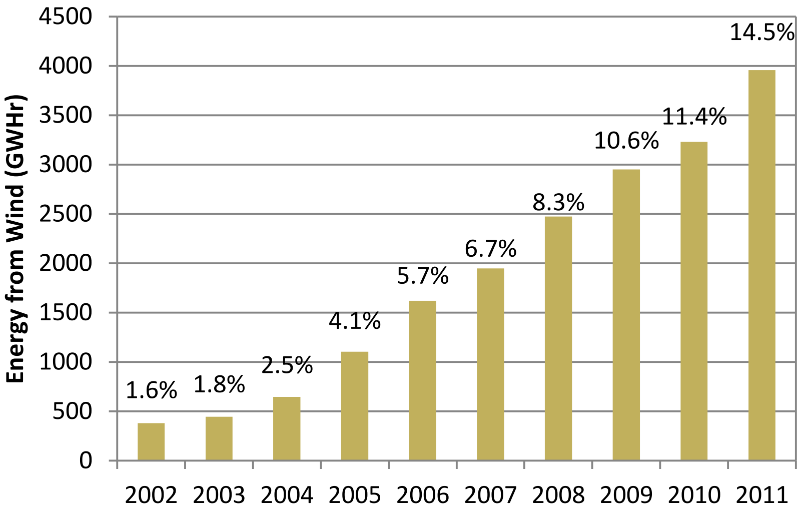


Figure 3-3 Historical wind generation in annual energy terms for Ireland (normalised), also given as a percentage of total electrical energy produced that year.

Based on historical records (historical wind capacity factors are shown in Figure 3-4), it is assumed that onshore wind has a capacity factor of 31.7%. 2007 was considered to be a poor wind year in terms of nationwide average wind speeds. Wind conditions recovered in 2008 and 2009, but 2010 had the worst performance of the decade. 2011 was slightly higher than average.

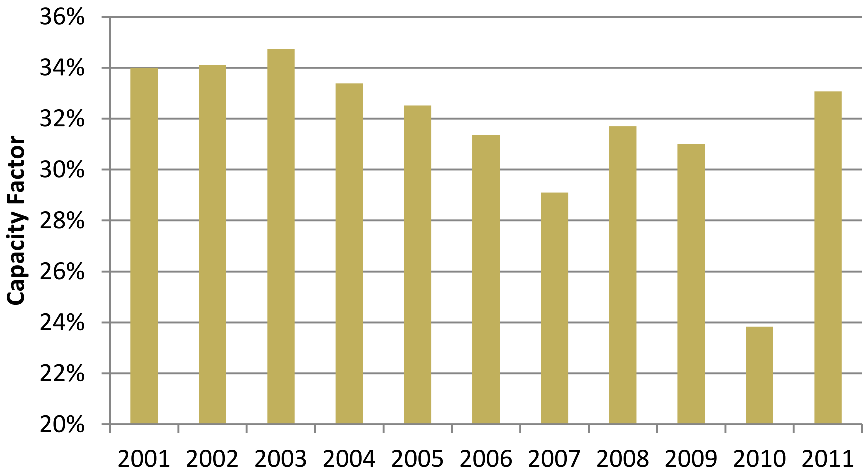


Figure 3-4 Historical wind capacity factors for Ireland.

3.6(b) Wind Power in Northern Ireland

The Strategic Energy Framework for Northern Ireland[42] restated the current target of 12% of electricity consumption from renewable resources by 2012 with a new additional target of 40% of electricity consumption from renewable resources by 2020. For 2011, 11.87% of electricity consumption was from renewable sources in Northern Ireland. This is a significant improvement as compared to 2010 when a relatively low renewable contribution of 7.93% was observed, mainly due to the wind being the major contributor of the renewable generation portfolio and 2010 being a poor wind year.

Installed capacity of wind generation has grown from 37 MW in 2002 to 469 MW (including 15 MW of small scale wind) at the time of writing. This is set to increase rapidly over the next number of years as increasing levels of planning applications[43] for new wind farms are made. It is this increasing level of wind that is expected to be the main contributor to achieving the 40% target.

While the exact amount is as yet uncertain, for the purposes of the studies for this report SONI assume that by 2022 there will be an installed wind capacity of 1828 MW in Northern Ireland (1097 MW of large scale onshore, 131 MW of small scale onshore and 600 MW of offshore). This is based on the assumption that the Government target for Northern Ireland of 40% of electricity production from renewable sources will be met by 2020. The 40% target also takes into account a contribution from other renewables, such as tidal and biomass as outlined below.

However, the main contribution will be made up from wind. It is estimated that an installed wind capacity of circa 1275 MW will be enough to achieve the 40% figure by 2020 (968 MW of large scale onshore, 116 MW of small scale onshore and 191 MW of offshore).

The figures for the amount of large scale onshore wind in each study year have been derived by incrementing the amount of connected onshore wind each year which will allow this target of 968 MW to be met by 2020.

---

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

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

These assumptions have also referenced a number of sources, including the Strategic Environmental Assessment (SEA)[44], the Onshore Renewable Electricity Action Plan (OREAP)[45] and the Strategic Energy Framework[46] (SEF) produced by the Department of Enterprise, Trade and Investment (DETI).

The assumptions also incorporate the recent announcements by the Crown Estates[47] who have now awarded development rights for three offshore renewable energy sites in Northern Ireland's coastal waters including a 600 MW Offshore wind farm, and two 100 MW Tidal sites as well as information provided on wind farm connections by Northern Ireland Electricity (NIE) and the Northern Ireland Planning Service[48].

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

For the purposes of calculating the forecasted energy produced by renewables, SONI assumes that large scale onshore wind has a capacity factor[49] of 30%, large scale offshore wind 35%, tidal 20% and large scale biomass 80%. There is also a factor to take account of an amount of potential energy from wind which cannot be used due to transmission or system constraints. It should be further noted that the actual amount of renewable energy required to meet the 40% target by 2020 will depend on the demand in future years, as the 40% is based on electricity consumption and not on installed capacity.

Figure 3-5 below illustrates the installed wind levels in Northern Ireland assumed for this report. Most of this wind will be built in the west of Northern Ireland, and transmission reinforcements will be required to transport it to the east, where demand is highest. To avoid extensive potential wind energy constraints, and to enable Northern Ireland to meet Government renewable targets, considerable investment is now urgently required on the Northern Ireland transmission system. The levels of connected wind capacity required are dependent on a number of key transmission corridors being reinforced by the asset owner, Northern Ireland Electricity, alongside the completion of the second North South tie line as highlighted in their Medium Term Plan[50].

Figure 3-6 shows the increase in energy supplied from wind generation in recent years. In 2005, just 3.4% of Northern Ireland's electricity needs came from wind generation. This share had grown to 11.1% by 2011.

---

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

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

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

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

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

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

[50] NIE Medium Term Plan: www.nie.co.uk/documents/Network-Renewable_Invest/Medium-Term-Plan-231110.aspx

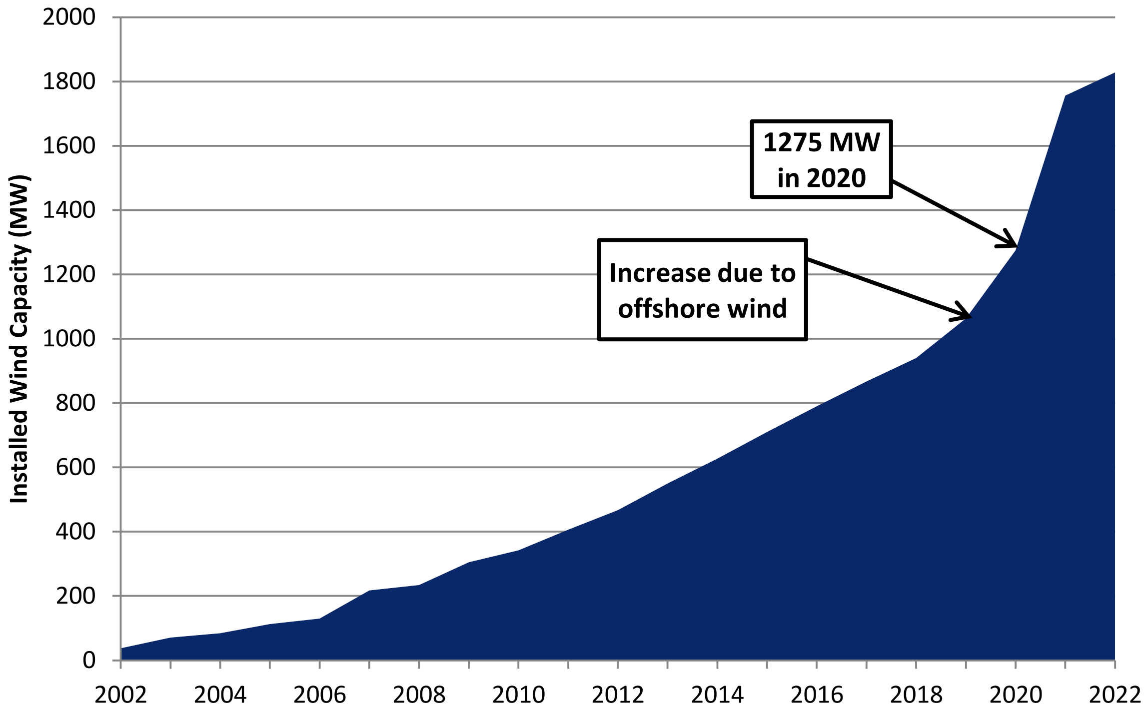


Figure 3-5 Northern Ireland wind levels assumed for this report.

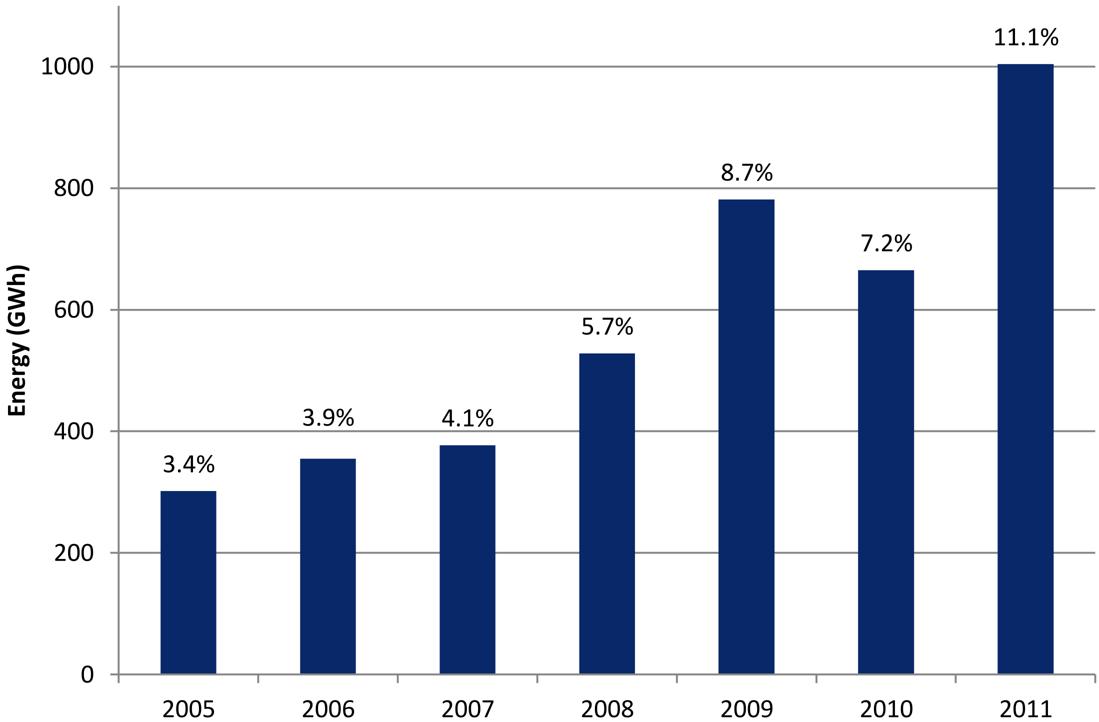


Figure 3-6 Historical wind generation in annual energy terms for Northern Ireland, also given as a percentage of total energy produced that year. Figures are based on Sent-Out Metering available to SONI.

Historical capacity factors for Northern Ireland are shown in Figure 3-7. The average wind capacity factor for the last 7 years is 31.4%. Again, it can be seen that in 2010 the wind capacity factor is much lower than the average.

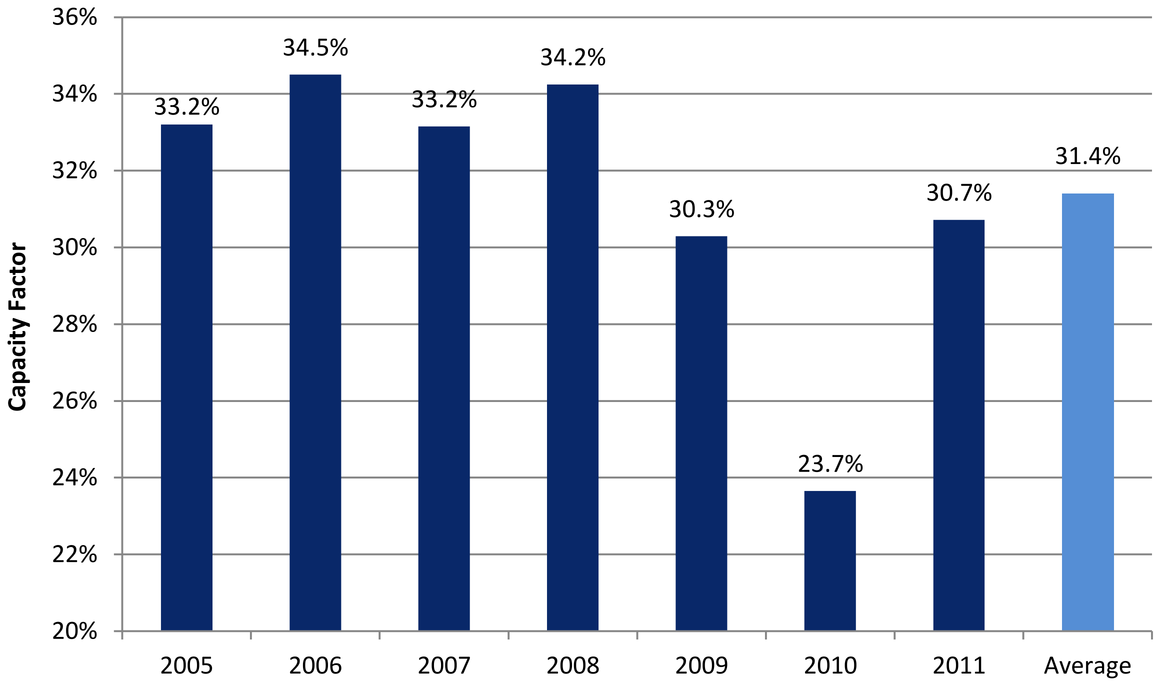


Figure 3-7 Northern Ireland historical wind capacity factors. Figures based on Sent-Out Metering available to SONI

The Strategic Energy Framework for Northern Ireland restated the target of 12% of electricity produced from renewable sources by 2012. Year to date figures to the end of October 2012 indicates that this target will be met. See Figure 3-8 below.

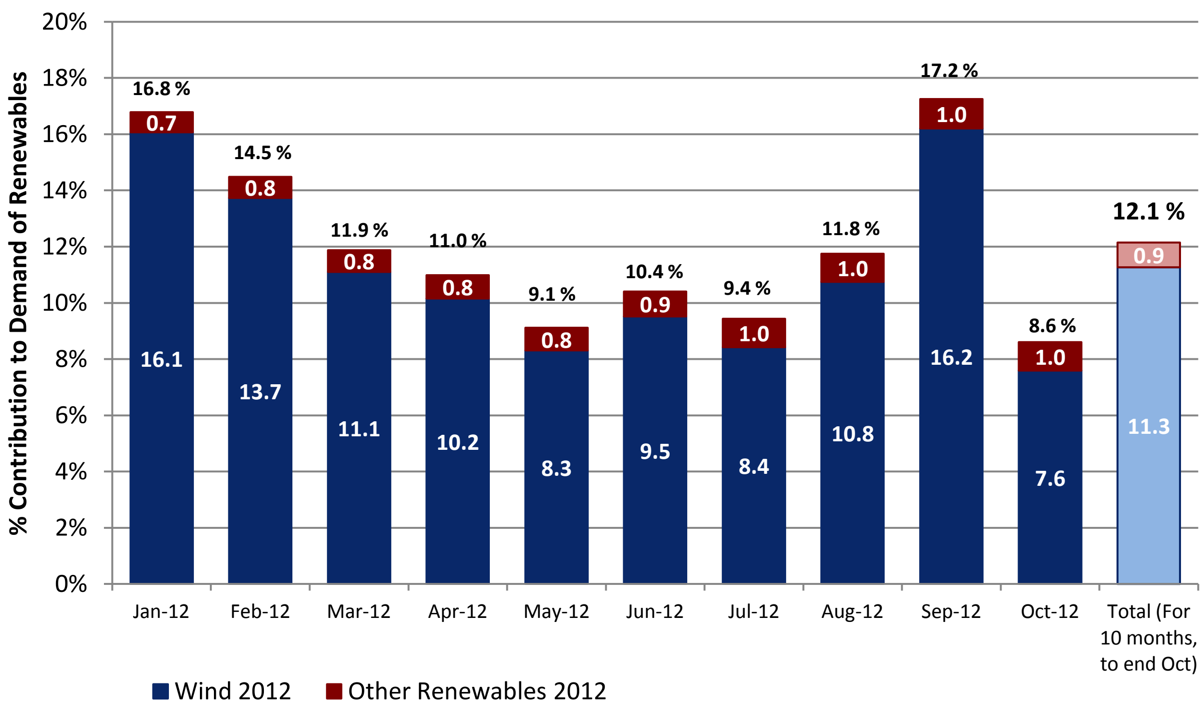


Figure 3-8 Percentage Renewable Contribution in Northern Ireland for 2012, based on Sent-Out Metering Available to SONI.

3.6(c) Wind Capacity Credit

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

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

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

It can be seen in Figure 3-9 that there is a benefit to the capacity credit of wind when it is determined on an all-island basis. The reason for this is that a greater geographic area gives greater wind speed variability at any given time. If the wind drops off in the south, it may not drop off in the north, or at the very least there will be a time lag. The result is that the variation in wind increases and the capacity contribution improves.

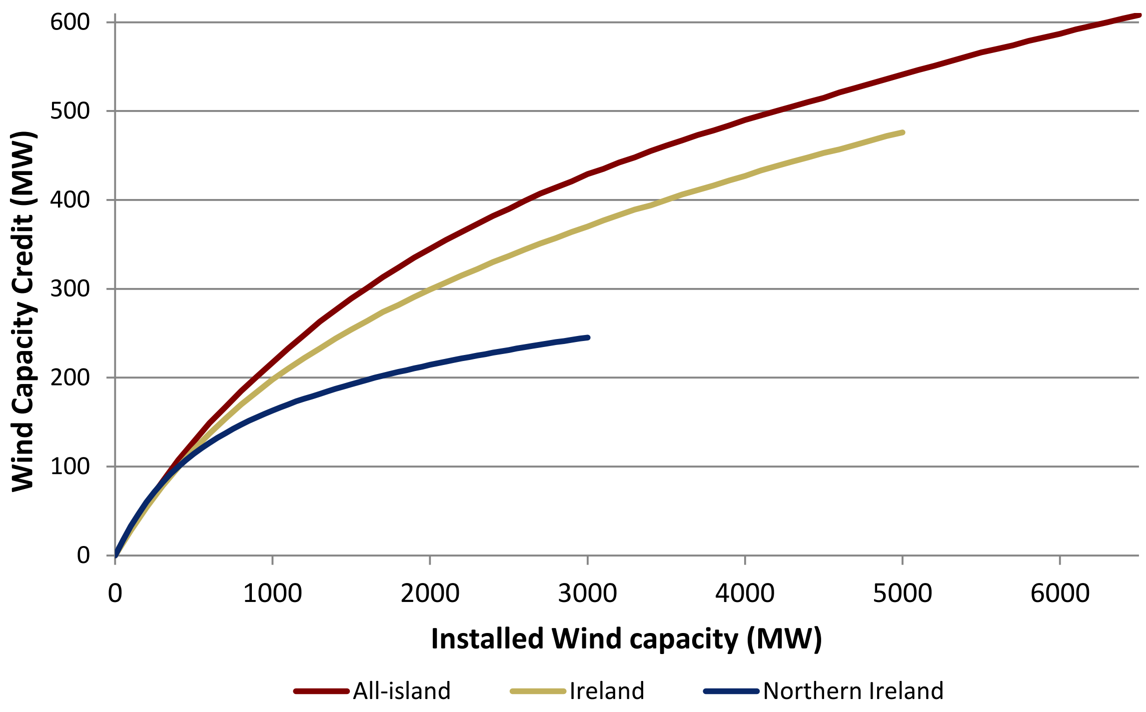


Figure 3-9 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation. For Ireland, the wind profiles were taken from 2009, the most recent, typical year. The curve for Northern Ireland is based on an average over several years.

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

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

- Relatively mature renewable-energy technology

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

3.7 Changes in Other Non-Conventional Generation

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

As discussed in Section 2.3, SONI have obtained information from NIE on the estimated amount of embedded generation that is present on the Northern Ireland system. Other sources, such as the Ofgem Renewable Obligation Certificate Register (ROC Register) and information for the Northern Ireland planning service have also been used to try and gain a better estimate of current and future levels of this. SONI assumptions based on these sources estimates circa 77 MW[51] of this small scale generation is currently connected to the Northern Ireland system, with various levels of this being utilised for self consumption on site.

3.7(a) Demand-Side/Industrial Generation

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

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

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

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

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

Estimates give a current installed CHP capacity (mostly gas-fired) of roughly 133 MW in Ireland (not including the 161 MW centrally dispatched CHP plant operated by Aughinish Alumina). The target for total CHP in Ireland[52] was 400 MW by 2010, whereas what was achieved was in the region of 300 MW. With the withdrawal of government incentives for fossil fuelled CHP, this area is not likely to grow much more.

In Northern Ireland, there is currently an estimated 11 MW of small scale CHP connected to the distribution system. (3 MW of which is renewable and 8 MW non-renewable). Without more detailed information an assumption has been made that for the purposes of this statement, the estimated 11 MW in 2012 will rise to 12 MW by 2022 in Northern Ireland.

---

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

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

CHP is promoted in accordance with the European Directive 2004/8/EC. The Strategic Energy Framework[53] for Northern Ireland acknowledges that the uptake of CHP in the region has been limited and therefore DETI have decided to encourage greater scope for combined heat and power in Northern Ireland.

3.7(c) Biofuel

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

In Ireland, there is currently an estimated 43 MW of landfill gas powered generation. The peat plant at Edenderry aims to power 30% of its output using biomass by 2015. A new incentive (REFIT 3)[54] for Biomass-fuelled CHP plant aims to have 150 MW installed by 2020. With some of this plant already planned, it has been assumed for the purpose of this report that the whole 150 MW will be achieved on time. This plant makes a significant contribution to the 40% RES target.

Currently in Northern Ireland, there is an estimated 7 MW of small scale biofuels (5 MW of Biomass & 2 MW of Biogas) and 13 MW of landfill gas powered generation. For the purposes of this report, and in the absence of more detailed information, it has been assumed that by 2022 the small scale biofuels capacity will rise to 48 MW (16 MW of Biomass & 32 MW of Biogas) while landfill gas powered generation capacity will reach 25 MW.

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

3.7(d) Small-scale hydro

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

3.7(e) Marine Energy

With the large amount of uncertainty associated with this new technology, EirGrid has taken the prudent approach that there will be no commercial marine developments operational before 2022.

In Northern Ireland the Strategic Environmental Assessment (SEA)[55] proposes a target of 300 MW from tidal generation by 2020. It is unclear at this stage as to which tidal technology will be used to achieve this.

However, the Crown Estates[56] recently awarded development rights for two 100 MW Tidal sites off the North Coast of Northern Ireland.

Therefore, for the purposes of this report, SONI have used a conservative assumption for tidal generation of 154 MW by 2020 and 200 MW by 2022.

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

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

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

56 The Crown Estate: www.thecrownestate.co.uk

3.7(f) Compressed Air Energy Storage (CAES)

SONI is in discussions with a renewables development company about connection of a proposed Compressed Air Energy Storage (CAES) Plant in the Larne area. Such an energy storage facility could potentially act as an ancillary services and balancing facility for renewable generation. A CAES plant uses a large compressor to store excess energy off the grid. It converts the excess electric energy to compressed air which is stored in an underground geological cavern, then released through an electric generator for later use. This technology could be applied to store surplus renewable energy, whilst also enabling variability balancing on the transmission system. The potential exists for a CAES facility consisting of up to 270 MW of generation and 200 MW of compression. Such a facility would be connected to the transmission system.

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

3.8 Plant Availability

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

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

3.8(a) Ireland

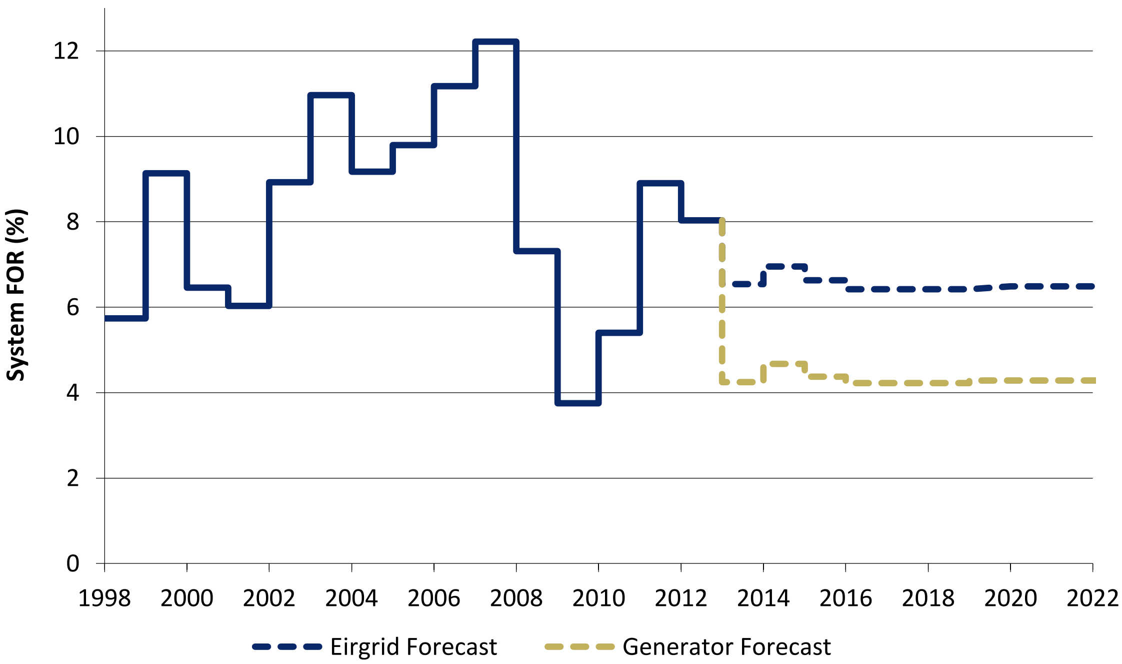


Figure 3-10 Historical and predicted Forced Outage Rates for Ireland. Future rates as predicted by both EirGrid and the generators are shown. Due to its atypical outage rates, Poolbeg Unit 3 has been excluded from historical calculations.

Figure 3-10 shows the system-wide forced-outage rates (FOR)[57] for Ireland since 1998, as well as predicted values for the study period of this report. After rising steadily in the years up to 2007, FORs in Ireland have started to drop in the past few years. One cause for this improvement is the introduction of new generators and removal of old generators. Another contributing factor is reduced demand, which means older peaking units are called on less often, giving them less of an opportunity to fail. However it must be noted that major impact events (e.g. Turlough Hill) have led to poorer availability in 2010 and 2011.

The operators of fully-dispatchable generators have provided forecasts of their availability performance for the ten year period 2013 to 2022. However, in the past these forecasts have not given an accurate representation of the amount of outages on the system. This is primarily due to the effect high-impact low-probability (HILP) events.

HILP events are unforeseen occurrences that don't often transpire but, when they do, will have a significant adverse impact on a generator's availability performance, taking it out of commission for several weeks. The probability of this occurring to an individual generator is low. However, when dealing with the system as a whole, there is a reasonable chance that at least one generator is undergoing such an event at any given time. EirGrid studies[58] have indicated that HILPs will make up around one third of forced outages on average.

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

3.8(b) Northern Ireland

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

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

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

Figure 3-11 shows the system forced-outage rates (FOR) for Northern Ireland since 2003, as well as predicted values for the study period of this report. This analysis is focused on fully dispatchable plant and does not include the Moyle Interconnector. After rising steadily in the years up to 2007, FORs in Northern Ireland have started to fall over the past few years. This coincides with the introduction of the Single Electricity Market (SEM) where incentives have been put in place to encourage better generator availability. Another contributing factor is reduced demand resulting from the ongoing economic downturn, which means older peaking units are called on less often, giving them less of an opportunity to fail.

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

[58] see GAR 2009-2015

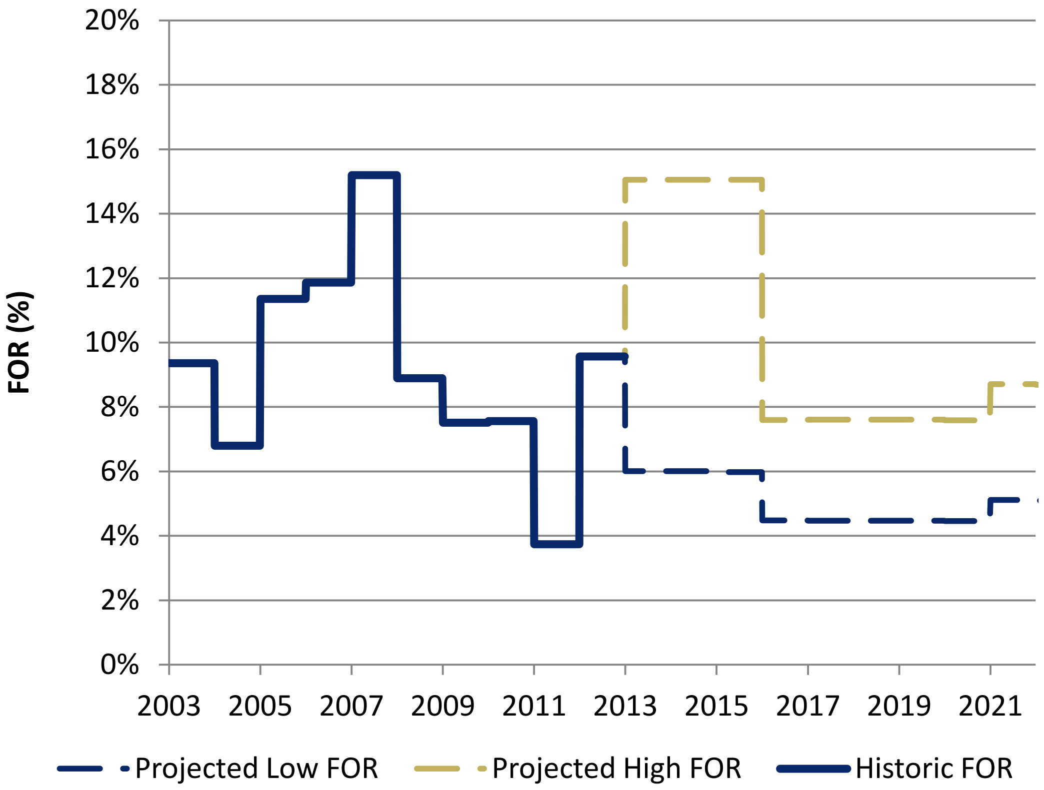


Figure 3-11 Historical and predicted Forced Outage Rates for Northern Ireland (not including the Moyle Interconnector)

Figure 3-12 shows the historical availabilities in Northern Ireland along with the projected high and low availabilities. The average high availability over the 10-year period is 89.6% and the low availability figure is 84.6%. This analysis is focused on fully dispatchable plant and does not include the Moyle Interconnector.

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

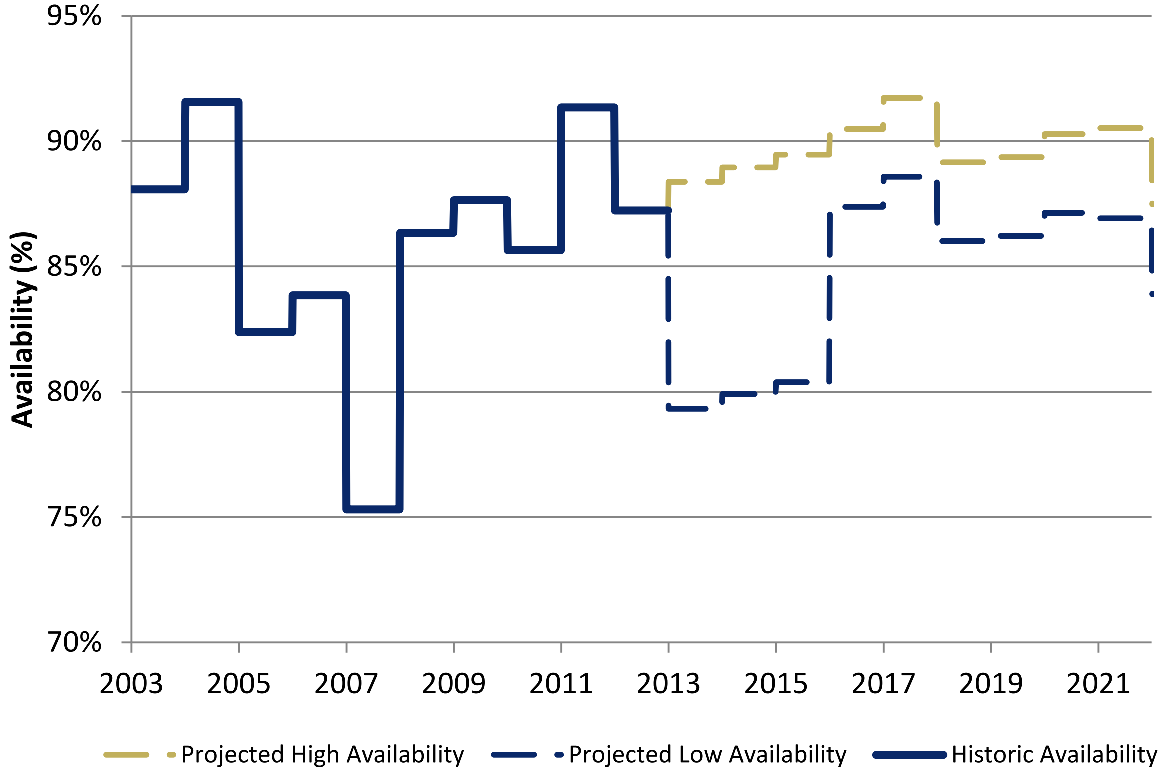
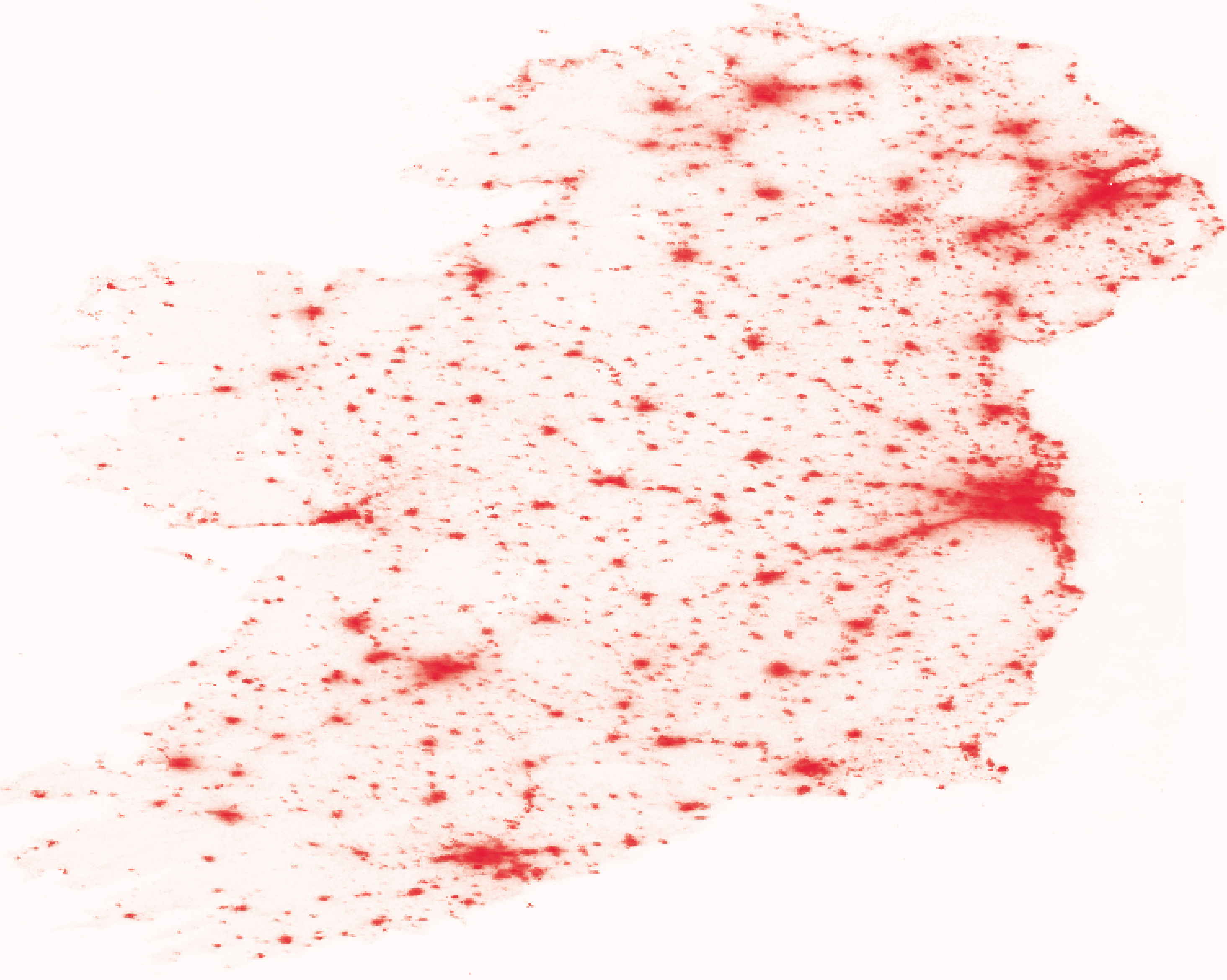


Figure 3-12 Historical and predicted Plant Availabilities in Northern Ireland (without Moyle)

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

4 ADEQUACY ASSESSMENT RESULTS



4 ADEQUACY ASSESSMENT RESULTS

4.1 Introduction

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

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

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

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

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

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

4.2 Base Case

The adequacy assessments from the base case scenario to 2022 are shown in Figure 4-1. When a case for any particular year results in a deficit, it is plotted below the red line, e.g. Northern Ireland in 2021 and 2022.

The base case assumes median demand growth in both jurisdictions, the EirGrid-calculated availability for the generation portfolio in Ireland, and high availability (based on historical performance) for the Northern Ireland generation portfolio.

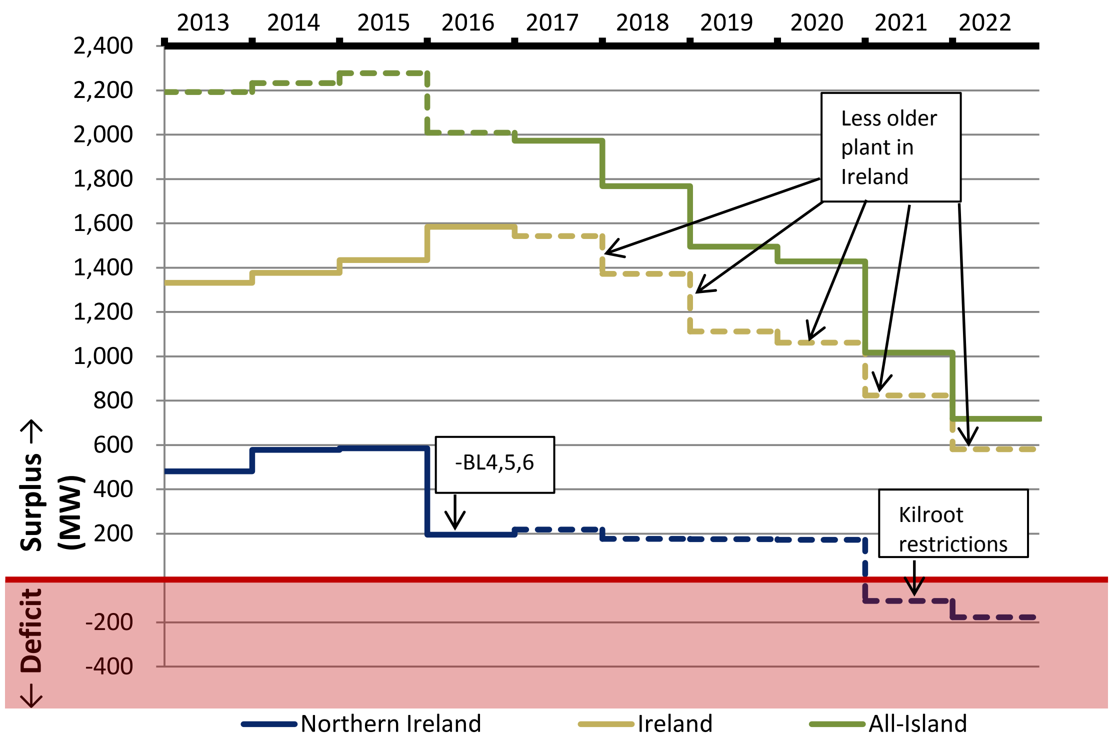


Figure 4-1 Adequacy results for the base case scenario, shown for Ireland, Northern Ireland, and on an all-island basis. Dashed lines convey the results if the additional North-South tie-line is completed earlier or later than 2017.

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

Plant decommissionings account for some of the major drops in adequacy, e.g. the loss of three units at Ballylumford in 2016 results in the surplus in Northern Ireland falling by almost 400 MW. In addition to these plant shut-downs, changes in adequacy are caused from year to year by demand growth, plant additions and increased wind penetration.

As mentioned in Section 3.5(a), single area studies for Ireland include a reliance on Northern Ireland of 100 MW. Similarly, Northern Ireland relies on Ireland for 200 MW in their single area studies. When modelling the all-island system, there are no such reliance values.

Ireland is in surplus for all years of 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 over 1300 MW until 2018. After this, the loss of older plant results in the surplus being reduced to 600 MW in 2022.

The surplus in Northern Ireland falls from circa 600 MW to just 200 MW when three units, B4, B5 and B6 at Ballylumford close at the end of 2015. The adequacy situation deteriorates from 2021 when the running hours of KPS1 and KPS2 at Kilroot are severely limited by emissions requirements. If the second North South tie line is not in place by 2021, then Northern Ireland will fall into a generation adequacy deficit.

The green line shows that no deficits are expected if the additional North-South tie line is completed, and hence the adequacy can be assessed on an all-island basis.

4.3 Loss of Interconnection with Great Britain

Due to recent long-term forced outages on the Moyle interconnector, it was thought prudent to examine a situation where both undersea interconnectors with Great Britain (Moyle and East-West) are unavailable. Figure 4-2 shows how the surplus reduces dramatically from the base case scenarios. Northern Ireland would be in a deficit position for most years from 2016, and particularly so from 2021. This again shows the importance of the planned extra North-South tie line to enable SONI to maintain generation security standards in Northern Ireland.

In combination with the plant being shut down in Ireland, this scenario would result in a tight adequacy situation from 2022 in Ireland.

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

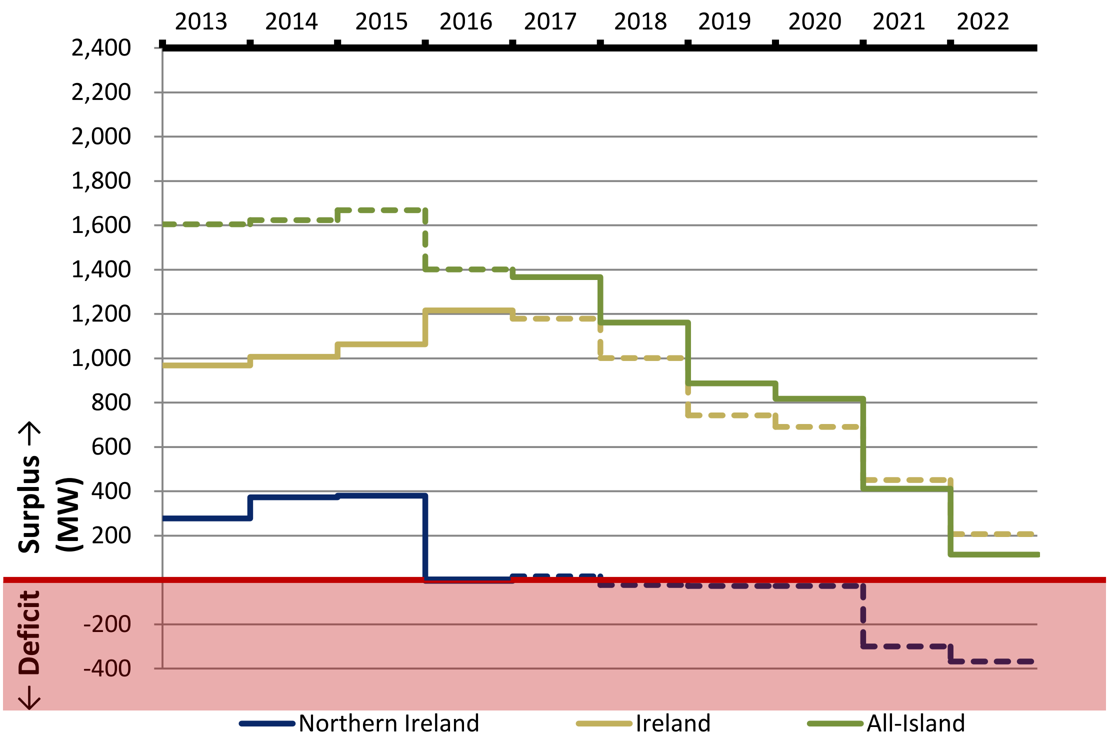


Figure 4-2 The effect of not having available the undersea interconnectors to Great Britain.

4.4 Loss of a CCGT in each Jurisdiction

In order to run a stable and secure power, it is prudent to examine the effect of major events which could have serious consequences on electricity supply. A scenario has been considered where a major combined cycle generator is out of action in both Northern Ireland and Ireland.

Because of the large amount of other plant available, Ireland remains in surplus, see Figure 4-3.

With this onerous scenario, the Northern Ireland system enters a deficit situation from 2016, when the system fails to meet the 4.9 hours LOLE standard. From 2021, the lone system then falls into a more serious deficit of circa 300-350 MW.

It can be seen from the green line that if the additional North-South tie line were in place, then the all-island system would be in surplus for all years, even with the loss of two CCGT units.

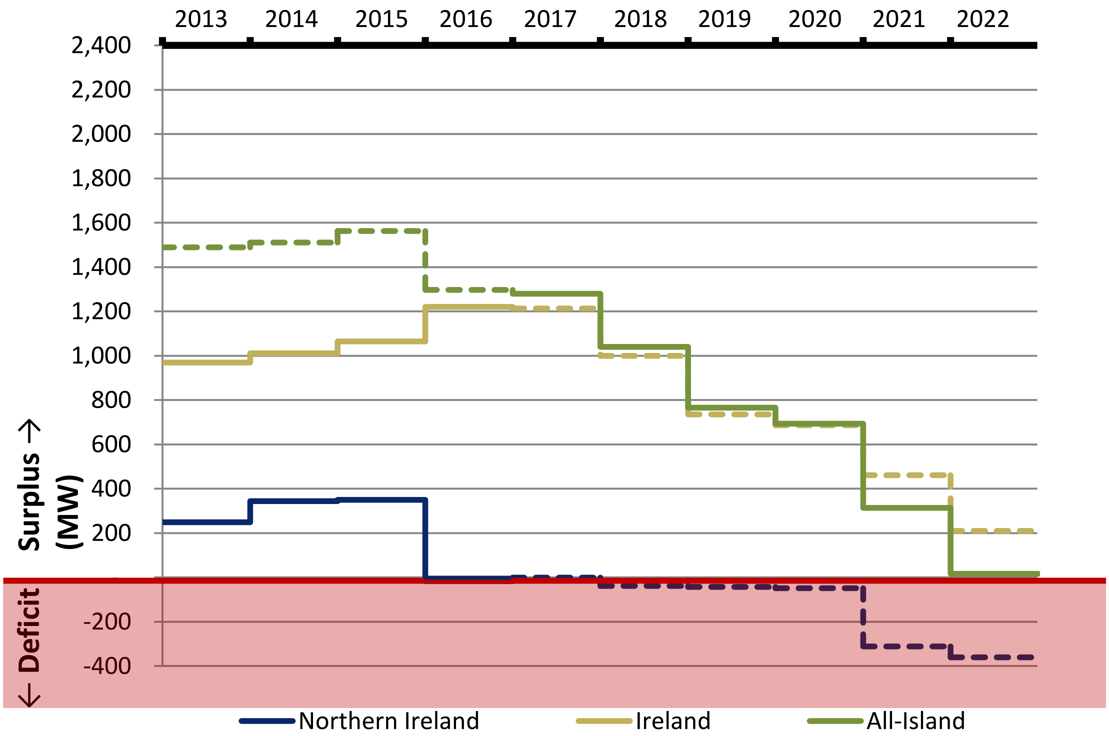


Figure 4-3 This shows the loss of two CCGTs from the base case median. Dashed lines convey the results if the additional North-South tie line is completed earlier or later than 2017.

Security of Supply in Northern Ireland - Post 2015

It is clear from the previous sections that security of supply is at increasing risk in Northern Ireland under many circumstances.

In summary this Statement finds that:

a) There is adequate generation capacity to meet demand in Ireland over the next ten years.
b) There is adequate generation capacity to meet demand on an all-island basis post completion of the second North–South tie line.
c) Without the North–South tie line, generation adequacy deteriorates in Northern Ireland post 2015, with the standards failing to be met from 2021.

This deterioration and eventual failure to meet standards is further discussed in this section.

In this analysis, future capacity requirements have been assessed against a statistical (or probabilistic) generation adequacy standard. Acceptance of such a standard means that the industry does not in fact aim to invariably meet demand, but accepts a small probability that, over some defined period, demand will not be fully met, i.e. customers may be off supply. In Northern Ireland, the adequacy standard at present is 4.9 hours per year expectation of failure. This is a measure of how long, on average, the available capacity may fall short of the unrestricted demand.

The total electricity generation capacity connected to the system is almost never fully available to the system operator. Plant may be scheduled out-of-service for maintenance, or forced out-of-service, for example, due to mechanical or electrical failure. It should be noted that lack of availability due to forced outages impacts much more heavily on the ability of the system to meet demand than the same lack of availability arising from scheduled outages. This is a consequence of the unpredictable nature of forced outages as compared to scheduled outages. Because of the uncertainty associated with these projections a number of scenarios have been considered in Sections 4.3 and 4.4 to demonstrate how the adequacy position could deteriorate further.

The decommissioning of three Ballylumford units at the end of 2015 (510 MW) has a major impact on the system. When Northern Ireland is assessed as a single system, it is only in the base case that the system remains adequate to meet demand reliably after 2015.

This base case scenario assumes that the Moyle Interconnector will provide 250 MW when required and that all other plant remains available. A prolonged outage of any large generating unit or the Moyle Interconnector could result in load shedding. In particular, the base case relies on the two main generating units at Kilroot remaining mostly available for the years from 2016 to 2020, even though there will be emission restrictions placed on them from 2016 due to the IED. The Northern Ireland adequacy position goes into deficit from 2021 when it is assumed that these two units at Kilroot will have further IED restrictions applied, resulting in reduced running hours. A deficit of circa 100-200 MW in a relatively small system could result in many hours of load shedding.

In conclusion, the analysis presented in this Statement demonstrates that, without the additional North–South tie line, there is a deteriorating generation adequacy situation in Northern Ireland post 2015, with the standards failing to be met from 2021. In a number of different scenarios, for example, the loss of a major generator or of the Moyle Interconnector, Northern Ireland fails to meet the generation adequacy standard post 2015. The restoration of the Moyle Interconnector to a higher available capacity at any stage would help the Northern Ireland adequacy position. However, the additional North–South tie line is the only project that SONI is currently aware of that has the potential to ensure that the security of supply position in Northern Ireland is fully compliant with both the present Northern Ireland and all-island generation adequacy standards for all study years covered in this statement.

4.5 Availability

If the Generators' own availability scenario is utilised for Ireland (i.e. if the generators perform to their own standard rather than a more realistic outcome as estimated by EirGrid), then Figure 4-4 shows that the increase in the surplus is of the order of 300 MW.

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

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

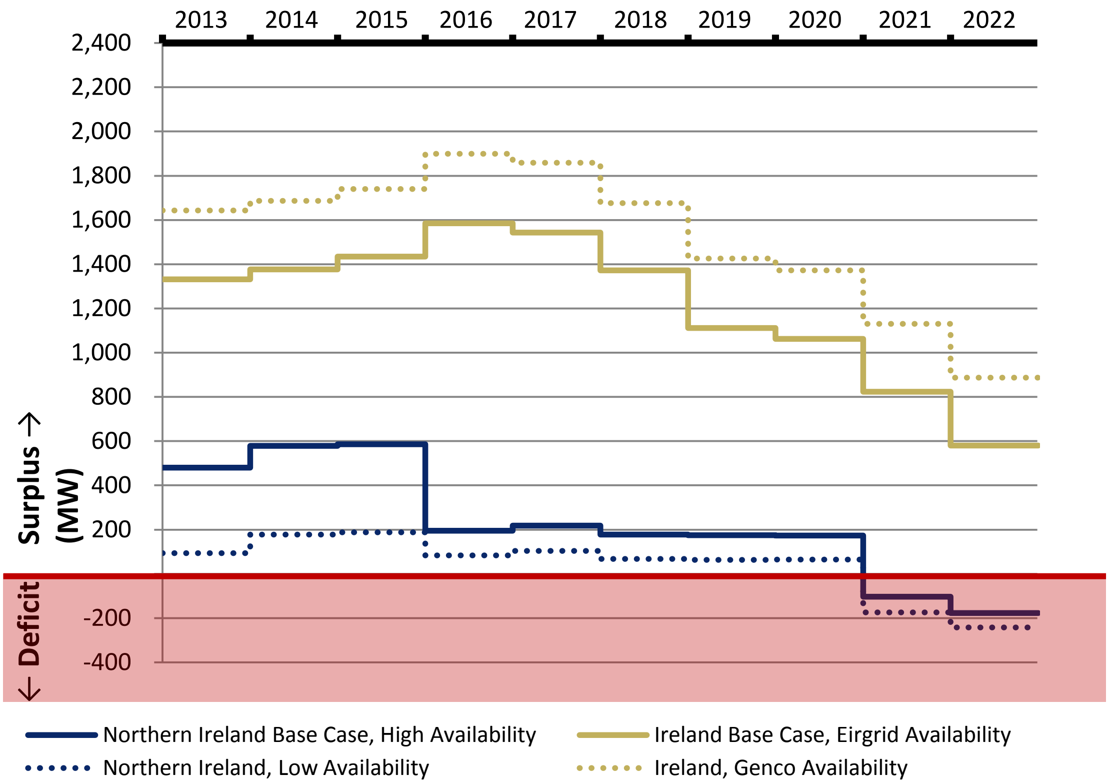


Figure 4-4 Comparison of availability scenarios for Ireland and Northern Ireland

4.6 Demand

Changing demand will have a certain impact on generation adequacy. Driven by economic variables, the effect of the lower demand forecast on the adequacy situation is illustrated in Figure 4-5, with base case availability (where the EirGrid calculated availability is assumed for the generation portfolio in Ireland, and the high availability for the Northern Ireland generation portfolio).

As expected, the low demand scenario leads to increased adequacy (see dotted lines) when compared with the base cases (solid lines) for both Ireland and Northern Ireland. The margin is small at first, then, as the low demand forecast diverges from the median, the margin grows to about 150 MW for Ireland and 50 MW for Northern Ireland.

The demand can also be affected by weather, where a severe winter might lead to increased demand. The effect of a winter as cold as one-in-10 is examined below (not every year is expected to have a severe winter, but the effect is shown for each year individually). It can be seen that as the demand has increased, adequacy levels fall (see dashed lines compared to the base case in solid lines). The drop averages 110 MW for Ireland and 55 MW for Northern Ireland.

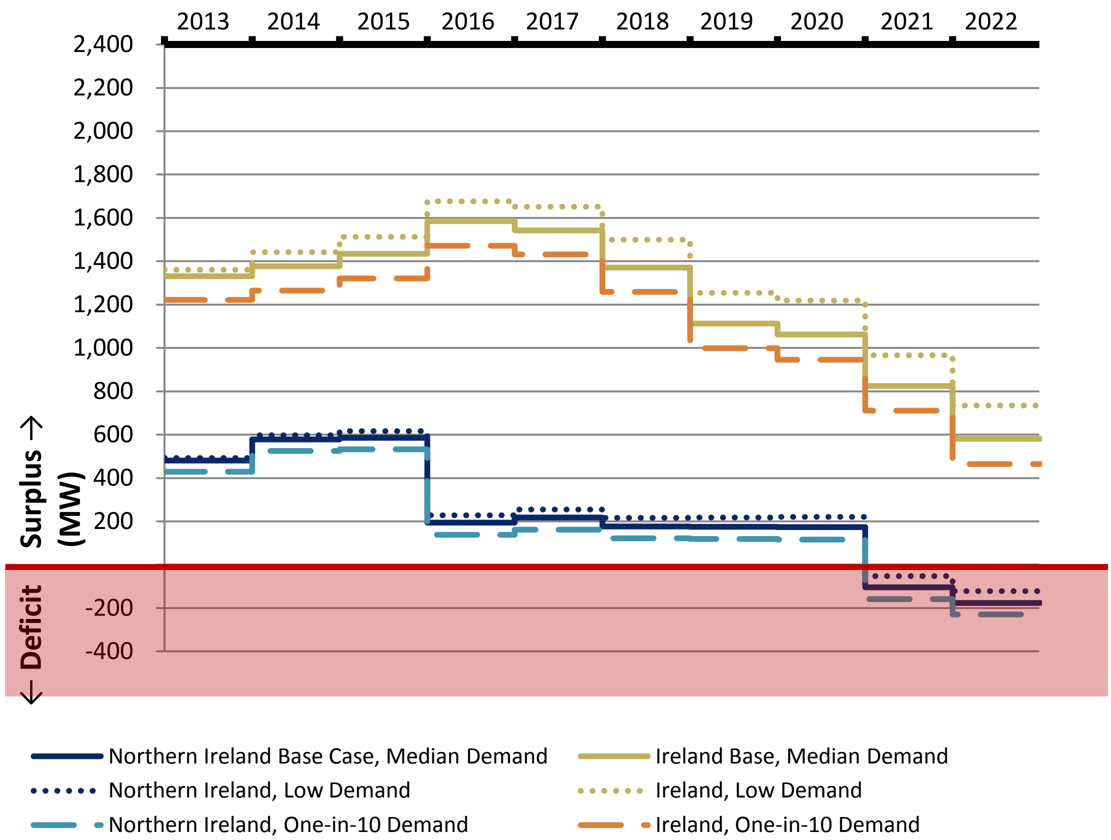


Figure 4-5 Comparison of demand scenarios for Ireland and Northern Ireland, all with base-case availability.

5 DATA CENTRES

5 DATA CENTRES

5.1 Introduction

Recently, there has been a significant expansion in Data Centres, largely driven by growth in Cloud computing. The island of Ireland has many advantages as a Data Centre location due to a number of favourable conditions, such as its temperate climate and good telecommunication links. There is currently in excess of 175 MW of Data Centre demand while another 25 MW Data Centre is scheduled to connect shortly.

A Data Centre or computer centre is a facility used to house computer systems and associated components, such as telecommunications and storage systems. It generally includes redundant or backup power supplies, redundant data communications connections, environmental controls (e.g., air conditioning, fire suppression) and security devices. Large Data Centres are industrial scale operations using as much electricity as a small town.

The number of additional Data Centres coming on-stream and their ever increasing workload has led industry analysts to predict in the environs of a threefold increase in global Data Centre power consumption from 2012 levels by 2020. It is anticipated that this projection should also hold valid in Ireland due to the increasing Data Centre presence and the volume of the associated traffic expected.

Data Centres can offer advantages to a TSO in the area of Demand Side Management. This can be financially beneficial to both parties, as explored in this section.

5.2 Advantages for locating in Ireland and Northern Ireland

5.2(a) Climate

The island's temperate climate means that there is little need for industrial scale cooling. Much of the Data Centres cooling requirements may be satisfied by running in a low cost "economiser" mode which utilises the ambient external air to either refresh the server room air directly or to chill a coolant fluid.

The maritime temperate climate enjoyed here has relatively cool summers and mild, relatively snow-free winters. The high temperature average of 20°C and low temperature average of 6°C correlate well with the recommended guidelines established by ASHRAE[59] as the recommended Data Centre operating range. As a point of reference, Dublin's maximum temperature hasn't exceeded 28.7°C in the last 40 years which deem it an ideal location in which air cooling may be utilised.

The relative humidity (R.H.) is an additional concern to the stringent temperature ranges stipulated for all types of Data Centre, and it too must remain within a desired bracket spanning 8% – 80%, but preferably reside within the 30% – 60% range. The average relative humidity on the island of Ireland is 83% which is just outside the suggested range although it varies periodically across the 70% – 90% R.H. band. However, much of this moisture can be stripped from the air before it enters the Data Centre server rooms.

[59] "2011 Thermal Guidelines for Data Processing Environments – Expanded Data Center Classes and Usage Guidance", American Society of Heating, Refrigerating and Air-Conditioning Engineers

The Mean Time Between Failure (MTBF) of a Data Centre is thought to be a function of both the temperature and humidity straying outside of the guidelines, or rapid variations (>1.5°C per hour) within them, which could result in downtime.

5.2(b) Renewable Energy

Data Centres have a high requirement for electrical power. Therefore, many companies utilising Data Centres have a keen interest in sourcing energy from renewable sources. This island, with its ample supply of wind, and both Governments' target to source 40% of all electricity from renewable sources by 2020, should be able to satisfy the Data Centre thirst for green energy.

5.2(c) Fibre Infrastructure

In addition to the mild climate, another advantage to residing on the Western perimeter of Europe is that the island is the first European landing point for several transatlantic fibre connections. There are currently two fibres coming ashore here;

(i) Hibernia D which lands in Dublin and
(ii) Hibernia A which makes land in Portrush, Co. Antrim before continuing to Dublin via Southport in the UK or using the terrestrial "Project Kelvin" fibre ring connecting through Dundalk and Drogheda.

Both of these fibres have been in operation since 2005 and are part of Hibernia Atlantic's 24,000km subsea cable system linking Halifax, Nova Scotia to Europe with a sub 65ms Round Trip Delay (RTD).

The transatlantic ring has sufficient bandwidth to facilitate most major carriers on both sides of the Atlantic.

Figure 5-1 Ireland's offshore fibre connections as at Jan 2012 are illustrated with red boules, while the dashed lines depict the proposed Emerald Express & Project Express cables which may be on-stream by 2014.

In addition to these transoceanic routes, there are four other non-repeated operational fibres connecting Dublin to the UK and a further four via Wexford to the UK. Another 6 fibre cables link Northern Ireland to the UK. Although some of this capacity is already lit, there is significant Dark fibre available; including that which is bundled with the East-West interconnector for further connectivity in the future.

There are also two new transatlantic projects proposing to connect by mid 2014 in the South and West of Ireland named "Project Express" and "Emerald Express" respectively as shown in Figure 5-1. If completed, these developments will further reinforce Ireland's bandwidth capacity and its position at the forefront of the Data Centre arena by shaving 5 – 10ms from the transatlantic round trip times.

5.2(d) Other considerations

Another factor involved in the choice of location for a Data Centre is having a stable regime with amenable laws and regulatory standards. The financial environment here is favourable, and the appropriate building codes and regulation are already in place.

Installation timeframes for Data Centres are getting shorter and capital costs are diminishing with each revolution in Data Centre technology. This can potentially pose issues since grid connectivity requires numerous planning requirements to be satisfied before works can proceed. Therefore, it is imperative that Data Centres enter into conversation with the Distribution and Transmission System Operators as early as is feasible in order to circumvent any undue application delays associated with grid delivery.

5.3 Demand Characteristics

Data Centres in Ireland typically utilise in excess of 60% of their maximum electrical capability at all times as portrayed in Table 5-1. Most experience a relatively flat load with a variability of just ±5% across a 24 hour period, although there is often a slight drop-off over the weekend period. This type of demand profile is benign for power systems. It is cheaper to provide for flat demand than for intermittent demand that occurs at peak times only.

Typical Characteristics	Dedicated Data Centre	3rd Party Data Centre
Power Consumption	>10MW	<10MW
Load factor	85-95%	60-70%
Floor space	>5,000m^2	<4,000m^2
Arrangement	Dedicated to the owning companies services	Provide hosting services to many companies

Table 5-1 Indicative characteristics of the two types of Data Centre in Ireland. Note: These specifications are not indicative of any individual Data Centre connected to the Irish power system nor are any members of either category bound to adhere to the above.

Electricity consumption is the dominant Data Centre operational cost once the server infrastructure has been accounted for. In fact, it can account for approximately 30% of the Total Cost of Ownership (TCO) over the entire lifetime of the Data Centre[60]. Figure 5-2 shows the electricity consumption of a typical Data Centre broken down into its components. Data Centre owners want to ensure that more electricity is used for the computing workload and less electricity consumption for auxiliary components such as cooling. This is one of the main benefits for locating Data Centres in Ireland. With its temperate climate all year round, there is little need for cooling, thus reducing electricity consumption. This is even more pertinent for modern Data Centres as the newer computing servers are capable of operating at higher temperatures.

[60] "Electrical Efficiency Modelling for Data Centers", Neil Rasmussen, Schneider Electric Data Center Science Center.

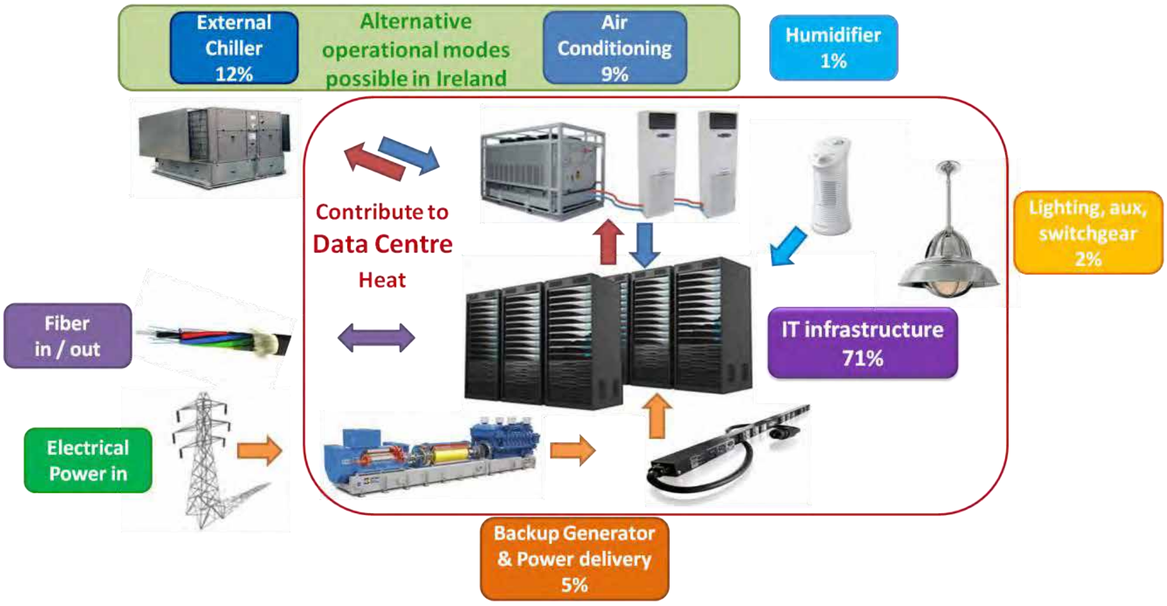


Figure 5-2 Breakdown of electricity consumption for a typical Data Centre

As both Ireland and Northern Ireland have Government policies to generate 40% of electricity from renewable sources by 2020, they are good locations for Data Centres that wish to source their electricity from renewable sources. Many of the large companies providing cloud computing services have such policies.

However, with electricity costs such a significant element in the total cost of building and running a Data Centre, it is worthwhile looking at ways of reducing electricity costs. In the next section, some operational strategies that could reduce electricity costs for Data Centres are assessed.

5.4 Operational strategies to reduce energy costs

Operation strategies to reduce electricity costs focus on the proposal to temporarily queue some IT services or to dynamically route IT workloads between two or more Data Centres, thus taking advantage of the lowest electricity costs in different locations of the world. There are a number of strategies such as "Follow the Moon" to utilise low night tariffs, "Follow the Sun" which aims to utilise solar energy while this report focuses on a "Follow the Wind" strategy to make use of the abundant wind energy resource here.

5.4(a) Price response

It is assumed that some of the Data Centre processes such as cooling or performing storage backups are interruptible and may be temporarily postponed. Other IT services may be queued where possible or otherwise migrated to a low-cost heterogeneous system during a peak price period. Possible cost savings achieved through electricity market exploitation and cost-based data transitions were explored from the viewpoint of one of the market locations being the Single Electricity Market (SEM).

The Data Centre's response to renewables can also have consequences for the System Marginal Price (SMP) through the modified profile. Data Centres operate as a base load on the electricity system. If they were capable of dynamic load shifting, they would also alter the SMP by reducing it during peak periods. Therefore, the Data Centres would potentially be able to avail of reduced electricity costs by electing to become suppliers within the SEM and operating in a cost-effective manner.

EirGrid carried out studies where the potential interactions between a large Data Centre and the electricity price were modelled. This concluded that electricity cost savings in the order of €5 – €10 per MWh are possible for Data Centres who opt to follow an economic running regime whereby equipment is powered up or down as per the market price. It may be prudent for any price-responsive Data Centre to participate in the SEM as a Demand Side Unit in order to best avail of any price savings and other ancillary service payments, providing any Service Level Agreements with their clients enable them to do so.

5.4(b) Reductions in Wind Curtailment

There is also considerable potential to offset wind energy curtailment through dynamically shifting a portion of the IT load in response to price signals. Studies found that with an increased Data Centre build out and power utilisation on the island, significantly more asynchronous renewable generation can be accommodated during off-peak periods with this “Follow the Wind” approach (see Figure 5-3). Naturally, a consequence of this abatement in wind curtailment is that there will be more “Guarantees of Origin” (GO) credits available for Data Centres operators to certify that their enterprises are utilising renewable power sources.

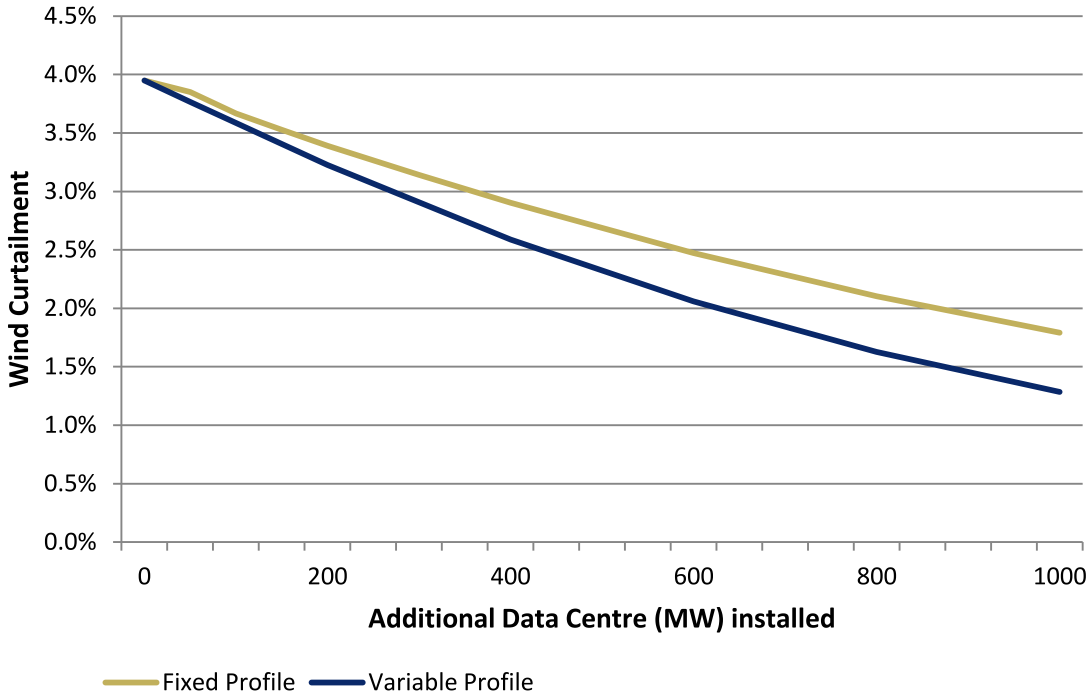


Figure 5-3 Wind Curtailment: "Fixed" vs. "Following the Wind". Possible Wind Curtailment levels in 2020 for both the “Fixed” demand profile and price-responsive “Variable” load profile with sufficient wind generation accommodated to meet the 40% RES-E targets.

5.5 Summary

Data Centres are responsible for an increasing load on the power system, and this load is expected to grow over the coming decade.

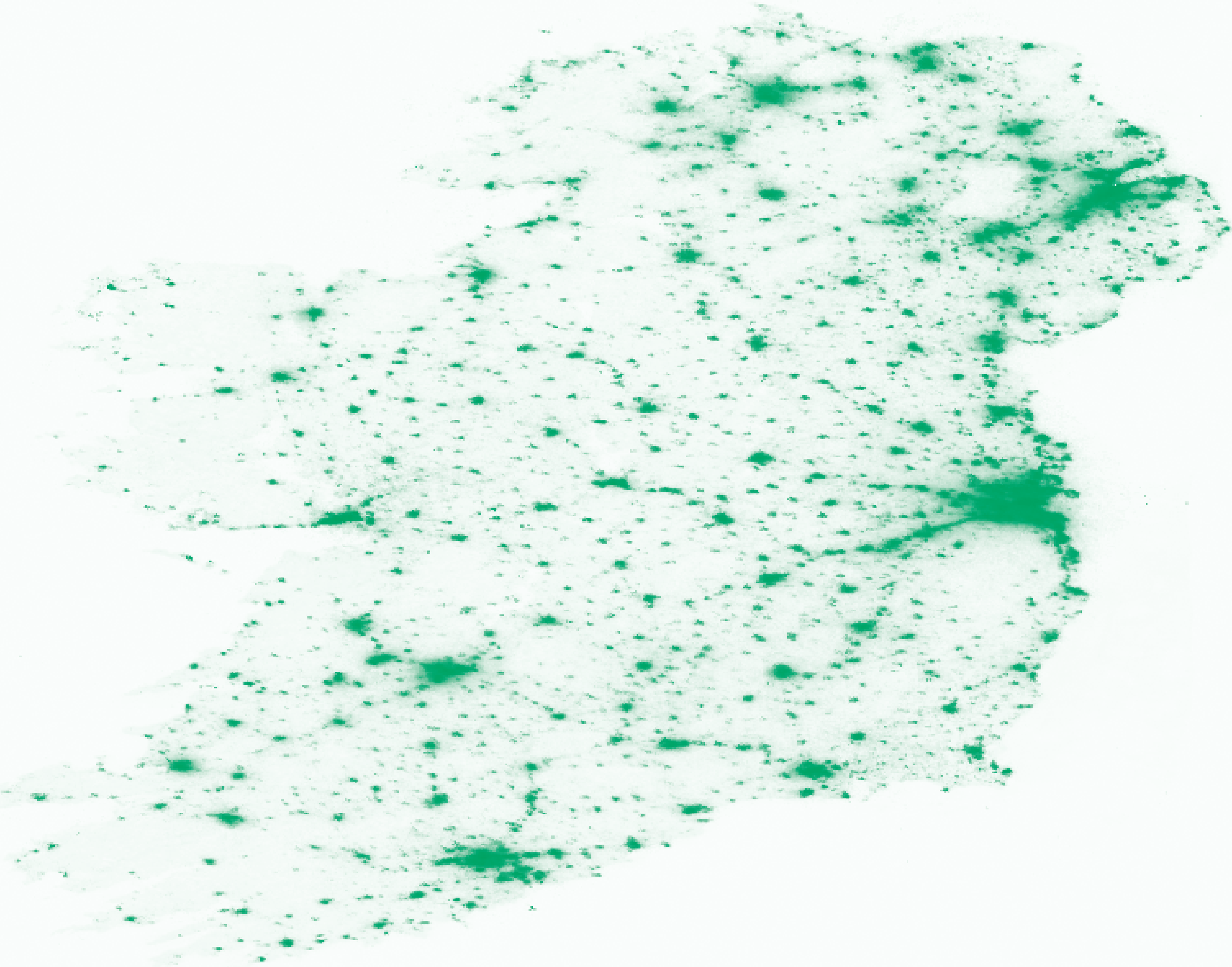
The island of Ireland has a number of advantages as a location for Data Centres:

- Temperate climate
- Good telecommunications links
- Reliable electricity supply
- Stable region of the world
- High levels of renewable energy sources in the electricity mix.

As Data Centres usually follow a stable, predictable demand, they have a benign impact on the power system. However, if some Data Centre load can be modified to follow price signals, there are operational strategies that could reduce the electricity costs of Data Centres. Studies estimate that a cost saving of the order of €5 – €10 per MWh is possible.

In addition, Data Centres can help integrate more wind generation by modifying their load according to whether there is a lot or a little wind blowing. Thus less wind might need to be curtailed to keep the system stability within safe limits.

APPENDICES



APPENDIX 1 DEMAND FORECAST

Med	Total Electricity Requirement (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2012	26,320	-1.3%	9,037	-1.2%	35,357	-1.3%	4,779	1,776	6,485	4,680	1,731	6,341
2013	26,503	0.7%	9,028	-0.1%	35,532	0.5%	4,882	1,779	6,591	4,768	1,733	6,431
2014	26,859	1.3%	9,103	0.8%	35,962	1.2%	4,952	1,794	6,676	4,825	1,747	6,501
2015	27,252	1.5%	9,259	1.7%	36,511	1.5%	5,030	1,823	6,781	4,888	1,773	6,590
2016	27,670	1.5%	9,418	1.7%	37,088	1.6%	5,102	1,852	6,881	4,946	1,800	6,674
2017	28,152	1.7%	9,575	1.7%	37,727	1.7%	5,167	1,881	6,974	4,996	1,828	6,751
2018	28,677	1.9%	9,731	1.6%	38,408	1.8%	5,232	1,910	7,068	5,048	1,856	6,829
2019	29,230	1.9%	9,886	1.6%	39,117	1.8%	5,313	1,941	7,177	5,114	1,885	6,923
2020	29,808	2.0%	10,043	1.6%	39,852	1.9%	5,422	1,971	7,317	5,210	1,915	7,049
2021	30,245	1.5%	10,201	1.6%	40,446	1.5%	5,494	2,002	7,417	5,281	1,946	7,148
2022	30,651	1.3%	10,361	1.6%	41,011	1.4%	5,559	2,034	7,511	5,346	1,977	7,241

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

Notes for Ireland:

1. *Electricity sales are measured at the customer level in GWh. To convert this to Total Electricity Requirement (TER), it is brought to exported level by applying a loss factor (for both transmission and distribution) and adding on an estimate of self-consumption.*
2. *The Transmission Peak (or Exported peak) is the maximum demand met by centrally-dispatched generation, measured at exported level by the Control Centre. To calculate the TER Peak, an estimation of the contribution from embedded generation is added to the Transmission peak. When forecasting the transmission peak, it is assumed that the wind contribution is zero*

*Please refer to Section 2.3 for an explanation of the method employed in **Northern Ireland**.*

Low	Total Electricity Requirement (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2012	26,320	-1.3%	8,972	-1.9%	35,292	-1.4%	4,779	1,772	6,482	4,680	1,728	6,337
2013	26,320	0.0%	8,891	-0.9%	35,212	-0.2%	4,848	1,769	6,546	4,734	1,723	6,387
2014	26,451	0.5%	8,886	-0.1%	35,337	0.4%	4,876	1,774	6,579	4,748	1,727	6,404
2015	26,753	1.1%	8,953	0.7%	35,705	1.0%	4,936	1,790	6,653	4,794	1,740	6,462
2016	27,090	1.3%	9,089	1.5%	36,180	1.3%	4,992	1,814	6,734	4,836	1,763	6,526
2017	27,452	1.3%	9,224	1.5%	36,675	1.4%	5,034	1,839	6,800	4,864	1,786	6,577
2018	27,875	1.5%	9,356	1.4%	37,231	1.5%	5,081	1,865	6,871	4,897	1,810	6,632
2019	28,339	1.7%	9,487	1.4%	37,826	1.6%	5,144	1,890	6,958	4,946	1,835	6,705
2020	28,830	1.7%	9,619	1.4%	38,449	1.6%	5,237	1,916	7,077	5,025	1,860	6,808
2021	29,342	1.8%	9,751	1.4%	39,093	1.7%	5,320	1,943	7,184	5,108	1,886	6,915
2022	29,713	1.3%	9,885	1.4%	39,599	1.3%	5,378	1,969	7,266	5,166	1,912	6,996

Table A-2 Low Electricity Demand forecast

High	Total Electricity Requirement (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2012	26,320	-1.3%	9,113	-0.4%	35,433	-1.0%	4,829	1,779	6,539	4,729	1,735	6,394
2013	26,556	0.9%	9,191	0.9%	35,746	0.9%	4,941	1,792	6,663	4,827	1,747	6,504
2014	26,966	1.5%	9,364	1.9%	36,329	1.6%	5,020	1,824	6,773	4,892	1,777	6,598
2015	27,414	1.7%	9,542	1.9%	36,956	1.7%	5,107	1,856	6,892	4,965	1,807	6,701
2016	27,889	1.7%	9,724	1.9%	37,613	1.8%	5,189	1,889	7,006	5,033	1,838	6,798
2017	28,431	1.9%	9,906	1.9%	38,336	1.9%	5,262	1,923	7,112	5,092	1,870	6,889
2018	29,017	2.1%	10,086	1.8%	39,103	2.0%	5,338	1,957	7,220	5,153	1,903	6,982
2019	29,636	2.1%	10,266	1.8%	39,902	2.0%	5,428	1,992	7,344	5,229	1,937	7,090
2020	30,281	2.2%	10,449	1.8%	40,731	2.1%	5,549	2,028	7,499	5,336	1,971	7,231
2021	30,786	1.7%	10,633	1.8%	41,419	1.7%	5,630	2,064	7,615	5,418	2,007	7,346
2022	31,260	1.5%	10,821	1.8%	42,080	1.6%	5,707	2,100	7,726	5,495	2,043	7,456

Table A-3 High Electricity Demand forecast.

One-in-10	TER Peak (MW)	
Year	Ireland	Northern Ireland
2012	4,948	1,864
2013	5,050	1,867
2014	5,121	1,882
2015	5,198	1,911
2016	5,271	1,940
2017	5,335	1,969
2018	5,401	1,998
2019	5,481	2,029
2020	5,591	2,059
2021	5,662	2,090
2022	5,727	2,122

Table A-4 Median Electricity Demand forecast with One-in-10 year cold weather conditions.

APPENDIX 2 GENERATION PLANT INFORMATION

Year end:	ID	Fuel Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Activation Energy	AE1	DSU	12	12	12	12	12	12	12	12	12	12
DAE Virtual Power	DAE	DSU	29	29	29	29	29	29	29	29	29	29
Aghada	AD1	Gas	258	258	258	258	258	258	258	258	258	258
	AT1	Gas/DO	90	90	90	90	90	90	90	90	90	90
	AT2	Gas/DO	90	90	90	90	90	90	90	90	90	90
	AT4	Gas/DO	90	90	90	90	90	90	90	90	90	90
	ADC	Gas/DO	431	431	431	431	431	431	431	431	431	431
Dublin Bay	DB1	Gas/DO	401	399	397	402	400	398	396	399	397	395
Edenderry	ED1	Milled peat/biomass	118	118	118	118	118	118	118	118	118	118
Edenderry OCGT	ED3	DO	58	58	58	58	58	58	58	58	58	58
	ED5	DO	58	58	58	58	58	58	58	58	58	58
Great Island	GI1	HFO	54	0	0	0	0	0	0	0	0	0
	GI2	HFO	49	0	0	0	0	0	0	0	0	0
	GI3	HFO	109	0	0	0	0	0	0	0	0	0
Huntstown	HN1	Gas/DO	341	340	340	339	339	338	338	337	337	336
	HN2	Gas/DO	399	398	398	397	397	396	396	395	395	394
Indaver Waste	IW1	Waste	15	15	15	15	15	15	15	15	15	15
Lough Ree	LR4	Peat	91	91	91	91	91	91	91	91	91	91
Marina CC	MRT	Gas/DO	88	88	88	88	88	88	88	88	88	88
Moneypoint	MP1	Coal/HFO	285	285	285	285	285	285	285	285	285	285
	MP2	Coal/HFO	285	285	285	285	285	285	285	285	285	285
	MP3	Coal/HFO	285	285	285	285	285	285	285	285	285	285
North Wall CT	NW5	Gas/DO	104	104	104	104	104	104	104	104	104	104
Poolbeg CC	PBC	Gas/DO	463	463	463	463	463	463	463	463	463	463
Rhode	RP1	DO	52	52	52	52	52	52	52	52	52	52
	RP2	DO	52	52	52	52	52	52	52	52	52	52
Sealrock	SK3	Gas/DO	80	80	80	80	80	80	80	80	80	80
	SK4	Gas/DO	81	81	81	81	81	81	81	81	81	81
Tarbert	TB1	HFO	54	54	54	54	54	54	54	54	0	0
	TB2	HFO	54	54	54	54	54	54	54	54	0	0
	TB3	HFO	241	241	241	241	241	241	241	241	0	0
	TB4	HFO	243	243	243	243	243	243	243	243	0	0
Tawnaghmore	TP1	DO	52	52	52	52	52	52	52	52	52	52
	TP3	DO	52	52	52	52	52	52	52	52	52	52
Tynagh	TY1	Gas/DO	384	384	384	384	384	384	384	384	384	384
West Offaly	WO4	Peat	137	137	137	137	137	137	137	137	137	137
Whitegate	WG1	Gas/DO	442	442	442	442	442	442	442	442	442	442
Ardnacrusha	AA1-4	Hydro	86	86	86	86	86	86	86	86	86	86
Erne	ER1-4	Hydro	65	65	65	65	65	65	65	65	65	65
Lee	LE1-3	Hydro	27	27	27	27	27	27	27	27	27	27
Liffey	LI1,2,4,5	Hydro	38	38	38	38	38	38	38	38	38	38
Turlough Hill	TH1-4	Pumped storage	292	292	292	292	292	292	292	292	292	292
EWIC	EW1	DC Interconnector	500	500	500	500	500	500	500	500	500	500
Extra Planned Generation*			0	486	548	744	744	744	744	744	744	744
		Total Dispatchable	**7135**	**7405**	**7465**	**7664**	**7662**	**7658**	**7656**	**7657**	**7063**	**7059**
		Year end:	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**

Table A-5 Registered Capacity of dispatchable generation in Ireland. Some capacities include minor degradation over the years. DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil.

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

Year End:		Fuel Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Ballylumford	ST4	Gas* / Heavy Fuel Oil	170	170	170	-	-	-	-	-	-	-
	ST5	Gas* / Heavy Fuel Oil	170	170	170	-	-	-	-	-	-	-
	ST6	Gas* / Heavy Fuel Oil	170	170	170	-	-	-	-	-	-	-
	B10	Gas* / Distillate Oil	97	97	97	97	97	97	97	97	97	97
	B31	Gas* / Distillate Oil	245	245	245	245	245	245	245	245	245	245
	B32	Gas* / Distillate Oil	245	245	245	245	245	245	245	245	245	245
	GT7 (GT1)	Distillate Oil	58	58	58	58	58	58	58	58	58	58
	GT8 (GT2)	Distillate Oil	58	58	58	58	58	58	58	58	58	58
Kilroot	ST1	Heavy Fuel Oil* / Coal	238	238	238	238	238	238	238	238	238	238
	ST2	Heavy Fuel Oil* / Coal	238	238	238	238	238	238	238	238	238	238
	KGT1	Distillate Oil	29	29	29	29	29	29	29	29	29	29
	KGT2	Distillate Oil	29	29	29	29	29	29	29	29	29	29
	KGT3	Distillate Oil	42	42	42	42	42	42	42	42	42	42
	KGT4	Distillate Oil	42	42	42	42	42	42	42	42	42	42
Coolkeeragh	GT8	Distillate Oil	53	53	53	53	53	53	53	53	53	53
	C30	Gas* / Distillate Oil	402	402	402	402	402	402	402	402	402	402
Moyle Interconnector	Moyle	DC Link - See **Note 1**	250	250	250	250	250	250	250	250	250	250
Contour Global (CHP)	CGC3	Gas	3	3	3	3	3	3	3	3	3	3
	CGC4	Gas	3	3	3	3	3	3	3	3	3	3
	CGC5	Gas	3	3	3	3	3	3	3	3	3	3
iPower AGU	AGU	Distillate Oil	47	47	47	47	47	47	47	47	47	47
Total Dispatchable			**2592**	**2592**	**2592**	**2082**	**2082**	**2082**	**2082**	**2082**	**2082**	**2082**

Table A-6 Dispatchable plant in Northern Ireland

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

***Note 1**: Moyle Interconnector Capacity: Import = 450 MW Nov-Mar & 410 MW Apr-Oct. (Export = 295 MW Sep-Apr & 287 MW May-Aug). It is assumed that both the Import and Export capacity on the Moyle Interconnector will be restricted to 250 MW for the foreseeable future due to an undersea cable fault on Pole 2.*

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Large Scale On-Shore Wind (MW)	452	517	581	646	710	775	839	904	968	1033	1097
Large Scale Off-Shore Wind (MW)	0	0	0	0	0	0	0	50	191	600	600
Large Scale Biomass (MW)	0	0	0	15	30	45	45	45	45	45	45
Tidal (MW)	1	1	1	1	1	1	51	131	154	201	201
Small Scale Wind (MW)	15	33	46	64	80	92	101	109	116	123	131
Small Scale Biogas (MW)	2	4	8	13	18	23	26	28	30	31	32
Landfill Gas (MW)	13	14	15	16	18	19	20	21	23	24	25
Waste To Energy (MW)	0	0	0	0	0	17	17	17	17	17	17
Small Scale Biomass (MW)	5	5	7	9	10	11	12	13	14	15	16
Other CHP (MW)	8	8	8	8	8	8	8	8	8	8	8
Renewable CHP (MW)	3	3	3	3	4	4	4	4	4	4	4
Small Scale Hydro (MW)	4	4	4	4	4	4	4	4	4	4	4
Small Scale Solar (MW)	2	2	2	2	2	3	3	3	3	3	3
Total (MW)	**505**	**591**	**675**	**781**	**885**	**1002**	**1130**	**1337**	**1577**	**2108**	**2183**

Table A-7 Partially/Non-Dispatchable Plant in Northern Ireland

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
All Wind	467	550	627	710	790	867	940	1063	1275	1756	1828
All Biomass/Biogas/Landfill Gas	20	23	30	53	76	98	103	107	112	115	118
Tidal (MW)	1	1	1	1	1	1	51	131	154	201	201
Waste To Energy (MW)	0	0	0	0	0	17	17	17	17	17	17
Renewable CHP (MW)	3	3	3	3	4	4	4	4	4	4	4
Hydro (MW)	4	4	4	4	4	4	4	4	4	4	4
Solar (MW)	2	2	2	2	2	3	3	3	3	3	3
Total (MW)	**497**	**583**	**667**	**773**	**877**	**994**	**1122**	**1329**	**1569**	**2100**	**2175**

Table A-8 All Renewable Energy Sources in Northern Ireland

Northern Ireland Wind Farms		Capacity (MW)			Capacity (MW)
Transmission connected	Slieve Kirk	27.6	**Distribution connected**	Mantlin (Slieve Rushen 2)	54
Distribution connected	Corkey	5		Altahullion 2	11.7
	Rigged Hill	5		Bessy Bell 2	9
	Elliott's Hill	5		Owenreagh 2	5.1
	Bessy Bell	5		Slieve Divena	30
	Owenreagh	5.5		Garves	15
	Lendrum's Bridge	5.94		Gruig	25
	Lendrum's Bridge 2	7.26		Tappaghan 2	9
	Altahullion	26		Hunters Hill	20
	Tappaghan	19.5		Crockagarran	17.5
	Snugborough	13.5		Screggagh	20
	Callagheen	16.9		Curryfree	15
	Lough Hill	7.8		Church Hill	18.4
	Bin Mountain	9		Crighshane	32.2
	Wolf Bog	10	**Total**		**451**

Table A-9 Existing wind farms in Northern Ireland as of end October 2012.

Year end:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Wind-Onshore	1617	1913	2113	2388	2662	2937	3212	3486	3761	4035	4310
Wind-Offshore	25	25	25	25	25	25	25	25	25	25	25
Wind-Total	**1642**	**1938**	**2138**	**2413**	**2687**	**2962**	**3237**	**3511**	**3786**	**4060**	**4335**
Small-scale Hydro	21	21	21	21	21	21	21	21	21	21	21
Biomass/Landfill gas, with 150 MW Biomass CHP by 2020	43	62	80	99	118	137	155	174	193	193	193
Tidal/Wave	0	0	0	0	0	0	0	0	0	0	0
Industrial	9	9	9	9	9	9	9	9	9	9	9
Conventional CHP	133	133	133	133	133	133	133	133	133	133	133
Total	**1848**	**2163**	**2381**	**2675**	**2968**	**3262**	**3555**	**3848**	**4142**	**4416**	**4691**

Table A-10 Partially/Non-Dispatchable Plant in Ireland

Year end:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
All Wind	1642	1938	2138	2413	2687	2962	3237	3511	3786	4060	4335
All Hydro	237	237	237	237	237	237	237	237	237	237	237
Biomass/LFG	43	62	80	99	118	137	155	174	193	193	193
Waste (assume 50% renewable)	15	15	15	77	77	77	77	77	77	77	77
Edenderry on Biomass	16	23	29	35	35	35	35	35	35	35	35
Total RES	**1953**	**2274**	**2500**	**2861**	**3154**	**3448**	**3741**	**4034**	**4328**	**4602**	**4877**

Table A-11 All Renewable Energy Sources in Ireland

Wind Farm	Phase	MEC (MW)	Wind Farm	Phase	MEC (MW)
Ballywater	1	31.5	Derrybrien	1	59.5
Ballywater	2	10.5	Dromada	1	46
Boggeragh	1	57	Garvagh - Glebe	1	58.2
Booltiagh	1	19.5	Glanlee	1	35.8
Castledockrell	1	20	Golagh	1	15
Castledockrell	2	2	Kingsmountain	1	23.8
Castledockrell	3	3.3	Kingsmountain	2	11.1
Castledockrell	4	16.1	Lisheen	1	36
Clahane	1	37.8	Meentycat	1	71
Coomacheo	1	41.2	Meentycat	2	14
Coomacheo	2	18.0	Mountain Lodge	1	24.8
Coomagearlahy	1	42.5	Mountain Lodge	3	5.8
Coomagearlahy	2	8.5	Ratrussan/Bindoo	1a	48
Coomagearlahy	3	30	**Transmission Connected Total**		**787**

Table A-12 Transmission connected wind farms in Ireland as of end October 2012.

Wind Farm	Phase	MEC (MW)	Wind Farm	Phase	MEC (MW)
Altagowlan	1	7.65	Gortahile	1	21
Anarget	1	1.98	Greenoge	1	4.99
Anarget	2	0.02	Grouse Lodge	1	15
Arklow Bank	1	25.2	Inis Mean	1	0.675
Ballincollig Hill	1	15	Inverin (Knock South)	1	3.3
Ballinlough	1	2.55	Inverin (Knock South)	2	0.66
Ballinveny	1	2.55	Kealkil (Curraglass)	1	8.5
Ballymartin	1	6	Killybegs	1	2.55
Bawnmore formerly Burren (Cork)	1	24	Kilronan	1	5
Beale	2	2.55	Kilvinane	1	4.5
Beale Hill	1	1.65	Knockastanna	1	7.5
Beallough	1	1.7	Knockawarriga	1	22.5
Beam Hill	1	14	Lackan	1	6
Beenageeha	1	3.96	Lahanaght Hill	1	4.25
Bellacorick	1	6.45	Largan Hill	1	5.94
Black Banks	1	3.4	Lenanavea	2	2.55
Black Banks	2	6.8	Lenanavea/Burren	1	2.1
Burtonport Harbour	1	0.66	Lios na Carraige	1	0.017
Cark	1	15	Loughderryduff	1	7.65
Carnsore	1	11.9	Lurganboy	1	4.99
Carrane Hill	1	3.4	Mace Upper	1	2.55
Carrig	1	2.55	Meenachullalan	1	11.9
Carrigcannon	1	20	Meenadreen	1	3.4
Carrons	1	2.5	Meenanilta	1	2.55
Carrons	2	2.49	Meenanilta	2	2.45
Coomatallin	1	5.95	Meenkeeragh	1	4.2
Coreen	1	3	Mienvee	1	0.66
Corkermore	1	15	Mienvee	2	0.19
Corrie Mountain	1	4.8	Milane Hill	1	5.94
Country Crest	1	0.5	Moanmore	1	12.6
Crocane	1	1.7	Moneenatieve	1	3.96
Crockahenny	1	5	Moneenatieve	2	0.29
Cronalaght	1	4.98	Mount Eagle	1	5.1
Cronelea	1	4.99	Mount Eagle	2	1.7
Cronelea	2	4.5	Mountain Lodge	2	3
Cronelea Upper	1	2.55	Muingnaminnane	1	15.3
Cronelea Upper	2	1.7	Mullananalt	1	7.5
Cuillalea	1	3.4	Owenstown	1	0.018
Cuillalea	2	1.59	Raheen Barr	1	18.7
Culliagh	1	11.88	Raheen Barr	2	8.5
Currabwee	1	4.62	Rahora	1	4.25
Curraghgraigue	1	2.55	Rathcahill	1	12.5
Curraghgraigue	2	2.55	Reenascreena	1	4.5
Donaghmede Fr Collins Park	1	0.25	Richfield	1	20.25
Dromdeeveen	1	10.5	Richfield	2	6.75
Dromdeeveen	2	16.5	Seltanaveeny	1	4.6
Drumlough Hill	1	4.8	Shannagh	1	2.55
Drumlough Hill	2	9.99	Skehanagh	1	4.25
Dundalk IT	1	0.5	Skrine	1	4.6
Dunmore	1	1.7	Slievereagh	1	3
Dunmore	2	2.5	Sonnagh Old	1	7.65
Flughland	1	9.2	Sorne Hill	1	31.5
Gartnaneane	1	10.5	Sorne Hill	2	7.4
Gartnaneane	2	4.5	Spion Kop	1	1.2
Geevagh	1	4.95	Taurbeg	1	26
Glackmore Hill	1	0.6	Tournafulla	1	7.5
Glackmore Hill	2	0.3	Tournafulla	2	17.2
Glackmore Hill	3	1.4	Tullow Mushroom Growers Ltd	2	0.133
Glanta Commons	1	19.55	Tullynamoyle	1	9
Glanta Commons	2	8.4	Tursillagh	1	15
Glenough	1	33	Tursillagh	2	6.8
Gneeves	1	9.35	WEDcross	1	4.5
			Distribution Connected Total		**855**

Table A-13 Distribution connected wind farms in Ireland as of end October 2012.

APPENDIX 3 METHODOLOGY

GENERATION ADEQUACY & SECURITY STANDARD

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

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

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

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

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

Table A-14 Expected Unserved Energy (EUE) for both jurisdictions

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

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

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

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

LOSS OF LOAD EXPECTATION (LOLE)

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

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

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

then the annual LOLE is given by

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

This equation is used in the following practical example.

SIMPLIFIED EXAMPLE OF LOLE CALCULATION

Consider a system consisting of just three generation units, as in Table A-15.

	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-15 System for LOLE example

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

1) How many different states can the system be in, i.e. if all units are available, if one is forced out, if two are forced out, or all three?
2) How many megawatts are in service for each of these states?
3) What is the probability of each of these states occurring?
4) Add up the probabilities for the states where the load cannot be met.
5) Calculate expectation.

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

Table A-16 Probability table

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

INTERPRETATION OF RESULTS

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

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

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

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

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

SURPLUS & DEFICIT

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

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

It should be noted that actual loss of load as a result of a supply shortage does not represent a catastrophic failure of the power system[61]. In all probability such shortages, or loss of load, would not result in widespread interruptions to customers. Rather, it would likely take the form of supply outages to a small number of customers for a period in the order of an hour or two. This would be done in a controlled fashion, to ensure that critical services are not affected.

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

APPENDIX 4 ADEQUACY ASSESSMENT RESULTS

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

Median	Year:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Surplus (Deficit)	Northern Ireland	481	578	586	195	218	177	175	173	-104	-177
	Ireland	1331	1377	1434	1585	1543	1371	1112	1062	824	581
	All-Island	2192	2233	2278	2008	1972	1768	1495	1428	1017	718

*Table A-17 The surplus of plant for each year for the **base case scenario**, i.e. Median demand growth, and availability as calculated by EirGrid for the generation in Ireland, and the high availability scenario for the Northern Ireland portfolio. All figures are given in MW of perfect plant. See section 4.2 for details.*

Median	Year:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Surplus (Deficit)	Northern Ireland	278	374	380	-4	16	-23	-27	-28	-299	-367
	Ireland	968	1007	1063	1216	1179	1002	743	690	451	207
	All-Island	1605	1624	1668	1401	1367	1161	887	817	412	114

*Table A- 18 Same as the Base Case, but **without the two interconnectors** to Great Britain.*

Median	Year:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Surplus (Deficit)	Northern Ireland	248	344	350	-16	-1	-38	-43	-49	-312	-361
	Ireland	970	1011	1064	1220	1213	999	736	687	461	210
	All-Island	1489	1511	1563	1298	1279	1040	765	694	313	16

*Table A- 19 Same as the Base Case, but **without one CCGT** in each jurisdiction.*

	Year:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Northern Ireland	High Availability	481	578	586	195	218	177	175	173	-104	-177
	Low Availability	94	178	187	84	104	67	64	65	-175	-242
Ireland	Generator Availability	1642	1686	1740	1900	1859	1677	1426	1373	1131	887
	EirGrid Availability	1331	1377	1434	1585	1543	1371	1112	1062	824	581

*Table A- 20 Comparison of **different availability** scenarios. Median demand in all cases.*

	Year:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Northern Ireland	One-in-10 year Demand	429	524	532	138	162	122	119	116	-158	-230
	Low Demand	492	597	616	229	255	216	218	221	-53	-122
Ireland	One-in-10 year Demand	1222	1265	1321	1472	1432	1259	998	946	711	464
	Low Demand	1360	1441	1513	1676	1651	1499	1254	1219	967	734

*Table A- 21 Comparison of **different Demand** scenarios.*

EirGrid plc
The Oval
160 Shelbourne Road
Ballsbridge
Dublin 4

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

www.eirgrid.com

SONI Ltd
Castlereagh House
12 Manse Road
Belfast
BT6 9RT

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

www.soni.ltd.uk