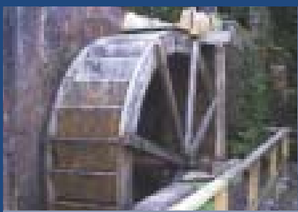
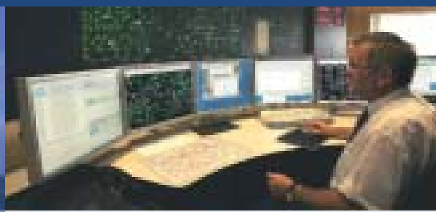
GENERATION ADEQUACY REPORT
2005–2011

Transmission System Operator Ireland






Front cover images

1) Water wheel at Coomhola Lodge, Bantry, Co. Cork (courtesy of StreamScapes)
2) Arklow Banks offshore wind farm (courtesy of Airtricity)
3) The National Control Centre, operated by the TSO
4) Poolbeg generating station in Dublin port (© Aiden McCabe)

Generation Adequacy Report 2005-2011

Transmission System Operator Ireland

Published November 2004

FOREWORD

As Transmission System Operator (TSO), we are pleased to present this, the fourth Generation Adequacy Report. We have prepared it in accordance with the provisions of Section 38 of the Electricity Regulation Act 1999, and it supersedes the previous Generation Adequacy Report 2004-2010 published in November 2003. The Commission for Energy Regulation has approved the form of this report.

It is widely accepted that the provision of adequate infrastructure is a prerequisite for ensuring Ireland's continued economic and social development. This report examines the requirement for one key piece of this infrastructure, namely generation capacity. We hope that the information contained in this report will be of assistance to policy makers and participants in the electricity industry.

It is our aim that the information contained in this report will be found to be both pertinent and accessible. As TSO, we welcome and value your feedback on the content, presentation or style of this report.

Bernard O'Reilly
Manager, Power System Development and Maintenance

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EXECUTIVE SUMMARY

Introduction

The primary purpose of this generation adequacy report is to inform market participants, regulatory agencies and policy makers of the likely generation capacity required to achieve an adequate electricity supply and demand balance for the period up to 2011.

This report supersedes the previous Generation Adequacy Report 2004-2010.

Methodology

The internationally accepted technique for establishing the likely generation capacity required to achieve an adequate electricity supply is to balance the risk of supply shortage against an accepted security standard. For this report statistical techniques are used to quantify the supply shortage risk in terms of the number of Loss of Load Expectation (LOLE) hours per annum. The accepted security standard for Ireland is eight hours LOLE per annum. This is known as the generation adequacy standard.

For a number of different scenarios it is determined if the existing plant and committed new capacity additions place Ireland above or below this adequacy standard. The next stage in the process is to quantify the gap between the forecast capacity position and that required to achieve the generation adequacy standard in terms of an approximate plant capacity requirement. This allows projected plant surpluses and deficits to be established.

Demand Forecast

To assess the generation adequacy in any future year, the amount and pattern of electricity demand over the course of that year, including the peak demand for the year, are required.

The electricity forecast model utilises economic projections provided by the Economic and Social Research Institute (ESRI). Gross Domestic Product is related to electricity sales in the non-domestic sector, while domestic sales are related to Personal Consumption of Goods and Services. By using the electricity forecasting model and these inputs a median demand growth rate of 3.9% per annum is projected over the next seven years. The ESRI also produces upper and lower bounds to its economic projections. These are used to calculate high and low electricity demand scenarios which lie above and below the median demand scenario. It is expected that the eventual outturn will lie within these bounds.

The electricity forecast is used to predict the annual peak demand. The peak demand is quite a volatile quantity and difficult to predict. A factor which contributes to this volatility is the influence of Demand Side Management (DSM). This DSM effect has been estimated, and used to correct the peak demand model. In the median demand scenario, the average increase in peak over the next seven years is forecast to be 187 MW per year.

Input Data Assumptions – Electricity Production

The next key ingredient for assessing generation adequacy is a prediction of how much plant will be available to meet the forecast demand. As well as the amount of plant, it is essential to predict how reliably that plant will perform.

From a base of 5952 MW at the end of 2004, the total capacity installed or contracted to supply Irish customers is projected to increase to 7336 MW by the end of 2011. The significant new plant coming onto the system includes 150 MW at Aughinish Alumina, 382 MW at Tynagh and 400 MW at Huntstown. Also 137 MW is to be added at West Offaly power, as part of ESB's peat replacement programme. As of September 1st 2004 there was 599 MW of additional committed wind farm capacity. The total capacity of wind powered generation installed is projected to reach 1010 MW by the end of 2011 in order to comply with the EU target that 13.2% of Ireland's electricity needs should come from renewable sources by 2010.

There are short-term capacity contracts currently in place (204 MW Additional Peaking Capacity at Aghada, Tawnaghmore and Rhode, and a 167 MW contract with Ballylumford, Northern Ireland Electricity) but these are due to lapse during the period 2005 to 2011.

The availability of plant is central to the assessment of generation adequacy. Plant that is scheduled out-of-service for maintenance, or forced out due to mechanical or electrical failure, cannot contribute to meeting the demand. Forced outages have a much greater impact on generation adequacy, due to their unpredictable nature. A one percentage point improvement in the forced outage rate tends to reduce the capacity requirement by 100 MW.

Ireland's generation portfolio has experienced a significant deterioration in availability performance since 2001, causing major concern. The current plant availability (based on a 52-week rolling average) stands at 77%. The owners of the generation plant predict that this situation will improve – their forecasts for availability in 2005 range from a low of 81% to a high of 85%. However, in light of recent availability performance it was considered prudent to also consider what would happen should plant availability remain at 77%.

As a study into international standards, many of Ireland's thermal generating units were benchmarked against a reasonable peer group. It was discovered that their availability performances (particularly their forced outage rates) compared quite poorly. With some effort, it might be considered realistic that these units could reach even the median of their peer group in terms of availability. Thus, another availability scenario was examined with these availability projections, termed the 'mid-benchmark' scenario.

Certain issues can impinge upon the ability of generation plant to contribute to generation adequacy, including the intermittent nature of wind and transmission constraints. Wind power is analysed and modelled separately to allow for the unpredictability and variability of this energy source.

A shortage of transmission infrastructure can arise when a new generation plant is completed before the transmission system is reinforced. Such an instance is forecast to occur in the Dublin area over the period covered by this report. During this time the capacity contribution of the Dublin based plant is modelled so as to reflect the capability of the transmission system in the area.

Interconnection

The power system in the Republic of Ireland is connected to the Northern Ireland system via AC interconnectors. Power flows between both jurisdictions for security of supply and economic reasons. Having considered the generation capacity situation in Northern Ireland, the ability of both systems to facilitate power transfers, and the position should the systems be separated, scenarios which include a capacity dependence of 300 MW are analysed. Under these scenarios, the interconnector provides 300 MW of capacity benefit to the ROI.

Further to instigating a policy of placing a capacity benefit on interconnection, the next stage would be to consider generation adequacy on a single "All-Island" basis. To do so would require harmonisation of adequacy standards and agreement on load loss sharing arrangements when faced with supply shortages.

Results

The generation plant requirements to maintain the supply demand balance are examined for a range of plausible future scenarios. The range of results is obtained by combining assumptions under the following categories: demand growth, plant availability, interconnection reliance, demand side management and the option of extending short term capacity contracts.

While many of the scenarios examined indicate that there may be a capacity surplus over the next seven years, if current plant availability performance (of 77%) persists there will be significant plant shortages throughout the period from 2005 to 2011. For example, deficits of 1400 MW may occur in 2011 if this poor level of availability performance persists and the high demand growth scenario is realised.

If availability performance could be improved to that projected by the owners of the generation plant, a range from 80.7 to 88.5%, capacity shortages would not be evident until at least 2009. Under the lowest of the generators' availability forecasts, deficits of approximately 600 MW would occur by 2011.

If availability could be improved to that of the mid-benchmark availability scenario (88%), then there would be no plant deficits over the period examined.

Results obtained after applying the potential remedial measures of placing a capacity reliance on the interconnector and extending the short term capacity contracts that currently exist, indicate that 2009 is the critical year by which there should be a sustained improvement in availability, additional plant installed or a mixture of both.

Any major delays in the commissioning of the newly committed 932 MW of thermal generation, or any additional plant closures, would cause a significant increase in the plant deficits outlined.

Comment and Discussion

Plant availability remains the dominant factor affecting generation adequacy and far outweighs other factors such as variations in demand forecasts. While recent history would suggest that sustained improvements in availability are not easy to achieve, any such improvement would reduce the amount of plant required to maintain the supply demand balance. If Ireland's generation portfolio was to achieve a sustained improvement in availability performance, equal to the median of its international peer group no new capacity would be required before the end of 2011.

While this report indicates the total amount of additional capacity which would be required under a number of plausible scenarios, consideration should also be given to the type and size of generation unit used to satisfy this requirement. An ever increasing number of large, highly efficient but comparatively inflexible combined cycle gas turbines are being installed in Ireland. In addition there is to be increased levels of wind power generation which by its variable and intermittent nature requires flexibility from other generation sources within the overall portfolio. Therefore, in the interest of maintaining system security, the opportunities for flexible responsive plant should be examined.

Sufficient advance notice of plant closures is critical as the amount of time required to plan, develop and commission new generation and transmission infrastructure can be well in excess of the current plant closure notification period of 24 months. If new generation is to make its full contribution to generation adequacy, the transmission system must be developed in tandem. Therefore developers should give careful consideration to the capability of the transmission system before choosing a site for new generation.

OVERVIEW

In broad terms, projections for new generation plant requirements in Ireland over the next seven years can be divided into two distinct scenarios. The reliability of the generation plant is the key variable which distinguishes these scenarios.

If plant reliability performance stays at the recently experienced levels, then …

There will be a significant shortage of generation plant over the next seven years. This plant shortage, or deficit, is forecast to be of the order of 500 MW in 2005. Short term availability improvement measures and heavy reliance on the interconnector with Northern Ireland are potential ways to reduce the shortfall.

Significant newly committed thermal generation capacity (932 MW) is due to be commissioned during 2006 and 2007. Even if this plant is commissioned on time, plant shortages remain in the region of 500 MW for the period between 2006 and 2009. The extension of short term capacity contracts, currently due to lapse over this period, may offer an additional remedial measure. By combining high interconnector reliance and the extension of these contracts, modest deficits in the region of 100 MW are projected.

By 2009, plant shortages increase and new generation plant is required.

If plant reliability performance returns to the levels forecast by generation companies then …

New Generation plant is not required before 2009.

These outlooks give a flavour, in approximate terms, of the detailed analysis presented in this report. Should there be any plant closures during this period the plant shortage situation would increase in proportion.

Members of the Generation Analysis team: (L-R) J. Butler, N. Ameijenda, M. Kelly, V. Camacho, B. Chapman

1 INTRODUCTION

This report is produced with the primary objective of informing market participants, regulatory agencies and policy makers of the likely minimum generation capacity required to achieve an adequate supply and demand balance for electricity for the period up to 2011. This report supersedes the previous Generation Adequacy Report published in November 2003, covering the period 2004 to 2010. All input data assumptions have been updated and reviewed. Key changes from the previous report, including those to the input data and consequential results, are identified and explained. Major changes include:

- the inclusion of an additional 932 MW of committed thermal plant;
- more detailed analysis of the potential capacity benefits of interconnection.

The Transmission System Operator (TSO) is required to publish forecast information about the power system (as set out in Section 38 of the Electricity Regulation Act 1999). This document provides the TSO's considered view on one aspect of the power system, namely, generation adequacy. Generation adequacy concerns the capability of the power production capacity to supply the electricity demand on the system. The development of new generation capacity and connection to the transmission system involves long lead times and high capital investment. Consequently this report provides information covering a seven-year timeframe.

While the outlook for generation adequacy has been summarised in the Overview section, the detail behind these and many other scenarios are presented in Sections 2 through 7 of this report. Section 2 describes the methodology used to calculate generation adequacy. Section 3 deals with the TSO's forecasts of the long-term demand for electricity in Ireland. The assumptions made in relation to sources of electrical energy are discussed in Section 4, while the treatment of interconnection is described in Section 5. The results of the current analysis are detailed in Section 6, with comments and discussion in Section 7. A glossary of technical terms is included at the end of this report, as well as several appendices which provide further detail of the data, results and methodology used in this study.

2 METHODOLOGY FOR ASSESSING GENERATION ADEQUACY

2.1 Introduction

In this section of the report an overview[1] of the method used to assess generation adequacy is presented. This method is in line with best international practice, and the advantages over other more simplistic approaches are outlined. How the results are to be presented and interpreted is then discussed. Finally issues related to the Transmission System and the handling of input data are discussed.

2.2 Overview of Methodology

Generation adequacy is assessed by determining the likelihood of there being sufficient generation to meet customer demand, or in other words, by calculating the risk that supply shortages will occur. The potential for supply surpluses or risk of supply shortages is calculated by using statistical techniques to determine the probability that demand will exceed supply. This assessment is carried out for every half hour of the study period. From these half hourly probabilities an annual expectation is determined of the total duration of time that demand would be anticipated to exceed supply.

This annual expectation, known as Loss of Load expectation (LOLE), is compared against a standard or benchmark level in order to assess if the level of risk is acceptable or not. The magnitude of any divergence from standard indicates the scale of the risk.

For Ireland the LOLE standard is 8 hours per year. LOLE levels above this indicate higher than acceptable levels of risk.

Figure 2-1 illustrates the effect of LOLE being outside or within standard. With this sample curve, a system with 7500 MW of installed capacity meets the standard exactly. But a system with just 7250 MW results in 45 hours LOLE per year, and is therefore outside standard and the system is in deficit. Conversely, a system of 7750 MW experiences an LOLE of 1.5 hours per year, and this being well within the standard, means that the system has surplus plant.

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[1] More detail on the calculation techniques are given in Appendix 3.

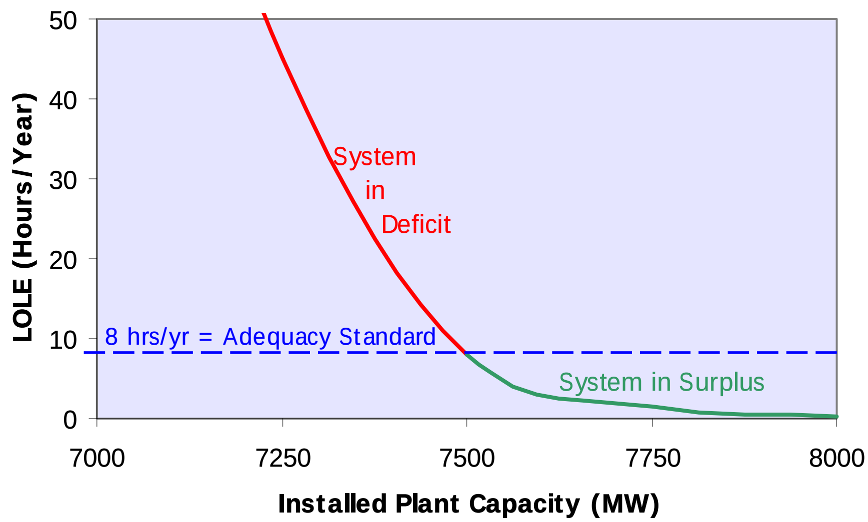

Figure 2-1 Adequacy standard and sample capacity - LOLE curve

2.2(a) The use of probabilistic techniques to assess generation adequacy

The use of probabilistic techniques is required in situations when one or more of the input variables in a calculation exhibit a level of random behaviour.

Generation adequacy, or the risk of supply shortage, is driven to a large extent by the unplanned failure of generation plant. Both the time of occurrence and duration of such outages are random in nature. At any particular time, several units may fail simultaneously, or there may be no such failures at all. Therefore, due to the random nature of forced outages, probabilistic techniques must be used to properly assess generation adequacy.

The use of deterministic calculations, such as capacity margin[2], cannot inherently capture the impact of random behaviour. In addition LOLE calculations have the advantage of taking the following factors into account.

- The load at every hour of the year is considered to have an influence on system adequacy, not just the hours of peak demand.

[2] Capacity Margin is defined as the ratio of installed capacity to peak demand.

- The number and relative sizes of generating units impact on the LOLE calculation. A large number of small units will provide more security than a small number of large units, other factors being equal.

2.2(b) Presentation 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 **definitely** be without supply for 16 hours or that if there is a supply shortage that 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 a total duration of 16 hours.

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 standard, from 24 hours LOLE as it would from 16 hours.

In the real-time operation of the power system a combination of events, such as very high coincident scheduled and forced outages can occur, even though the statistical probability of such occurrences is very small. This can lead to supply shortages during periods when the balance of probability would have suggested a supply surplus.

On the other hand, a period for which there is a very high loss of load expectation can pass without failure provided actual conditions are benign (i.e. “the dice fall kindly”). However, valuable conclusions can be drawn from probabilistic analysis. For example, if LOLE is greater than standard then a higher than acceptable risk of supply failure is indicated.

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).

This is achieved by calculating the Peak Carrying Capability (PCC). This is an estimation of the level of peak demand that a certain amount of plant could meet at the standard adequacy level.

The PCC is always less than the total installed capacity, because of scheduled or forced outages. The difference between the PCC and the forecast peak for the year is an approximate indication of how far away from the standard the system is:

- if the PCC is greater than the peak, then the difference indicates how much surplus plant there is;
- if the PCC is less than the peak, then the difference is an approximate indication of the additional plant capacity required to meet the adequacy standard.

This measure can only be an approximation, as the exact amount of plant required would depend on the particular size and availability of any new plant to be added.

Furthermore, once the plant surplus or deficit has been estimated from the PCC calculation, a required capacity margin can be calculated. Therefore while generation adequacy is not determined by assessing the plant surplus/deficit or capacity margin, results are translated into these terms where appropriate.

2.3 Impact of the Transmission System

Historically generation adequacy has been assessed without reference to any limits that might be imposed by the bulk electricity transport system (the Transmission System). During the period covered by this report it was necessary to consider the impact of constructing generation plant before the Transmission System could be reinforced to accommodate the additional transport requirement. These transport problems tend to limit on occasion the generation which can be exported from a particular area. Therefore the methodology adopted involved the de-rating of generation capacity within the affected area so as to reflect the interaction between the transmission and generation system capabilities. This is described in more detail in section 4.6(e).

2.4 Data Freeze

To enable the detailed analysis required to produce this report, data relating to the performance of the Irish economy, generator capacity and availability was 'frozen' on the 1 September 2004. Following the collection process the data was checked and confirmed before detailed analysis and modelling commenced. All quantitative analysis, the results of which are presented in this report, is based on data unchanged from these dates.

However any changes that have come to the TSO's attention since that date have been noted in the appropriate section. The impacts of such changes are assessed in qualitative terms where appropriate.

3 DEMAND FORECAST

3.1 Introduction

A forecast of how much electricity will be needed in the future is essential for determining generation adequacy. With Ireland's economy set for continued growth, the growth of electricity demand averaged over the next seven years is projected to be between 2.8% and 4.4% per annum. The calculation of this forecast is detailed in the remainder of this section by presenting the structure of the models and their input data.

3.2 Historical Demand

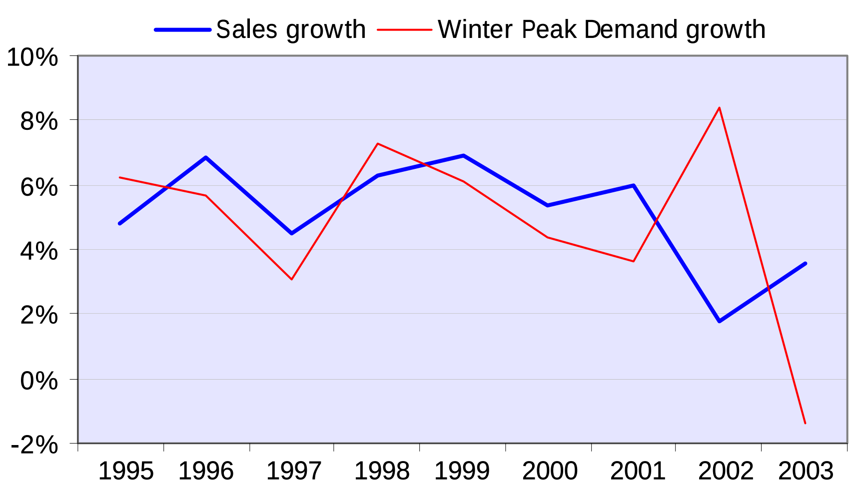

Figure 3-1 Percentage growth rates of total electricity sales and of the winter peak demand

A forecast of both the electricity sales and the peak demand are required. Historically, these growth rates have been of similar magnitudes, see Figure 3-1, though in recent years the peak has been more volatile. Contributing to this volatility is the influence of Demand Side Management on the peak, see section 3.4.

3.3 The Electricity Forecast Model

3.3(a) Structure of the electricity forecast model

The energy forecast model is a linear model which divides electricity demand into two sectors, each requiring different economic input:

- non-domestic electricity demand is related to GDP[3];
- domestic electricity demand is related to PCGS[4].

Relating the electricity demand of a country to its economic performance is a standard international practice.

3.3(b) Review of the electricity model in GAR 2004-2010

The energy model from last year's GAR performed reasonably well. Figure 3-2 shows the sales forecast made in the *GAR 2004-2010* (pink diamond) was only 200 GWh less than the outturn sales of 21,965 GWh (blue square).

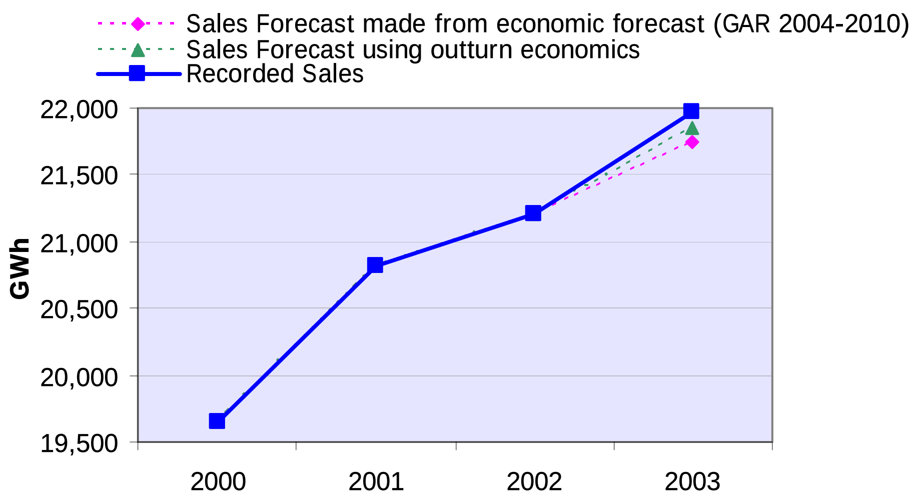

Figure 3-2 Records of total sales from 2000 to 2003, with forecasts for 2003

The model was retrospectively tested with 'perfect' input, i.e. the actual outturn economic data rather than a forecast. The resultant sales forecast for 2003 (green triangle) was only 100 GWh less than the outturn sales, thus confirming the model structure to be appropriate under current conditions.

[3] Gross Domestic Product is the total value of goods and services produced in the country.
[4] Personal Consumption of Goods and Services measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.

3.3(c) Training the electricity forecast model

The electricity model used is trained using historical data. For the *GAR 2005-2011*, the most recent figures were used – economic data from the Central Statistics Office and demand data supplied by ESB Public Electricity Supply and the market settlement system.

It should be noted that historical data for 2002 was not used. This seems to be an anomalistic year, as there is a large and unprecedented gap between GDP and GNP[5] due to certain accounting anomalies. The actual economic activity of the country seems not to be represented clearly by either GDP or GNP, and thus the ESRI has advised that 2002 data should not be included when training the energy model.

3.3(d) Forecasting causal inputs

In order for the trained energy model to predict forwards, it needs a forecast of the causal inputs (GDP and PCGS). The ESRI has expertise in modelling the Irish economy as a whole, and has produced the *Medium Term Review* (*MTR July 2003*) which forecasts economic factors until 2020. These forecasts incorporate expert views on Irish and global economic prospects.

As well as its median, or 'best-guess' forecast, the ESRI models two other scenarios, where it investigates the possibility of higher and lower growth in the economy by introducing economic shocks in 2005. These three scenarios are used to make three different electricity forecasts, high, median and low. The final out-turn of electricity consumption is expected to lie within the bounds of these scenarios.

The ESRI also produces a short-term macroeconomic forecast which provides detail over the following two years, the *Quarterly Economic Commentary July 2003*. This forecast is quite similar to the MTR in the overlapping years, and it is used in the electricity model for the years 2004 and 2005. The economic forecast used in this report is summarised in Table 3-1, and is detailed in Appendix 1.

[5] Gross National Product is defined as GDP less the Net Factor Income from the rest of the world (the profits of foreign multinational companies operating in Ireland, less the profits of Irish companies operating abroad).

Average annual forecast values for 2005-2011		
Demand scenario	**GDP growth (%)**	**PCGS growth (%)**
High	6.1	4.7
Median	5.3	3.9
Low	3.8	1.1

Table 3-1 Forecast growth of GDP and PCGS

Figure 3-3 graphically shows the three GDP forecast scenarios. In the median scenario the economy is seen to grow strongly over the next three years. After 2008 the growth rate decreases in all three scenarios, driven by changes in demographics. The high growth scenario is quite close to the median, while the low growth scenario is well below the median. This reflects the ESRI's opinion that the economy is more likely to grow less than their predictions rather than to exceed them.

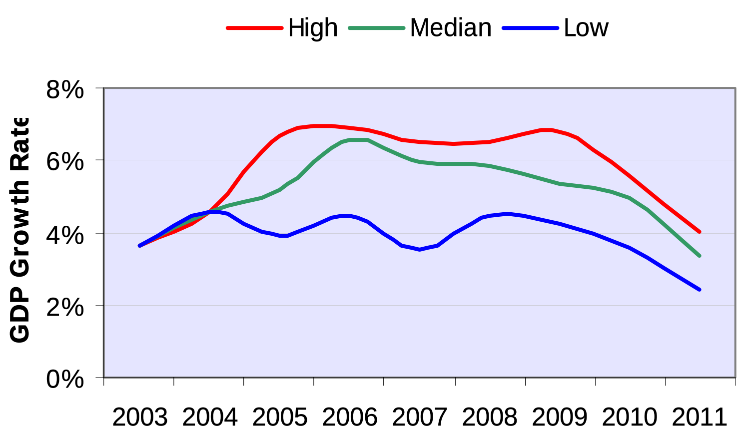

Figure 3-3 Forecast growth of GDP

The three forecast scenarios of PCGS are shown in Figure 3-4. The median forecast describes steady growth of around 4%.

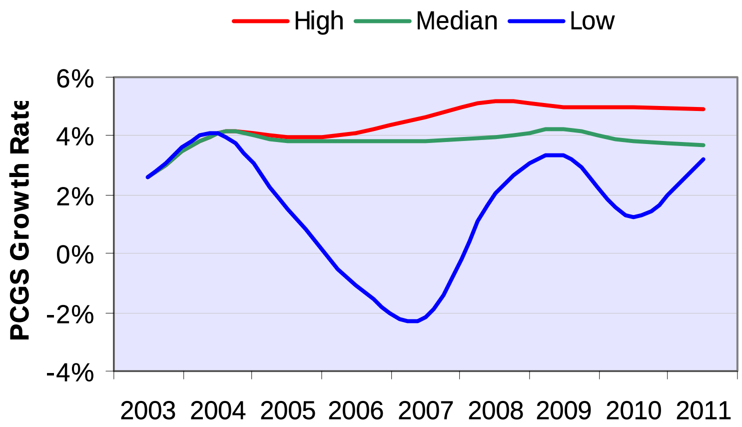

Figure 3-4 Forecast growth of PCGS

In the ESRI's forecasts, the low scenario is driven by a possible loss of competitiveness. This is particularly dramatic in the PCGS forecast where negative growth is reversed after 2007 because of a change in the labour market – a switch from net immigration to net emigration causes less of a drain on government resources (unemployment benefit, etc.) and so the performance of the economy improves.

3.3(e) Electricity forecast results

Using these economic inputs in the electricity model, three electricity sales forecasts are produced for the Republic of Ireland for the next seven years (high, median and low). Over the transmission and distribution network, electrical losses are incurred and must be accounted for. The electricity sales forecasts are therefore translated to the equivalent amount of generation, which must be supplied to the network in order to satisfy that level of sales. A combined distribution and transmission system loss factor[6] is used for this translation.

Some large-scale industrial customers produce and consume electricity on site. This electricity consumption (known as self-consumption) is not included in sales or transported across the network. Consequently an estimate[7] of this quantity is added to the energy which must be exported by generators to meet sales in order to arrive at a Total Electricity Requirement (TER) that must be met by all sources. As all generating sources are considered in the analysis, it is this TER that is utilised for generation adequacy calculations.

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[6] Based on analysis of historical production and sales figures this loss factor is estimated to be 9.3%.
[7] Self-consumption represents approximately 2% of system demand. Therefore this estimation does not introduce significant error.

The forecast growth rates for TER are actually very similar to those of electricity sales, see Table 3-2. The full TER forecast in GWh is detailed in Appendix 1.

Average annual forecast values for 2005-2011		
Demand scenario	**Electricity sales growth (%)**	**TER growth (%)**
High	4.4	4.4
Median	3.9	3.9
Low	2.8	2.8

Table 3-2 Electricity demand forecast, at sales level and at TER level

The forecast year on year growth rates of TER are plotted in Figure 3-5. The median and high growth scenarios are quite close, echoing the economic forecast. The low growth scenario is significantly below, showing a dip in growth in 2007.

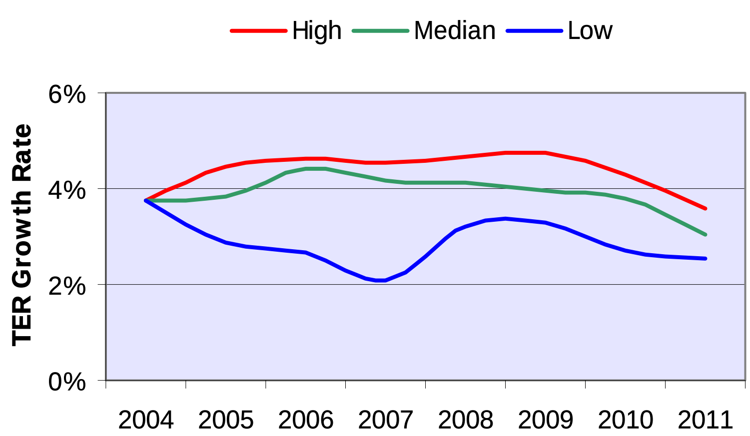

Figure 3-5 Forecast growth of Total Electricity Requirement

3.3(f) Electricity demand per capita

As an objective check on the plausibility of the demand forecast, it was worthwhile to compare the electricity demand per capita for Ireland with that of our European neighbours, particularly the UK which experiences similar climatic conditions (see Figure 3-6). In the early nineties, Ireland was far behind the UK, but rapid economic growth led to the gap being closed by the year 2002. Using the median electricity consumption forecast and the population forecast from the ESRI's *Medium Term Review*, the consumption per capita for Ireland is predicted into the future. By way of comparison, the historical EU-15 and UK per capita consumption is trended forwards linearly. The forecast for Ireland is seen to be bracketed by these projections, confirming its plausibility. Data for this study was sourced from Eurelectric and Eurostat. 'EU-15' refers to an average of the 15 EU member states prior to 2004 enlargement.

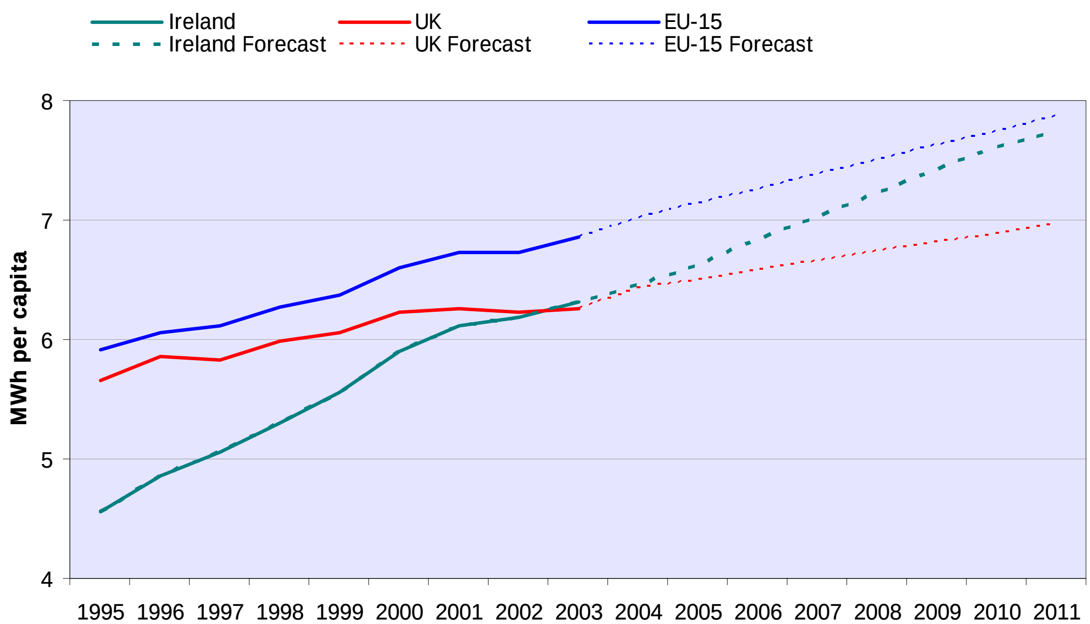

Figure 3-6 Electricity demand per capita

3.4 The Peak Demand Model

The peak demand model is based on the historical relationship between the annual electricity consumption and the winter peak (their ratio is known as the Annual Load Factor). For these purposes the winter period is defined as November through to February.

3.4(a) Volatility of the peak

Historically, the winter peak is somewhat erratic (not fitting any model in a fully satisfactory manner), as it is subject to many disparate influences, including:

- temperature
- changing customer habits, especially domestic customers
- Demand Side Management (DSM) schemes[8].

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

The peak for winter 2002/2003 showed a remarkably big increase over the previous winter, even though there was a relatively small increase in annual electricity sales. This can plainly be seen in Figure 3-1 where the growth rates of electricity sales and peak had been close historically, but diverged dramatically in 2002. Almost the opposite happened in winter 2003/2004 when the sales grew by 3.6% while the peak actually dropped, recording the first negative peak demand growth in over a decade.

This behaviour can in part be explained by the effect of DSM. In winter 2002/2003 some customers who had previously participated in the WDRI[9] scheme moved to other suppliers, and so their reducing effect on the peak was lost and the peak increased dramatically. In winter 2003/2004 a new DSM scheme was introduced (WPDRS[10]), and so the peak was lowered.

3.4(b) The modified peak demand model

To include these DSM effects in the peak demand model, an estimate of their magnitude is made, and the model corrected. The residual WDRI effect is estimated at 50 MW, while the best estimate of the new WPDRS effect is 80 MW. These effects are assumed to continue into the future.

3.4(c) Results – peak forecast

Using the forecast electricity consumption values in the modified peak demand model, the winter peaks for the next seven years were calculated for the three different scenarios. Brought to the exported level, the forecast average annual increases in winter peak are given in Table 3-3 (and are detailed in Appendix 1).

Average annual forecast values for 2005-11	
Demand scenario	**Winter peak increase (MW)**
High	216
Median	187
Low	122

Table 3-3 Winter peak forecast

[9] The Winter Demand Reduction Incentive scheme is run by ESB.
[10] The Winter Peak Demand Reduction Scheme is open to customers of all suppliers, subject to a number of conditions.

3.5 Comparison with Generation Adequacy Report 2004-2010

The overall demand growth projections have not changed significantly between the two reports. However, in the early years the demand growth is higher in the current forecast, due to the recent economic recovery. This is illustrated in Figure 3-7 for the median demand forecasts. The forecasts of the annual peak increase are only slightly higher than those for last year, compare Table 3-3 with Table 3-4.

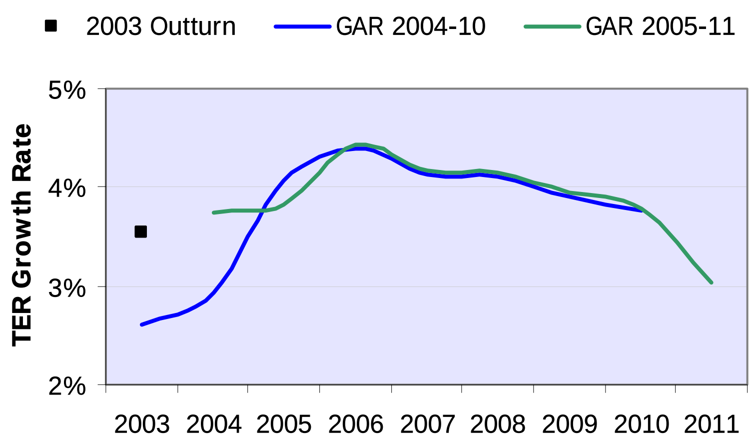

Figure 3-7 Comparison of current and previous TER forecasts

Average annual forecast values for 2004-2010		
Demand scenario	**TER growth (%)**	**Annual peak increase (MW)**
High	4.3	200
Median	3.9	176
Low	2.9	120

Table 3-4 Forecasts from the GAR 2004-2010

3.6 Load Shape

In order to study generation adequacy, projections of electricity demand are required for each hour of the study period. 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 3-8 shows a typical daily demand profile for both a summer and winter weekday in 2003. Winter peak and summer minimum load days are also included in order to illustrate the range of possible demand levels. Many factors impact on this electricity usage pattern throughout the year. Examples include: weather, sporting or social events, and customer demand management.

The load shape for the year 2003 (as recorded at the National Control Centre in ESB National Grid) was examined for the presence of non-standard demand patterns. Such non-standard patterns could be caused by extreme weather conditions or unusual social events. As no such patterns were identified, 2003 was deemed to be a "typical" year. Therefore it is used for all of the analysis as it does not introduce any significant bias.

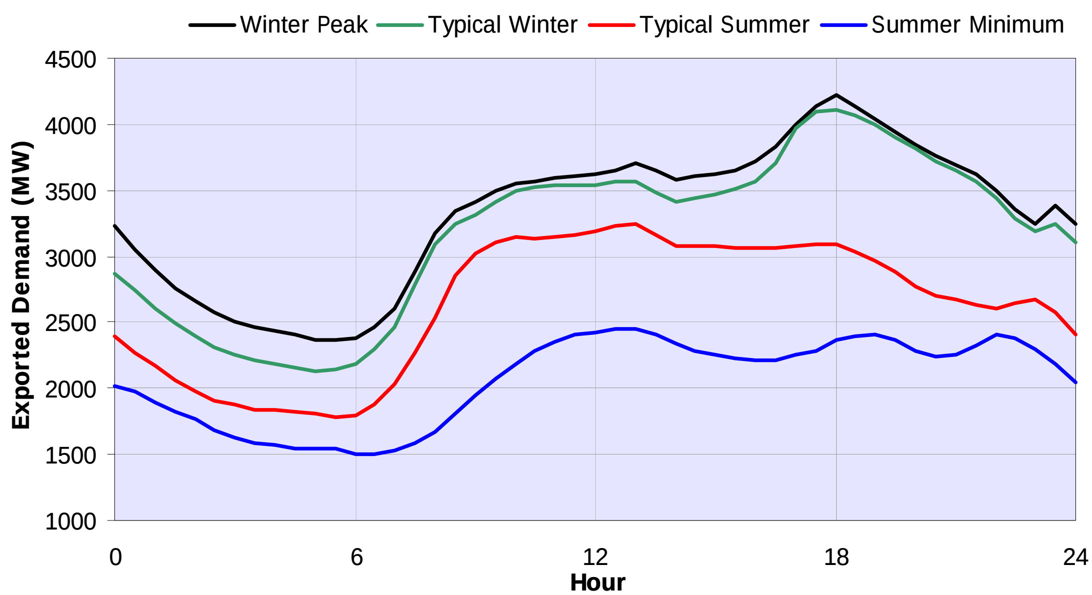

Figure 3-8 Typical daily demand patterns from 2003

3.6(a) Demand side management

As discussed in Section 3.4, DSM can have an important influence on the demand peak. Before the opening of the electricity market (February 2000), the main DSM scheme operated by the ESB was called WDRI (Winter Demand Reduction Incentive). It provided financial incentives to customers to reduce their demand between 17.00 and 19.00 on winter weekday evenings.

With market opening, a lot of these customers moved to other suppliers and therefore stopped participating in the WDRI. Therefore in 2003, the TSO commenced a new DSM scheme called WPDRS (Winter Peak Demand Reduction Scheme). In winter 2003/04 it is thought that WPDRS contributed 80 MW of a peak reduction, while WDRI still added 50 MW. These figures were included in the peak demand forecast model.

In the adequacy studies, it is assumed that this level of DSM will continue. With the ongoing promotion of the WPDRS scheme, it is quite possible that more customers will sign up to it. Therefore a further investigation will explore the effect of an extra 40 MW of WPDRS. This will be done by shaving 40 MW off the winter weekday peaks in the load shape. This further scenario will also model the effect of extending the WPDRS scheme an extra month (March) as is being planned for winter 2004/2005[11].

3.6(b) Load duration curve

The load duration curve in Figure 3-9 shows a distribution of projected customer electricity demand in 2010 (under the median demand growth scenario). This representation of system demand illustrates the percentage of the year customer demand exceeds any given MW level. For example it can be seen that the load exceeds 2140 MW for 100 % of the time, or in other words the minimum demand level is 2140 MW. At the other end of the spectrum, demand is expected to exceed 5000 MW for only 2.4% of the year or on 210 individual hours. The relatively small number of peak demand hours is reflected in the steep gradient at the higher demand levels. Below these peak hours the gentle slope of the load duration curve indicates that demand is expected to be in the 4000 to 5000 MW range for significant periods.

[11] It should be noted that there is no intention at present to extend the WDRI scheme into March.

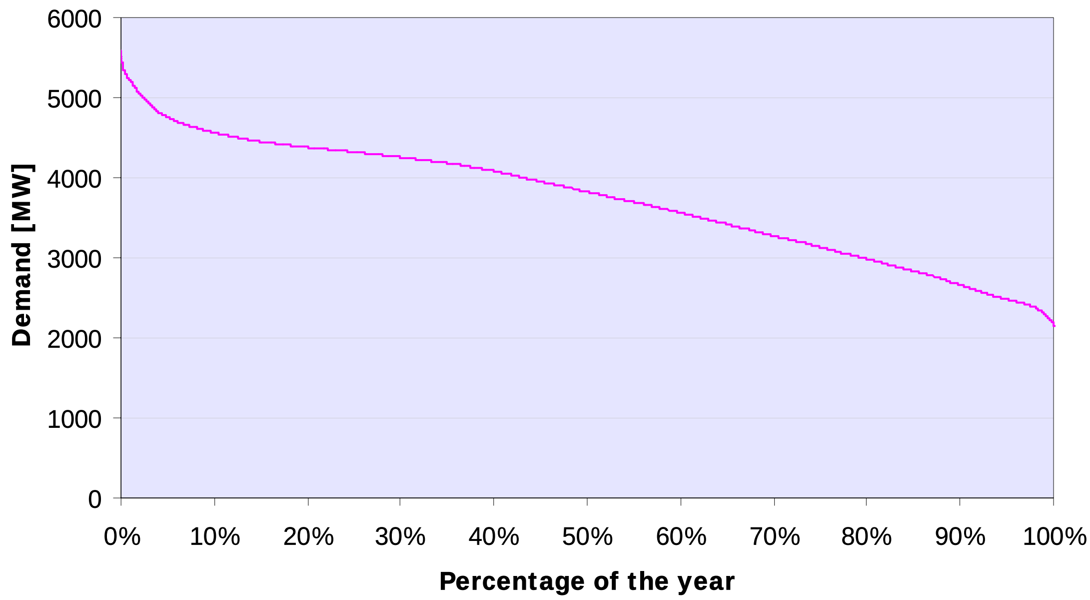

Figure 3-9 Load duration curve for customer demand in 2010

4 INPUT DATA ASSUMPTIONS – ELECTRICITY PRODUCTION

4.1 Introduction

In this section, the sources of electrical energy that are likely to be used over the period 2005 to 2011 are examined. Initially the capacity of the current and committed plant portfolio is described. In all cases, it is the *exported*[12] capacity which is given.

The characteristics which influence the ability of the individual unit types to contribute to the supply demand balance are then considered.

Finally for information purposes, the structure of the plant portfolio is presented by age and plant type.

4.2 Existing and Forecast Plant Portfolio

By year end 2004 it is estimated that there will be 5952 MW of generation capacity installed (or contracted[13]) to supply Irish customers. By the end of 2011, this will have risen to 7336 MW.

The generation portfolio comprises many different plant types, some of which contribute more than others towards generation adequacy. The modelling techniques used take account of these differences and are explained throughout this section. In order to highlight different aspects of the portfolio, plant has been grouped under a number of different headings throughout this section of the report. These groupings are also used to explain how different plant types are treated in our data gathering and analysis.

The plant portfolio can be categorised in many different ways. One of the most pertinent categorisations from the generation adequacy perspective is whether or not the plant can be fully dispatched[14]. The operation of *fully-dispatchable* plant can be both monitored and controlled from the TSO's central control room, the National Control Centre (NCC). Customer demand is

[12] A generator's exported capacity is defined as its gross capacity less the power required for its auxiliary equipment.
[13] Refers to capacity contract with Northern Ireland for 167 MW, and peaking plant with short term contracts.
[14] Dispatch refers to the instructions given to control a unit's output when it is on load.

also monitored from the NCC. The output of fully-dispatchable plant is continuously varied in order to meet this demand.

There is also an amount of generation connected to the system the output of which is not currently monitored in the NCC and whose operation cannot be controlled. This *non-dispatchable* plant has historically been connected to the lower voltage distribution system (know as embedded generation) and has been made up of many units of small individual size.

Large wind farms can fall between these two categories. In the future, all wind farms with an installed capacity greater than 5 MW must have the ability to be dispatched, in the sense that their output can be curtailed. However, an instruction to increase output can only be followed if wind conditions permit. Therefore, large wind farms are categorised as being *partially-dispatchable*.

The capacity of both partially- and non-dispatchable plant makes a reduced contribution to generation adequacy due to the inability to call these units to full output at times of supply shortage.

At year end:	2004	2005	2006	2007	2008	2009	2010	2011
Fully-Dispatchable	5382	5465	5842	6033	6028	6028	6025	6025
Partially/Non-Dispatchable	570	967	1057	1107	1158	1209	1260	1311
Total	5952	6432	6899	7140	7186	7237	7285	7336

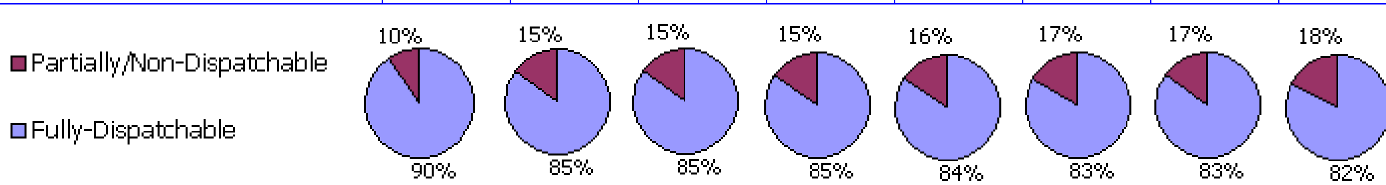

Table 4-1 The subdivision of fully-dispatchable and partially/non-dispatchable generating units

Forecasting of fully-dispatchable plant is carried out in a different way than for partially/non-dispatchable plant. This is due to the fact that fully-dispatchable plant is generally connected to the transmission system and will therefore require a connection agreement with the TSO. This allows individual potential projects to be identified and included in this report as appropriate.

On the other hand, partially/non-dispatchable plant, with the exception of some larger wind farms, tends to be added to the distribution system in the form of a large number of small individual projects. The forecasts for this category are therefore based on generic targets rather than tied into specific individual projects. Wind capacity forecasting is carried out in a hybrid manner as explained in Section 4.4(e). However due to the large number of committed wind farms the forecast is largely based on known projects.

Over the period the percentage of the total portfolio which is partially/non-dispatchable is forecast to increase from 10% to 18%, see Table 4-1. Consequently, as a greater percentage of the portfolio will be made up of plant which makes a lower contribution to generation adequacy (and over which there is less dispatch control), the total amount of plant required will increase.

4.3 Forecasts of Fully-Dispatchable Plant

For the forecast of fully-dispatchable plant, capacity additions were included for units which had a signed connection agreement with the TSO as of the data freeze date (1 September 2004). Table 4-2 details units which have a decommissioning date within the period covered by this report, while plant being commissioned are listed in Table 4-3.

Plant name	Capacity (MW)	Decommissioning date
Bellacorick U1	18	March 2005
Bellacorick U2	19	March 2005
NIE contract	167	October 2005
APC[15] – Tawnaghmore	51	December 2006
APC – Aghada	51	December 2006
APC - Rhode 1	51	September 2007
APC - Rhode 2	51	September 2007

Table 4-2 Plant decommissioning dates and export capacities

As part of ESB's peat plant replacement programme, the Bellacorick units are due to be decommissioned in March 2005.

The decommissioning dates for the NIE contract and for the APC (Additional Peaking Capacity) contracts have been advised by ESB Power Generation. While the TSO is aware that there is a certain amount of flexibility with these contracts, there is at present no indication that these contracts might be extended. However, to allow the impact of this potential action to be assessed, additional studies have been carried out where the contracts remain in place until 2011. These will be referred to as the 'extended contract' scenarios.

[15] APC = Additional Peaking Capacity

The winners of the CER[16] Capacity 2005 Competition are Aughinish Alumina and Tynagh, which will add 532 MW to the plant portfolio. In addition to the competition winners, a second Huntstown unit, with an estimated capacity of 400 MW, is planned for 2007. The inclusion of these three units increases the thermal plant portfolio by 932 MW over that reported in *GAR 2004-2010*.

Unit name	Capacity (MW)	Commissioning date
West Offaly Power	137	January 2005
Aughinish Alumina 1	75	November 2005
Aughinish Alumina 2	75	November 2005
Tynagh	382	March 2006
Huntstown 2	400	June 2007

Table 4-3 Plant commissioning dates and export capacities

As part of ESB's peat plant replacement programme, two new peat fired units are due to be commissioned in 2004 and 2005. Lough Ree Power, a 91 MW unit, is to be commissioned towards the end of 2004 on what was formally the Lanesboro site. West Offaly Power (137 MW) is due to be commissioned in January 2005 on what was formally the Shannonbridge site.

If it becomes known that additional plant is to close, the impact of this closure can be reasonably approximated by increasing the deficits (or reducing the surplus) published in this report by the export capacity of the plant in question. It should be noted that the Grid Code[17] stipulates that notification of planned closure must be given to the TSO just 24 months in advance. Considering the significant impact on generation adequacy, and the lead times required for installation and connection of replacement plant, a longer notification period would be desirable.

4.3(a) Changes to export capacity

Maximum Export Capacity (MEC)

In between the data freeze date for this and the previous Generation Adequacy Report, ESB Power Generation have requested that the Maximum Export Capacities (MEC) for a subset of its portfolio be modified. These adjustments were requested on the basis that the new MEC values would more accurately reflect the current and future generation capability of these units. The CER is currently considering this request. While formal approval of this request has not been

[16] Commission for Energy Regulation
[17] An industry document outlining procedures and technical standards to which the users of the system must adhere.

granted, the CER has advised as follows "*for the purposes of the GAR only, CER has asked ESBNG to assume that the deratings have been approved. Currently CER considers this assumption to be a more accurate forecast of the future MEC position.*"

Therefore these adjustments have been incorporated into all the analysis conducted for this report. Table 4-4 illustrates the modified MEC for the effected units and the magnitude of the adjustment over that previously utilised.

	Present rating (MW)	**Proposed rating (MW)**	**Proposed de-rating (MW)**
Poolbeg 1	114.5	109.5	5
Poolbeg 2	114.5	109.5	5
Poolbeg 3	257	242	15
Great Island 1	57	54	3
Great Island 2	57	54	3
Great Island 3	112	108	4
Tarbert 1	57	54	3
Tarbert 2	57	54	3
TOTAL			**41**

Table 4-4 MEC changes

<u>Normal Continuous Rating</u>

In addition to these changes in maximum export capacity, two additional changes as advised by the generation companies are included in this report. The export capacities of the Moneypoint units are reduced by 6 MW during the study period to reflect the impact of fitting emissions limiting technology. The capacity of the Dublin Bay unit has been increased from 392 to 409 MW. This reflects the removal of an operational limit which had been in place since this unit was first commissioned.

4.4 Forecasts of Partially/Non-Dispatchable Plant

There are many different types of partially/non-dispatchable plant. It is the ability to monitor and fully control their output that determines this classification rather than generation technology or fuel source. For the Irish system the non-dispatchable portfolio is made up of industrial standby generation, small scale hydro, biomass, combined heat and power and some wind. Some larger wind farms will be partially dispatchable in the future. Different factors will stimulate growth in each of these generation types. Therefore separate forecasts have been developed for each.

4.4(a) Industrial generation

This category refers to generation, usually powered by distillate engines, located on industrial or commercial premises, to act as on-site supply during peak demand periods. It is estimated that the total installed capacity of such generation is 53 MW. However, as the condition and mode of operation of this plant is uncertain, it has been assumed that this plant is generating 9 MW at peak hours. This capacity is assumed to remain constant over the forecast period.

4.4(b) Small scale hydro

It is currently estimated that there is 21 MW of small-scale hydro, supplying 63 GWh of electrical energy per year. In the most recent Alternative Energy Requirement (AER VI) competition, contracts for 5 MW of additional small-scale hydro were offered. Contracts were awarded for only 1.309 MW. For this report it has been assumed that small-scale hydro capacity will increase at the rate of 1 MW per year or by a total of 7 MW over the study period.

4.4(c) Biomass

The current installed capacity of generation from biomass fuel sources is 24 MW, fuelled mainly by landfill gas (LFG), and delivering 133 GWh per year. The assumption, for the purpose of this report, is that this plant is added at the rate of 4 MW per year. A recently completed 2 MW wood-fired CHP plant in Co Cork is included in the CHP category.

4.4(d) Combined Heat and Power (CHP)

The current installed CHP capacity is 145 MW. Of this some 57 MW is assumed to use all its electricity production on site, i.e. 100% self consumption. The capacity of this type of CHP is assumed to be constant at 57 MW over the forecast period.

The remaining 88 MW is assumed to have an overall capacity factor of 70%. Current figures indicate that this generation exports 18% of its electrical output. The percentage of electrical energy exported is forecast to increase to 30% by 2009 and remains constant thereafter. This reflects an assumed increase in participation of CHP in the liberalised electricity market.

For this report it has been predicted that new CHP plant is installed at the rate of 10 MW per year.

4.4(e) Wind

The forecast for additional wind capacity has been carried out by combining projections based on committed wind projects with a forecast based on meeting renewable energy targets. For the early years, 2005 and 2006, the forecast is largely based on proposed wind projects which have a signed connection agreement[18]. For 2005 and 2006, there are 600 MW of plant in this category. Table 4-5 gives details of capacity and forecast commissioning date by project.

[18] Projects with connection agreements, as of 1 September 2004, to either the distribution or transmission system are included.

	Project Name	Capacity (MW)	Year
Transmission Connected	Meentycat	70.96	2004
	Ballywater	31.5	2005
	Booltiagh	19.45	2005
	Coomagearlahy	42.5	2005
	Derrybrien	60	2005
	Mountain Lodge	24.80	2005
	Ratrussan	70	2005
	Arklow Banks	60	2006
	Subtotal	**379.21**	
Distribution Connected	Anarget	1.1	2004
	Beam Hill	14	2004
	Coomatallin	5.95	2004
	Cronelea Upper	2.55	2004
	Gartnaneane I & II	15	2004
	Kilbranish (Greenoge)	5.2	2004
	Meenanilta II	2.45	2004
	Moanmore	12.6	2004
	Mountain Lodge	3	2004
	Mount Eagle	5.1	2004
	Altagowlan	7.6	2005
	Ballinlough	2.55	2005
	Ballylickey-Kealkil (Curraglass)	8.5	2005
	Black Banks II	6.8	2005
	Butlerstown - Beallough	1.7	2005
	Caranne Hill	3.4	2005
	Dromdeeveen	10.5	2005
	Glanta Commons	19.55	2005
	Gneeves	9.35	2005
	Kilvinane	4.5	2005
	Moneenatieve	3.96	2005
	Richfield	20.25	2005
	Sorne Hill	31.5	2005
	Tournafulla	7.6	2005
	Lee Strand Co-Operative	15	2006
	Subtotal	**219.71**	
	TOTAL	**598.92**	

Table 4-5 Wind projects with connection agreement as of 1 September 2004

For the period 2007 to 2011 a more generic ‘target driven’ methodology is used. EU directive 2001/77/EC on the promotion of electricity produced from renewable sources specifies an indicative target for Ireland’s energy production from Renewable Energy Sources (RES) of 13.2% by 2010. Using the most recent median demand forecast for 2010, and assuming that wind energy will bridge the gap between the energy produced from other renewable sources (Hydro and Biomass) and the overall target, some 974 MW of wind will need to be installed by 2010.

The rate at which wind power is added to the system is forecast on the basis of signed connection offers up until 2006 and as illustrated in Figure 4-1, this implies a rapid increase in wind power capacity in the short term. These projections may be optimistic as recent analysis would suggest that not all plant with targeted connection dates between 2004 and 2006 will be completed in this period. However any moderate deviation from this projection is unlikely to have a material impact on the results and conclusions of this report.

After 2006 a linear rate of capacity increase is assumed in order to meet the renewable energy target.

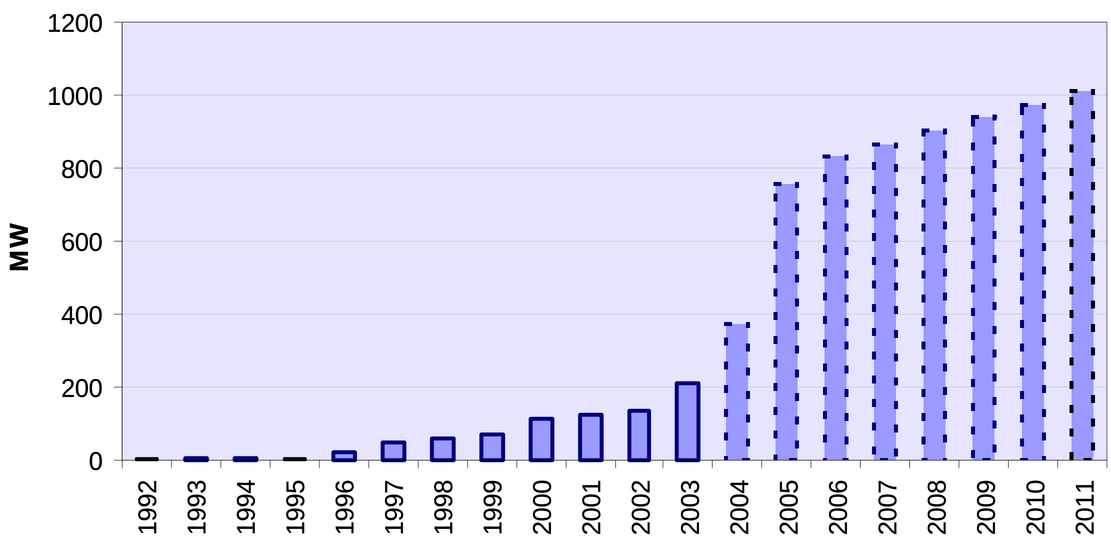

Figure 4-1 Historical and forecast installed wind capacity (year end values)

Since the data freeze date, eight new wind farm projects have signed connection offers, one wind farm has connected and three have deferred connection dates (all at distribution level), see Table 4-6. The total capacity of new wind farm projects is 34.3 MW. This level of new wind farm connection would have no material impact on the results presented in this report.

	Project name	1-Sept-2004 Capacity (MW)	1-Sept-2004 Year	12-Nov-2004 Capacity (MW)	12-Nov-2004 Year
Connected	Meenanilta II	2.55	2004	Now Connected	
Delayed Connection Date	Cronelea Upper	2.55	2004	2.55	2005
	Mountain Lodge	3	2004	3	2005
	Kilbranish (Greenoge)	5.2	2004	5.2	2005
New Project	Knockastanna			7.5	2005
	Geevagh			4.95	2005
	Ballinveny			2.55	2005
	Glenshesk			5	2005
	Killacullen			2.5	2005
	Rathcahill			5	2005
	Carrig			2.55	2005
	Skehanagh			4.25	2005

Table 4-6 Changes to wind farm information since the data freeze date

4.4(f) Summary of partially/non-dispatchable generation

The forecasts for partially/non-dispatchable plant are grouped into Renewable and Non-Renewable categories in Table 4-7.

Type	Total end 2004	Annual capacity additions (MW) 2005	2006	2007	2008	2009	2010	2011	Total added 2005-2011	Total end 2011
Renewables										
- Wind	371	384	75	36	36	36	36	36	639	1010
- Hydro (small-scale)	21	1	1	1	1	1	1	1	7	28
- Biomass	24	4	4	4	4	4	4	4	28	52
Non-Renewables										
CHP	145	7	10	10	10	10	10	10	67	212
Industrial	9	0	0	0	0	0	0	0	0	9
Total	**570**	**396**	**90**	**51**	**51**	**51**	**51**	**51**	**741**	**1311**

Table 4-7 Summary of partially/non-dispatchable Plant

4.5 Availability

4.5(a) General

The *total* electricity generation capacity connected to the system is never likely to be available to the system operator at any particular instant. Plant may be scheduled out-of-service for maintenance or forced out-of-service because of mechanical or electrical failure. Lack of availability due to forced outages has a much greater impact 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 with the planned nature of scheduled outages.

Generation plant may also be energy limited. By this it is meant that such plant may be unable to produce energy for reasons other than the requirement to carry out scheduled or forced maintenance. For example wind powered generation is not always able to generate at full output due to low or high wind speeds. The amount of energy that a pumped storage plant can provide is limited by the physical size of its storage reservoirs. As energy limited plant provides a lower contribution to generation adequacy than plant which operates from a primary energy source which is essentially unrestricted, it must be given special consideration. Sections 4.6(a) and 4.6(b) explain the method by which its contribution is determined.

4.5(b) Historical availability

The variation in historical plant availability is illustrated in Figure 4-2. The availability figure, of 77%, for 2004 is a provisional figure based on a 52-week period up to the end of August 2004. The fall off in generator availability since 2001 has been a major cause for concern and an advisory note entitled “Adverse Trends in Power System Availability” was published by the TSO in July 2003, and appeared in the Appendix of *GAR 2004-2010*.

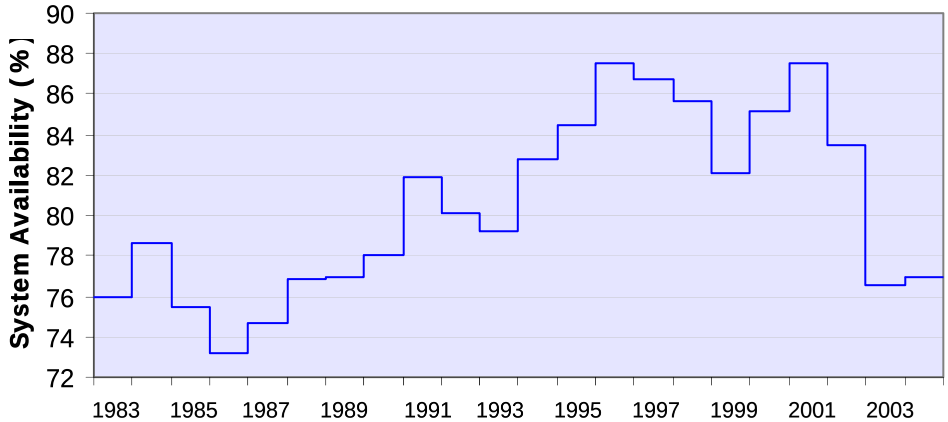

Figure 4-2 Historical availability for fully-dispatchable plant

The difference between the best and worst plant availability experienced over the last 22 years has been over 14 percentage points, and the maximum year-on-year variation has been a substantial 7 percentage points. The difficulty in either maintaining a continuous improvement or holding a constant level of availability over sustained periods of time is also apparent from Figure 4-2.

This volatility in plant performance makes it unrealistic and inappropriate to consider a single scenario, as a one percentage point change in the forced outage rate is estimated to cause an additional plant requirement of 100 MW. This report therefore presents a range of results based on plausible scenarios. In reviewing historical statistics it is important to recognise that the largest units on the system each represent six to seven percent of the total installed capacity. Therefore the loss of even one unit can impact significantly on system availability and partially explains the volatility seen in Figure 4-2.

4.5(c) International availability standards

Due to the deterioration of system availability experienced since mid 2001, a project was completed by the TSO to benchmark the availability of Ireland's generation units. The objective of the benchmarking project was to identify availability performance data for thermal generating plants operating in other countries in such a manner as to allow comparison with the performance of Ireland's generation portfolio.

Statistical resources required for the completion of this analysis were made available by the North American Electric Reliability Council's (NERC) Generating Availability Data System (GADS). The NERC GADS was selected as the most comprehensive and accurate database for benchmarking power plant availabilities. The GADS database contains data from over 5000 units in North America covering a wide range of technologies and extending back as far as 1982. From this data base, groups of plant with similar characteristics to those in Ireland were selected. This peer group selection was carried out by comparing plant type, net capacity, fuel type, boiler or steam conditions, running regime and capacity factors. Seven peer groups, with a total of 341 units and sample sizes varying from 32 to 98, were identified and used to carry out this study. The variables selected to benchmark were Forced Outage Rate (FOR), Scheduled Outage Duration (SOD) and Availability.

The benchmarking study involved the comparison of single Irish generating units with their peer groups over a five year period. The potential improvements have been quantified on the basis that non-thermal units perform with a business as usual scenario. The figures utilised for thermal units in the benchmark availability scenarios remain constant for the period 2005-2011, whereas performance figures for other units were taken from the generators' availability projections. System availability levels which would be achieved if Ireland's thermal plant portfolio performed in line with the upper quartile, median and lower quartile of the peer group are illustrated in Table 4-8.

	System availability (%)
Upper quartile	90
Median	88
Lower quartile	85.7

Table 4-8 Benchmark scenarios, 2005

Results from the study show significant divergence between the availability performance of Irish generation plant and that of their peers. Therefore it would appear that a substantial opportunity to improve availability exists. While the duration of scheduled maintenance for Irish plant was found to be in line with best international practice, the forced outage rates were found to be well in excess of international norms.

4.5(d) Sources of availability data

The operators of all fully-dispatchable generation plant have supplied to the TSO forecast values for their scheduled maintenance requirements and forced outage probabilities for the period 2005 to 2011 inclusive. These forecasts were supplied in response to a TSO survey issued in July 2004. Individual unit availability data is commercially sensitive and confidential information. However the combined availability of all generating units, or 'system availability', is published in this report as it is considered to be non-confidential[19] and permits an understanding of how projected availability changes are impacting on generation adequacy.

Generators were asked to provide a range of forecasts covering possible high, median and low availability scenarios. These forecasts resulted in a range of system availability predictions, from 80.7% to 88.5%. As current system availability (77%) is far below this range, it was decided to use a fourth availability scenario. Plant availability in this fourth scenario has been derived by scaling down the generators' low availability forecast, so that the resultant system availability is 77%. This aligns this scenario with the recorded availability over the 52 weeks up to the end of August 2004.

By way of contrast to this poor 77% availability scenario, a further study was carried out where the plant portfolio attained a high availability, akin to international standards. For this report a benchmark availability level for Ireland's generation portfolio was established by assuming they could achieve performance levels in line with the median of their peer group. This is referred to as the "Mid-benchmark" availability scenario, and if achieved would translate to a system availability figure of 88% in 2005.

[19] System availability is considered to be non-confidential as it is an aggregate of individual unit scheduled and forced outage information.

4.5(e) System availability predictions

The total system (excluding Renewables/CHP/SSG plant) availability figures are shown in Figure 4-3.

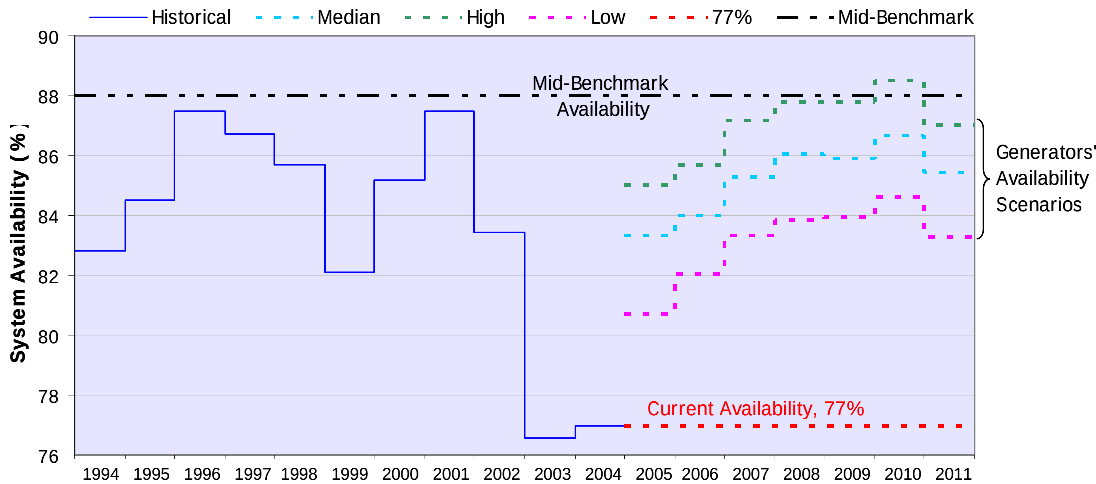

Figure 4-3 System availability – historical and forecast values for fully-dispatchable plant

It should be noted that twice in the last decade, the mid-benchmark availability level was almost achieved. The high availability scenario as projected by the generation companies and the mid-benchmark scenario converge from 2007 onwards.

4.5(f) Comparison with previous Generation Adequacy Report

Since the first GAR was published, in March 2001, the owners of generation plant have provided the TSO with their best estimate of how their plant would perform over a seven year time horizon. These projections take the form of an envelope. Ideally actual availability performance would lie within this envelope.

The range of generators' availability forecasts (low to high scenario) for all four generation adequacy reports published to date are shown in Figure 4-4. It can be seen, for example, that in *GAR 2001-2007* availability forecasts ranging from 86.3 to 87.9% were provided for the year 2003. An updated range of 83.5 to 87.4% was provided for *GAR 2003-2009*. The actual outturn for 2003 was below both of these ranges at 76.5%.

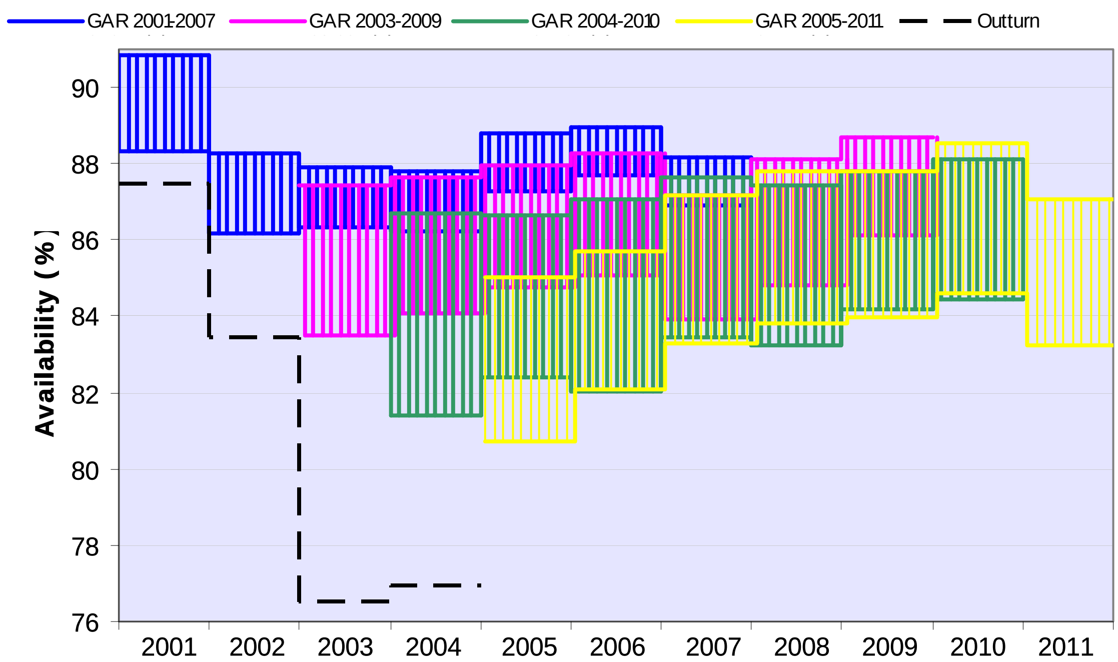

Figure 4-4 Range of generators' availability forecasts in the four GARs

As can be seen from Figure 4-4, to date the forecasts have not encompassed the availability that transpired. Actual performance lies significantly below the projected envelopes. This does not prove that the current projections are implausible but does serve to place them in historical context. It should be noted that the 2004 outturn shown in Figure 4-4 is the rolling 52 week average value up to the data freeze (1 September 2004), and that plant availability has improved from 77 to 78% between then and the publication date.

4.6 Other Factors Impacting on Generation Adequacy

4.6(a) Wind – intermittent energy source

The contribution of wind power to generation adequacy has been analysed separately. This detailed analysis is required due to the intermittent nature of wind energy. There is a significant risk that a single source of failure (e.g. very low or very high wind speeds across the country) will result in all wind farms producing practically no output for a number of hours. This has been verified by monitoring the output from wind generation, at quarter hourly intervals, over a number of years. In contrast, the forced outage probabilities for conventional units are assumed to be independent of each other. Therefore, the probability of all conventional units failing simultaneously is infinitesimal when compared to the risk that wind power will be zero.

The methodology adopted for assessing the impact of wind on generation adequacy has been detailed in *GAR 2004-2010*.

4.6(b) Pumped storage – limited energy source

The pumped storage plant operates on a daily cycle, using low cost electricity at night to pump water from a lower to an upper reservoir. The potential energy stored as a result of this pumping segment of the cycle is then released to generate electricity during high demand periods. The amount of energy which can be produced during the generation segment of the pump storage cycle is largely limited by the physical size of the reservoir. This places a limit on the amount of energy which can be stored and then released in any 24 hour period.

Due to this energy limitation the adequacy assessment model (CREEP) does not utilise the full installed capacity, 292 MW, of the pumped storage station for every hour of the day. An accurate assessment of the contribution of pumped storage plant to generation adequacy is achieved by constraining the probable output of the pumped storage plant to within the defined daily energy limit.

4.6(c) Fuel supply

All calculations utilised for the production of this report assume that sufficient stocks of fuel are available, and that these stocks are delivered to the power plant in a fully reliable manner. In other words no allowance is made for the possibility that electricity supply will be insufficient to meet customer demand due to fuel shortages or fuel supply interruptions.

This has always been an inherent assumption when assessing generation adequacy for Ireland. Two factors supported this assumption. The majority of Ireland's thermal generation portfolio is dual[20] fired, being able to run on either gas or heavy fuel oil, gas or distillate, coal or oil. Therefore if a unit's stock of one fuel runs low or supply is interrupted (e.g. damage to a gas pipeline) the unit can change over to its alternate fuel. However it should be noted that while adequate stocks of the replacement fuels are stored to deal with short duration supply interruptions there may be an issue if such interruptions persist. In addition, it has been the practice for the owners of generation plant to enter into long term, robust, fuel supply contracts. Such robust contracts reduce the risk of price volatility or supply shortages.

[20] Can be powered by more than one fuel type. Dual firing capability is a requirement for compliance with the Grid Code.

Following the liberalisation of the gas and electricity supply markets there has been some evidence that generation plant is subject to less robust fuel supply contracts. This seems to be particularly prevalent in the area of gas supply i.e. non-firm gas contracts. There is a risk that such contracts could have a negative impact on security of supply. It is beyond the remit of this report to consider contractual arrangements and their likely impact on fuel supply.

On the current evidence the assumption that fuel shortages will not impact on generation adequacy has been maintained.

4.6(d) Environmental considerations

Overview of Environmental Legislation

The generation of electrical energy has the potential to create a significant impact on the environment. Emissions of Sulphur Dioxide (SO_2) and Nitrous Oxides (NO_X) from burning fossil fuels contribute to the phenomena of 'acidification' (or 'acid rain') and 'eutrophication'. Power stations also emit Carbon Dioxide (CO_2) and it is contended that CO_2 contributes to 'global warming'. As a response to these issues, over past decades a series of measures have been established at national and international level aimed at controlling and reducing a variety of emittants from generation plant.

Measures to control SO_2 and NO_X at a European level include the Large Combustion Plant Directive (LCPD) and the National Emissions Ceiling (NEC) Directive (2001/81/EC). The LCPD specifies the amounts of these acidifying gases that may be emitted from large combustion plants such as thermal generating stations. The directive first issued in 1988 and the electricity sector has complied with the required limits. In a revision in 2001, more stringent limits were specified which will become binding in 2008. To meet the specified limits on a least-cost basis a National Emission Reduction Plan (NERP) has been developed which, if implemented, would exceed the requirements of the LCPD.

The NEC Directive is the culmination of the EU strategies on the control of acidifying gases. The NEC directive prescribes the emissions ceilings for SO_2 and NO_X, to be achieved by each member state by 2010. Of the many EC Directives to-date relating to air quality and emissions control, this is the first directive to set limits on the total emissions of pollutants in member states. Member states are obliged to draw up programmes for the reduction of national emissions with the aim of complying with their national emissions ceilings by 2010. A discussion paper was published in July 2003 and a strategy has yet to be finalised by the Government.

The phenomenon of 'global warming' in recent times is attributed by some experts to be largely due to the effect of human activities. The Kyoto protocol, recently ratified, adopts the 'precautionary principal' and seeks to limit the build up of so-called 'Greenhouse gases' (GHG) that are believed to be the cause of this effect and CO_2 is one of the principal GHGs. In 2002 Ireland, along with the other EU countries, ratified the Kyoto Protocol to the UN Framework Convention on Climate Change (UNFCCC), which established international emissions reduction targets for GHGs. Ireland is required to limit GHG emissions to an average of 13% above base year emissions in the period 2008-2012. Flexible mechanisms in the Kyoto Protocol, such as emissions trading, can reduce the costs of meeting targets.

The EU has instigated an Emissions Trading Scheme (ETS) as the principal policy instrument aimed at meeting the collective target agreed under the Kyoto protocol. This scheme applies to large installations such as combustion plant with a rated thermal input exceeding 20 MW and as such will apply to dispatchable thermal generation plant. The ETS will commence at the start of 2005. Each installation will be allocated a certain quantity of CO_2 emission allowances free of charge. If an installation emits more CO_2 than the allowance then it must acquire the shortfall in the market. The allowances for the first phase of the scheme (from 2005-2007) are stated in the National Allocation Plan (NAP). There is also provision for allowances for New Entrant generation plant. Some concern has been raised as to whether that amount is sufficient and may act as a disincentive for new entrants. Two versions of the NAP have been open for public consultation; the last consultation ceased in October 2004 and the NAP has yet to be finalised.

<u>Impact on Adequacy</u>

To-date the ability of generation plant to meet customer demand has not been impeded by emission limits or compliance with environmental obligations. For this report the assessment has been that generation adequacy will continue to be unaffected for the following reasons.

i. In 2005, the ETS will be established and each generation installation will be allocated a CO_2 allowance according to the NAP. Any installation that generates CO_2 in excess of its allowance may purchase additional CO_2 allowances. This may have an impact on the cost of generation but there should be no adverse impact on generation adequacy, unless these additional costs become a significant barrier to new entry into the generation market.

ii. In 2008, the provisions of the revised LCPD (2001) come into force. Two factors suggest that the directive will not impact on generation adequacy. Firstly, article 7 of the LCPD states that 'the competent authority may allow exceptions…where…there is overriding need to maintain energy supplies'. Secondly, the projected emissions in the proposed NERP are below the limits in the directive and consequently emergency provisions should not be called upon.

iii. In 2010, the NEC directive is due to come into effect. The strategy to comply with this directive has yet to be finalised by the Government. The consultation document implies stringent limits for NO_X in particular and there are serious concerns about the technical ability and economics of the measures proposed to meet with the limits for the electricity sector. Technical controls and market mechanisms must be sufficient to meet with emission obligations otherwise generation adequacy may be compromised. This is an issue that will be kept under review by the TSO.

4.6(e) Impacts of the transmission system

If the major electricity transport system, the Transmission System, is not capable of accepting the output from all the generation plant in a particular area, it is possible that customers will be left without supply not because of a generation plant shortage but because of a transport shortage.

A shortage in transport (or Transmission) infrastructure can occur because construction lead times for modern generation plant have shortened considerably. It is possible to commission new generation plant within four years of the project start date while major reinforcements of the transmission system can take between six to ten years to complete. Therefore the transmission system cannot always be reinforced before new plant is completed.

Such an instance is forecast to occur in the Dublin area between mid 2007 and 2010. During this period the contribution of the Dublin based generation plant to generation adequacy is curtailed. This curtailment is a function of plant availability in the area. Low plant availability reduces the plant's inherent contribution to adequacy and thereby lowers the transmission curtailment that will occur.

For each of the availability scenarios studied, a level of transmission curtailment was calculated. The effective capacity of the Dublin units, from mid 2007 to 2010, is therefore their rated capacity less this curtailment. These levels are illustrated in Table 4-9.

Availability scenario	Transmission curtailment of Dublin plant capacity [MW]
Mid-benchmark	146
Generators' high	125
Generators' median	98
Generators' low	72
Current (77%)	0

Table 4-9 Transmission curtailment

The TSO's transmission *Forecast Statement*[21] seeks to identify areas where additional capacity exists on the transmission system and where the building of new plant is unlikely to lead to transmission curtailments. In the most recent *Forecast Statement*[22], the transmission station at Knockraha has been identified as offering the best potential.

4.7 Additional Information on Fully Dispatchable Plant

For information purposes the portfolio of fully-dispatchable generation is sub-divided under a number of additional headings. This allows the balance of the portfolio in terms of age and plant type to be visualised. The impact of short term capacity additions, in the form of APC and the NIE capacity contract are excluded from these tables. These forecasts do not take into account any capacity that may be built over the next seven years but which is not yet confirmed.

[21] Public document published by the TSO, which documents the transmission system capability over a seven year time period.

[22] *Forecast Statement 2004-2010* was issued in June 2004.

4.7(a) Plant age

Age	Capacity in 2005 (MW)	Capacity in 2008 (MW)	Capacity in 2011 (MW)
Under 5 years	1248	1160	782
5-15 years	460	1330	1708
15-30 years	2791	2243	1645
Greater than 30 years	762	1295	1890
Total	5261	6028	6025

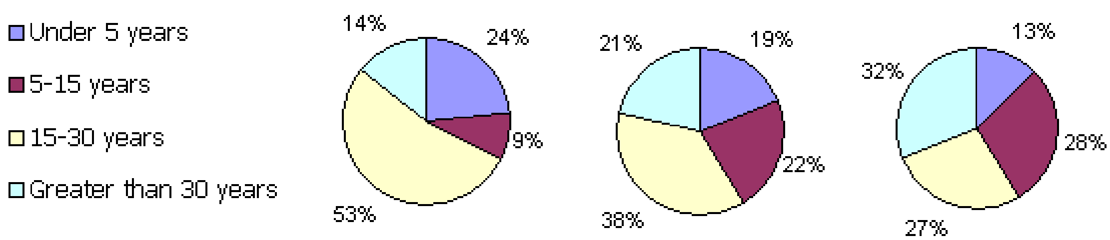

Table 4-10 Age profile of predicted plant capacity

As time passes, the relatively new plant ages and thus the percentage of plant in the 5-15 year category increases from 9 to 28%. By 2011, a third of the plant will be over 30 years old. However the TSO's Availability Benchmarking study showed that plant age and availability performance are not necessarily correlated. Some of the best performers within the international peer groups were in the over 30 year old category, suggesting that performance is more strongly linked to maintenance and operational practice than to age.

4.7(b) Plant type

Plant type	Capacity in 2005 (MW)	Capacity in 2008 (MW)	Capacity in 2011 (MW)
Combined cycle gas turbine	1487	2269	2269
Conventional steam	2734	2719	2716
Hydro	219	219	219
Open cycle gas turbine	379	379	379
Pumped storage	292	292	292
Combined Heat and Power	150	150	150
Total	5261	6028	6025

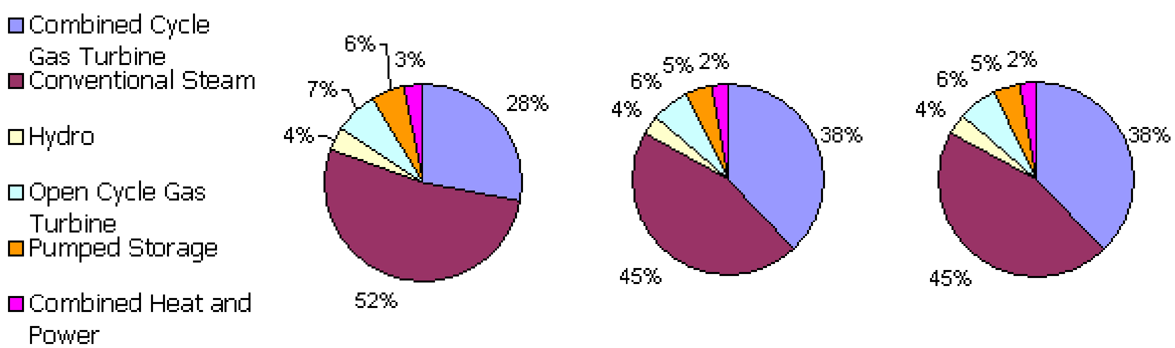

Table 4-11 Predicted plant capacity by type

The share of CCGT plant on the system increases from 28% to 38% over the study period as two large units come online (Tynagh and Huntstown 2). Proportionally, the share of the other types of plant falls in response. The balance of the total plant portfolio is important from a technical and economic perspective. If too much base-load[23] plant is installed, then some of it will not operate at full capacity during periods of low demand. Low load or intermittent running can have a detrimental effect on both the economic viability and technical reliability of plant designed to run at base load. To cope with the peaks and troughs of the daily load pattern, a balanced portfolio of base-load, cycling and peaking plant is important for smooth and efficient running of the system.

[23] A unit is considered to be in base-load operation if it operates on an almost continuous basis and at output levels close to its maximum capability. High-capital, low-running-cost units are designed for this type of operation.

In order to accurately establish the utilisation (or capacity factor) that any generator in a portfolio will achieve, a sophisticated model, incorporating unit commitment, economic dispatch and market conditions, should be used. However, if it is assumed that plant is operated simply in accordance with its variable production cost, it is possible, to a first order approximation, to determine from a load duration curve how much base-load, cycling and peaking plant a system can support. Base load units are defined as those which operate at a capacity factor of 91%, as estimated in the CER's paper "Best New Entrant Price 2005". Peaking plant is defined as that which operates at capacity factors less than 10%, while cycling plant operates below base load but above peaking plant capacity factors.

For this analysis a modified load duration curve is generated. This curve is based on Figure 3-9, but by removing projected energy provision by renewable and non-dispatchable sources, the demand which is to be met by centrally dispatched generation is obtained.

Figure 4-5 illustrates the load duration curve available to dispatchable plant in 2010. It indicates that of the order of 2200 MW of total plant capacity will be able to operate under base load conditions. With 346 MW of peat fuelled capacity tending to run continuously, approximately 1850 MW of the remaining plant portfolio will be in a position to achieve the Best New Entrant (BNE) capacity factor of 91%. Other plant will tend to operate in cycling mode or as peaking plant. It should be noted that 1212 MW of combined cycle BNE type plant has been commissioned since 1999, with a further 932 MW committed to begin operating over the next seven years. This would suggest that Ireland's base-load plant requirements are well in hand. In developing generation proposals, potential investors should consider the type of operating regime that will exist on the Irish system in the future.

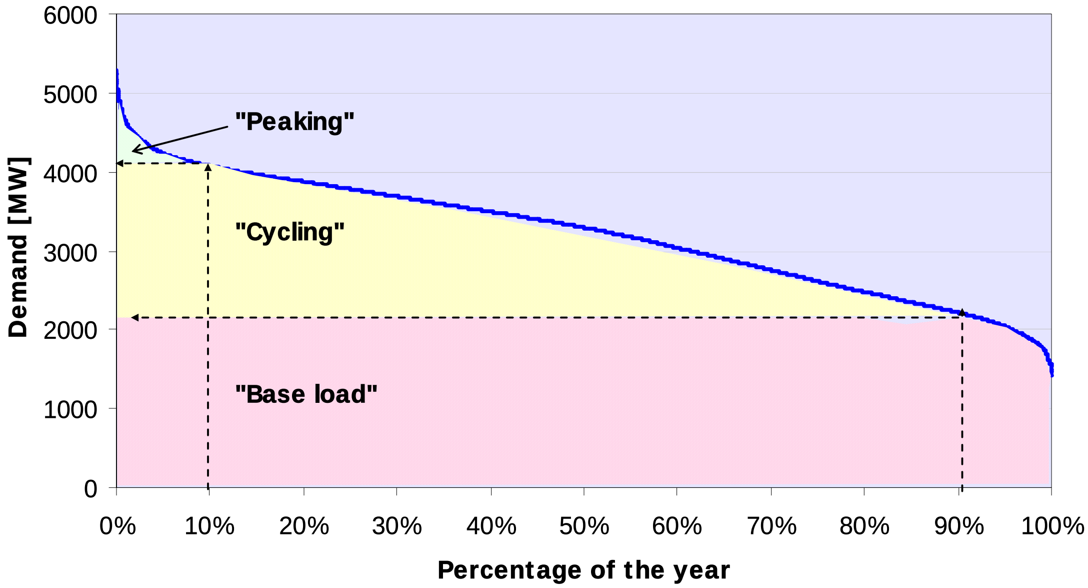

Figure 4-5 Load duration curve for dispatchable plant in 2010

5 INTERCONNECTION

5.1 Introduction

In this section information relating to the existing interconnection with Northern Ireland is provided. An assessment of the potential reliance that can be placed on this interconnection for generation adequacy purposes is outlined. The potential for further interconnection is then discussed. Finally comment is made on some of the technical and policy issues that should be taken into account if generation adequacy is to be considered on an 'All-Island' basis and a single Generation Adequacy Report adopted for the island.

5.2 Interconnector Data

The power system in the Republic of Ireland is connected to the Northern Ireland system via AC interconnectors. There is a 220/275 kV interconnector which connects Louth Station to Tandragee in Co. Armagh. In addition to the main 220/275 kV interconnector there are two 110 kV connections, one between Letterkenny and Strabane, and the other between Corraclassy and Enniskillen.

By the end of 2005 there is projected to be 1979 MW[24] of fully-dispatchable generation plant in Northern Ireland. This figure excludes a single 170 MW unit in Ballylumford which is contracted to ESB. These generators are located in three stations; Ballylumford, Kilroot and Coolkeeragh. Further to these fully-dispatchable generators there is approximately 126 MW of small-scale generation, mainly wind powered.

In addition to these generation resources, the Northern Ireland system is interconnected to Scotland. The interconnector from Moyle to Scotland is a two pole DC interconnector with a capacity of 450 MW.

The System Operator of Northern Ireland (SONI) has advised that, in Northern Ireland, the total peak winter demand in 2003/2004 was just under 1688 MW and the annual energy consumption in 2003 was 8,600 GWh. Demand is forecast to grow at a rate of just under 1.8% per annum.

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[24] In exported terms, i.e. generated less unit house load.

5.3 Interconnector-Reliance Scenario

The inputs required to assess the capacity benefits of interconnection are outlined in this section. There is a limit on the capacity benefit of the interconnector with Northern Ireland. This limit can arise from a lack of North-South transfer capability, limited surplus generation in the North, or consideration of the capacity deficit which would arise if the two systems were separated.

It has been assumed that the current contract for 170 MW (167 MW at point of import) of generation capacity in the North will continue until Autumn 2005. As discussed in Section 4.3, this capacity has already been included in the Republic of Ireland's portfolio, and must therefore be excluded from any 'interconnector-reliance' scenario.

At present the interconnector transfer capacity North to South offered to the market is 330 MW. This is known as the Net Transfer Capacity (NTC) of the interconnector, in the North-South direction. While flows in excess of 330 MW may occur for a period immediately after the loss of a generation unit in the Republic of Ireland, firm continuous trades[25] in excess of this amount are not allowed for system security reasons.

The likelihood of there being sufficient plant in the North to supply up to this 330 MW transfer limit was analysed. In addition, the consequences of system separation on the adequacy position in both jurisdictions, was considered. For this purpose, information relating to the installed capacity and projected demand growth has been provided by SONI. Conservative assumptions have been made in relation to plant availability in the North. From this analysis it was determined that a 300 MW capacity reliance on the interconnector was a reasonable scenario to illustrate its potential capacity benefit.

Therefore the 'interconnector-reliance' scenario will examine the effect of relying on the interconnector for an additional 133 MW up until October 2005 and for 300 MW thereafter. Alternatively under the extended contract scenario 'interconnector-reliance' implies an additional 133 MW until the end of 2011.

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[25] It is the physical power flow limit which constrains the contribution of interconnection to generation adequacy. The 'superposition' of commercial contracts is allowed on the interconnector. This will allow for example, a 430 MW trade North to South as long as there is at least a 100 MW trade occurring from South to North at the same time. In this way the commercial flows can exceed the NTC. However it is only the resultant or net import which can help to meet the supply demand balance.

5.4 Further Interconnection

In August 2004 Dermot Ahern TD, the then Minister for Communications, Marine and Natural Resources announced the Government's intention to press ahead with the development of two 500 MW interconnectors to Wales. A report from the Commission for Energy Regulation looking at the feasibility of all the interconnectors costs being borne by the private sector revealed that the Public Private Partnership or hybrid merchant/regulated model was the one favoured.

In November 2004, the Minister for Communications, Marine and Natural Resources, Noel Dempsey TD, and his Northern Ireland counterpart, Barry Gardiner MP, Minister for Enterprise, Trade and Investment reaffirmed their Governments' commitment to an All-Island energy market. As part of this process they endorsed the Regulatory Authorities' plans for a second North-South interconnector.

These interconnection projects are likely to have an impact on the long term Generation Adequacy position in Ireland. However national and international experience indicates that the planning, financing and development of such projects can take between seven and ten years to complete. Therefore the impacts of further interconnection are not considered within the timeframe of this report.

5.5 All-Island Adequacy

Following a consultation process an All-Island Energy Market Development Framework was published by the relevant government departments in each jurisdiction: the Department of Communications, Marine and Natural Resources in the Republic of Ireland and the Department of Enterprise, Trade and Investment in Northern Ireland, in November 2004. This framework sets targets for the *"co-ordinated release of GARs by TSOs with a common methodology used to determine requirements in both jurisdictions"* by 2007-2008, and the *"Publication of a single GAR"* in 2009-2010.

To achieve a single assessment of how much generation is required on the island of Ireland to meet the demand of all customers, both North and South, certain changes and agreements will have to be in put in place. Areas of potential change are outlined in the following sections.

5.5(a) Sources and limits of capacity benefit.

In general, two interconnected systems are able to maintain their required adequacy standard with less generation plant capacity than if they were isolated. If the two systems did not choose to reduce their plant capacity as a result of interconnection, each would experience a substantial improvement in its adequacy position, with, for example, LOLEs very much better than standard. By reducing capacity requirements, with the possibility of substantial cost savings, the LOLE can still be kept close to the required level. Effectively there is a choice between the extremes of accepting an improved reliability, but with no plant capital cost saving, or achieving a cost saving through omitting plant and keeping the reliability at its standard level.

The reliability improvement or capacity saving is possible because of the relatively low probability that the two systems will be short of plant at the same time. This means that the operators on each side will normally have the potential to support one another if required with additional capacity. There are potentially two reasons why this is so:

- diversity in peak demand
- non-coincidence of plant forced outages.

In the Irish situation, because both parts of Ireland share similar weather conditions and working practices, there is comparatively little benefit from diversity of peak demand.

The principal benefit here arises from non-coincidence of generation plant forced outages. Normally, serious risks of shortage would be expected for only a limited number of hours in the year. Since there is no reason to suppose any correlation between the probability of plant outages in RoI and NI, on most of these occasions the other side will have a satisfactory plant position and so be able to provide assistance.

The amount of capacity benefit ascribed to the interconnector can be limited by:

- concern over the adequacy position should the systems become separated;
- the reliance that the other system is placing on the interconnector;
- policy with regard to closure notice in both jurisdictions.

5.5(b) Stages in adequacy reliance

Three stages in adequacy reliance may be distinguished.

Stage 1: Informal assistance

With this type of co-operation, each side knows that it can ask the other for assistance when it faces a likely capacity shortage. Assistance would normally be given to the extent possible, taking account of both generation and transmission conditions at the time.

A feature of this stage is that neither side places any firm reliance on the other. Each side endeavours to attain its adequacy standard without such reliance, and effectively regards the possibility of assistance from its neighbour as a bonus. This is the current situation between RoI and NI.

The fact that no formal reliance is placed on the north/south interconnector by either side is largely due to its history. It was commissioned in 1970 and remained in operation until 1975 when it was forced out of service by malicious damage to several towers. The uncertain security situation prevented its restoration until 1995. Given that almost ten years of uninterrupted operation have now been achieved, it may be time to consider moving to a degree of adequacy reliance.

Stage 2: Reliance with a No Load-Loss Sharing (NLLS) Agreement

When there is a formal reliance agreement between two interconnected systems it would normally be expected that if one side was facing a shortage at a time when the other had sufficient surplus capacity to eliminate the shortage, then an urgent support flow would take place, subject only to any transmission restrictions.

However, it is important to clarify precisely what should happen when there is an overall deficit, that is, when one side has a deficit greater than the other's surplus, or both sides have a deficit. In these circumstances, a choice can be made between two policies: No Load-Loss Sharing (NLLS) and Load-Loss Sharing (LLS).

With NLLS, the strong system will help the weak one only to the extent of any surplus it may have. For example, suppose system A has a surplus of 100 MW at a time when system B has a deficit of 250 MW. Under NLLS, system A would export 100 MW leaving system A still able to meet its demand, and system B with a deficit of 150 MW.

With such a policy neither system ever puts itself into a deficit situation in order to help its neighbour. It is worth noting that with this policy it is not strictly necessary for each system to have the same adequacy standard.

In the Irish situation, it is likely that a NLLS policy would be regarded as a logical first step towards realising the potential adequacy benefits of an All-Island Energy Market. It avoids any danger of adverse public reaction to the possibility of power cuts in one system in order to help the other, and does not require any sensitive decisions on apportioning deficits in difficult circumstances.

Stage 3: Reliance with a Load-Loss Sharing (LLS) Agreement

A LLS policy would represent a further step in the integration of the adequacy policies of the two systems.

With LLS the objective is to share losses on an agreed basis, typically in proportion to demand. Suppose A's demand is twice B's, so that the objective is to share load loss in the ratio 2:1. With the same example as above, system A would now export 200 MW, leaving itself with a deficit of 100 MW, and system B with a deficit of 50 MW.

The distinctive feature of LLS is that each system is prepared to put itself into deficit in order to help its neighbour. With LLS it is essential that each system have the same adequacy standard, since all final shortages are seen as shortages in both systems, subject only to possible transmission constraints.

With such a policy in place in Ireland, the adequacy situation would be effectively the same as in a fully-integrated system. A deficit in one part of the island would be alleviated as far as possible by rescue flows; if these were insufficient the residual deficit would be spread across the island. The benefit, in comparison with NLLS, would be a reduction in the size of likely shortages.

All the adequacy studies referred to in the remainder of this section, and consequently all discussion of the feasible adequacy benefits to each side are on the basis of a NLLS policy. As stated above, this is considered to be the most likely next step in harmonising the approach to adequacy in the context of the All-Island Energy Market.

5.5(c) Reconciliation of adequacy standards

As outlined in section 2.2 the adequacy standard in RoI is an LOLE of 8 hours/year. The NI standard is expressed as a disconnection rate of 70 days in 100 years, or a voltage and frequency reduction rate of 140 days in 100 years.

As well as the apparent difference in the way the two standards are expressed, there are also important differences in the way they are implemented. In order to make a valid comparison it is necessary to reconcile all of these differences.

The RoI standard of 8 hours/year is calculated over all the half-hours of the year. The demand used in the calculation of the LOLE is the unrestricted demand, that is, the demand before any loads have been interrupted and before any voltage or frequency reduction.

The NI standard is calculated over the top 50 days of the year, and only for the peak loads on those days. Since the analysis is confined to the winter period, it is therefore not normally necessary to estimate scheduled outages for NI adequacy analysis, and so their inclusion in an RoI type analysis would introduce a new factor.

The NI target is to achieve 70 days per 100 years where the load will be interrupted after allowing for voltage and frequency reduction, or in an alternative formulation, 140 days per 100 years when voltage and frequency reduction will be required. The latter value, being closer to the RoI concept of failure to meet the unrestricted demand, is therefore more appropriate for comparison with the RoI standard. Another difference in the implementation of the NI standard is that it is applied after the effect of contracted demand reduction has been allowed for. These differences would have to be reconciled prior to the adoption of a single All-Island generation adequacy standard. As the adoption of a new single standard would have consequences for all electricity customers, it is likely that such a decision would require input and agreement from policy makers in both jurisdictions.

6 RESULTS

6.1 Introduction

A key function of this report is to assess how much generation plant is required to meet customer demand in future years. By combining the input data (as described in sections 3 through 5) and the methodology and models (outlined in section 2 and Appendix 3), a large number and range of potential answers, to this apparently simple question, emerge. A comprehensive range of results is required to deal with the obvious uncertainty associated with the future. This range of results is obtained by combining assumptions under the categories:

- demand growth
- plant availability
- status of short term capacity contracts
- interconnector reliance
- demand side management.

The publication of a comprehensive set of results allows the user of this report to identify their own preferred set of input assumptions (or scenario) and to readily establish what the resultant plant requirement would be. By comparing a number of such scenarios, the sensitivity of results to any given input can also be easily examined. This information may be of particular relevance for those wishing to evaluate the risks associated with long term projections. For example, the consequences of moving from median to high demand growth scenario can be quickly identified.

Therefore the full range of results is presented in this section with the numerical values contained in Appendix 4. In the remainder of this section some significant results are extracted from this range and discussed.

Throughout this section results are presented in approximated additional plant requirement terms. This form of presentation, while an approximation, is more readily understandable than results presented in the form of LOLE tables.

6.2 The Complete Set of Results

From the analyses completed, Figure 6-1 shows the full range of potential supply surpluses or deficits.

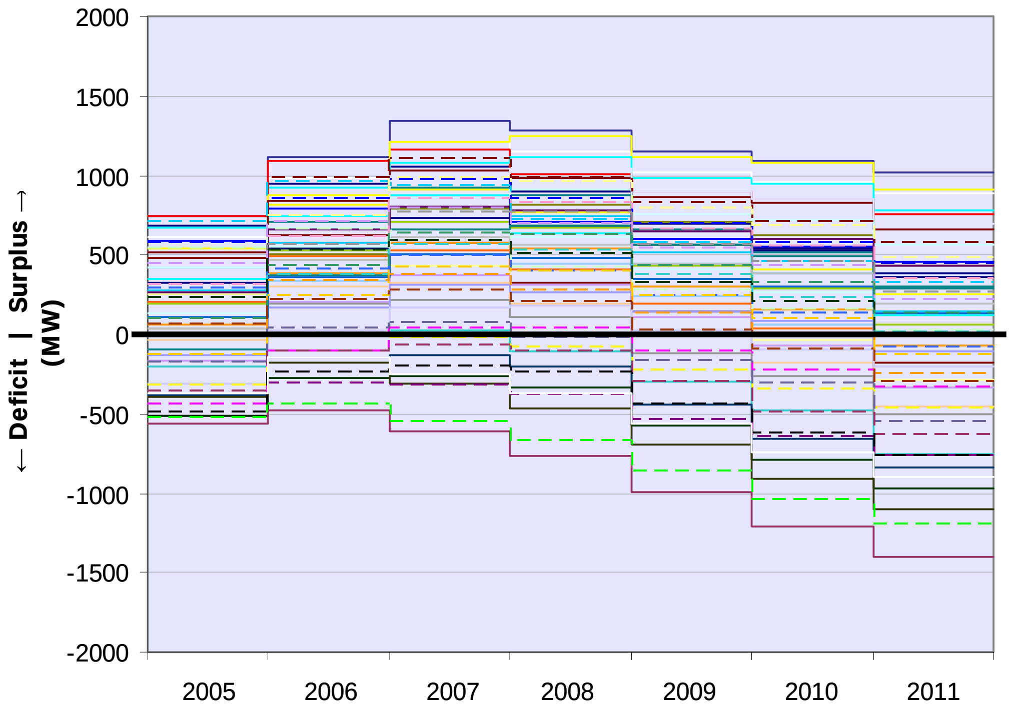

Figure 6-1 Resulting surplus/deficit from all scenarios

Each of the 60 lines represents a scenario which is formed by combining projections of generator availability, demand growth, interconnection reliance and the option of extending capacity contracts. It can be seen that surpluses reach 1350 MW in 2007 under the most benign scenario and plummet to a deficit of 1400 MW by 2011 in the most arduous scenario. The most benign scenario is formed by taking mid-benchmark plant availability, low demand growth, high reliance on the interconnector and assuming that all capacity contracts are extended. The most arduous scenario considers 'current 77%' plant availability continuing, high demand growth, no reliance on the interconnector and non-extension of capacity contracts.

While the majority of scenarios show that there will be a supply surplus, rather than shortages, it is important to consider more carefully the consequences of scenarios which have a higher probability of occurrence.

6.3 Using the Full Table of Results

While Figure 6-1 illustrates graphically the full range of results, due to the volume of information to be presented, the full results set is given in tabular form in Appendix 4. In these tables, results are presented under five categories. Under each category there are a number of cases as illustrated in Table 6-1, where each is given an index code.

Category	**Case**	**Index code**
Demand Growth	Low	G_1
See Section 3.3(e)	Median	G_2
	High	G_3
Availability	Current (77%)	A_1
See Section 4.5(e)	Generators' Low	A_2
	Generators' Median	A_3
	Generators' High	A_4
	Mid-benchmark	A_5
Capacity	As Notified	C_1
See Sections 4.3 and 4.4	Extended Contracts	C_2
Interconnection	No Reliance	I_1
See Section 5.3	Reliance (300 MW)	I_2
Demand Side Management	Existing	D_1
See Section 3.6(a)	Enhanced	D_2

Table 6-1 Index codes for different cases

Results for any desired combination (such combinations are referred to as scenarios in this report) can be obtained from Appendix 4. For illustrative purposes an extract from this appendix is shown in Table 6-2. Using the index codes, it can be seen that for median demand growth (G_2), current availability (A_1), capacity as notified (C_1), no dependence on the interconnector (I_1) and the existing level of demand side management (D_1), the deficit in 2007 is 550 MW.

					2005	2006	2007	2008	2009	2010	2011
G_2	A_1	C_1	I_1	D_1	-530	-442	-550	-674	-859	-1046	-1197
				D_2	-516	-430	-536	-660	-845	-1030	-1181
			I_2	D_1	-491	-241	-201	-243	-438	-624	-768
				D_2	-479	-229	-189	-231	-426	-610	-754
		C_2	I_1	D_1	-358	-108	-68	-110	-305	-491	-635
				D_2	-346	-96	-56	-98	-293	-479	-621
			I_2	D_1	-12	338	377	280	128	-14	-251
				D_2	0	348	387	290	138	-2	-239

Table 6-2 Extract from results table

6.4 Generator Availability and TSO Demand Growth Scenarios

In this section, the variation in results when plant availability varies from the low to the high generator predicted values are examined. The impact of demand growth following the three different demand growth scenarios is also illustrated. For these results there is consistently no dependence on interconnection, no extension of the short term contracts, and no enhanced DSM measures.

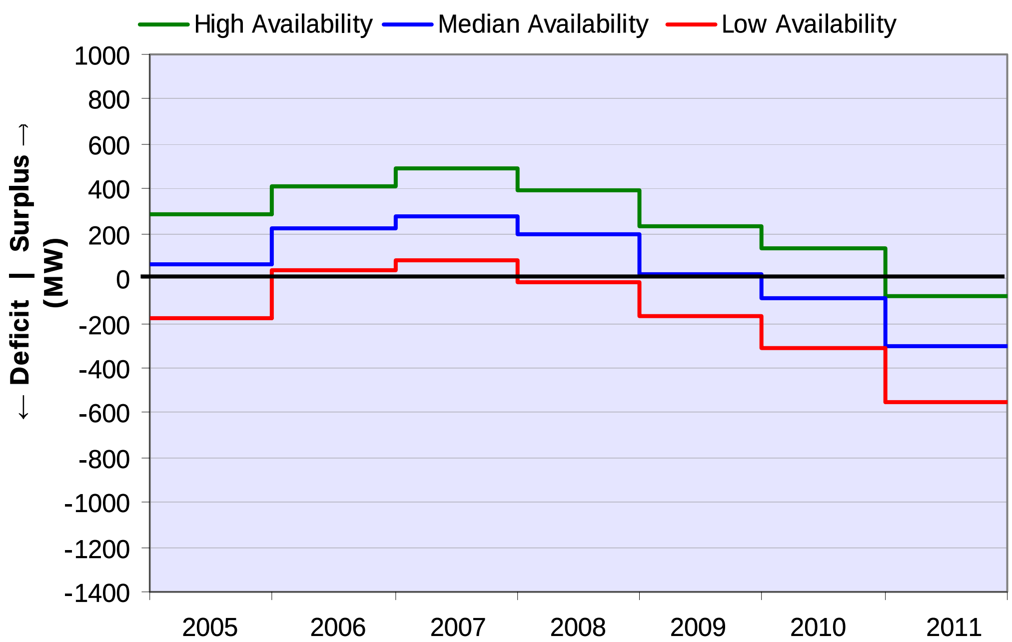

Figure 6-2 Generator predicted availability scenarios, with median demand

Figure 6-2 illustrates that under the median demand growth scenario, if even the generators' low availability projections could be achieved then (apart from an immediate deficit in 2005) an additional supply requirement is not apparent until 2009. Options for dealing with the post 2009 supply requirement would include dependence on the interconnector or new plant build. These conclusions are drawn from scenarios with the demand growth fixed at the median scenario.

The impact of different demand growth scenarios, while keeping availability constant, is illustrated in Figure 6-3. It can be seen that the more demanding impact of high growth is not apparent until the later years. This is to be expected as the high demand growth forecast used in this report has an annualised growth rate which is just 0.5 percentage points greater than the median scenario. Therefore conclusions drawn by keeping demand growth fixed at the median, are not significantly affected by consideration of the high rather than median demand growth forecast.

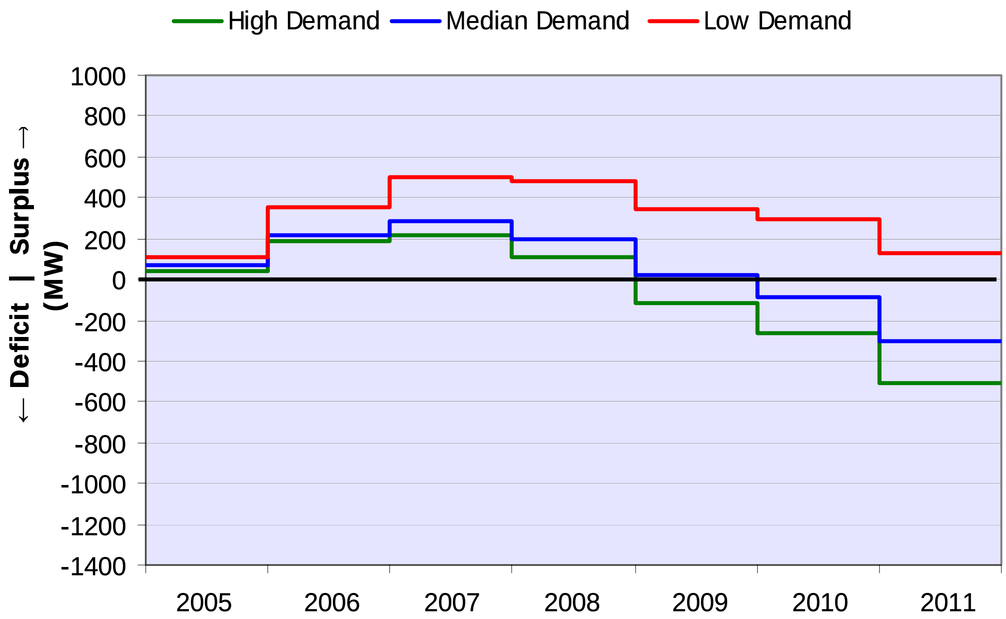

Figure 6-3 Different demand scenarios, with generator-predicted median availability

Accepting that the dominant messages can be extracted by utilisation of the median demand growth projection alone allows for simplified presentation and analysis of results without sacrificing substantial accuracy. Indeed, median demand is assumed in the presentation of results in the remainder of this section. It should be noted, however, that the unique results for all scenarios are to be found in Appendix 4.

6.5 Current Availability (77%) Persists

As currently experienced availability levels are substantially outside the envelope projected by generators, it is important to consider the consequences of availability remaining at 77%.

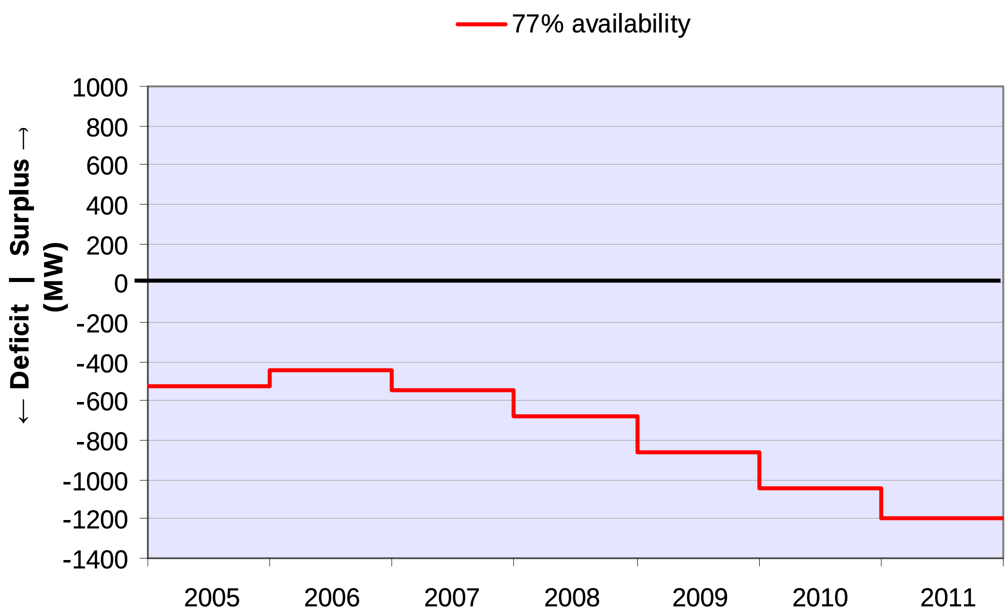

Figure 6-4 Current 77% availability, with median demand

The results under this scenario indicate large plant deficits in the range of 500 to 1200 MW over the period of the study. Initially there is a large deficit of 500 MW in 2005. This is moderated in 2006 by the forecast completion of generation plant currently under construction. Plant deficits increase thereafter. Significant remedial actions would be required to deal with the magnitude of deficits present for all years under this scenario.

The impacts of such potential remedial actions are now examined.

6.5(a) Extension of capacity contracts

Extending the five contracts (four 51 MW peaking units and the NIE capacity contract for 167 MW) to 2011 would lead to a considerable reduction in plant deficits. However the remaining deficit would still be significant, as indicated in Figure 6-5. The deficits in 2005 are not materially improved as only the NIE contract was due to lapse in 2005, and then only in October of that year. The deficits in 2006 to 2008 are in the range of 200 to 250 MW. From 2009 on there is a persistent deterioration in the situation until deficits of approximately 800 MW are reached in 2011.

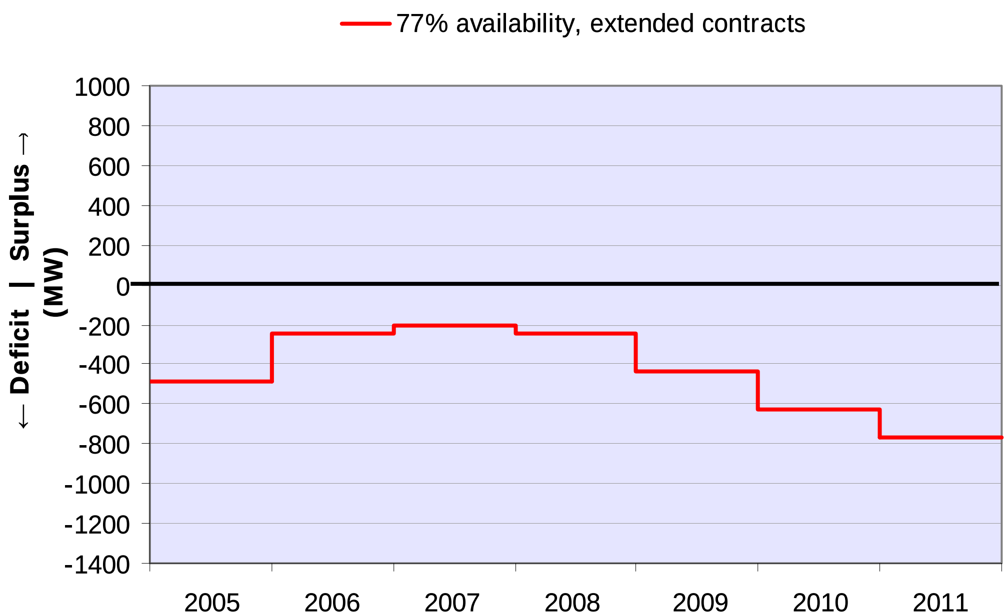

Figure 6-5 Current 77% availability, with median demand and extension to contracts

6.5(b) Extension of capacity contracts and high interconnector reliance

As discussed in section 5, if it becomes policy to place a long term capacity reliance on the North-South interconnector, current technical analysis would suggest that it is feasible for the Republic of Ireland to rely on Northern Ireland for up to 300 MW. It should be noted that this is translated to a net improvement of 133 MW, as the NI contract for 167 MW is also in place under this scenario. By adding in this high reliance it can be seen from Figure 6-6 that modest deficits in the order of 100 MW occur from 2006 to 2008. In 2009 significant supply shortages are likely even with the deployment of these remedial measures. The only options remaining at this stage would be to build new generation plant and/or improve availability.

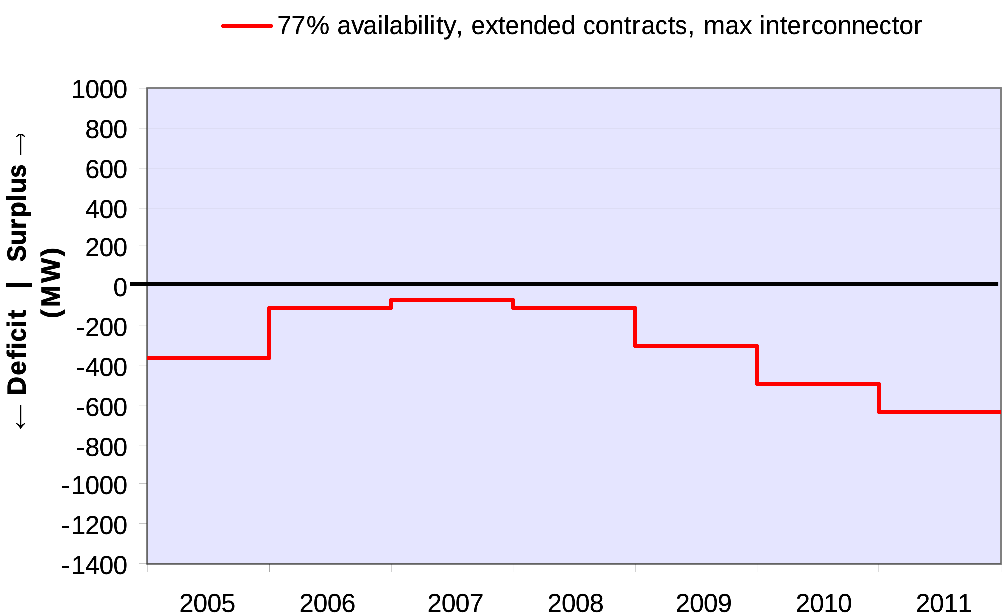

Figure 6-6 Current 77% availability, with median demand, extension to contracts and 300 MW reliance on the interconnector

6.6 Mid-Benchmark Availability

The consequences of improved availability are now examined. If mid-benchmark availability could be achieved then the results indicate that no new plant, extension of contracts or dependence on the interconnector would be required over the period of this study. Indeed, surpluses of approximately 600 MW would be experienced in the short to medium term.

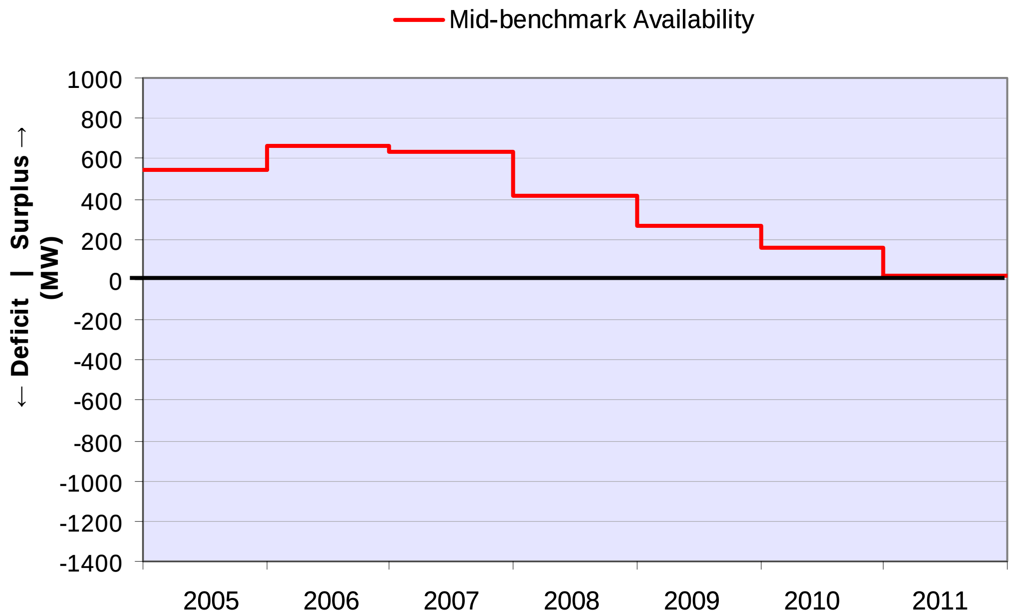

Figure 6-7 Mid-benchmark availability with median demand

6.7 Enhanced DSM

As detailed in section 3.6(a), a further study was carried out to assess the impact of an extra 40 MW of WPRDS, and the extension of the WPDRS scheme into March. The equivalent capacity contribution of enhanced DSM to system adequacy is related to the actual surplus/deficit before the extra DSM was applied. Table 6-3 lists these benefits.

Range of surplus / deficit (MW)	Benefit of additional 40 MW of WPDRS and extension of scheme for 1 month
1000 to 1500	6
500 to 1000	8
0 to 500	10
-500 to 0	12
-1000 to -500	14
-1500 to -1000	16

Table 6-3 Benefits of extra DSM

6.8 Comparison with Generation Adequacy Report 2004-2010

In *GAR 2004-2010* a deficit of 622 MW was forecast for 2007 if plant availability remained at 78% and demand followed the high growth scenario. As the winners of the CER Capacity 2005 Competition were unknown at the time this forecast was based on two 265 MW units being successful. The current forecast for a similar scenario, based on 77% availability and the actual competition winners, is a deficit of 609 MW in 2007. These results are quite close which is to be expected as other major inputs such as plant availability and demand growth are not dissimilar.

It can be seen from Figure 6-8 and Figure 6-9 that both reports have similar deficits up to 2008. By comparing the low availability scenarios between 2008 and 2010, it can be seen that the current projections are more benign due to the inclusion of an additional 400 MW unit from mid 2007.

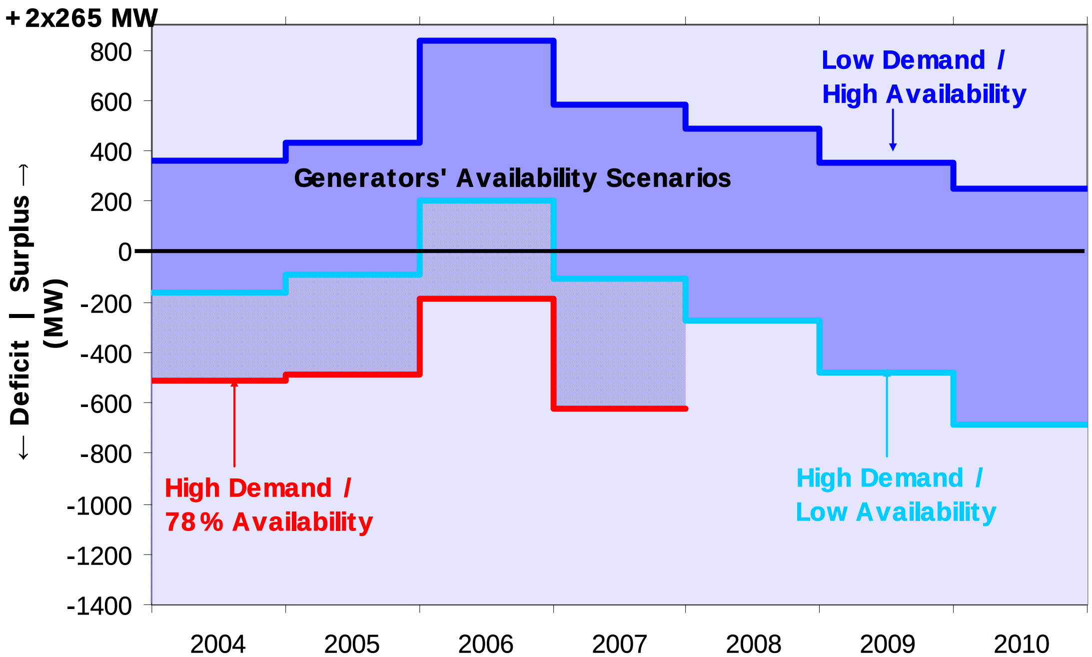

Figure 6-8 Results from GAR 2004-2010 with two 265 MW units as the competition winners

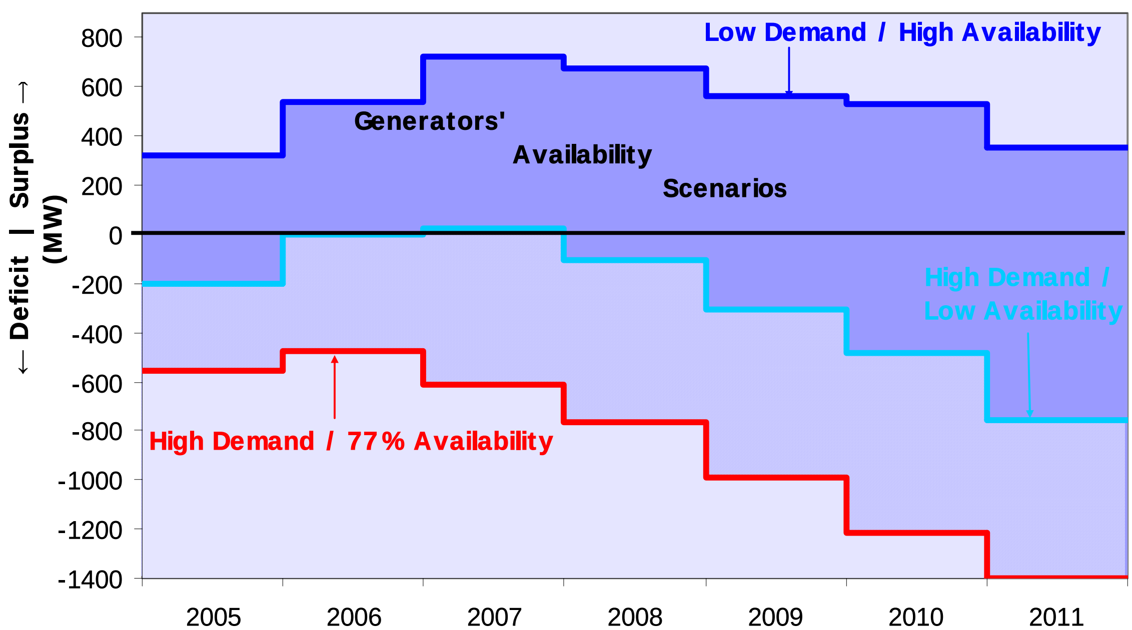

Figure 6-9 Results from GAR 2005-2011

7 COMMENT AND DISCUSSION

7.1 Current Availability

Plant availability still remains the dominant factor affecting system adequacy, and far outweighs other factors such as variations in demand. At the current poor availability levels, and without the extension of short term capacity contracts or reliance on interconnector, deficits in the range of 500 to 1200 MW are likely to prevail over the period 2005 to 2011. These deficits are first evident in 2005, decreasing marginally with the addition of new capacity in 2006, but increasing again in the longer term.

The previous GAR highlighted the central role of poor plant availability in bringing down the overall system adequacy. Yet over the past year the system availability has shown only a marginal improvement; see Figure 4-2. The 'current' scenario is based on 77% availability, which is lower than the equivalent scenario in the last GAR.

Despite the addition of three new large generation stations over the next three years (Aughinish, Tynagh and Huntstown 2 will contribute over 900 MW), the adequacy of the system will still be below standard if system availability remains at the current levels. The magnitude of the shortfall in the future will depend largely on what actions are taken to improve the availability situation, and any additions to the expected plant portfolio.

The current system availability is materially below what the generators themselves predict in their *generator-predicted low* availability scenario (80.5% in 2005). Recent history would suggest that even with a major effort, it is difficult to improve system availability in a short timeframe and to maintain it at that level.

Options for dealing with this deficit may include the extension of the current short term capacity contracts (Additional Peaking Capacity Plant and the NIE contract) and reliance on the interconnector up to a value of 300 MW. If these options were exercised and the planned new generation comes online as forecast, the deficits are not likely to exceed 100 MW in 2006, 2007 and 2008.

7.2 Improved Availability

If the availability is improved and can be maintained at the level of the generator-predicted low availability scenario, then the system would be returned to standard until 2009. This assessment is also based on the assumption that the planned new generation arrives on time.

However in 2009 our analysis indicates that the system would be back in deficit to the order of 170 MW. This shortfall could be prevented by new build (conventional plant or peaking capacity plant) or though higher reliance on interconnection.

Without any extra intervention, (i.e. just the improvement in Availability to the *generator-predicted low* availability scenario) the deficits would be of the order of 550 MW by 2011. As this is greater than the potential capacity benefit of the interconnector new plant build would be required.

If availability can be improved to the level suggested by the TSO's benchmarking study, no new generation plant, reliance on the interconnector or extension of short term capacity contracts would be required over the study period.

Table 7-1 below summarises the system adequacy position over the next seven years, highlighting the important role played by generator availability. Depending on the availability performance of the plant portfolio, different options may be exercised in the future to cope with supply/demand imbalance.

	Potential scenarios		
Year	**Availability remains at current level (77%)**	**Availability improves to generator predicted values (80.7% to 88.5%)**	**Mid-benchmark availability. (88%)**
	Consequences / Options		
2005	• Short term measures • High reliance on interconnector	• Short term measures • High reliance on interconnector	No action required
2006-2008	• High reliance on interconnection • Extend capacity contracts • New plant build	• No action required	
2009-2011	• New plant build	• New plant build • High reliance on interconnector	

Table 7-1 Actions required under various scenarios.

7.3 Capacity Margin

While there are significant drawbacks in using capacity margin to determine generation adequacy, examining the outcome in terms of the resulting capacity margin[26] can be informative.

For example, under the current availability, median demand growth scenario the resulting capacity margin is 48% by 2011. In other words plant capacity would have to be 148% of peak demand in order to meet the adequacy standard. In absolute terms this would mean that the installed plant capacity would exceed peak demand by 2778 MW. This very large margin is largely driven by low plant availability. The increasing penetration of wind generation also has the effect of increasing the capacity margin.

[26] For different scenarios the resulting capacity margin is determined by converting LOLE results into a plant deficit/surplus and then calculating the ratio of installed capacity plus the plant deficit to the peak demand, see Glossary.

By way of contrast, under the most benign scenario of mid-benchmark availability, low demand growth, extension of contracts and high dependence on the interconnector there is a plant surplus of approximately 1000 MW in 2011. This implies that under these circumstances the capacity margin would reduce to 17%.

The resulting capacity margin therefore varies widely depending on the scenario considered. A 48% capacity margin would be considered to be high. However, a survey of current capacity margins in other European countries indicates that there is no standard or correct value. For example, in 2003 the capacity margin in Finland was 18% while it was 100% in Denmark. It is interesting to note that countries with large levels of wind penetration also have high capacity margins, for example, Spain (71%) and Denmark.

7.4 New Plant Characteristics

While this report indicates the total amount of additional capacity which would be required under a number of plausible scenarios, consideration should also be given to the type and size of generation unit used to satisfy this requirement. An ever increasing number of large, highly efficient but inflexible combined cycle gas turbines are being installed in Ireland. In addition there is to be increased levels of wind power generation which by its variable and intermittent nature requires flexibility from other generation sources within the overall portfolio. Therefore, in the interest of maintaining system security, the opportunities for flexible responsive plant should be examined.

All of the above analysis is based on the planned plant portfolio detailed earlier in the report. Any changes to this plan (late delivery of new generation, decommissioning or de-rating of existing plant) would affect the adequacy studies. Sufficient advance notice of plant closures is critical as the amount of time required to plan, develop and commission new generation and transmission infrastructure can be well in excess of the current plant closure notification period of 24 months. If new generation is to make its full contribution to generation adequacy, the transmission system must be developed in tandem. Therefore developers should give careful consideration to the capability of the transmission system before choosing a site for new generation. In addition, information on the location of new generation plant should be provided to the TSO at the earliest possible stage.

7.5 Conclusion

From the beginning of 2002 until mid 2004 there has been a persistent and significant decrease in the annual availability performance of the generation portfolio. Low plant availability is the dominant factor which is driving the plant deficit forecast over the next seven years. While a recent upward trend in availability is to be welcomed, the sustainability of this improvement is as yet uncertain. If this improvement is not sustained any reduction in system availability would result in greater deficits, and greater risk of supply not being able to meet demand. As a rough approximation, every 1% increase in the forced outage rate will result in a loss of 100 MW of system adequacy.

In conclusion, the prospects for generation adequacy in Ireland over the next seven years range from good to poor, largely depending on whether or not plant availability can be properly incentivised, improved and maintained.

GLOSSARY

CAPACITY MARGIN

The percentage excess of installed generation capacity (without regard to actual availability) over annual peak demand.

$$\text{CapacityMargin} = \left[\frac{\text{InstalledCapacity}}{\text{Peak Demand}} - 1\right] \times 100$$

FORCED OUTAGE PROBABILITY (FOP)

This is the statistical probability that a generation unit will be unable to produce electricity for non-scheduled reasons, due to the failure of either the generating plant or supporting systems. Periods when the unit is on scheduled outage are not included in the determination of forced outage probability.

GENERATION ADEQUACY

The ability of all the generation units connected to the electrical power system to meet the total demand imposed on them at all times. The demand includes transmission and distribution losses in addition to customer demand.

GIGAWATT HOUR (GWh)

Unit of energy

1 gigawatt hour
= 1,000,000 kilowatt hours
= 3.6 x 10^{12} joules

GROSS DOMESTIC PRODUCT (GDP)

Value of the output of all goods and services produced within a nation's borders, normally given as a total for the year. It thus includes the production of foreign owned firms within the country, but excludes the income from domestically owned firms located abroad.

LOSS OF LOAD EXPECTATION (LOLE) hours/year

The mathematical expectation of the number of hours in the year during which the available generation plant will be inadequate to meet the instantaneous demand.

MEGAWATT (MW)

Unit of power

1 megawatt
= 1,000 kilowatts
= 10^6 joules / second

PEAK CARRYING CAPABILITY (PCC)

The PCC of the total generation capacity of a system is the measure in MW of the system annual peak demand which it can meet, to a given adequacy standard and with a given annual demand profile.

PERSONAL CONSUMPTION OF GOODS AND SERVICES (PCGS)

Personal consumption is a measure of consumer spending on goods and services. It includes such items as food, drink, cars, holidays, etc.

SYSTEM AVAILABILITY

System availability is calculated according to the formula.

$$\text{S.A.} = \frac{\sum_{i=1,n} \text{A}i \times \text{C}i}{\sum_{i=1,n} \text{C}i}$$

n = number of generation units in the system

$$\text{A}i = (1 - \text{SOD}i) \times (1 - \text{FOP}i)$$

Ai = Availability of generation unit i

SODi = Scheduled outage duration of unit i, as fraction of year

FOPi = Forced outage probability of unit i

Ci = Capacity of unit i

APPENDIX 1 DEMAND FORECAST

Year	GDP Forecast (€m at constant 1995 prices)	GDP Growth year-on - year (%)	PCGS Forecast (€m at constant 1995 prices)	PCGS Growth year-on-year (%)	Total Electricity Requirement TER[27] (GWh)	Electricity Demand Growth year-on-year (%)	Peak Generation (Exported) (MW)
	High Demand Forecast						
2005	109,066	6.7	50,988	3.9	26,808	4.5	4633
2006	116,616	6.9	53,079	4.1	28,052	4.6	4839
2007	124,190	6.5	55,550	4.7	29,331	4.6	5052
2008	132,299	6.5	58,411	5.1	30,698	4.7	5281
2009	141,255	6.8	61,315	5.0	32,151	4.7	5526
2010	149,142	5.6	64,363	5.0	33,535	4.3	5760
2011	155,148	4.0	67,526	4.9	34,737	3.6	5962
	Median Demand Forecast						
2005	107,570	5.2	50,918	3.8	26,647	3.8	4608
2006	114,636	6.6	52,875	3.8	27,829	4.4	4803
2007	121,451	5.9	54,904	3.8	28,987	4.2	4994
2008	128,573	5.9	57,096	4.0	30,188	4.1	5193
2009	135,444	5.3	59,512	4.2	31,381	3.9	5391
2010	142,154	5.0	61,768	3.8	32,568	3.8	5590
2011	146,923	3.4	64,056	3.7	33,559	3.0	5755
	Low Demand Forecast						
2005	106,240	3.9	49,788	1.5	26,403	2.9	4559
2006	110,975	4.5	49,257	-1.1	27,107	2.7	4668
2007	114,912	3.5	48,204	-2.1	27,675	2.1	4753
2008	120,067	4.5	49,211	2.1	28,561	3.2	4895
2009	125,186	4.3	50,842	3.3	29,498	3.3	5048
2010	129,655	3.6	51,471	1.2	30,300	2.7	5178
2011	132,828	2.4	53,137	3.2	31,067	2.5	5302

Table A-1 Electricity demand growth scenarios. Economic projections are based on ESRI forecasts. The following values are assumed for 2004:

- GDP 102,253 €m
- PCGS 49,054 €m
- TER 25,664 GWh
- Peak Demand 4448 MW

[27] Total Electricity Requirement, this is stated at the generator exported level and includes an estimate of self-consumption (i.e. own-use by CHP plant).

	Historic (%)	GAR 2004-2010 (%)	GAR 2005-2011 (%)
1996	7.0		
1997	4.9		
1998	6.7		
1999	5.8		
2000	7.0		
2001	4.8		
2002	1.9		
2003	3.5	2.6	
2004		2.9	3.7
2005		4.1	3.8
2006		4.4	4.4
2007		4.1	4.2
2008		4.1	4.1
2009		3.9	3.9
2010		3.8	3.8
2011			3.0

Table A-2 Historical TER growth and comparison of median forecasts from GAR 2004-2010 and GAR 2005-2011

Year	Total Electricity Sales (GWh)	Winter Peak Demand, exported, excluding self consumption (MW)
1995	14,699	2914
1996	15,707	3080
1997	16,410	3175
1998	17,440	3407
1999	18,648	3614
2000	19,646	3772
2001	20,821	3909
2002	21,209	4238
2003	21,965	4179

Table A-3 Historical sales and winter peak demand

APPENDIX 2 PLANT CAPACITY

Generation Plant Capacity (MW)										
Station	ID	Fuel Type	Export Capacity (MW)							
		At year end:	2004	2005	2006	2007	2008	2009	2010	2011
Fully-Dispatchable Plant										
Moneypoint	MP1	Coal/HFO	287.5	287.5	287.5	287.5	282.5	282.5	281.5	281.5
	MP2	Coal/HFO	287.5	287.5	287.5	282.5	282.5	282.5	281.5	281.5
	MP3	Coal/HFO	287.5	287.5	282.5	282.5	282.5	282.5	281.5	281.5
Poolbeg	PB1	Gas/HFO	109.5	109.5	109.5	109.5	109.5	109.5	109.5	109.5
	PB2	Gas/HFO	109.5	109.5	109.5	109.5	109.5	109.5	109.5	109.5
	PB3	Gas/HFO	242	242	242	242	242	242	242	242
	PBC	Gas/DO	460	460	460	460	460	460	460	460
Aghada	AD1	Gas	258	258	258	258	258	258	258	258
	AT1	Gas/DO	90	90	90	90	90	90	90	90
	AT2	Gas/DO	90	90	90	90	90	90	90	90
	AT4	Gas/DO	90	90	90	90	90	90	90	90
Aughinish Alumina	SK3	Gas/DO	0	75	75	75	75	75	75	75
	SK4	Gas/DO	0	75	75	75	75	75	75	75
Huntstown	HN0, HN1	Gas/DO	343	343	343	343	343	343	343	343
Huntstown 2	HN2, HN3	Gas/DO	0	0	0	400	400	400	400	400
Marina	MRT	Gas/DO	112	112	112	112	112	112	112	112
North Wall	NW4	Gas/DO	163	163	163	163	163	163	163	163
	NW5	Gas/DO	109	109	109	109	109	109	109	109
Tynagh	TY	Gas/DO	0	0	382	382	382	382	382	382
Dublin Bay	DB1	Gas	409	409	409	409	409	409	409	409
Gt. Island	GI1	HFO	54	54	54	54	54	54	54	54
	GI2	HFO	54	54	54	54	54	54	54	54
	GI3	HFO	108	108	108	108	108	108	108	108
Tarbert	TB1	HFO	54	54	54	54	54	54	54	54
	TB2	HFO	54	54	54	54	54	54	54	54
	TB3	HFO	241	241	241	241	241	241	241	241
	TB4	HFO	241	241	241	241	241	241	241	241
Bellacorrick	BK1	Peat	18	0	0	0	0	0	0	0
	BK2	Peat	19	0	0	0	0	0	0	0
Edenderry	ED1	Peat	118	118	118	118	118	118	118	118
Lough Ree Power	LR4	Peat	91	91	91	91	91	91	91	91
West Offaly Power	WO4	Peat	0	137	137	137	137	137	137	137
NIE Contract			167	0	0	0	0	0	0	0
Aghada APC	AP5	DO	51	51	51	0	0	0	0	0
Tawnaghmore APC	TP1	DO	51	51	51	0	0	0	0	0
Rhode APC 1	RP1	DO	51	51	51	0	0	0	0	0
Rhode APC 2	RP2	DO	51	51	51	0	0	0	0	0

Generation Plant Capacity (MW)										
Station	**ID**	**Fuel Type**	**Export Capacity (MW)**							
		At year end:	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Fully-Dispatchable Plant (continued)										
Ardnacrusha Hydro	AA1, AA2, AA3, AA4	Hydro	89	89	89	89	89	89	89	89
Erne Hydro	ER1, ER2, ER3, ER4	Hydro	65	65	65	65	65	65	65	65
Lee Hydro	LE1, LE2, LE3	Hydro	27	27	27	27	27	27	27	27
Liffey Hydro	LI1, LI2, LI4, LI5	Hydro	38	38	38	38	38	38	38	38
Turlough Hill	TH1, TH2, TH3, TH4	Hydro	292	292	292	292	292	292	292	292
Partially/Non-Dispatchable Plant										
Wind		Renewable	371	756	831	866	902	938	974	1010
Hydro		Renewable	21	22	23	24	25	26	27	28
Biomass		Renewable	24	28	32	36	40	44	48	52
CHP		---	145	152	162	172	182	192	202	212
Industrial[28]		---	9	9	9	9	9	9	9	9
Total			**5952**	**6432**	**6899**	**7140**	**7186**	**7237**	**7285**	**7336**

Table A-4 Generation plant capacity, for the base case assumptions

- HFO=Heavy Fuel Oil
- DO=Distillate Oil
- APC=Additional Peaking Capacity
- CHP=Combined Heat and Power

[28] This is an estimate of the effective capacity of industrial generation, see section 4.4(a).

	Wind Farm	Capacity (MW)
Transmission Connected	Golagh	15
	Kingsmountain	23.75
	Subtotal	**38.75**
Distribution Connected	Anarget	1.98
	Arklow Banks	25.2
	Beale	4.2
	Beenageeha	3.96
	Bellacorick	6.45
	Black Banks	3.4
	Burtonport Harbour	0.66
	Cark	15
	Carnsore	11.9
	Corneen	3
	Corrie Mountain	4.8
	Crockahenny	5
	Cronalacht	4.98
	Cuillalea	3.4
	Culliagh	11.88
	Curabwee	4.62
	Curraghgraigue	2.55
	Drumlough Hill	4.8
	Inis Mean	0.68
	Inverin (Knock South)	3.3
	Kilronan	5
	Largan Hill	5.94
	Meenadreen	3.4
	Meenanilta I	2.55
	Mienvee	0.66
	Milane Hill	5.94
	Raheen Barr	18.7
	Sonnagh Old	7.65
	Spion Kop	1.2
	Tursillagh	15
	Tursillagh	6.8
	Subtotal	**194.60**
	TOTAL	**233.35**

Table A-5 Existing wind farms

APPENDIX 3 SUPPLEMENTARY NOTES ON METHODOLOGY

Loss Of Load Expectation (LOLE)

A computer program CREEP (Capacity Requirement Evaluation by Exact Probability) is used to calculate LOLE. With an hourly load model as used in CREEP, the loss of load expectation (LOLE) is the expected number of hours in the year when the available generation plant is less than the load[29].

The annual LOLE is the sum of the contributions from each hour. In general:

Expectation = Probability x Outcome

Eg. A 10 MW generation unit has a forced outage probability (FOP) of 1% in hour j. In other words, there's a 1% probability that the outcome will be 'failure to meet load of 10 MW', so

Expectation in hour j = 0.01 x '*failure*' = 0.01 hours of failure = 36 seconds of failure

The Loss Of Load Expectation in hour j is 36 seconds, i.e. in hour j, we expect that the unit will fail to meet the load for 36 seconds. If the unit and the load maintain the same characteristics over the course of a year, each hour of the year will contribute 36 seconds to give a total LOLE for the year of:

36s x 24 x 365 = 87.6 hours

The sum of all the hourly expectations of failure gives the annual LOLE in hours.

In reality, a power system will consist of many different generators with different FOPs, and the load will vary each hour. Consider now the simplest case of a single-system study, with a deterministic load model (that is, with only one value used for each load), and no scheduled maintenance, so that there is one generation availability distribution for the entire year. If

L_{hd} = load at hour h on day d

[29] Although this is sometimes called the loss of load probability (LOLP), the latter term should be reserved for dimensionless probability values, such as the average probability of deficiency over a given number of trials.

G = generation plant available

H = number loads/day to be examined (i.e. 1, 24 or 48)

D = total number of days in year to be examined

then the annual LOLE is given by

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

This equation is used in the following practical example.

Simplified example of LOLE calculation

Consider a system consisting of just three generation units, as in Table A-6.

	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-6 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-7 Probability table

The probability for each state to occur is calculated by multiplying together the probabilities for each generating unit, e.g. for state 5, unit A is available (0.95 probability), unit B is available (0.92 probability), while unit C is forced out (0.10 probability). These are multiplied together to give 0.0874.

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

This analysis would be carried out for the system to meet the load at every hour of the year, and the individual contributions added up to get the overall yearly LOLE.

If scheduled maintenance is allowed for, a different generation availability distribution is used for each hour. Otherwise the procedure is the same.

Peak Carrying Capability (PCC)

PCC is derived as follows. An adequacy standard is specified in terms of LOLE. A new factor, F_p, is introduced which is multiplied by the load L_{hd} (for every hour) such that the required LOLE is achieved.

$L_{hd}' = F_p \times L_{hd}$

If the LOLE had been outside standard, then the load would be reduced proportionally until the generation available could meet it. If the LOLE had been less than the standard, then the load would be increased until the LOLE equalled the standard.

PCC is defined as the original peak load multiplied by this new factor.

$\text{PCC} = F_p \times L_{peak}$

The difference between the original peak load and the PCC is the surplus/deficit. The surplus/deficit therefore describes the difference in magnitude between two load curves in peak terms, however, it is also a useful indication of the amount of generation plant required to exactly meet the standard.

APPENDIX 4 RESULTS

Using the full table of results

In these tables, results are presented under five categories. Under each category there are a number of cases as illustrated in Table A-8, where each is given an index code.

Category	Case	Index Code
Demand Growth	Low Median High	G_1 G_2 G_3
Availability	Current (77%) Generators' Low Generators' Median Generators' High Mid-benchmark	A_1 A_2 A_3 A_4 A_5
Capacity	As Notified Extended Contracts	C_1 C_2
Interconnection	No Reliance Reliance (300 MW)	I_1 I_2
Demand Side Management	Existing Enhanced	D_1 D_2

Table A-8 Index codes for different cases

Results for any desired combination (such combinations are referred to as scenarios in this report) can be obtained from Table A-10. For illustrative purposes an extract from this table is shown in Table A-9. Using the Index Codes, it can be seen that for median demand growth (G_2), current availability (A_1), capacity as notified (C_1), no dependence on the interconnector (I_1) and the existing level of demand side management (D_1), the deficit in 2007 is 550 MW.

					2005	2006	2007	2008	2009	2010	2011
G_2	A_1	C_1	I_1	D_1	-530	-442	-550	-674	-859	-1046	-1197
				D_2	-516	-430	-536	-660	-845	-1030	-1181
			I_2	D_1	-491	-241	-201	-243	-438	-624	-768
				D_2	-479	-229	-189	-231	-426	-610	-754
		C_2	I_1	D_1	-358	-108	-68	-110	-305	-491	-635
				D_2	-346	-96	-56	-98	-293	-479	-621
			I_2	D_1	-12	338	377	280	128	-14	-251
				D_2	0	348	387	290	138	-2	-239

Table A-9 Extract from the results table

					2005	2006	2007	2008	2009	2010	2011
G_1	A_1	C_1	I_1	D_1	-486	-315	-319	-389	-533	-651	-763
				D_2	-474	-303	-307	-377	-519	-637	-749
			I_2	D_1	-324	-15	-19	-89	-233	-351	-463
				D_2	-312	-3	-7	-77	-221	-339	-451
		C_2	I_1	D_1	-448	-110	30	41	-110	-225	-331
				D_2	-436	-98	40	51	-98	-213	-319
			I_2	D_1	-315	23	163	174	23	-92	-198
				D_2	-303	33	173	184	33	-80	-186
	A_2	C_1	I_1	D_1	-129	164	311	259	149	80	-113
				D_2	-117	174	321	269	159	90	-101
			I_2	D_1	33	464	611	559	449	380	187
				D_2	43	474	619	567	459	390	197
		C_2	I_1	D_1	-93	367	660	684	568	493	302
				D_2	-81	377	668	692	576	503	312
			I_2	D_1	40	500	793	817	701	626	435
				D_2	50	510	801	825	709	634	445
	A_3	C_1	I_1	D_1	106	354	504	482	344	294	131
				D_2	116	364	512	492	354	304	141
			I_2	D_1	268	654	804	782	644	594	431
				D_2	278	662	812	790	652	602	441
		C_2	I_1	D_1	135	553	858	909	760	714	558
				D_2	145	561	866	917	768	722	566
			I_2	D_1	268	686	991	1042	893	847	691
				D_2	278	694	999	1048	901	855	699
	A_4	C_1	I_1	D_1	322	540	727	678	559	527	357
				D_2	332	548	735	686	567	535	367
			I_2	D_1	484	840	1027	978	859	827	657
				D_2	494	848	1033	986	867	835	665
		C_2	I_1	D_1	351	741	1080	1109	980	945	780
				D_2	361	749	1086	1115	988	953	788
			I_2	D_1	484	874	1213	1242	1113	1078	913
				D_2	494	882	1219	1248	1119	1084	921
	A_5	C_1	I_1	D_1	583	787	865	703	597	553	456
				D_2	591	795	873	711	605	561	466
			I_2	D_1	745	1087	1165	1003	897	853	756
				D_2	753	1093	1171	1009	905	861	764
		C_2	I_1	D_1	614	979	1204	1144	1014	958	881
				D_2	622	987	1210	1150	1020	966	889
			I_2	D_1	747	1112	1337	1277	1147	1091	1014
				D_2	755	1118	1343	1283	1153	1097	1020

Demand		**Availability**		**Capacity**		**Interconnector**		**DSM**	
G_1	Low	A_1	77%	C_1	As Notified	I_1	No Reliance	D_1	Existing
G_2	Median	A_2	Low	C_2	Extended Contracts	I_2	Reliance (300 MW)	D_2	Enhanced
G_3	High	A_3	Median						
		A_4	High						
		A_5	Mid-benchmark						

Table A-10 Results – Positive numbers indicate a plant surplus, while negative numbers (shaded cells) show plant deficits.

					2005	2006	2007	2008	2009	2010	2011
G_2	A_1	C_1	I_1	D_1	-530	-442	-550	-674	-859	-1046	-1197
				D_2	-516	-430	-536	-660	-845	-1030	-1181
			I_2	D_1	-368	-142	-250	-374	-559	-746	-897
				D_2	-356	-130	-238	-362	-545	-732	-883
		C_2	I_1	D_1	-491	-241	-201	-243	-438	-624	-768
				D_2	-479	-229	-189	-231	-426	-610	-754
			I_2	D_1	-358	-108	-68	-110	-305	-491	-635
				D_2	-346	-96	-56	-98	-293	-479	-621
	A_2	C_1	I_1	D_1	-174	38	77	-20	-172	-314	-551
				D_2	-162	48	87	-8	-160	-302	-537
			I_2	D_1	-12	338	377	280	128	-14	-251
				D_2	0	348	387	290	138	-2	-239
		C_2	I_1	D_1	-136	240	425	397	240	98	-127
				D_2	-124	250	435	407	250	108	-115
			I_2	D_1	-3	373	558	530	373	231	6
				D_2	9	383	566	538	383	241	16
	A_3	C_1	I_1	D_1	65	221	281	200	19	-92	-303
				D_2	75	231	291	210	29	-80	-291
			I_2	D_1	227	521	581	500	319	208	-3
				D_2	237	529	589	510	329	218	9
		C_2	I_1	D_1	91	426	630	628	433	319	130
				D_2	101	436	638	636	443	329	140
			I_2	D_1	224	559	763	761	566	452	263
				D_2	234	567	771	769	574	462	273
	A_4	C_1	I_1	D_1	282	412	493	394	234	132	-83
				D_2	292	422	503	404	244	142	-71
			I_2	D_1	444	712	793	694	534	432	217
				D_2	454	720	801	702	542	442	227
		C_2	I_1	D_1	308	609	847	829	653	549	350
				D_2	318	617	855	837	661	557	360
			I_2	D_1	441	742	980	962	786	682	483
				D_2	451	750	988	970	794	690	493
	A_5	C_1	I_1	D_1	540	659	634	418	270	159	20
				D_2	548	667	642	428	280	169	30
			I_2	D_1	702	959	934	718	570	459	320
				D_2	710	967	942	726	578	469	330
		C_2	I_1	D_1	569	851	974	848	694	569	447
				D_2	577	859	982	856	702	577	457
			I_2	D_1	702	984	1107	981	827	702	580
				D_2	710	992	1113	989	835	710	588

Demand		**Availability**		**Capacity**		**Interconnector**		**DSM**	
G_1	Low	A_1	77%	C_1	As Notified	I_1	No Reliance	D_1	Existing
G_2	Median	A_2	Low	C_2	Extended Contracts	I_2	Reliance (300 MW)	D_2	Enhanced
G_3	High	A_3	Median						
		A_4	High						
		A_5	Mid-benchmark						

					2005	2006	2007	2008	2009	2010	2011
G_3	A_1	C_1	I_1	D_1	-557	-479	-609	-762	-992	-1213	-1401
				D_2	-543	-467	-595	-748	-978	-1197	-1385
			I_2	D_1	-395	-179	-309	-462	-692	-913	-1101
				D_2	-383	-167	-297	-450	-678	-899	-1085
		C_2	I_1	D_1	-520	-277	-261	-331	-571	-791	-972
				D_2	-506	-265	-249	-319	-557	-777	-958
			I_2	D_1	-387	-144	-128	-198	-438	-658	-839
				D_2	-375	-132	-116	-186	-426	-644	-825
	A_2	C_1	I_1	D_1	-201	0	20	-108	-305	-480	-754
				D_2	-189	12	30	-96	-293	-468	-740
			I_2	D_1	-39	300	320	192	-5	-180	-454
				D_2	-27	310	330	202	7	-168	-442
		C_2	I_1	D_1	-163	202	370	309	106	-70	-333
				D_2	-151	212	380	319	116	-58	-321
			I_2	D_1	-30	335	503	442	239	63	-200
				D_2	-18	345	511	452	249	73	-188
	A_3	C_1	I_1	D_1	37	187	221	112	-114	-259	-504
				D_2	47	197	231	122	-102	-247	-490
			I_2	D_1	199	487	521	412	186	41	-204
				D_2	209	497	529	422	196	51	-192
		C_2	I_1	D_1	64	388	570	540	301	151	-73
				D_2	74	398	578	548	311	161	-61
			I_2	D_1	197	521	703	673	434	284	60
				D_2	207	529	711	681	444	294	70
	A_4	C_1	I_1	D_1	252	372	434	306	103	-35	-285
				D_2	262	382	444	316	113	-23	-273
			I_2	D_1	414	672	734	606	403	265	15
				D_2	424	680	742	614	413	275	25
		C_2	I_1	D_1	281	572	788	741	520	383	149
				D_2	291	580	796	749	528	393	159
			I_2	D_1	414	705	921	874	653	516	282
				D_2	424	713	929	882	661	524	292
	A_5	C_1	I_1	D_1	513	621	574	329	138	-16	-182
				D_2	521	629	582	339	148	-4	-170
			I_2	D_1	675	921	874	629	438	284	118
				D_2	683	929	882	637	448	294	128
		C_2	I_1	D_1	544	814	915	761	561	403	248
				D_2	552	822	923	769	569	413	258
			I_2	D_1	677	947	1048	894	694	536	381
				D_2	685	955	1054	902	702	544	391

Demand		**Availability**		**Capacity**		**Interconnector**		**DSM**	
G_1	Low	A_1	77%	C_1	As Notified	I_1	No Reliance	D_1	Existing
G_2	Median	A_2	Low	C_2	Extended Contracts	I_2	Reliance (300 MW)	D_2	Enhanced
G_3	High	A_3	Median						
		A_4	High						
		A_5	Mid-benchmark						