Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment

June 2011

KEY MESSAGES

The power system of Ireland and Northern Ireland is changing. The combined system will have more windfarms installed and operated as a percentage of the overall annual energy requirement by 2020 than anywhere else in the world. This is driving major changes in not only the need for appropriate infrastructure but, as importantly, in the behaviour of the power system over a wide range of operational metrics. These system behaviour changes require a fundamental understanding of the needs of the power system, the implementation of appropriate new system operational policies and tools, and the evolution of the necessary complementary conventional portfolio capability. Appropriate incentivisation and regulation of plant capability and performance is fundamental to achieving this and is a key finding of this report.

A significant step in understanding the system needs of the future power system was made in June 2010 with the publication of the EirGrid and SONI "Facilitation of Renewables" report. This report augments the results of that study with additional analysis quantifying the level of change required over a range of key operational and plant portfolio metrics. It also considers the implications of the current levels of performance. From this analysis the key challenges and solutions are grouped into four areas:

<u>System Frequency Response</u>
New operational practices are required to ensure system frequency response remains adequate with increasing penetrations of wind. In particular, as the average level of synchronous inertia will potentially fall by 25% in 2020, power imbalances will have a greater impact on the minimum frequency reached and the rate of change of frequency experienced following a disturbance. There will be an increased reliance on fast acting reserve provision from all plant to ensure that system security is not compromised and significant additional curtailment of windfarms is avoided.

<u>Ramping Services</u>
New operational policies are needed to manage the increased variability and uncertainty that wind generation will bring. These policies will need to ensure that there is sufficient ramping capability over multiple time horizons to meet the ramping needs of the system. The effectiveness of these policies will be dependent on the level of controllability of all windfarms, the accuracy of wind forecasts, and the portfolio ramping capability and performance.

<u>Voltage Control</u>
A co-ordinated approach to voltage control across the transmission and distribution systems is required to allow for the changing nature and location of reactive power sources. This approach will need to consider a number of factors: a potential decrease of over 25% on-line synchronous reactive capability; that windfarms reactive capability and their control will be a key requirement to manage voltage; and that the nature of windfarms reactive behaviour during voltage disturbances has implications for the stability of the power system.

<u>Portfolio performance</u>
The current experience is that generators are not reliably meeting the expected performance and capability standards. This creates uncertainty in system service delivery, which manifests itself today in increased costs in the operation of the power system, and in the long run may compromise system security.

To deliver the solutions to the key operational challenges of frequency response, ramping services, voltage control and unreliable portfolio performance, EirGrid and SONI are putting in place a three-year multi-stakeholder "Programme for a Secure, Sustainable Power System". This programme will systematically address the challenges identified, by consistently monitoring plant performance and using the information gained to determine the performance needs of the future system, and by developing the necessary operational policies and tools to manage the increased system operational complexity.

EirGrid and SONI believe that the incentivisation of the necessary portfolio capability is best achieved by changing the level and structure of ancillary services payments and designing performance incentives to align with the needs of the system. This must work in tandem with rigorous performance monitoring by the TSOs. The results of this monitoring can then be used to identify non-compliances, which the TSOs can seek to rectify with individual generators. This needs to be supported by an effective process to examine derogations requests which consistently applies the Grid Code standards with a high bar placed on granting derogations by the Regulatory Authorities.

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EXECUTIVE SUMMARY

The power system of Ireland and Northern Ireland is currently operating at high penetrations of wind never previously experienced on the island. There is already sufficient installed windfarms to meet over 15% of the annual electricity consumption. This level of installed wind is expected to grow significantly over the coming years in line with government targets and obligations under the EU Climate Change package. By 2020, it is estimated that the contiguous synchronous island power system will have over 37% of its electricity from wind power generation. The current and expected 2020 level of installed wind across the island (in percentage terms) is, and will continue to be, greater than any other synchronous region in Europe over this timeframe. This transformation requires significant and appropriate investment in the necessary transmission and distribution infrastructure, which are being managed through the connection offer processes and long term strategic development plans in both jurisdictions and are not a focus of this report.

In addition, this transformation will induce significant changes to the nature and behaviour of the power system which needs to be fundamentally understood in order to be managed effectively. Based on this understanding, an appropriate holistic programme of work can be formulated to ensure the evolution of the necessary plant portfolio capability and reliable performance levels combined with complementary system operational policies and real-time support tools. It is only through this co-ordinated approach, based on a fundamental understanding of the behaviour of the system, that the continued secure, reliable and efficient operation of the power system can be ensured.

EirGrid and SONI released the “Facilitation of Renewables” (FoR) studies in June 2010 which identified the expected changes to system behaviour up to 2020. Amongst the many issues the studies identified, it showed that system frequency response would be difficult to manage with reduced synchronous inertia, and issues related to the rate of change of frequency (RoCoF) of distribution protection and generation capability would be problematic. In addition, reactive power control, especially during voltage disturbances, would be important in order to preserve the transient stability and integrity of the system. These studies were based on thousands of detailed dynamic simulations of the power system at distinct load levels and portfolio dispatches. Moreover, the simulations were based on models where it was assumed that generators, in general, met the performance standards stipulated under the Grid Codes.

Recognising the importance of the FoR studies, the SEM Committee in November 2010 requested the TSOs to provide evidence and objective operational metrics to highlight potential issues with the on going transformation of the power systems and to provide advice on the priority actions required to successfully manage and implement the necessary changes.

This report builds on the FoR studies by examining the hour-to-hour behaviour of the power system in 2010 and comparing this with the predicted behaviour in 2020. Arising from this analysis, there are four major areas to be addressed:

- System frequency response will be more important as there will be on average a 25% reduction in on-line synchronous inertia which has significant implications for the rate of change of frequency (RoCoF) and the need for consistent and reliable reserve from the portfolio.

- Ramping requirements will increase as wind power generation increases both the variability and uncertainty in energy sources than has been previously managed on power systems. With increasing volumes of wind there will be an increase in the ramping capability required on the system over certain time periods ranging from 1 hour to 12 hours ahead. This required increase in ramping capability will be influenced in the short to medium term by both the variability of the wind and by the magnitude of the wind forecast error, and will need new operational policies to be managed securely.
- System voltage control will be challenged as there will be over 25% less synchronous generator reactive capability on-line. While windfarms can produce reactive power, it is generally of lower quality than synchronous generators especially during voltage collapse and transient incidents.
- Non-adherence of the current plant to mandated Grid Code capabilities combined with unreliable performance when required further increases the challenges to managing an efficient and secure power system in this changing environment. For example, only 30% of generators in Ireland[1] have reliably provided their contracted level of primary operating reserve during low frequency disturbances; the aggregate all-island plant portfolio of synchronous leading Mvar capability is 30% less than that required by the Grid Code; and over 400MW of windfarms have not provided both the regulated active and reactive power control back to the control centres as required.

EirGrid and SONI consider that the issues identified in the FoR studies and the additional analysis presented in this report have highlighted the necessary relevant issues that, if successfully managed, will result in ensuring the secure, reliable and efficient power system operation in a changing environment. To this end, a "Programme for a Secure Sustainable Power System" is set out in this paper with the objective of ensuring the secure, reliable and efficient power system operation into the future. As requested by the SEM Committee, this programme details the priority actions that are required over the next three years to achieve this. This work programme includes augmenting the monitoring of portfolio performance, developing new operational policies and system tools to efficiently use the plant portfolio to the best of its capabilities, and regularly reviewing the needs of the system as the portfolio capability evolves. Industry stakeholders will be required to participate in the clarification of the appropriate standards, to ensure existing plant comply with the standards where determined by the Regulatory Authorities and, going forward, invest in new plant that is fully compliant with all relevant standards.

There is evidence that where commercial incentives exist around performance, the industry reacts positively to this. For example, the introduction of Generator Performance Incentives (GPIs) has improved the performance of the existing plant, particularly around the minimum stable generation of plant and the contracted levels of ancillary services. There is also evidence to show that without the appropriate incentives, investment in portfolio capability is impacted. Against this backdrop, the

[1] This percentage is interpolated based on the data obtained from those plant for which there is sufficient performance monitoring data.

TSOs recommend that the development of targeted ancillary service payments, which are aligned to the required portfolio capability of a power system with high penetrations of wind, is pursued. These payments need to be at a level and a certainty that impact on new investment decisions, and should be performance related throughout the life of a plant. It is clear from the current level of portfolio capability and performance that the existing ancillary service payments are not structured to achieve this.

In addition, the Regulatory Authorities and the TSOs should work to ensure material compliance with the existing Grid Code standards (or in a few cases define new standards) and only in rare circumstances grant derogations. This will provide certainty in the expected portfolio capability which can be efficiently incorporated into developing the necessary operational policies and real-time system support tools. This measure is a prerequisite to reducing costs to the consumer and acts as a fundamental building block to operating a power system with high penetrations of wind.

This report, including the proposed programme of work and key priority actions for the industry and the Regulatory Authorities, has been presented. The TSOs consider this should form the basis for implementing a three year, multi stakeholder project to co-ordinate and focus the industry on tackling the key challenges to ensuring a secure, reliable and efficient operation of a power system in this changing environment.

1 INTRODUCTION

1.1 CONTEXT

The nature of where societies are getting, and will get, their primary energy sources is under constant review at political and governmental levels. These reviews are mainly concerned with macro factors including economics, security and sustainability. In Europe, a key long term outcome from these deliberations is to move the portfolio of electricity generation to a more sustainable source of indigenously produced renewable power. This political outcome has been reflected in the Member States' recent National Renewable Energy Action Plan (NREAP) submissions to the EU. These include a detailed year-by-year breakdown to 2020 of the percentage of the electricity portfolio from various renewable sources. The NREAPs show that most countries are increasing their percentage of electricity from Variable Non-Synchronous Renewable (VNSR) generation, in particular wind power (mostly onshore) and photo-voltaic solar power (Figure 1). This move to VNSR technology has profound implications for the nature of the power system, the operating characteristics and system operational practices and as such will need to be managed carefully.

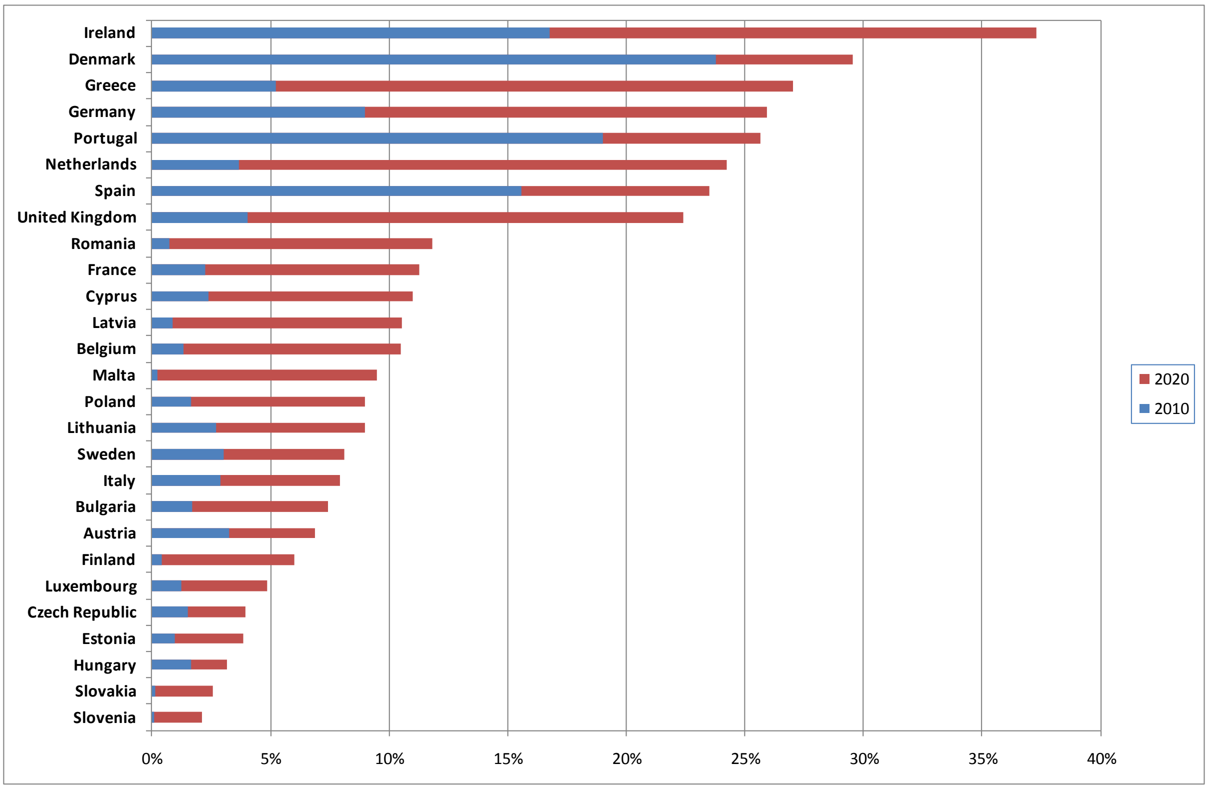

Figure 1: Member State percentage electricity from Variable Non-Synchronous Renewables 2010 and 2020. Derived from the NREAP figures available from the EU Commission (EirGrid, 2011)

From the NREAP figures it is clear that many Member States' power systems will be impacted by a significant growth in VNSR technologies (notably Ireland, Denmark, Greece, Germany, Portugal and Spain). However, when the NREAP submissions are examined from a contiguous synchronous area[2]

[2] For a synchronous area the system frequency is the same across all generators and they act in unison to manage energy imbalances

perspective, the challenges that Ireland and Northern Ireland face are far in advance of the other three main synchronous areas in Europe: Great Britain (GB), Continental Europe (CE) and Scandinavia (Figure 2). In particular, Ireland and Northern Ireland's 37%[3] is far ahead of the other synchronous systems VNSR penetration levels of 22% (GB), 18% (CE) and 8% (Scandinavia). The transformation of the power system will be challenging as the high level of VNSR will fundamentally alter the dynamic characteristics of the electricity power system. Understanding the changes is essential to developing the operational strategies needed to manage the power system in a secure, reliable and efficient manner in the years ahead.

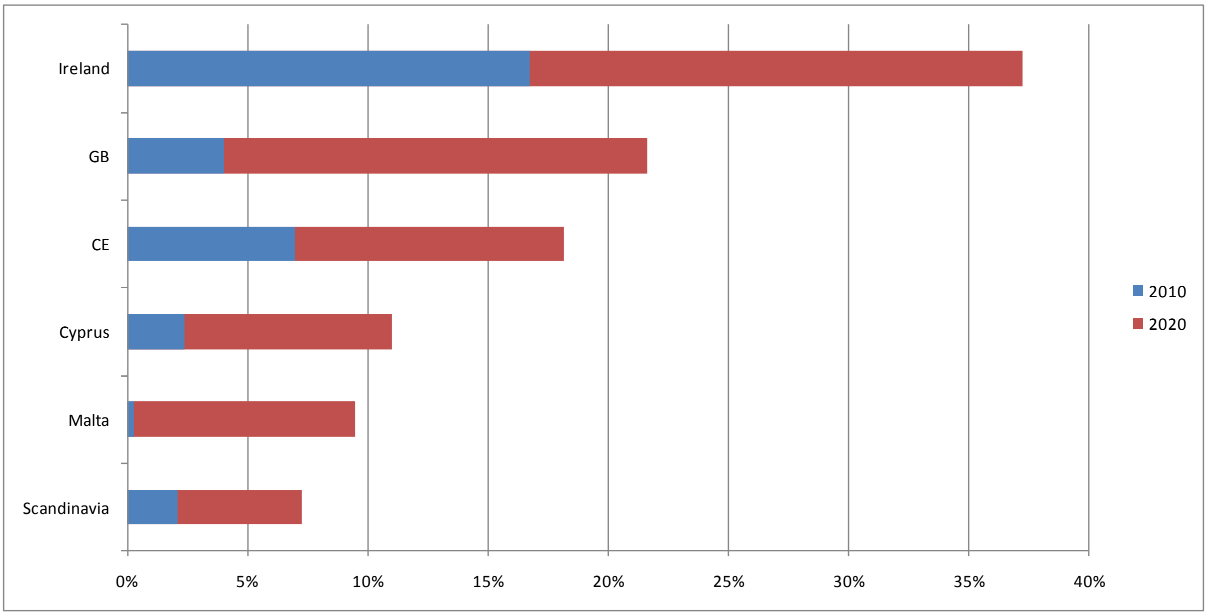

Figure 2: Synchronous Systems in Europe: percentage electricity from Variable Non-Synchronous Renewables 2010 and 2020. Derived from NREAP figures available from the EU Commission (EirGrid, 2011)

1.2 Progress to Date

Since 2000, there has been significant year-on-year growth of installed windfarms on the Ireland and Northern Ireland system. In order to meet the renewable targets as specified in the NREAP a continued annual increase of over 25% is required.

[3] This is based on Ireland's submission to the NREAP and the recent Northern Ireland Strategic Energy Framework decision 2010

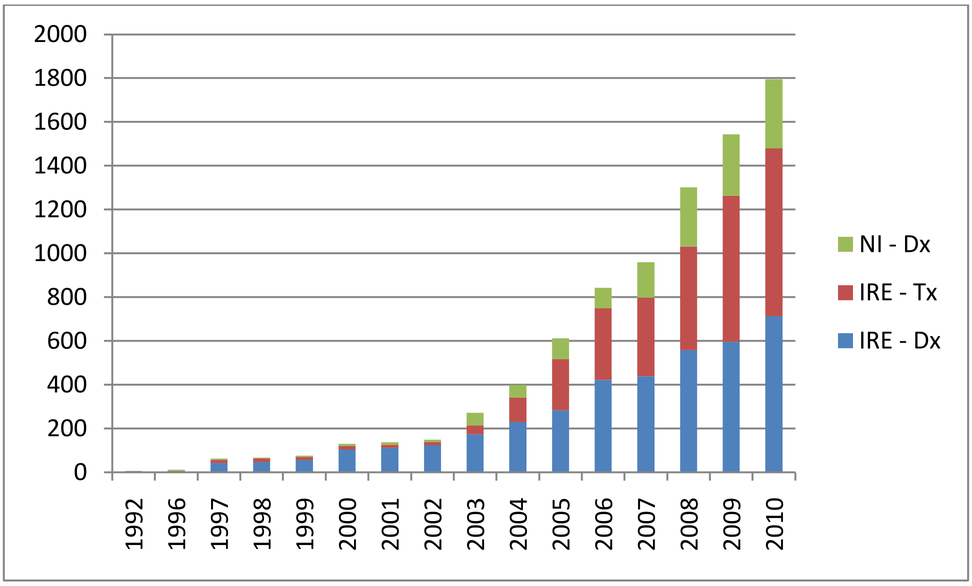

Figure 3: Installed MW of Windfarm in Ireland and Northern Ireland connected at Transmission (Tx) and Distribution (Dx) Levels (EirGrid, 2011)

Much work has been done over the past number of years to get a better understanding of these issues. First, in 2003 the industry developed a new section in the Irish Grid Code covering the technical requirements for windfarms. This set of standards paved the way for clarity of control and performance over a range of system conditions. The Grid Code provisions for windfarms were recognised as a leading set of standards essential for the development of high levels of wind generation and many components were replicated in Northern Ireland Grid Code and internationally. In early 2006, the ramifications of this Grid Code began to be seen as dispatch and control of windfarms became a common practice in the control centres in Ireland and Northern Ireland.

In 2008, the "All Island Grid Study" led by the Department of Communication, Energy and Natural Resources and the Department of Enterprise, Trade and Investment provided resource analysis, portfolio comparison and a high level technical and economic analysis to show that a penetration level of 42% from windfarms in Ireland and Northern Ireland was potentially possible. However, the report contained a number of significant caveats, which indicated that detailed market modelling, transmission infrastructure design, planning and build, and dynamic technical studies were still required.

In January 2009, the SEM Committee published the study *"Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market (SEM)".* This provided market modelling of the impact wind would have on the SEM. In particular it noted that costs to the consumer would reduce with wind but that the financial sustainability of both windfarms and conventional generators might be compromised depending on the fuel scenario chosen. In addition, it was noted that system constraints, costs of ancillary services and network reinforcements were not considered and as a consequence, the results should be interpreted with some care.

In parallel, significant work was underway in the design and construction of necessary transmission and distribution infrastructure including the long term Grid25 strategy and the Group Processing Approach. A similar long term infrastructure development strategy has now emerged in Northern

Ireland. It was through these processes that a greater clarity on the costs and design of necessary infrastructure was and is being identified as recommended in the "All Island Grid Study". The construction of the necessary transmission and distribution infrastructure is a key requirement in developing a power system to securely, reliably and efficiently manage a system with almost 40% of the power system from variable renewable generation. However, the focus of this report is on the operational needs of the portfolio and the system in addition to those of the infrastructure.

From an operational perspective significant progress has been made in the last decade in managing wind generation in a secure and efficient manner. The first significant changes began to manifest themselves in the first part of the decade when wind became a materially noticeable segment of the portfolio. This required investment in forecasting and dispatching tools. Much detailed work on forecasting was conducted both in EirGrid and SONI, and also in partnership with a European consortium through the ANEMOS programme, which led to the development of a platform for using a range of forecasting tools. This has subsequently been updated with ANEMOS Plus programme examining the use of stochastic and probabilistic forecasting and scheduling tools. The operational forecasting tools have recently been updated in both control centres.

The dispatch of windfarms necessitated a bespoke development of the "Wind Dispatch Tool", currently employed in the National Control Centre in Dublin and a similar tool in the Castlereagh House Control Centre in Belfast. This provides real-time remote control capability of the active power output of windfarms[4], which respond in 10 seconds on receipt of an instruction. This practice is now a core tool in maintaining system security today.

A final example of the progress made in operating a power system is the development of real-time stability assessment tool called WSAT (Wind Security Assessment Tool). This tool takes real-time snapshots of the Ireland power system and performs over 300,000 detailed transient and voltage stability assessments daily and presents a simplified representation of any stability issues to the real-time operator. This tool has been in operation since October 2010 providing support to the control centre engineers. The data and results from this tool will be used to improve the modelling of all generators and the tool will be extended to include the Northern Ireland system.

1.3 The "Facilitation of Renewables" (FoR) Study

In 2009, EirGrid and SONI initiated a suite of studies – entitled the Facilitation of Renewables – designed to examine the technical challenges with integrating significant volumes of windfarms onto the power system of Ireland and Northern Ireland. Three separate internationally recognised consultancy firms – Siemens-PTI, Ecar and DigSilent-ECOFYS – were engaged to perform the various distinct technical studies and to rigorously analyse and challenge the outputs in conjunction with EirGrid and SONI engineers and independent industry peer reviewers Mr. Peter Harte (SWS Windfarms) and Professor Mark O'Malley (UCD).

The main findings of the study indicated that the integrity of the system following a frequency event is potentially compromised at high instantaneous penetrations of wind. In addition, the transient and dynamic stability of the power system following a disturbance are similarly compromised. The modelling used in the studies suggested that the voltage and reactive power behaviour of the

[4] Note that not all windfarms are required to provide active power control to the TSO.

system is directly related to the performance of all generators on the island as well as how the network is developed; this will require management of the significant changes over the coming years. The studies also indicated that voltage disturbances could result in the temporary loss of windfarm output, threatening the stability of the system.

However, the findings indicated that, subject to the fulfilment of a number of technical and operational criteria, Ireland and Northern Ireland can achieve the renewable energy targets securely and effectively by 2020. The studies determined that the TSOs can securely manage the system provided that the System Non-Synchronous Penetration (SNSP)[5] level in real-time operations remains below 50%. In the next few years, with the development of enhanced system operational policies, tools and practices, the investment in the required transmission and distribution infrastructure, and the evolution of the appropriate complementary portfolio, the studies indicate that an SNSP level of up to 75% is achievable (Figure 4).

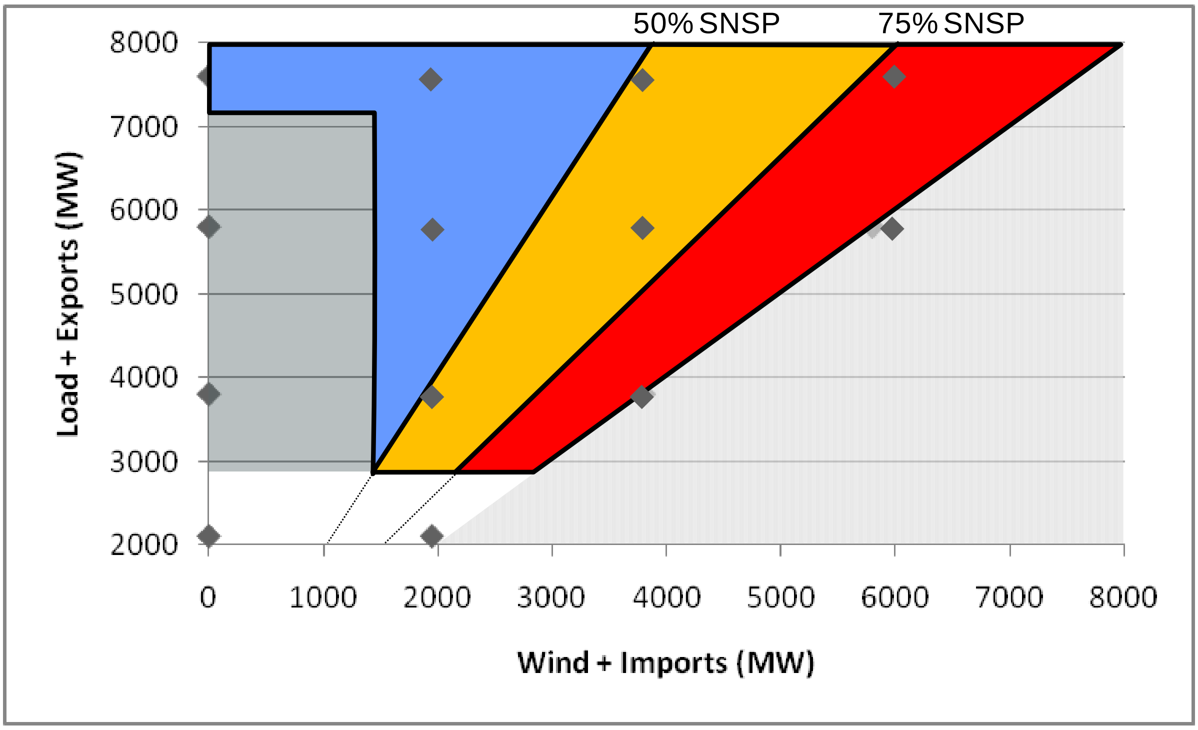

Figure 4: System Operability Regions Load and HVDC Exports vs. Wind Generation and HVDC Imports (Blue - Operable, Amber - needs actions to be achieved, Red - unlikely to be feasible even with significant mitigating actions), (FoR Studies EirGrid/SONI, 2010)

1.4 Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment

The operational SNSP limit[6] has a direct impact on the running levels on all generators (both conventional and renewable) and in particular on the level of energy utilisable (on an annual basis)

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[5] SNSP is a measure of the non-synchronous generation on the system in an instant. It is a ratio of the real-time MW generation from wind and HVDC imports to demand plus HVDC exports

[6] The limit of SNSP which a prudent TSO would not operate as it posed an unreasonable security threat to the system

from windfarms. Figure 5[7] shows the impact the operational SNSP limit has for a projected Ireland and Northern Ireland system with 6000 MW[8] of installed windfarms. If actions are taken to allow an increasing operational SNSP limit from 60%-75% the level of annual curtailment on windfarms falls from over 13% to 4%. This has a resultant benefit of increasing the annual amount for energy coming from windfarms from 34% to 39%.

Following the publication of the FoR report, the SEM Committee wrote to the TSOs in November 2010 requesting their advice on the implications of this study for the development of the power system and implications for the priority actions that the Regulatory Authorities should be aware of in consideration of the ongoing industry work programme. This advice was to be based, where possible, on objective and observable evidence and key operating metrics.

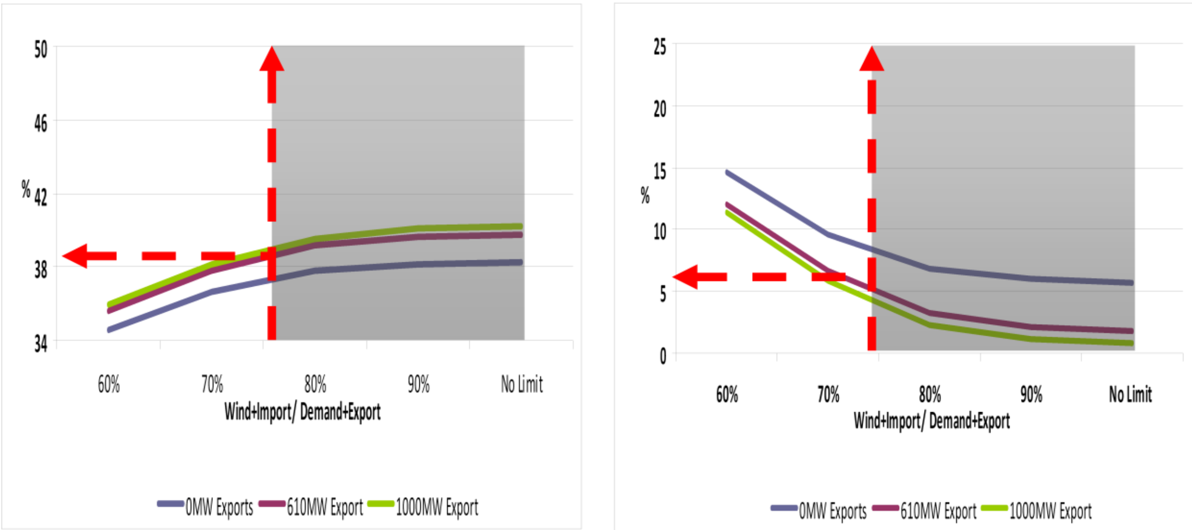

Figure 5: Annual Energy Output from windfarms and curtailment levels vs. maximum level of non-synchronous generation (EirGrid at FoR Forum Dundalk, 2010)

This report provides the response to this request. It takes the findings of the FoR study and combines this with an hour-by-hour assessment of the needs of the power system in 2020 across three key operational criteria:

- Frequency Response;
- Ramping Services; and
- Voltage Control

This report provides detailed information about the changing characteristics of the Ireland and Northern Ireland power system. In addition, an analysis of the actual performance of the current plant portfolio is presented. The report also provides a structured programme of work and priority actions ("Programme for a Secure, Sustainable Power System") that in the TSOs' opinion can

[7] Presented by EirGrid at the forum in Dundalk June 2010

[8] 6000 MW of windfarm installed on the power system chosen as it was consistent with connection offer applications being processed in Ireland and Northern Ireland

effectively address these issues in a timely fashion. This programme identifies the necessary steps that the TSOs, the RAs and the industry are required to take.

2 ASSUMPTIONS AND MODELLING

2.1 SCOPE

On the basis of the results of the Facilitation of Renewables studies and the operational experience of the TSOs, the current and likely future all-island generation portfolios were examined under three main headings:

- Frequency Response (including Reserve and Inertia)
- Ramping Services
- Voltage Control

The impact of generators' minimum generation (including minimum load for provision of services) has also been examined as this has implications for each of these three focus areas. For each of the areas, the current portfolio capability has been assessed, the projected portfolio capability and system characteristics have been inferred and the resultant issues and operational challenges have been identified.

Note that a data freeze date of December 2010 was necessary for the analysis. There have inevitably been some changes to the portfolio capabilities since then that are not captured here.

There are a number of areas identified in the FoR studies as being less critical or requiring further study before determining if there was an issue and are not covered in this report:

- Fault levels
- Small signal stability
- Reserve policy with respect to voltage dips
- Fault Ride Through capability of generators
- Frequency regulation

In addition, the longer term adequacy of the system has not been considered here. It has been assumed that the projected 2020 portfolio will have sufficient installed capacity to satisfy generation adequacy standards. However, for longer timeframes it is essential that there are appropriate market signals to provide incentives for the necessary adequacy.

2.2 CURRENT PORTFOLIO

A key element of the analysis presented in this report is an assessment of the current generation portfolio. The following is a summary of the generation portfolio[9] at the end of 2010:

- 9,070 MW of conventional synchronous generation that is subject to central dispatch, split 75% in Ireland, 25% in Northern Ireland.
- 1,730 MW of wind generation, split 80% in Ireland, 20% in Northern Ireland. 740 MW (43%) of this is transmission connected, the remainder is distribution connected (note: there is currently no transmission-connected wind in Northern Ireland).

[9] The All-Island Generation Capacity Statement 2011-2020 was used as the data source for the current portfolio.

- 230 MW of embedded non-wind generation, which is currently not centrally dispatched, split 90% in Ireland, 10% in Northern Ireland.
- There is also a DC interconnector, linking Northern Ireland and Scotland, with an import capacity of 450 MW. The export capacity is currently limited to 300 MW. While the interconnector is controlled by SONI, it is afforded special status in the SEM, and is therefore not dispatchable to the same degree as generators on the island.

2.3 ASSUMED FUTURE (2020) PORTFOLIO

Based on the models developed for Grid25 (and the All Island Grid Study) analysis, an assumed future portfolio has been used for analysis. This portfolio represents a credible evolution of the current portfolio into one which can meet the policy objectives and government targets with respect to an efficient and secure electricity supply (including generation adequacy) and electricity from renewable sources (i.e. the conventional portfolio complements variable renewable generation from a load factor perspective by comprising a balance of "base-load", "mid-merit" and "peaking" generators).

- Conventional Generation – retirement of 2,900 MW of older thermal generation; addition of 2,200 MW of new generation, primarily gas-fired or distillate-fired CCGTs and OCGTs.
- Wind generation installed on the all-island system will increase from 1,700 MW to 6,100 MW.

A comparison of the 2020 portfolio with the current portfolio is shown in Figure 6 below, which illustrates the change in the proportion of different technology types.

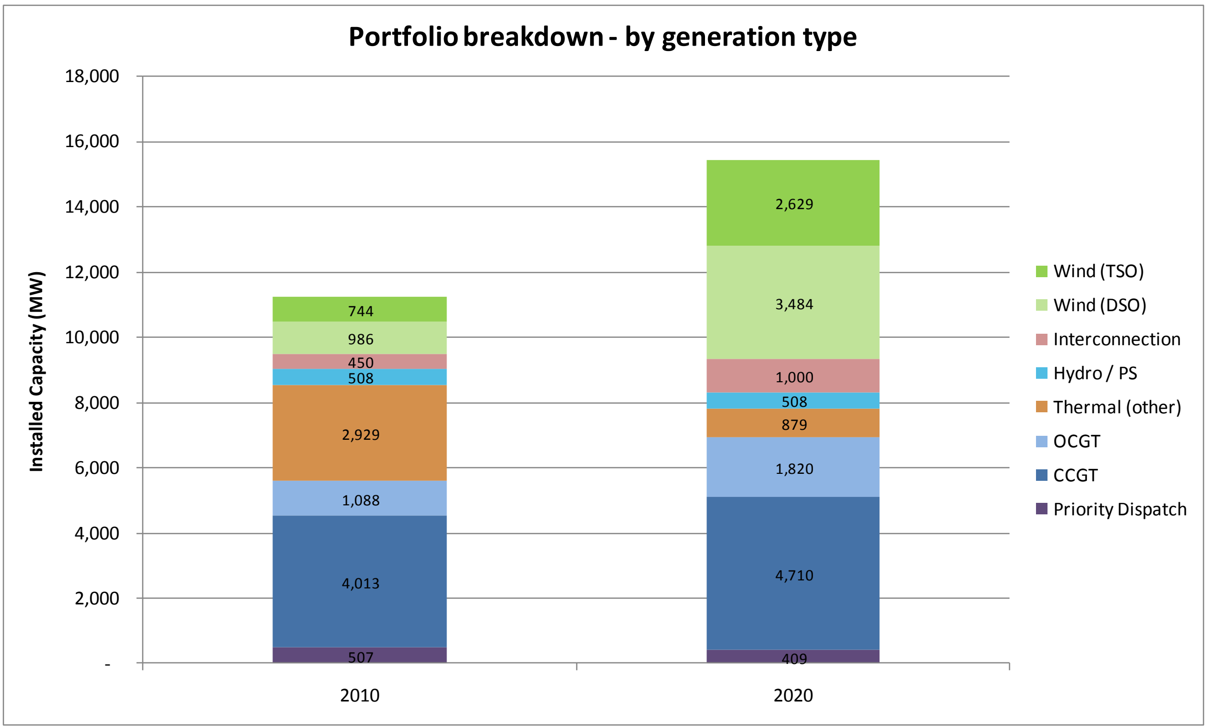

Figure 6: Portfolio breakdown by generation type - 2010 and 2020, (EirGrid, 2011)

It is assumed that there is 1 GW of interconnection with Great Britain (GB), capable of full import or full export. In practice, interconnector flows are determined by the *ex ante* market schedule. Due to the complex interaction between the two markets (SEM and BETTA), which determines prices and hence volumes, flows are difficult to predict. For the purposes of this analysis, the GB system is modelled as a fixed price so the interconnectors will import at times of high demand and/or low wind (when prices will be high) and export at times of low demand and/or high wind (when prices will be low).

The 2020 portfolio has been modelled using Plexos, which produces an hourly generation dispatch profile. The network is not modelled in Plexos as it is assumed that sufficient reinforcement has taken place to minimise the effects of transmission constraints. Furthermore, it is assumed that the second North-South tie-line has been commissioned, removing the need for the current regional security constraints. Reserve constraints have been modelled and based on the results of the FoR studies, a limit of 75% has been applied to non-synchronous generation.

A number of further sensitivity scenarios were also examined including:

- No Interconnection (zero MW flow on interconnectors) – this allows an assessment of the capability of the indigenous portfolio.
- No Pumped Storage generation available (with no interconnection) – when compared with the 'No Interconnection' case this allows the impact of pumped storage to be assessed.
- 300 MW of inflexible generation (with no interconnection) – this allows the impact of increased levels of inflexible generation (e.g. non-dispatchable generation) to be assessed.

The Plexos results indicate that the range of possible wind curtailment is from 5% to 22% depending on a number of factors. It is important to note that these figures do not take into account any potential constraints on the transmission network, and therefore should be interpreted as a lower bound on the amount of unused wind energy.

Table 1: 2020 wind curtailment levels by scenario

Base Case	5%
No Interconnection	13%
No Pumped Storage (no interconnection)	22%
300 MW Inflexible (no interconnection)	18%

2.4 Grid Code

User compliance with the Grid Codes is essential to ensure that the all-island power system can be operated safely, securely and reliably, and that other users are not adversely affected. In addition, Grid Code compliance (with a common set of standards) ensures that there is parity of treatment between users across both jurisdictions.

It should be noted that there are differences between the Grid Code in Ireland and the Northern Ireland Grid Code. In particular, whereas the Irish Grid Code has generic Connection Conditions, which define the minimum technical capability of a generator in respect of a range of characteristics (e.g. minimum load, ramping capability), in Northern Ireland some of these requirements, while based on the Northern Ireland Grid Code, are unit-specific and are described in the connection agreement or associated documentation.

To allow meaningful comparison across the entire all-island generation portfolio, a single set of standards is required. Thus for the purposes of this paper, the standards from the Irish Grid Code will be used.

3 FREQUENCY RESPONSE

The laws of physics demand that generation and consumption of electricity is balanced at all times. Variations in electricity demand or generation results in fluctuations in frequency. Control of these fluctuations is effected via two mechanisms: inertia, the inherent electro-mechanical response of the synchronous system; and operating reserve, the rapid, active control of power output. These two mechanisms, which are intrinsically linked, are discussed in turn below.

3.1 INERTIA

All rotating machines have a store of kinetic energy due to their inertia. In the case of synchronous generators, the mechanical stored energy of each generator is coupled together via the electrical power system. This stored energy increases or decreases in response to frequency changes that arise due to power imbalances and acts to damp out or slow down these frequency fluctuations. This response is an intrinsic capability of synchronous generators and, as such, is entirely automatic.

System inertia[10], which is analogous to the "weight" of the power system, is a key determinant in how rapidly the system frequency will change in response to a disturbance. In particular, the maximum rate of change of frequency is directly proportional to the system inertia. Based on the Facilitation of Renewables studies, it is known that, due to the RoCoF (rate of change of frequency) relays that are used to provide protection functions to distribution generation, a maximum rate of change of frequency greater than 0.5 Hz / s could result in loss of generation which could lead to system instability. For a largest infeed of 450 MW, a minimum system inertia level of 25,000 MW s results in a maximum rate a change of frequency of 0.45 Hz/s, which allows a prudent margin of safety.

It should be noted that there is a link between inertia and primary operating reserve: inertia determines the rate of change of frequency; reserve arrests the falling frequency and then restores it towards its nominal value. The lower the system inertia, the faster the frequency will fall following the loss of a generator and hence the faster the primary reserve response needs to be; conversely, at high inertia levels (such as for larger interconnected systems) slower-acting primary reserve is adequate to cope with generation loss. Thus the minimum system inertia level suggested here is only achievable provided there is an adequate amount of sufficiently fast-acting reserve to arrest the frequency fall before load shedding occurs.

3.1.1 CURRENT PORTFOLIO CAPABILITY

Unlike some other services, a generator contributes to system inertia whenever it is synchronised – it does not depend on power output. Synchronous system inertia varies according to the combination of generators that are synchronised and will therefore vary through the day as generators synchronise and desynchronise. The daily maximum and minimum inertia values are shown in Figure 7, which illustrates the variation from day to day, arising due to different levels of

[10] For simplicity, the term "System inertia" is used to represent the equivalent kinetic energy of the synchronous system, which is determined by the inertial constant of all synchronised machines and their (synchronous) speed of rotation.

wind, demand and interconnector flows. A seasonal effect is apparent, with lower inertia values during the summer. The average daily wind output is also plotted; there is a weak negative correlation (-0.25) between wind generation and inertia.

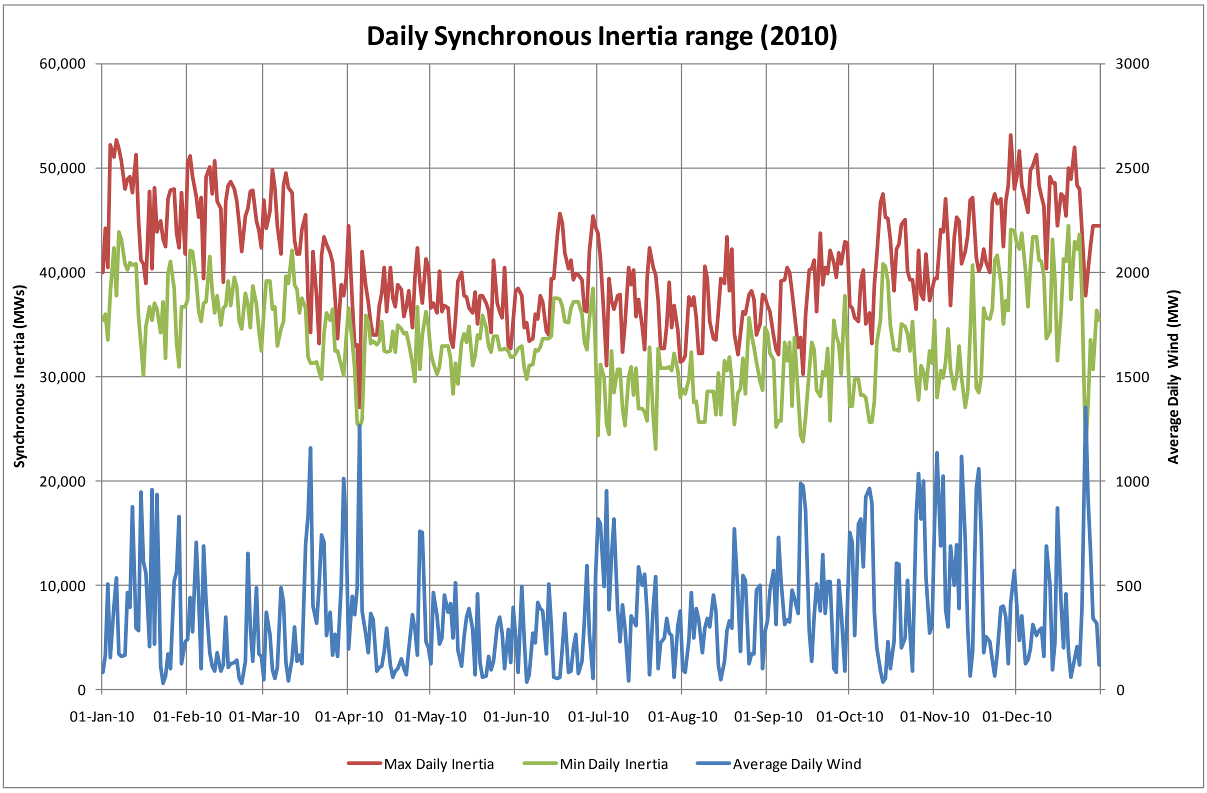

Figure 7: Actual daily maximum and minimum synchronous inertia compared to average daily wind output, (EirGrid, 2011)

The daily and hourly variability of inertia makes interpreting a full year of data and comparing different years extremely difficult. However, the inertia values can be presented as a duration curve, which shows the percentage of hours in the year that the inertia exceeds a particular level. Figure 8 shows the inertia duration curve for 2010 and for the simulated 2020 system.

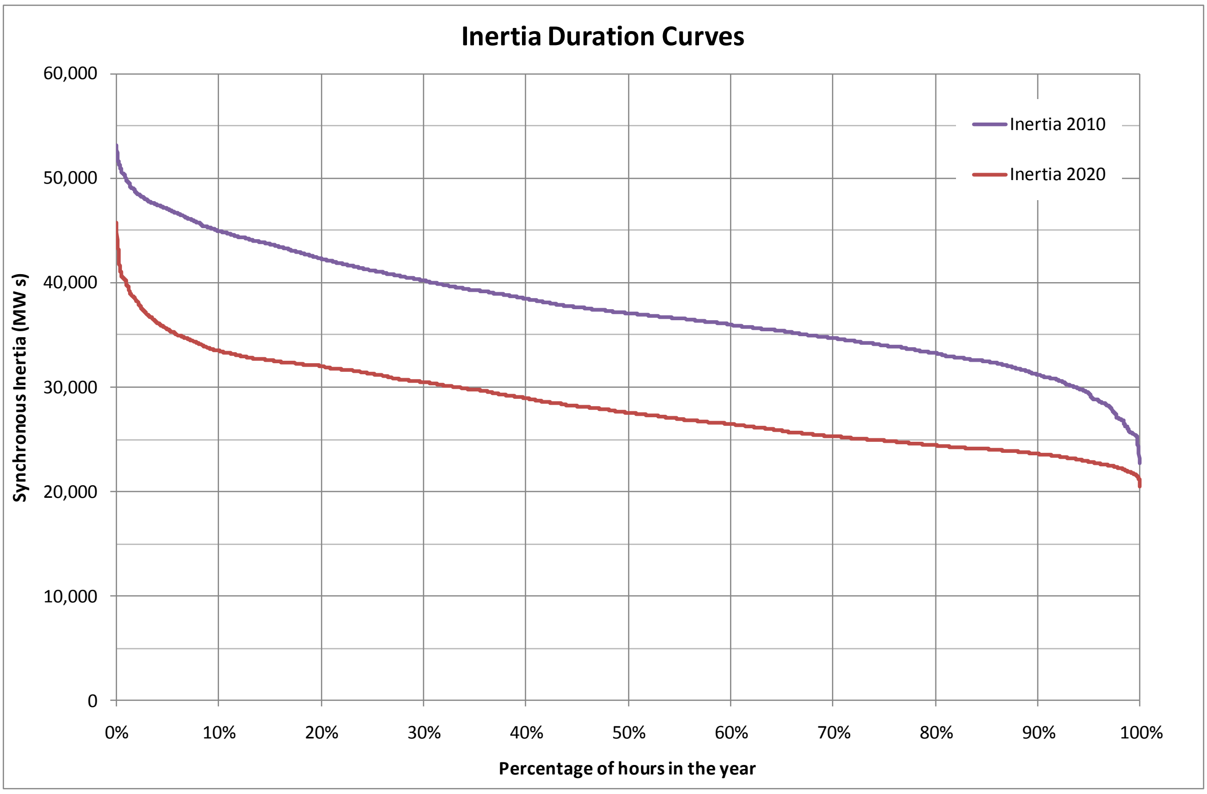

Figure 8: Synchronous Inertia Duration Curves calculated from actual 2010 and modelled 2020 data (EirGrid, 2011)

The average synchronous system inertia in 2010 was 37,600 MW s. Excluding the 20 hours with the lowest inertia (which coincided with system being in a disturbed state following the tripping of a generator), the minimum value observed was 25,000 MW s. This is illustrated in Figure 8, which shows that the system inertia was greater than 25,000 MW s for 99.8% of the hours in the year. This minimum level, based on operational experience, is consistent with the theoretical minimum level explained above.

3.1.2 Projected Portfolio Capability and System Characteristics

It is expected that as the level of installed wind generation increases, synchronous conventional generation will be displaced by non-synchronous renewable generation. This will result in a decrease in the synchronous system inertia.

- For the simulated 2020 system (Figure 8), the average inertia has dropped to 28,300 MW s, representing a reduction of 25% on average 2010 levels.
- At present, the main determinant of inertia is the system demand, with the level of wind having a smaller effect. However, for the 2020 studies, the level of installed wind has increased, and the negative correlation (negative since higher wind generation means lower inertia) between wind and system inertia has increased from 0.25 to 0.7.
- The duration curve in 2020 is flatter since the interconnectors tend to import at times of high load, thus displacing synchronous generation, resulting in lower inertia.

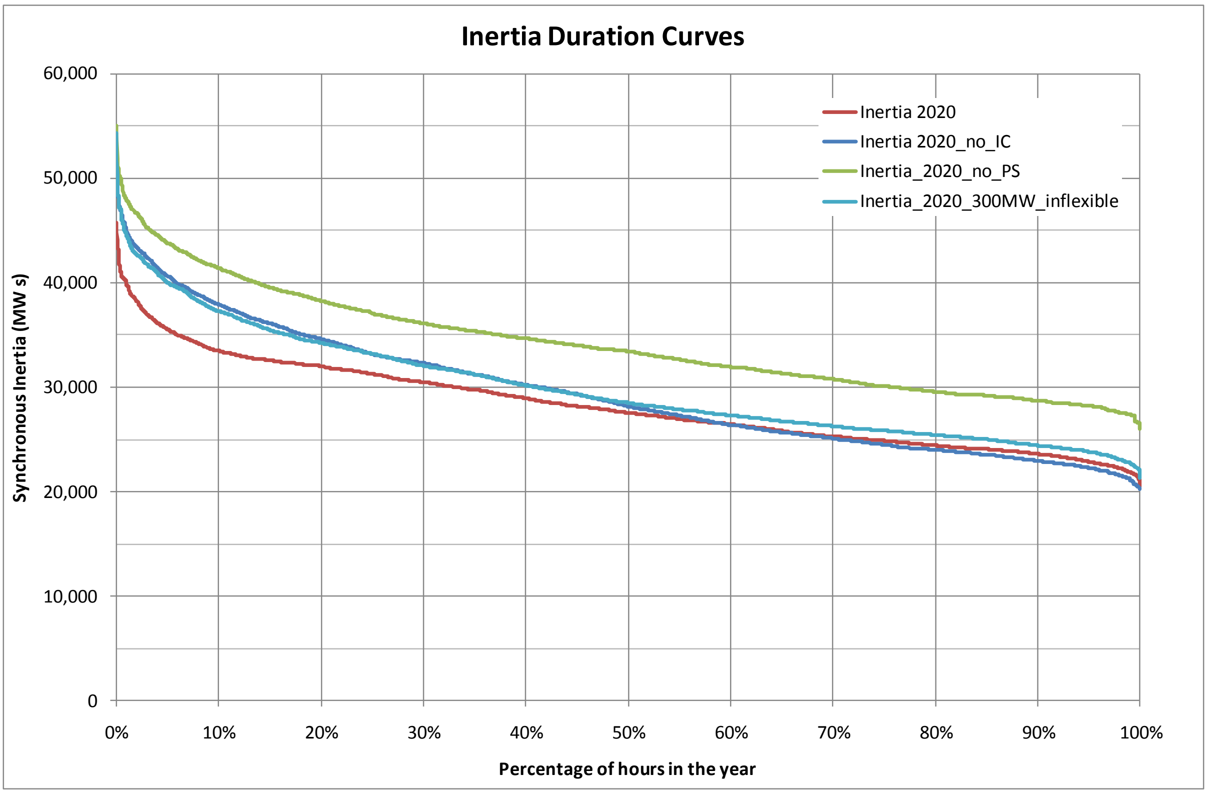

Figure 9: Synchronous Inertia Duration Curves from three 2020 modelled scenarios (EirGrid, 2011)

Other scenarios

Figure 9 above shows the inertia duration curve for the simulated 2020 system and compares with the curves for three sensitivity studies: 1) No Interconnection, 2) No Pumped Storage, and 3) 300 MW Inflexible generation.

1) In the base case (with interconnection), the interconnectors tend to import at times of high load. Thus, in the "No Interconnection" case this must be replaced by synchronous generation, thereby increasing system inertia. At times of low system inertia, since the interconnectors would generally have been exporting, there is less "room" for non-synchronous wind generation (and hence higher curtailment as evidenced in Table 1 in Section 2) and also, at times, lower synchronous generation, thus slightly reducing system inertia. The overall effect is to increase inertia (by approximately 3%), with an average value for this case of 29,400 MW s, which represents a 22% reduction on the average 2010 inertia levels.

2) For the No Pumped Storage case, the significant reserve contribution of pump storage, particularly at times of low load must be sourced elsewhere, which means that additional synchronous generation is required, resulting in considerably higher system inertia levels. While the inertia is always above the 25,000 MW s level in this case, it should be noted that much higher curtailment is observed compared to the base case.

3) The Inflexible generation case, which also has no interconnection, should be compared with the No Interconnection case. At times of high load, the inflexible generation is generally displacing larger, heavier CCGTs, thus somewhat reducing overall system inertia. In contrast,

at times of low load, due to binding reserve constraints, the inflexible generation is displacing non-synchronous wind generation (which has no inertial contribution), thus increasing system inertia. This is evident from the increased levels of curtailment in this case.

3.1.3 Resultant Issues and Operational Challenges

In summary, synchronous inertia will tend to fall as the System Non-Synchronous Penetration (SNSP) level rises. Since a minimum inertia must be maintained, curtailment of non-synchronous generation will be required if current performance levels are maintained.

If the current minimum inertia limit of 25,000 MW s is extrapolated forward to 2020, it can be seen (Figure 9) that the limit is breached in 30% of the hours. In the absence of other corrective measures, this would necessitate additional curtailment of non-synchronous generation which is estimated to be between 2% and 3.5%

The results presented here are consistent with the findings of the FoR studies. This is illustrated in Figure 10, which shows the relationship between system inertia and the minimum frequency reached following a frequency disturbance (e.g. loss of the largest infeed).

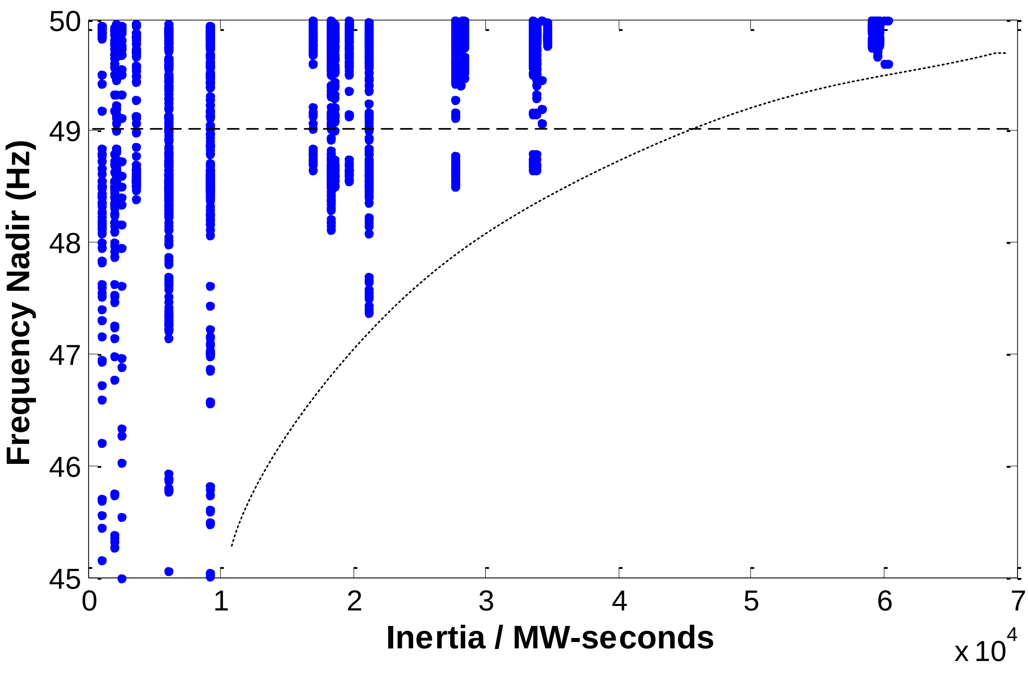

Figure 10: Frequency Nadir vs Synchronous System Inertia – FoR studies (EirGrid/SONI, 2010)

There are opportunities for mitigation strategies to address the expected reduction in system inertia. These include:

- Removal or reconfiguration of RoCoF protection from windfarms
- Improve (or confirm) the capability of generators to remain synchronised for higher RoCoF (i.e. greater than 0.5 Hz/s)
- Improve speed and magnitude of reserve response
- Reduce minimum stable generation levels of synchronous generation
- Develop new, alternative sources of synchronous inertia (e.g. flywheels)

These strategies are described further in section 8. The first of these strategies was indentified in the FoR studies. Here, it was shown that if RoCoF protection of distribution generation was disabled, significantly higher levels of SNSP could be accommodated without unacceptably low frequencies (i.e. frequencies that would result in automatic load shedding). This is illustrated in Figure 11 below.

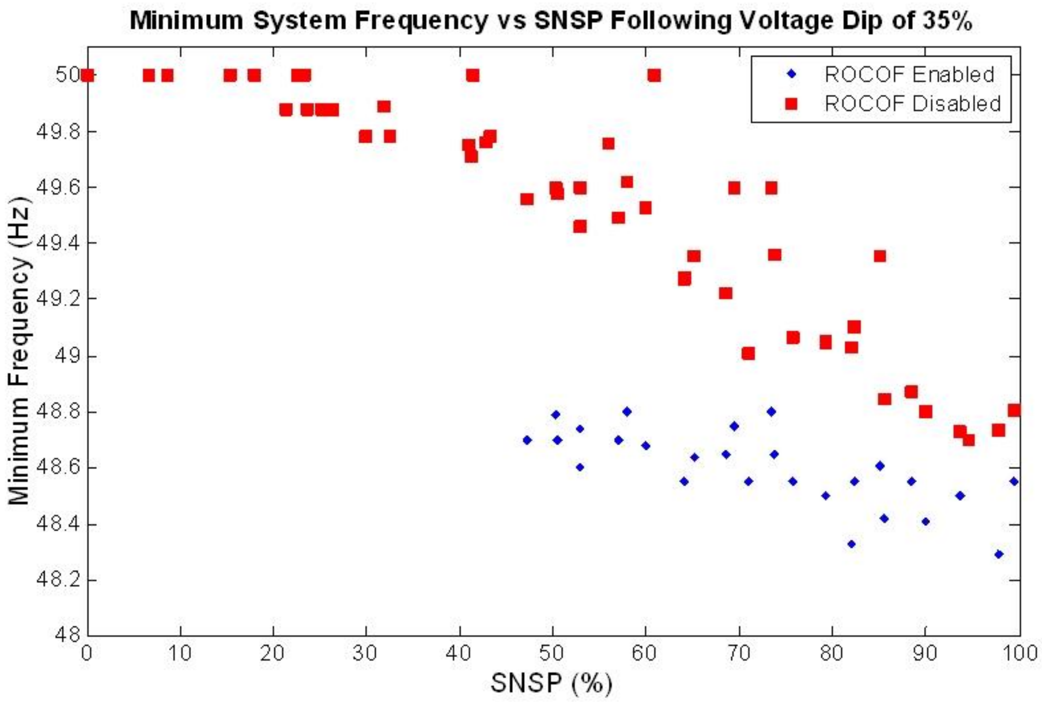

Figure 11: Frequency Nadir vs SNSP - effect of disabling RoCoF protection extracted from FoR studies (EirGrid, 2011)

3.2 Operating Reserve

In the event of the loss of a generating unit, there will be a mismatch between the generation and demand on the power system. The system frequency will fall, at a rate proportional to the system inertia, until this mismatch is corrected. Since the frequency can fall at rates up to 0.5 Hz/s, it is important that power balance is restored rapidly if a system collapse is to be avoided. This is achieved using operating reserve, which is provided by part-loaded generators that have the capability to increase output automatically or by demand which can be automatically reduced.

Primary Operating Reserve (POR), which covers the period from 5 to 15 seconds after a frequency disturbance, tends to be the most challenging category of operating reserve, both from the perspective of individual generator provision, and in terms of system operation. It therefore forms the focus of this analysis.

For comparison purposes, the requirements set out in the Irish Grid Code have been used in this analysis. The required capability of each generator, which is described in section 7.3.1.1 (u) of the Irish Grid Code, is illustrated in Figure 12.

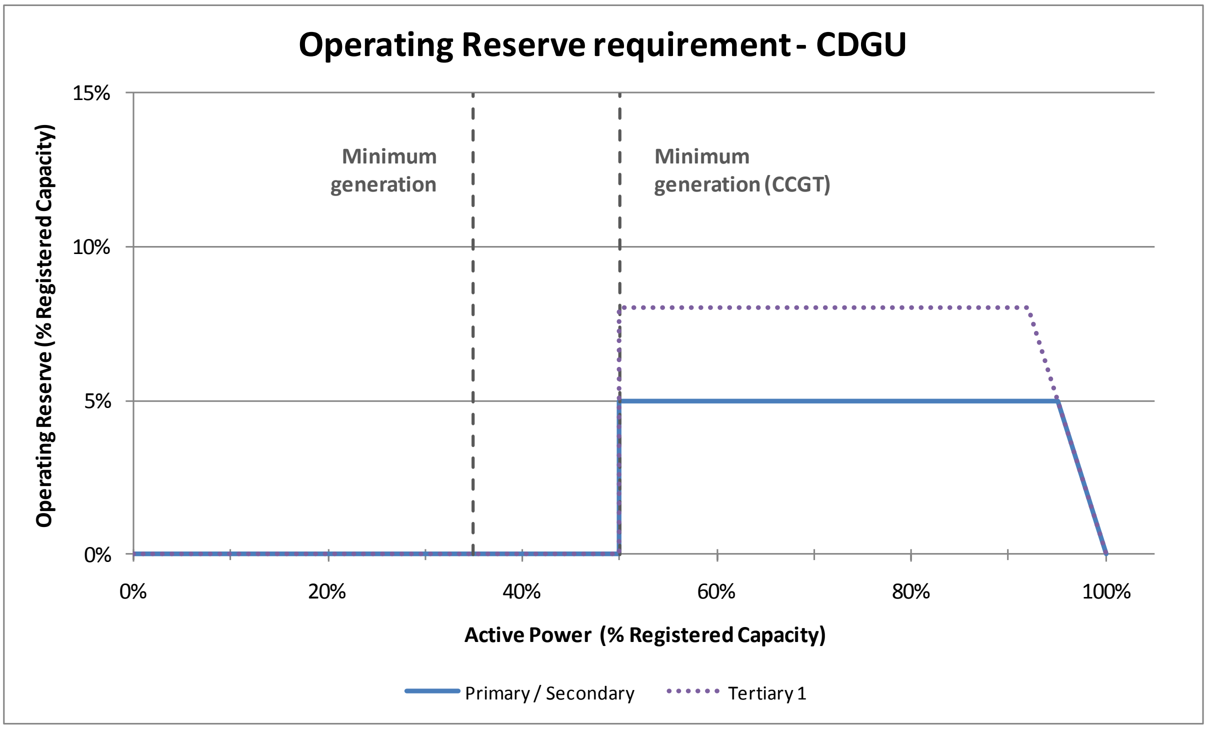

Figure 12: Minimum Operating Reserve capability for CDGUs derived from EirGrid Grid Code V3.4 (EirGrid, 2011)

3.2.1 Current Performance Capability

The capability of the current portfolio has been examined based on the registered capabilities of generators as recorded in their Ancillary Service Agreements. This is illustrated in Figure 13 below. The following observations can be made:

- There are currently 70 generating units contracted to provide operating reserve.
- There is a POR shortfall versus the Grid Code requirement (5%) of 63 MW which is equivalent to 14% of the minimum expected level of the portfolio of 450 MW (i.e. 5% of the total conventional capacity of 9,000 MW).
    - There are 19 units with zero contracted POR (primarily hydro units in Ireland and OCGTs in Northern Ireland), comprising 35 MW of the shortfall.
    - A further 5 units (in Ireland) have contracted POR less than[11] 5%, comprising 28 MW of the shortfall.
- The impact of this shortfall is counter-balanced by the remainder of the portfolio (46 units representing 75% of the MW capacity), which in aggregate has 330 MW more POR capability than the required 5%.
- Thus the overall portfolio, with an average POR capability of 8%, has sufficient POR, albeit not spread evenly across the portfolio.

[11] Shortfalls of less than 0.5 MW have been ignored to account for rounding errors.

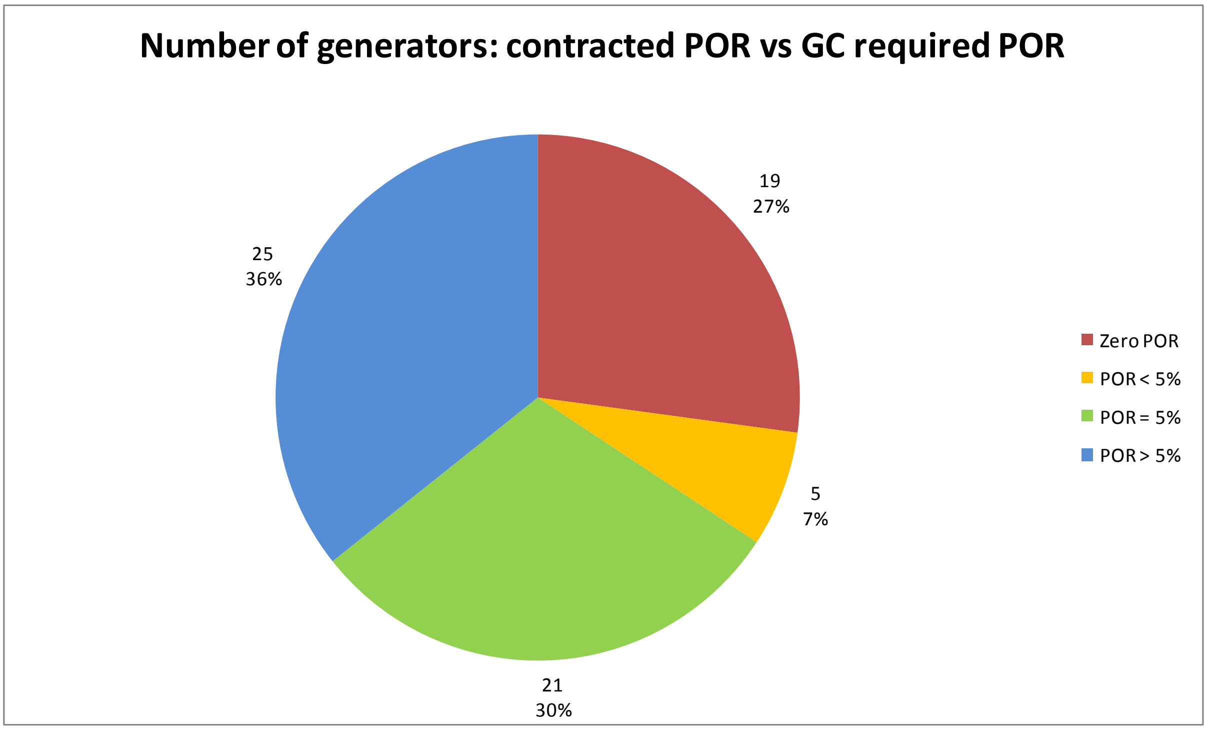

Figure 13: Number of generators by Primary Operating Reserve capability (EirGrid, 2011)

It should be noted that the generators with capabilities that exceed the Grid Code minimum are generally concentrated in Northern Ireland and in the older part of generation portfolio in Ireland. This can be attributed to the importance of reserve (particularly prior to the interconnection of the all-island system) and the centrally planned nature of the system prior to deregulation.

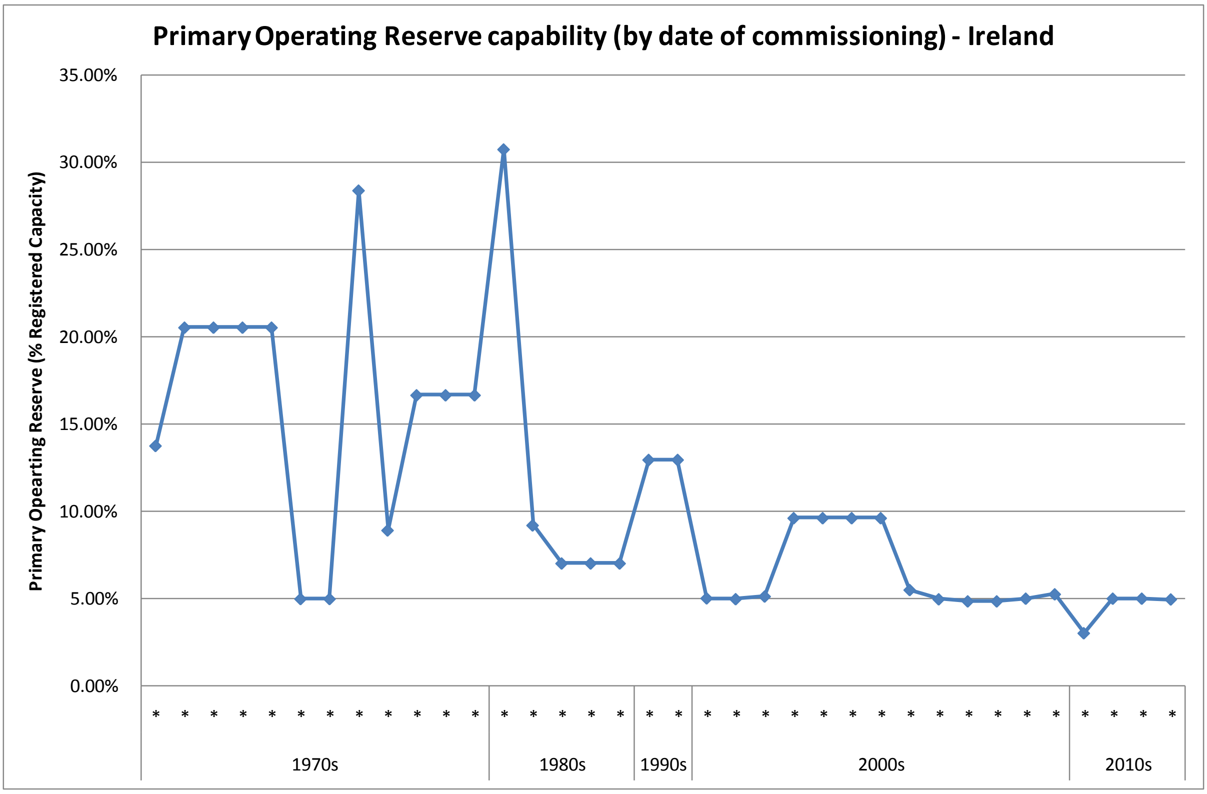

Figure 14: Primary Operating Reserve capability at date of commissioning (Ireland) (EirGrid, 2011)

3.2.2 Projected Portfolio Capability and System Characteristics

It has been assumed that the new generation in the 2020 portfolio will provide the minimum Grid Code required levels of operating reserve. However, since some of the older generators in the existing portfolio will have been retired by then, it is expected that the overall reserve capability of the portfolio will decline (as some of the expected retirements have reserve capabilities well in excess of the Grid Code minimum), thus continuing the trend observed in Figure 14.

The primary driver for the requirement for operating reserve is the size of the largest in-feed. The FoR studies indicate that this requirement (over short timescales) is not expected to fundamentally change[12] even with significant levels of variable generation. The commissioning of the East-West Interconnector between Ireland and Wales, will increase the potential largest infeed to 500 MW, thus somewhat increasing the reserve requirement versus today.

3.2.3 Resultant Issues and Operational Challenges

Lower operating reserve capabilities would mean that a larger number of generators are required to provide the necessary level of operating reserve, potentially limiting the level of wind that can be securely accommodated on the system. Conversely, if greater reserve capabilities can be delivered, the system reserve requirement could be achieved using less generators, allowing a higher level of wind on the system (i.e. lower curtailment), and at a lower cost, since less redispatch would be required.

Reserve provision

The FoR studies were based on a modelling assumption of reliable reserve provision in line with stated capabilities. In practice, performance issues mean that reserve provision is not 100% reliable. The analysis presented here provides an illustrative example of the performance issues currently experienced. It should be noted that the analysis, which is for units in Ireland only, is based on real-time SCADA data. As such, the results presented are indicative and should not be taken as definitive measures of generator performance. EirGrid is making on-going efforts to improve the data available for performance monitoring so that a better understanding of the performance of the system can be obtained.

Preliminary analysis of Primary Operating Reserve (POR) and Secondary Operating Reserve (SOR) performance of generators in Ireland for low frequency disturbances in 2010 has been carried out. For comparison purposes, generators in Ireland have been classified by performance as follows (Figure 15 and Figure 16):

- Good[13]: achieved at least 80% of expected response for at least 80% of events

[12] Further studies are required to examine the performance of windfarms during voltage disturbances

[13] These subjective measures have been used to highlight the differences between performance levels. Generators should be expected to perform to an "excellent" standard, e.g. achieving 100% of the expected response in at least 90% of events.

- Moderate: achieved at least 80% of expected response for at least 40% of events but less than 80% of events
- Poor: achieved at least 80% of expected response for less than 40% of events

Note that the charts only show units that were expected to provide reserve in a sufficient number of events to allow meaningful analysis. Thus units that were off-line or not contracted for reserve are not shown.

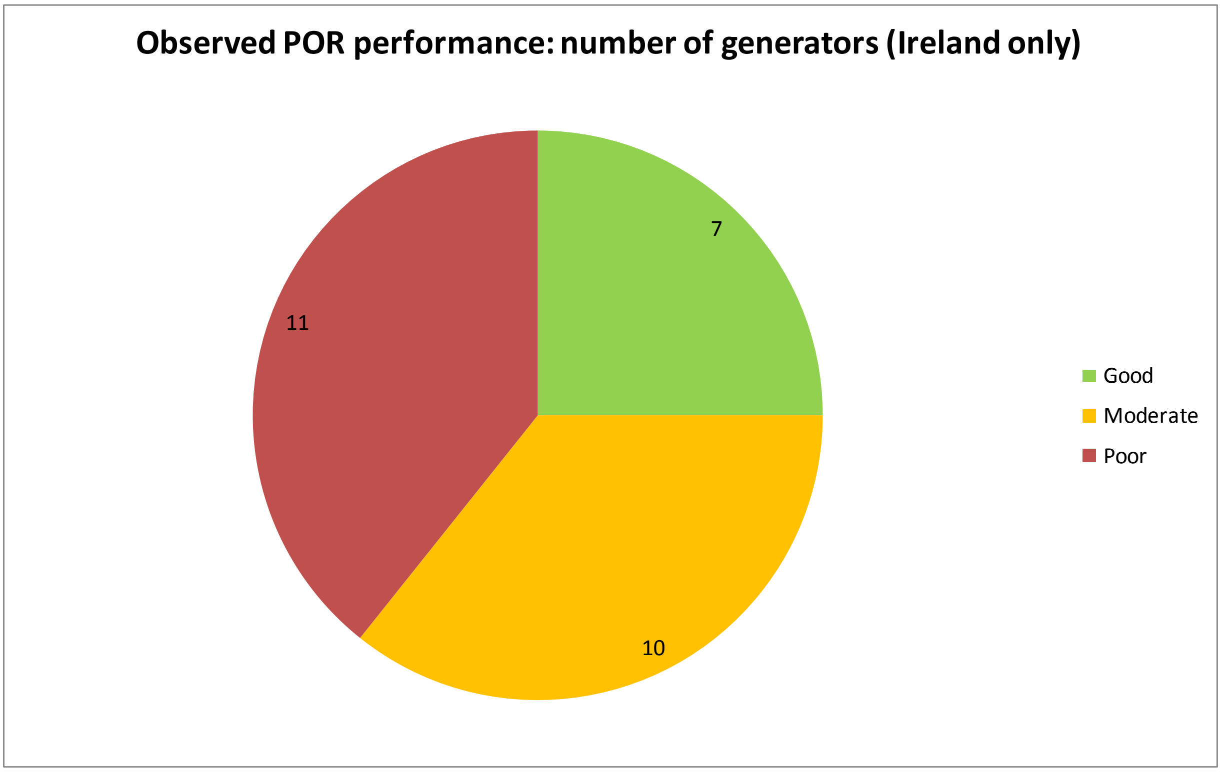

Figure 15: POR performance during frequency disturbances (Performance monitoring data EirGrid, 2011)

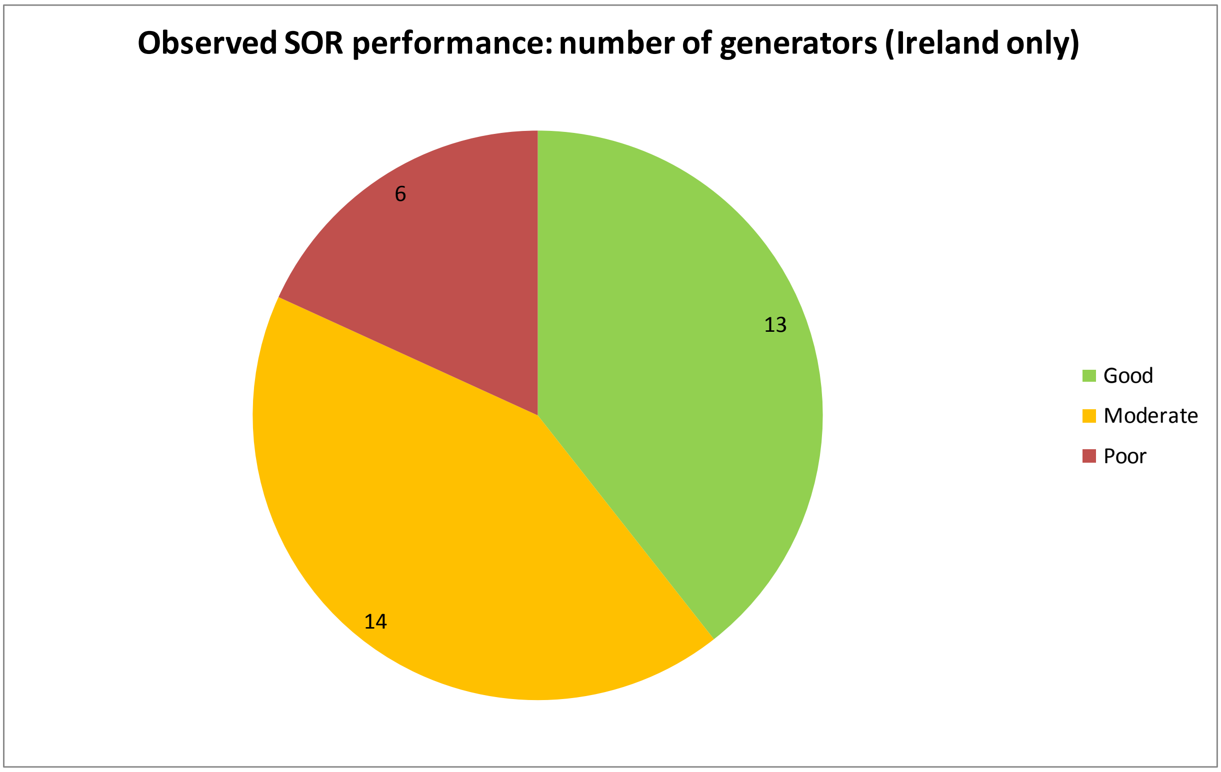

Figure 16: SOR performance during frequency disturbances (Performance monitoring data EirGrid, 2011)

To maintain system security, poor reserve performance must be managed by sourcing additional reserve. This will increase cost (through higher constraint costs) and, to the extent that extra synchronous generators are required to provide this reserve, will increase the amount of wind curtailment.

Reserve slope

Generators are required, per the Grid Code, to have a reserve slope of -1. This slope means that reserve is provided on a one-for-one basis, i.e. to provide 1 MW of reserve, a generator's output must be reduced by 1 MW. However, there are 12 generators that have non-unity slopes. These include 8 CCGTs, which have reserve slopes of approximately -⅔, meaning that for each MW of reserve, their output must be reduced by 1.5 MW. These CCGTs tend to provide primary reserve from their gas turbine(s) only, while their steam turbines, which typically account for ⅓ of the total output, tend not to provide primary reserve.

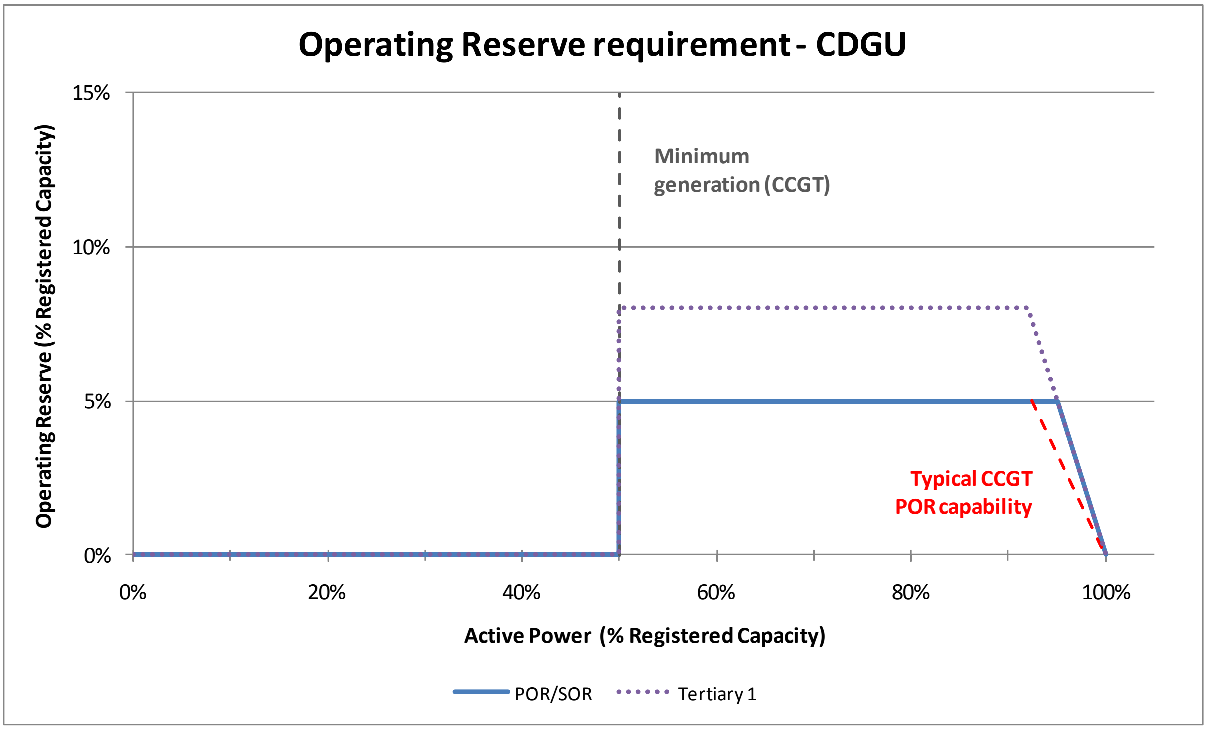

Figure 17: Grid Code minimum Operating Reserve requirement - CCGTs

Although this type of characteristic does not have a direct effect on system security, it acts to increase constraint costs by virtue of necessitating a greater amount of generation re-dispatch to achieve the same amount of reserve. If the trend towards a greater proportion of CCGTs in the portfolio continues, consumer costs will rise if the current performance capability is maintained.

4 RAMPING SERVICES

4.1 Generator Ramping

As explained above, over short timeframes, imbalances between generation and demand are managed using operating reserves, which are activated to restore the system frequency to normal. The most common cause of imbalance is the sudden, unexpected loss of a generator. Over longer timeframes additional factors can cause a generation/demand imbalance which, if not managed, would result in unacceptable frequency excursions. These factors are:

- Demand variation
- Wind variation
- Interconnector flow changes
- Dispatchable generator availability changes (including generator tripping or failure to start)

The net effect of these factors determine the "ramping duty", that is the increase or decrease of the dispatchable generation that is required to ensure balance over the timeframe in question.

Since the power system is operated in real-time, there is always uncertainty about the future generation/demand balance. Regular forecasts are carried out of demand, variable generation sources including wind, and the availability of dispatchable generation. Any errors in these forecasts can increase the ramping duty required. Thus the "ramping requirement" can be defined as the combination of the ramping duty and the likely forecast error. To ensure system security and adequacy, sufficient ramping services must be in place to meet the ramping requirements at all times.

4.1.1 Current Portfolio Capability

There are no explicit Grid Code requirements for Ramping Services. Instead, the requirements over the various timeframes required, can be inferred from the ramp up and ramp down capability requirements for on-load generation and from the notice times and loading characteristics for off-load generation. Based on submitted Technical Offer Data (which contains the technical parameters necessary to calculate each generator's ramping capability) and outturn data for 2010 (generator outputs and availability), the ramping capability of the current portfolio has been calculated for each hour in 2010. The average values are shown in Figure 18, which also shows the expected capability for a number of the 2020 scenarios based on the outputs of the Plexos modelling.

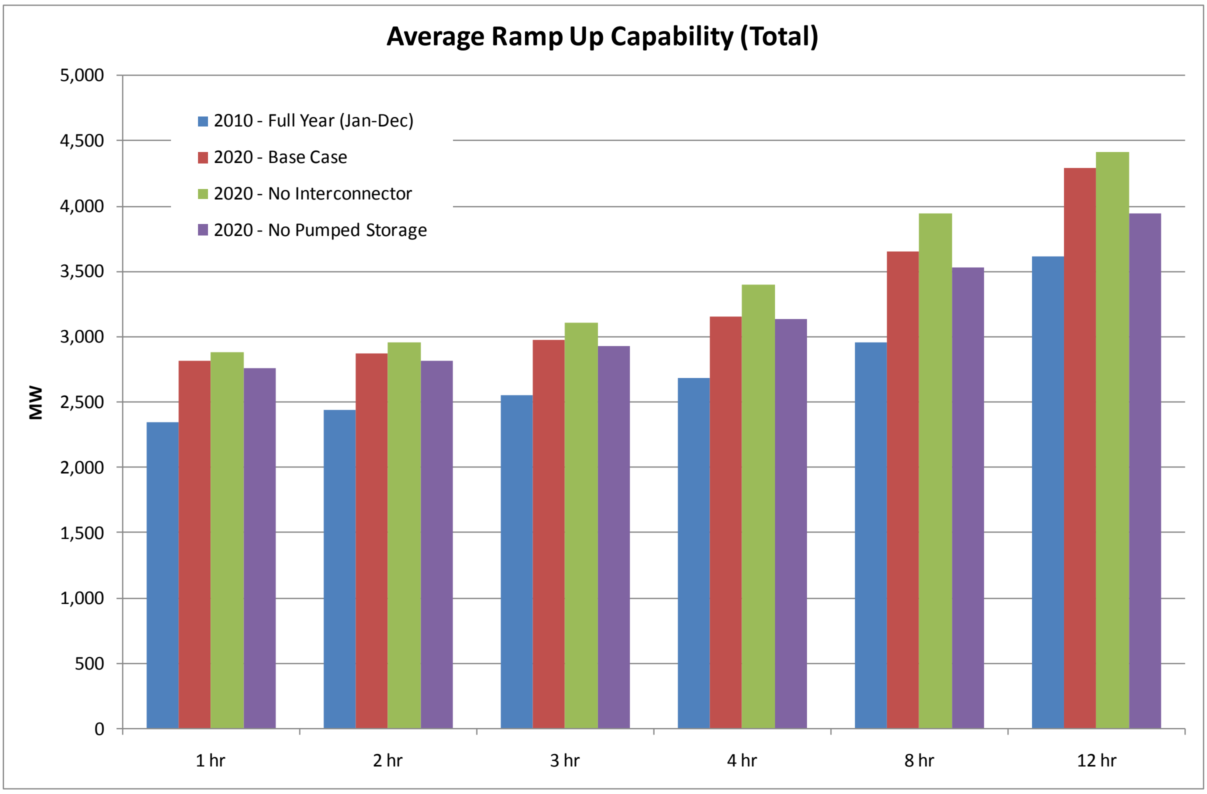

Figure 18: Average Ramp Up capabilities for 1 hour to 12 hour horizons in 2010 (actual) and three modelled 2020 scenarios (EirGrid, 2011)

It can be seen that the ramping capability of the system is expected to increase in 2020. This is due to the replacement of existing thermal generation with more flexible CCGT and OCGT generation. In addition, since the level of wind is expected to increase, the amount of unused non-wind capacity is expected to increase. In the absence of interconnection, the ramp up capability increases slightly. In the scenario with no pumped storage (and no interconnection), the ramping capability reduces, which reflects the contribution that pumped storage makes to ramping services.

4.1.2 Ramping Requirement

Based on the factors listed in section 4.1 above, a ramping requirement has been calculated for each period using the ramping duty (i.e. the change in demand, wind generation and interconnector flows) combined with a forecast error (to account for errors in the demand forecast and wind forecast, and to account for uncertainty of availability of conventional generation). This calculation has been calculated for each hour in 2010, and for each 2020 scenario, over time horizons ranging from 1 hour to 12 hours.

Upwards ramping (i.e. increasing generator output) has formed the focus of this analysis since the requirements tend to be greater in this direction due to the asymmetric risk of a generator tripping. In addition, provided there is adequate active power control of wind generation, for a shortfall in downward ramping can be more effectively met by wind generation, rather than by increasing conventional generation which would result in higher curtailment.

The calculated ramping requirement in each period has been compared with the ramping capability and periods with a deficit (i.e. ramping requirement less than ramping capability) have been examined. The aggregated results are detailed in Table 2. For each scenario, the number of instances of deficit and the total MWh deficit are recorded for each look-ahead horizon.

Table 2: Summary of ramping deficit derived from analysis (EirGrid, 2011)

		Ramping deficit				
Look-ahead horizon (hours)		Current system (2010)	2020 Base case	2020 No inter-connection	2020 No Pump Storage	2020 with 300 MW inflexible
1	No of days	2	-	-	1	-
	No of hours	2	-	-	1	-
	MWh	***759***	**-**	**-**	***89***	**-**
2	No of days	2	-	-	1	-
	No of hours	3	-	-	1	-
	MWh	***867***	**-**	**-**	***130***	**-**
4	No of days	2	-	6	10	2
	No of hours	5	-	6	10	2
	MWh	***835***	**-**	***601***	***877***	***422***
8	No of days	12	-	5	14	2
	No of hours	26	-	9	19	4
	MWh	***5,302***	**-**	***1,475***	***2,580***	***1,411***
12	No of days	2	1	22	36	13
	No of hours	6	2	47	117	27
	MWh	***2,147***	***28***	***9,104***	***28,007***	***5,519***

Findings 2010

Based on the assumptions used, there are instances of deficit in 2010. Since the system is operated as economically as possible, there will be times when, following a disturbance (e.g. loss of a large generator), the system is in an insecure state for a number of hours. It is for events such as this that the ramping capability is required.

Turlough Hill was unavailable for the second half of 2010. Given the contribution that pumped storage makes to both operating reserves and ramping capability, it could be expected that there would be a considerable impact of this outage on ramping. However, by comparing the first half of the year with the second half, no significant effect is apparent. This can be explained by noting that when Turlough Hill became unavailable, the operation of the system was adapted to ensure that the level of system security was maintained by sourcing the operating reserve and ramping normally provided by Turlough Hill from other generators. In addition, the commissioning of new generation (two 440 MW CCGTs in Cork harbour and two 60 MW peaking generators) in 2010 contributed to a greater ramping capability in the second half of the year.

Findings 2020

In the 2020 base case scenario, for the assumptions used, there is significantly less deficit than 2010. While there will be increased interconnection to Great Britain, it has been assumed that the interconnectors cannot directly provide ramping services since the market schedule rather than the system operators will determine the flows. However, the interconnectors, based on the assumption of a fixed price in GB, tend to import at times of high demand and/or low wind (and hence high prices) and export at times of low demand and/or high wind (and hence low prices). As a consequence, the modelled market flows reduce the ramping duty on the indigenous generation portfolio (i.e. the imports and exports flatten the net load profile). In turn, this increases the ramping capability while reducing the ramping requirement and thus there are very few instances of surplus. In reality, however, the interconnector flows are influenced by a wide range of factors, including prices in SEM, prices in BETTA, capacity payments and long-term contracts, and it would therefore be unwise to assume that the interconnectors will necessarily improve the ramping capability.

For the "No Interconnection" case, there are less instances of deficit in the shorter time horizons than in 2010. This is due to the "perfect foresight" effect – a feature both of the market schedule and the Plexos model. The method of modelling used means that any loss of generation can be anticipated and other generation can be rescheduled accordingly. Thus, while in reality reserves are activated and fast ramping capability is used up following the loss of a large generator, this cannot be seen in the modelling studies. Over the longer time horizons, the ramping deficit increases. This is primarily attributable to the variability and predictability of wind generation which increases the ramping requirement as the amount of installed wind capacity increases.

There are considerably more instances of deficit in the case without pumped storage generation. This is not unexpected since pumped storage contributes to ramping in two ways: firstly, its flexibility means it provide a sizable contribution to the ramping capability of the system; and secondly, its ability to act as negative generation reduces the ramping requirement of the system.

4.2 Wind Variability and Forecasting

Variable generation sources (including wind) introduce additional ramping requirements, both due to the inherent variability of the energy source, and due to uncertainty of its availability (i.e. forecast accuracy).

The inherent variability of wind generation, due to the movement of weather systems across the power system can be reported in any number of ways. An illustration of wind variability is shown in Figure 19, which shows the maximum daily 1-hour variation of wind generation plotted against the maximum daily wind generation.

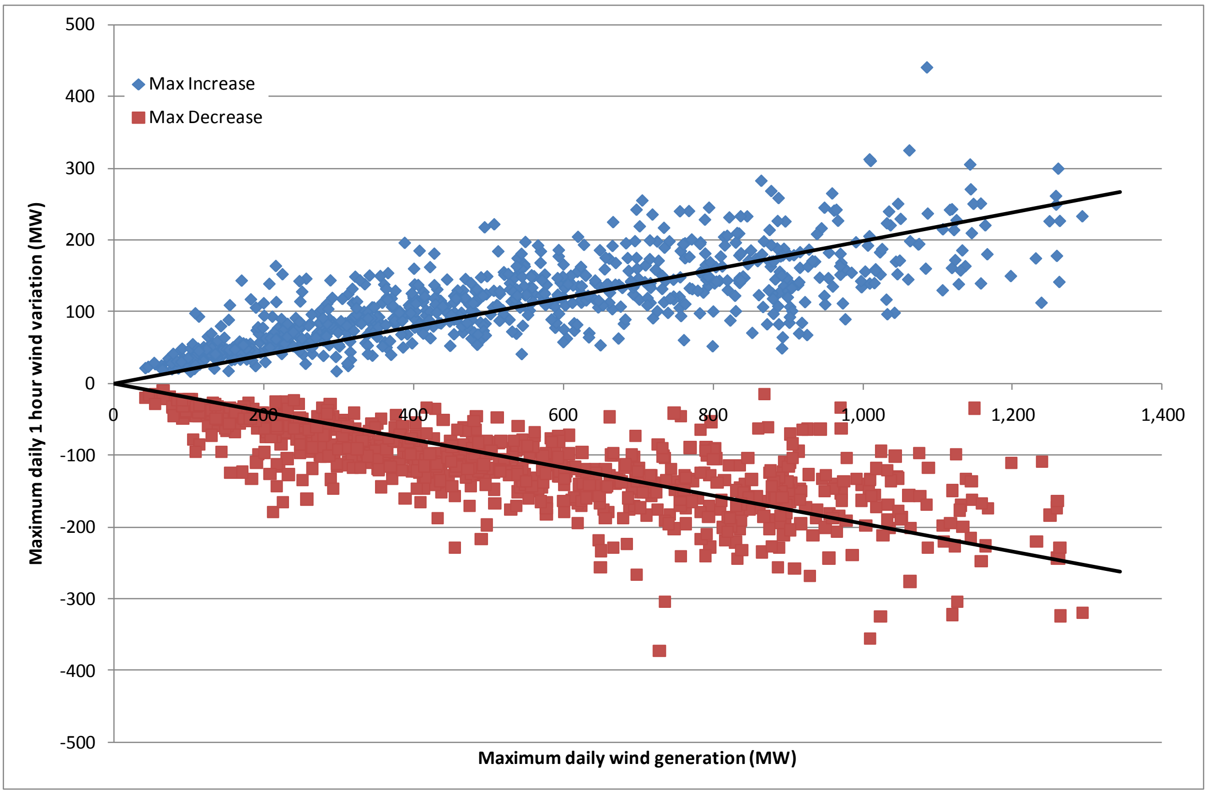

Figure 19: Maximum daily 1 hour wind variation vs maximum daily wind generation from SCADA data (EirGrid, 2011)

The correlation between variability and wind output is clear. The graph suggests that the maximum 1-hour wind variation is typically 20% of the maximum daily wind generation.

The variability in wind generation may, when combined with the variation in demand and interconnector imports and exports, impact on the ramping duty imposed on the remaining generation portfolio. Higher ramping capabilities are required as the time horizon extends, since the size of wind variation tends to increase for longer time periods. This is illustrated in Figure 20 below which shows the distribution of changes in wind output over different time horizons. It can be seen that in one hour the normalised change in wind output (blue curve) is relatively small with the bulk of the changes between plus and minus 15%. Essentially if the wind was producing 1000 MW there is a likelihood that the change in wind in one hour will be up to 150 MW in either direction. However, over a 12 hour period (the green curve) it is as possible to have a 45% change in output in either direction. At 1000 MW wind output, this is equivalent to 450 MW – the size of the largest conventional generator.

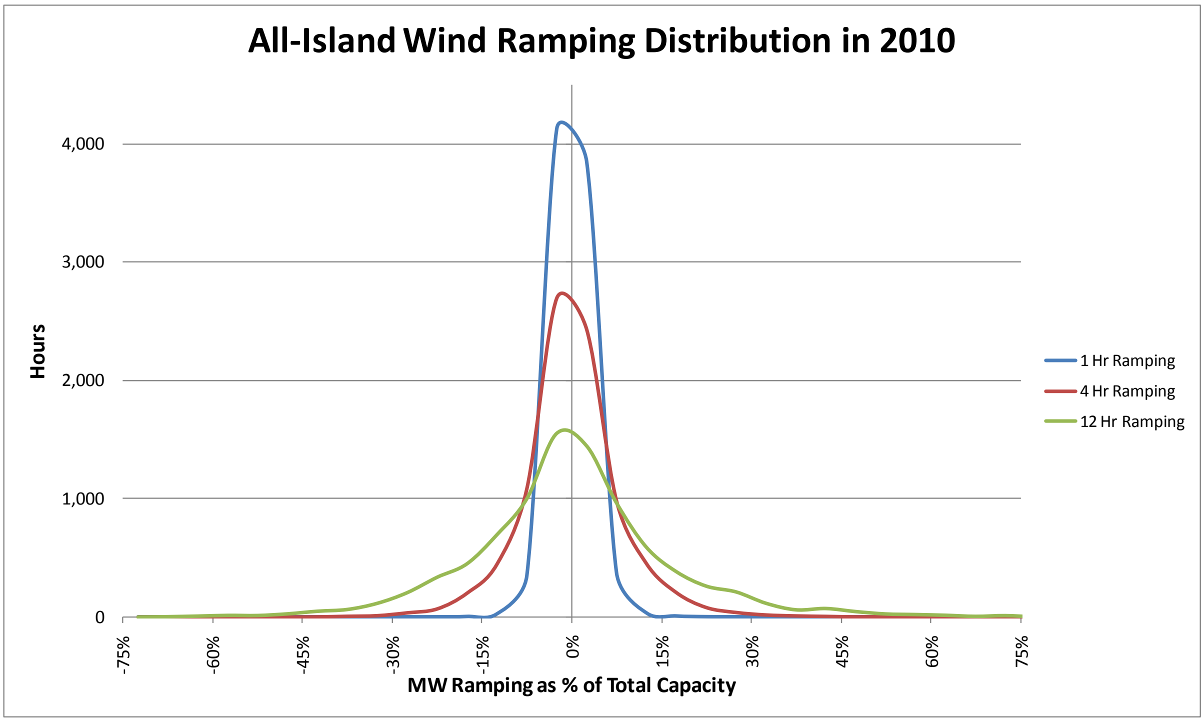

Figure 20: Distribution of wind generation variation based on analysis of 2010 data (EirGrid, 2011)

The level of increasing wind has an impact on the reliability and certainty of the actual portfolio at a given time period into the future. While there is always an element of uncertainty in system operation (e.g. a generator could trip and be forced out at short notice) and operational policies have developed deterministic mechanisms to manage this, new practices may be required going forward. To date an analysis of the current forecasting shows that at longer horizon time periods the error increases. This is to be expected. In addition, there has been a notable improvement over the last number of years (Figure 21) as more information and improved forecasting methods have been developed, and a greater number[14] of windfarms were installed.

[14] As the number of windfarms increases, there is an increase in geographic diversity, which reduces the correlation between windfarm forecast errors and thus reduces the aggregate error.

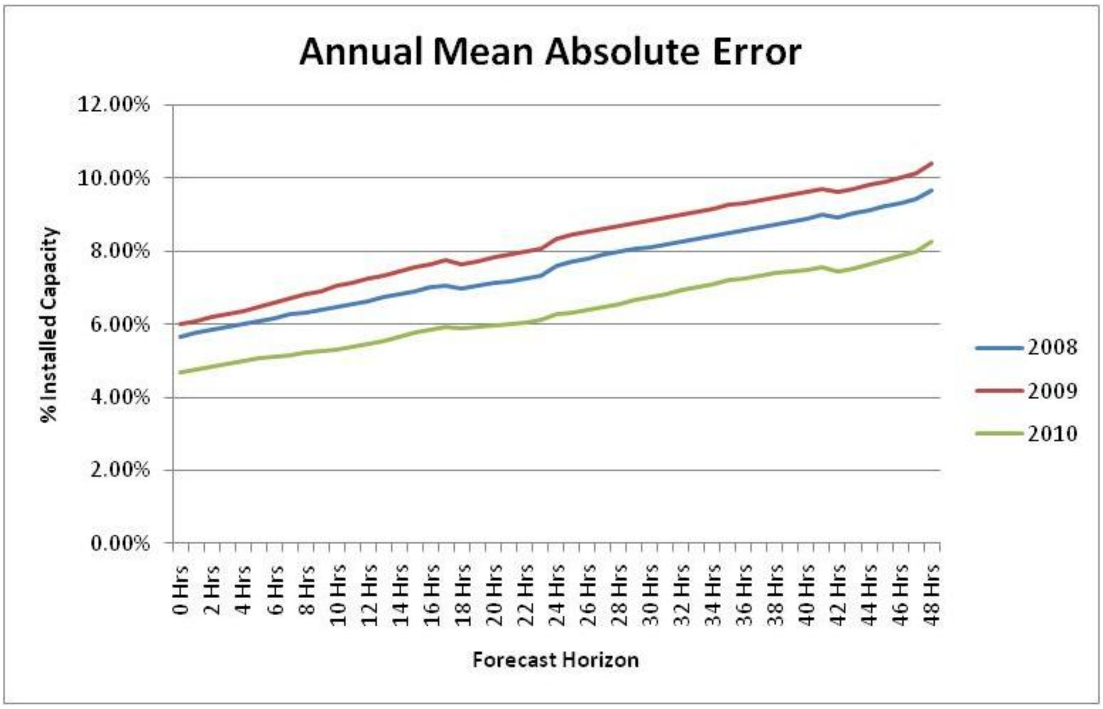

Figure 21 Mean Absolute Error against installed wind capacity in wind forecasts from one hour to two days ahead (EirGrid, 2011)

However, underlying the mean absolute error (for an installed capability of 6000 MW there is on average 5% mean error in 10 hours equating to 300 MW) it hides the reality that in any given period there is a possibility of a higher error. This uncertainty in forecast error has, in the first instance, an increased cost of operation as policies are required to hold sufficient reserves and ramping services to manage. In the longer term, with significant level of windfarms, this uncertainty has the potential to threaten system security. In particular an over-forecast of wind could lead to energy shortage[15].

An example of the nature of the error is provided in Table 3. The mean absolute error is calculated as 9% but the maximum error in any half hour was 17%. The experience of EirGrid is that at 4 hours notice at the 95% percentile there is on average a possibility of an 18% error and has been as high as 43%. In the short term, improvements in forecasting may pay dividends. However, in the medium term it is unlikely that forecasting techniques on their own will be sufficient to manage the increasing uncertainty and therefore new operational policies will be required. In the long run, stochastic scheduling and probabilistic forecasting need to be investigated to determine if they provide more efficient and secure mechanisms to manage this uncertainty. While this issue is being driven by increasing wind, it is highly likely that these developed techniques will have direct relevance in managing a power system with significant demand side participation and electrification of new loads including electric vehicles.

[15] Excess energy above forecast can be managed at least by dispatching the wind to the forecasted level in used in the scheduling of the system provided the necessary active controls are in place.

Table 3: Illustration of Mean Error calculation

Time Forecast Received	Time Period it applies to	Forecast MW	Actual MW	Error	Absolute Error	Installed Capacity	Error
00:00	06:00	150	175	25	25	1450	2%
00:00	06:30	160	145	-15	15	1450	1%
00:00	07:00	225	150	-75	75	1450	5%
00:00	07:30	260	260	0	0	1450	0%
00:00	08:00	290	210	-80	80	1450	6%
00:00	08:30	400	225	-175	175	1450	12%
00:00	09:00	480	275	-205	205	1450	14%
00:00	09:30	520	350	-170	170	1450	12%
00:00	10:00	650	400	-250	250	1450	17%
00:00	10:30	750	550	-200	200	1450	14%
00:00	11:00	800	650	-150	150	1450	10%
00:00	11:30	650	800	150	150	1450	10%
Average Error							**9%**

4.3 Active Power Control

To maintain a secure power system and control system frequency, the TSOs require sufficient control of the active power output of generators at all times. Conventional power stations are normally[16] continuously manned. Active power control is effected using dispatch instructions sent by the TSO to the power station and implemented locally by the power station operator. Windfarms are not normally manned and therefore active power control is implemented directly by the TSO using an electronic interface. The requirements for this remote active power control are set out in the Grid Codes. Of the 1,730 MW of installed wind generation, 25% is not required to provide active power control either by virtue of being exempt from the Grid Code (e.g. for windfarms that pre-date the implementation of the Wind Grid Code), by having a derogation in respect of active power control, or by being less than the *de minimis* level for distribution-connected windfarms (i.e. Registered Capacity of less than 5 MW).

The implementation of active power control requires the integration and interfacing of windfarm control systems with the TSOs' Energy Management Systems. This is a complicated process and can

[16] Some power stations have remote control facilities and are therefore not required to be manned continuously (e.g. ESB hydro generators are controlled from Turlough Hill).

take time to fully commission. As a result, not all windfarms (that are required to) currently have active power control. This is illustrated in Figure 22 below.

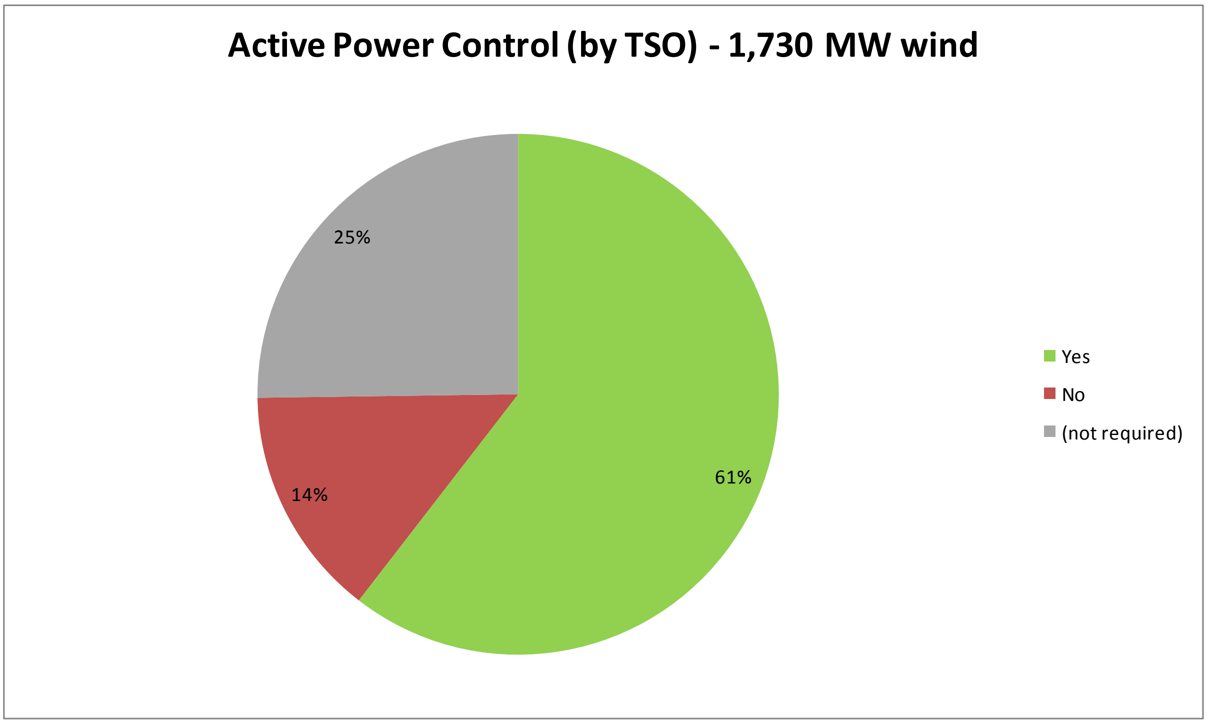

Figure 22: Percentage of all-island installed windfarms with TSO active power control (EirGrid/SONI, 2011)

5 VOLTAGE CONTROL

5.1 Reactive Power

The management of voltage on a power system is essential for the reliable transportation of electrical energy from point to point. In a similar way to the relationship between frequency and active power balance, the system voltage is determined by the balance of reactive power production and absorption. Generators have traditionally been a primary source of reactive power, which compensates for the reactive power produced and absorbed by consumers and by the network itself. Without this reactive power capability, used in an efficient manner, system losses would increase and system security would be compromised. Reactive power, unlike active power, is predominately a local phenomenon, i.e. it is not easily transmitted over significant distances. However, the management of voltage requires a co-ordinated approach of reactive power control throughout the whole system as deficiencies in a local area at a certain point can have an inordinate impact on other voltages, potentially leading to a collapse.

The Grid Code standards for reactive power control for both thermal plant and wind farms, as set out in the Irish Grid Code[17], are shown in the figures below. The different shapes of the characteristics are due to the typical capabilities of the different technologies. It should be noted that these requirements currently apply only to generation connected at voltage levels of 110 kV or higher.

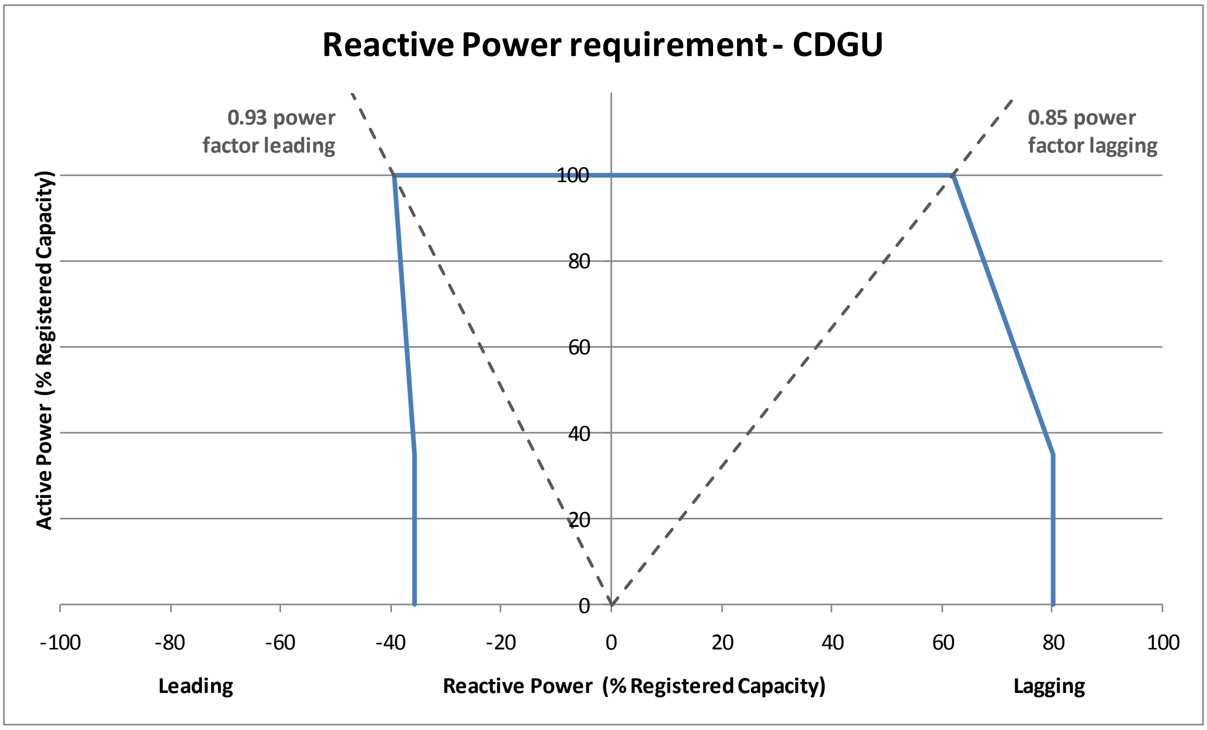

Figure 23: Required Reactive Power characteristic for CDGUs from Grid Code ver 3.4 (EirGrid, 2011)

[17] The Northern Irish Grid Code has similar provisions but, as noted previously, for comparison purposes a single standard has been used.

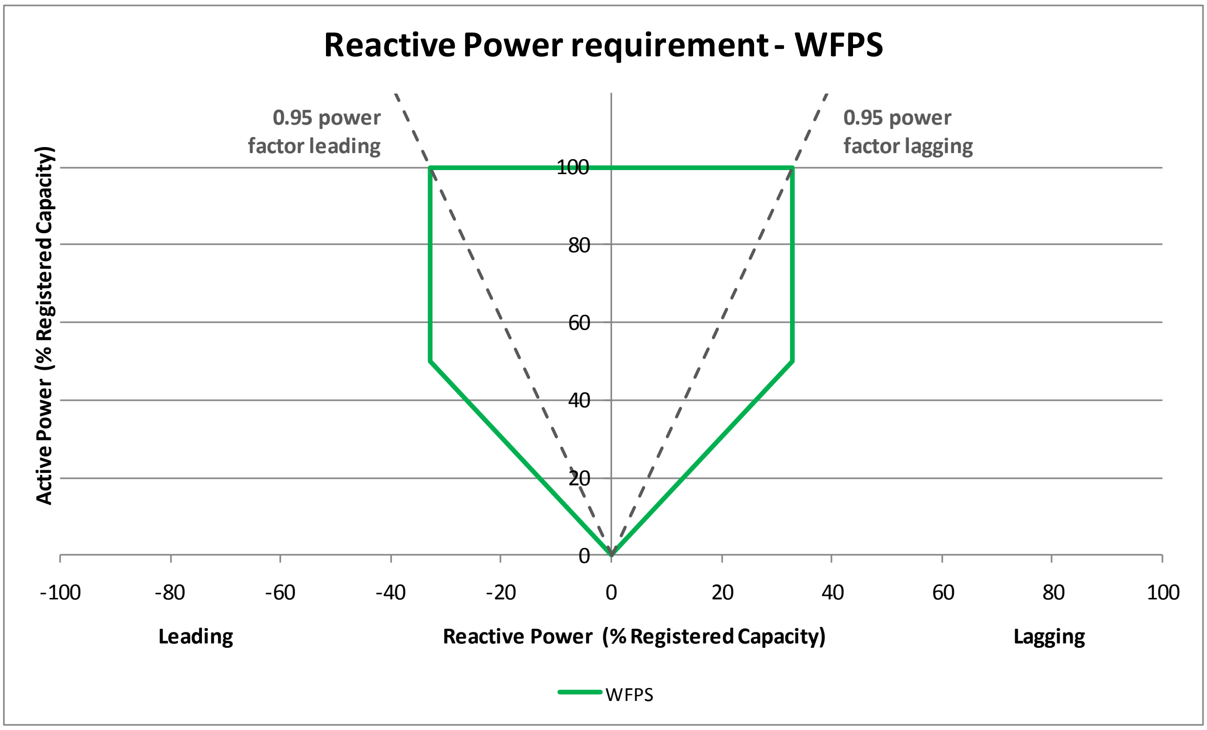

Figure 24: Required Reactive Power characteristic for windfarms derived from Grid Code ver3.4 (EirGrid, 2011)

5.1.1 CURRENT PORTFOLIO CAPABILITY

The current portfolio has been assessed by comparing the reactive power capability of each generator with the capability inferred from Grid Code requirements shown above. The portfolio capability, being the aggregate across all generators is shown in Figure 25. There are deficiencies in respect of both lagging and leading reactive for some generators. However, the portfolio deficiency in respect of leading Mvars is more pronounced, with a shortfall of approximately 30% (in both jurisdictions) against the Grid Code standard.

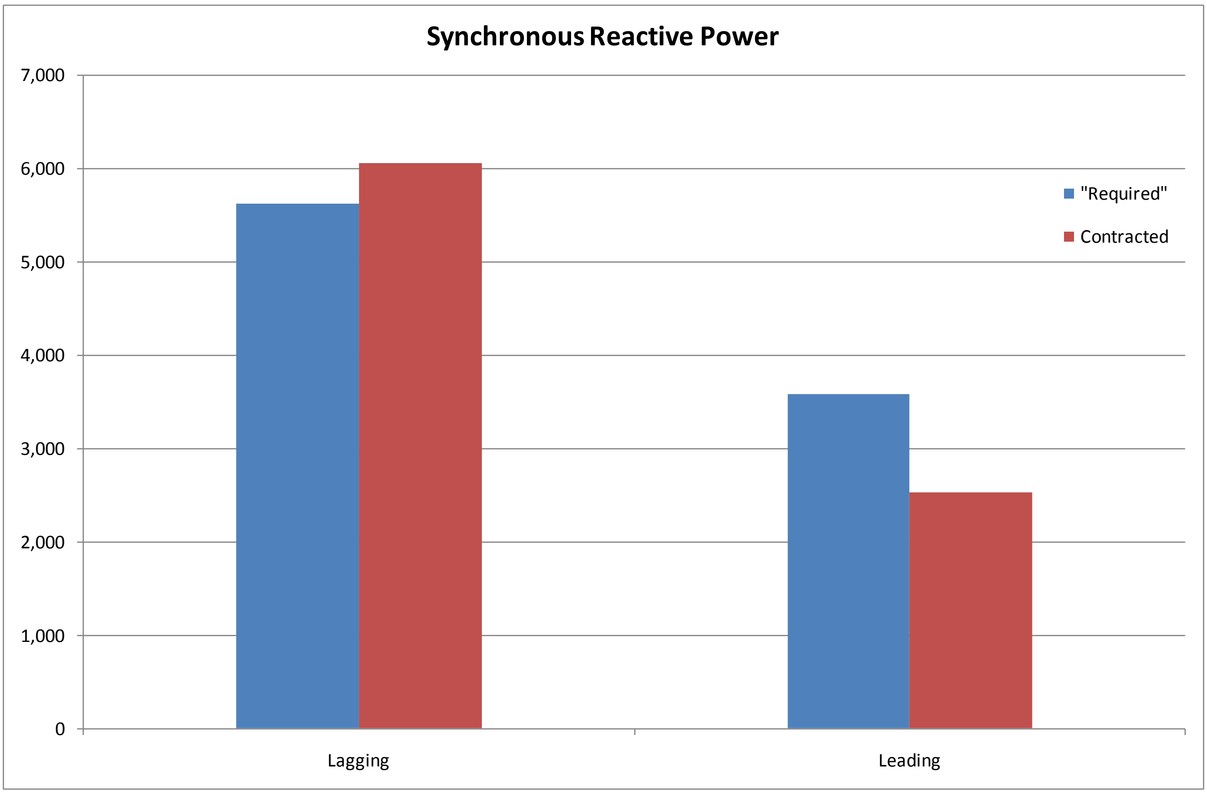

Figure 25: 2010 portfolio: Reactive Power Capability (Mvar) – Required vs Contracted (EirGrid, 2011)

Wind portfolio: of the 1730 MW of installed wind, 783 MW is Transmission connected[18] (all of this is in Ireland). Of this, only 470 MW (60%) has remote voltage control capability from the Control Centres and of this 170 MW has derogations in respect of voltage control. The derogations are mainly in respect of the quality of voltage control (e.g. speed of response) or reactive power capability (e.g. windfarm unable to provide full reactive power requirements at maximum active power output). Based on the issuance of Operational Certificates, only 25% of Transmission connected wind has demonstrated full GC compliance.

[18] For the purposes of Reactive Power analysis, distribution-connected, Type A windfarms (i.e. connected at 110 kV) are included in the transmission-connected figures as they have the same voltage control requirements as transmission-connected windfarms.

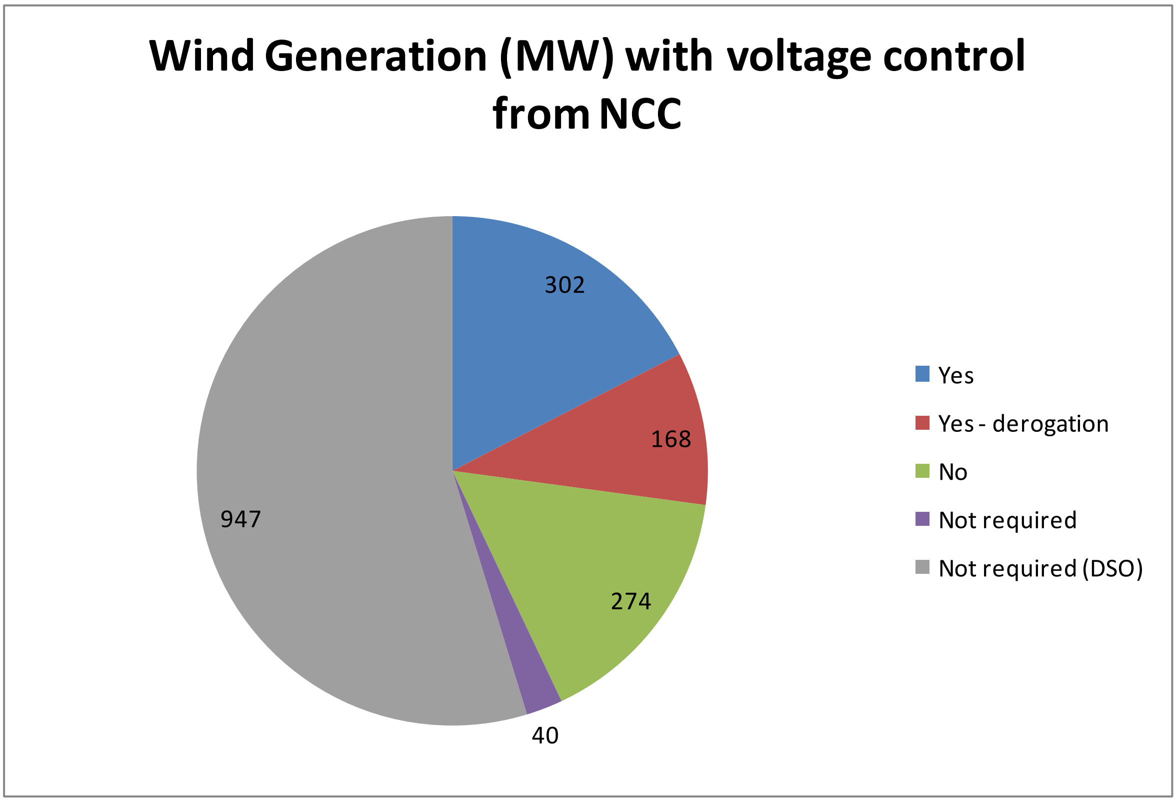

Figure 26: Windfarms with TSO voltage control (EirGrid, 2011)

The figures above show the capability of the portfolio to provide reactive power. In practice, since generators can normally only provide reactive power when synchronised, the actual available reactive power on the system will vary depending on system conditions. This variability is illustrated in Figure 27, which shows the maximum and minimum daily synchronised available reactive power.

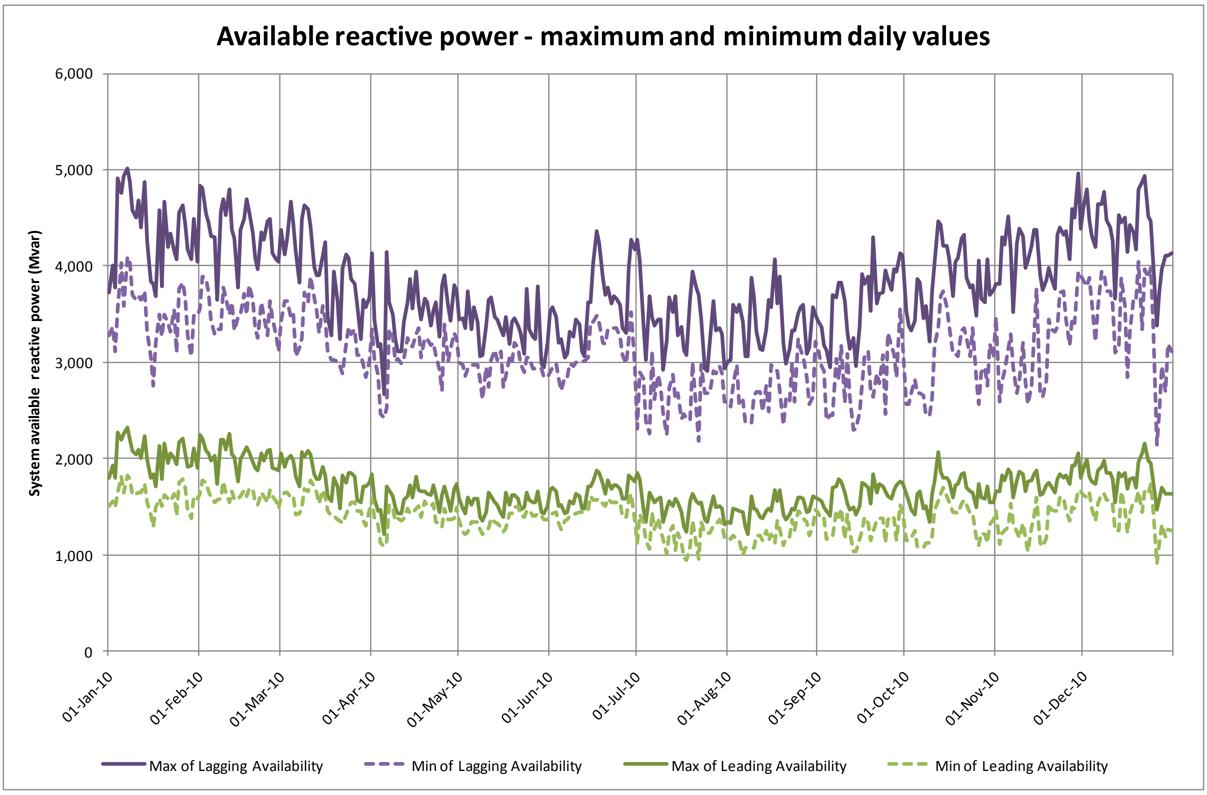

Figure 27: Actual daily maximum and minimum values of available reactive power from synchronised generation (EirGrid, 2011)

The daily and hourly variability of available reactive power makes interpreting a full year of data difficult. However, the values can be presented as a duration curve, which shows the percentage of hours in the year that the available reactive power exceeds a particular level. Figure 28 shows the available reactive power duration curve for 2010 (for both leading and lagging reactive power).

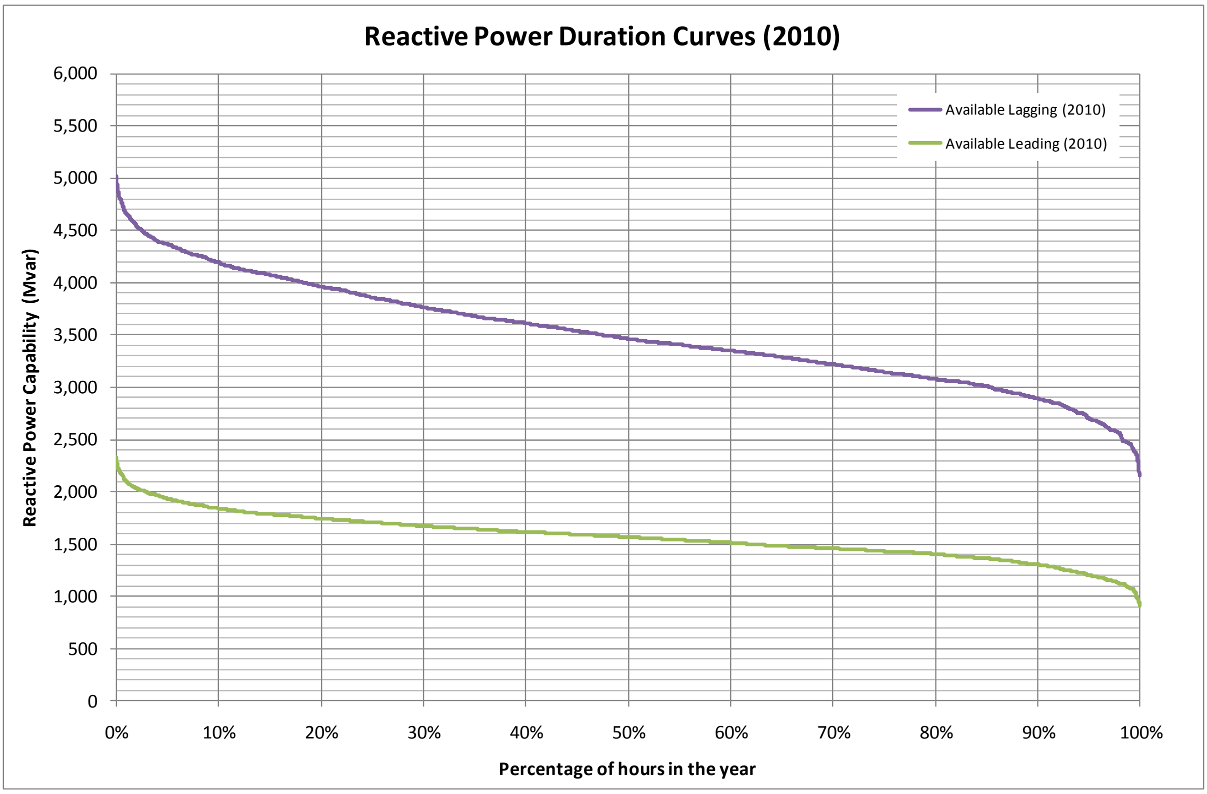

Figure 28: Actual 2010 Reactive Power duration curves for on-line synchronous leading and lagging reactive power (EirGrid, 2011)

5.1.2 Projected Portfolio Capability and System Characteristics

It has been assumed that as the generation portfolio evolves, the new synchronous generation that is commissioned will provide the reactive power capability shown in Figure 23. This means that existing generation, which has slightly better than Grid Code capabilities in terms of lagging reactive power but poorer than Grid Code capabilities in terms of leading reactive power, will be replaced with Grid Code compliant generation. In addition, the level of installed synchronous generation is expected to fall by approximately 700 MW. Thus, as illustrated in Figure 29, the system capability for lagging reactive power is expected to fall while the level of leading reactive power is expected to rise.

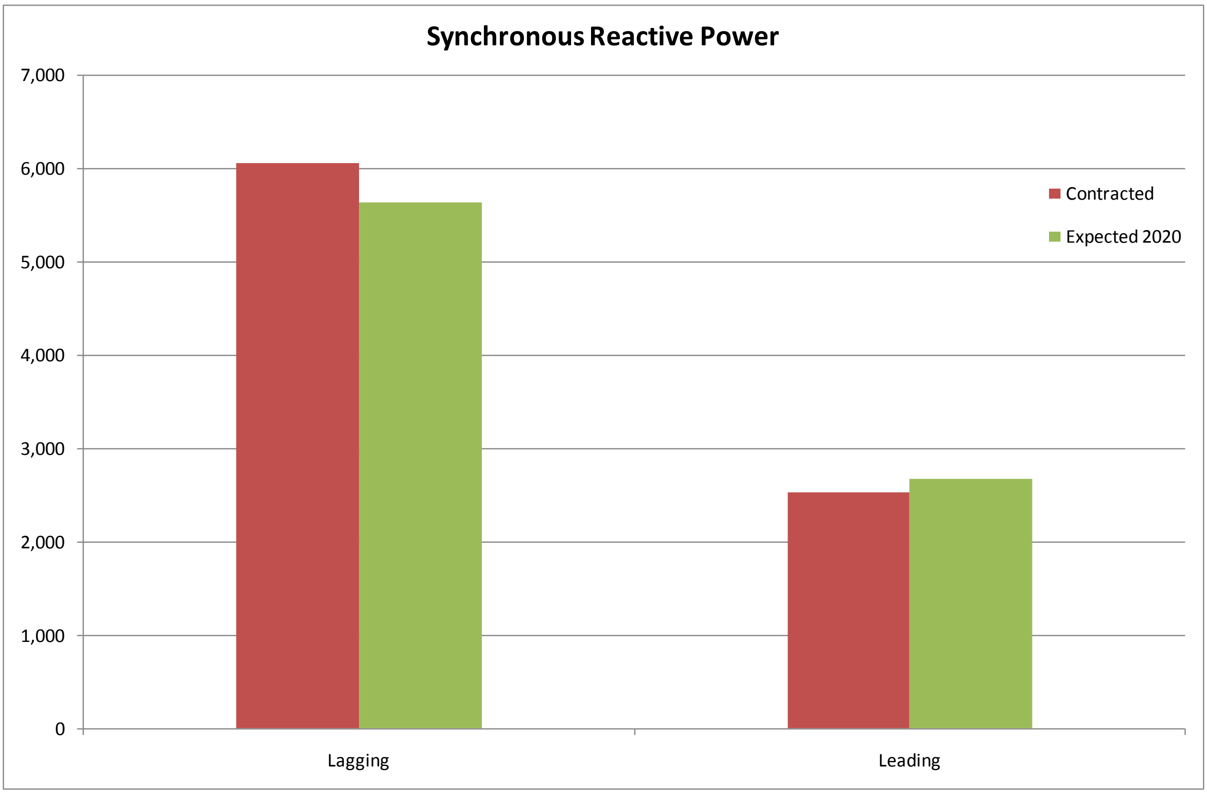

Figure 29: Expected 2020 portfolio synchronous Reactive Power capability (Mvar)

Given the nature of the changes to the types, connection methods and location of the future generation portfolio, together with the development and evolution of the transmission and distribution networks, it is difficult to predict exactly how much reactive power will be required and where. However, it is reasonable to expect that secure system operation will require a reactive power range that is broadly similar to at present. In other words, while static compensation devices (e.g. switched capacitors or reactors) could be installed to offset an underlying shift in reactive power requirements (e.g. the addition of additional 400kV circuits), the daily variation in system conditions (as the load and generation pattern changes) will continue to require variable reactive power provision by the generation portfolio.

It should also be noted that the power system is changing from one of bulk power generation and transmission to load centres into a system with high levels of embedded generation, much of which is variable. This means that the transmission and distribution systems need to be capable of a much wider operating range: from peak demand with low embedded generation to minimum demand with high embedded generation. This is a fundamental shift and may increase the range of reactive power control that is required to maintain system voltages within limits.

In addition to the portfolio capability changing, the available (on-line) reactive power is expected to change significantly by 2020 as non-synchronous renewable generation displaces synchronous generation. Based on the Plexos studies of the 2020 system[19], available reactive power figures have been calculated.

[19] Since the precise reactive power capabilities of the East-West Interconnector are not yet fully determined, the "No Interconnector" case has been used for the reactive power analysis.

The following table shows average available reactive power (i.e. from on-line generation) in 2010 and 2020 (with percentage increase/decrease). Also shown are two wind cases, one where it is assumed that only Transmission-connected wind (approximately 50%) provides the Grid Code required levels of reactive power, and a second where it is assumed that all wind provides the capability set out in Figure 24.

Table 4: System Reactive Power with different 2020 portfolio and windfarm capabilities

	Lagging Mvar	Leading Mvar
2010	3510	1570
2020 (conventional only)	2650 **(-24%)**	1310 **(-16%)**
2020 (Transmission wind)	3240 **(-8%)**	2000 **(+21%)**
2020 (all wind)	3830 **(+9%)**	2480 **(+58%)**

These average values, along with the reactive power duration curves shown in Figure 30, clearly show that the level of available synchronous reactive power is expected to fall by 2020. This reduction can be offset to an extent, however, if the wind generation that will displace the synchronous generation provides an equivalent reactive power service.

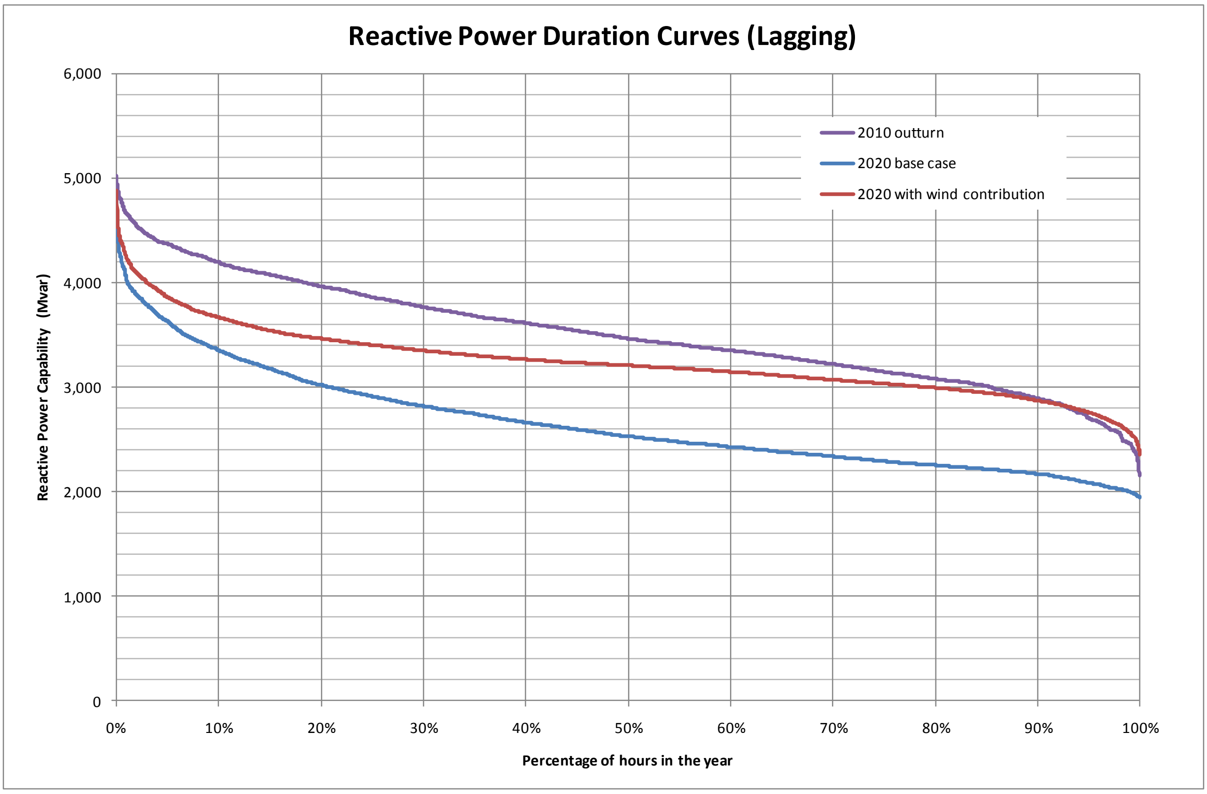

Figure 30: Reactive Power duration curves – evaluated from 2010 actual data and two modelled scenarios in 2020 (EirGrid, 2011)

A particular feature of reactive power is that, unlike active power, it is difficult to transmit over long distances (even if there is adequate transmission capacity). This means that to ensure an acceptable voltage profile throughout the system reactive power sources need to be electrically dispersed in a way that complements the reactive power requirements of the system (including the demand on the system). For example, even if the total system demand could be met by generation in Dublin and Belfast, reactive power sources would be required in Cork to maintain voltages within operational limits. At times, this can lead to minimum generation levels in particular regions of the system.

The locational aspect of reactive power is illustrated in Figure 31, which compares the duration curves for available leading reactive power in the Dublin region in 2010 and 2020. The Dublin region, with its considerable underground cable[20] network, has a high leading reactive power requirement, which at times is a binding operational constraint. It can be seen from the graph that the current normal minimum level is 500 Mvar.

For the 2020 dispatch[21], this minimum level was breached in over 80% of the hours. This is due to windfarms (outside Dublin) replacing conventional generation, combined with new CCGT generation, which would be expected to be more efficient than existing generation, locating outside Dublin. This suggests that alternative sources of reactive power, or alternative voltage control will need to be found. Otherwise additional constraints on generation will be required, which will increase cost and potentially increase the amount of wind curtailment.

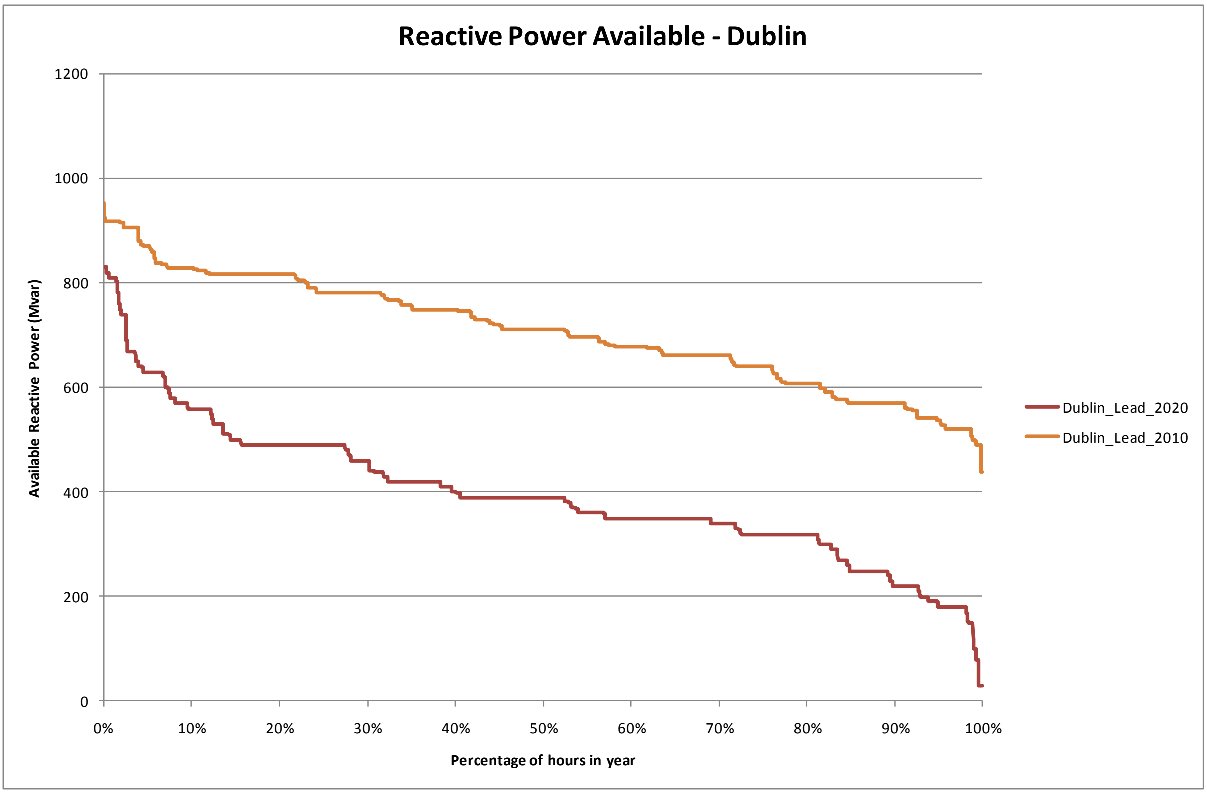

Figure 31: Available reactive power (Leading) in the Dublin region – 2010 actual and 2020 simulated data (EirGrid, 2011)

[20] Underground cables, due to their high capacitance, produce reactive power (causing voltages to rise), which must be compensated for using Leading reactive power.

[21] It should be noted that the 2020 dispatch was produced using Plexos, which did not consider voltage constraints.

5.1.3 Resultant Issues and Operational Challenges

The current performance levels are not causing significant problems at present, although the system is becoming more stretched due to demand growth and increasing levels of wind displacing synchronous generation. Due to the locational aspect of reactive power, local deficits may arise in high wind scenarios, which would necessitate the constraining on of synchronous generation in the required parts of the network, thereby increasing costs and potentially increasing wind curtailment.

The magnitude of reactive power required on the power system in 2020 is difficult to predict with certainty. More reactive compensation (than estimated to date) may be required on the system to compensate for additional capacitance in the transmission network and the distributed nature of the wind generation portfolio.

As wind replaces synchronous generation, the location and nature of available reactive power will change. This means that steady state voltage control will become more difficult. However, if wind generation provides reactive power services, this is expected to be manageable.

5.2 Dynamic Reactive Power Considerations

While reactive power can be provided by a number of different sources (e.g. synchronous generation, power electronic devices, shunt capacitors/reactors), not all reactive power is equal. This is true both from a steady state perspective – for example the reactive power output of a capacitor depends on the voltage whereas a synchronous generator can normally provide constant reactive power as voltage varies – and from a dynamic or transient perspective.

As explained above, steady state voltage control is expected to become more difficult as the level of controllable reactive power falls and the location of it changes. However, this is expected to be manageable provided wind generation contributes to the reactive power capability of the system.

On the other hand the FoR studies indicated that at high system non synchronous penetration levels the transient stability of the system will be significantly compromised (Figure 32). This arises since with fewer on-line synchronous generating units[22] there is a reduction in synchronising torque – the forces that keep generators operating in unison. As the instantaneous penetration of wind increases relative to system demand (and exports), the percentage of contingencies with a critical clearance time (CCT) less than 200ms increases. Since critical clearance time is a measure of the transient stability of the system (with higher CCT denoting greater stability), this means that the system becomes less transiently stable at high wind penetrations relative to system demand.

[22] The fault-ride through capabilities of synchronous generators directly impacts the minimum secure level of synchronising torque.

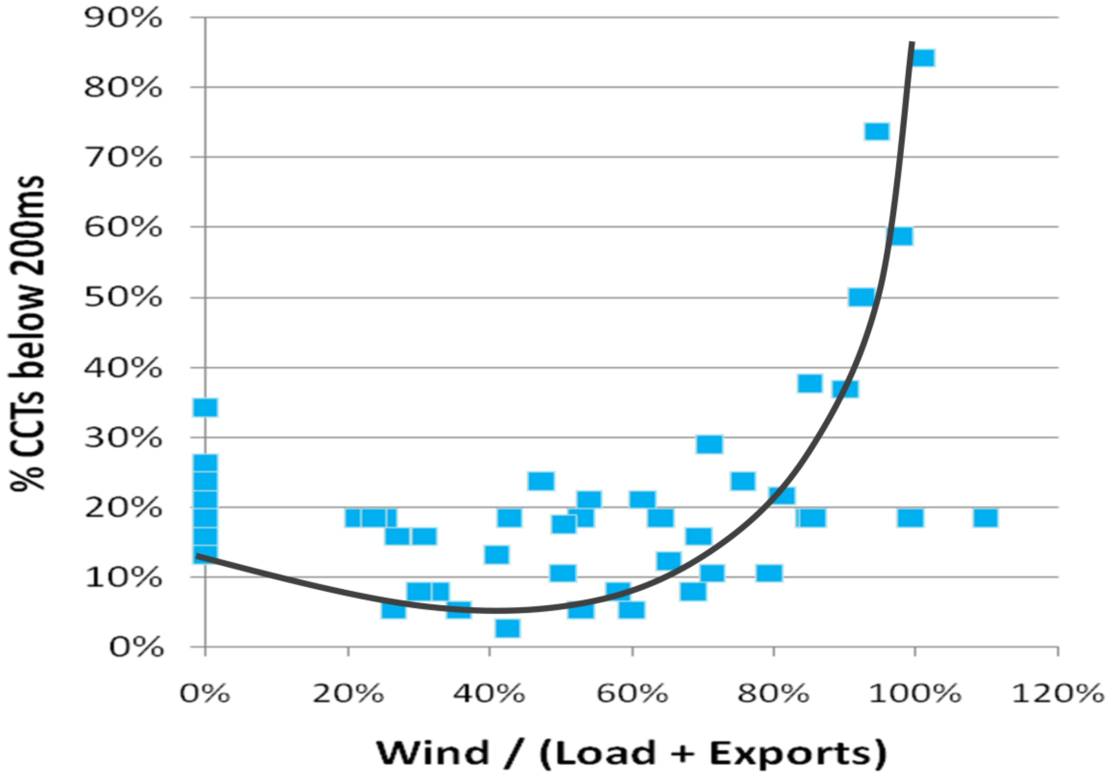

Figure 32: Percentage of contingencies causing Critical Clearance Times (CCT) lower than 200ms vs SNSP (FoR studies, EirGrid-SONI, 2010)

However, the FoR studies also indicated that the provision of dynamic reactive power in a measured fashion from network devices (e.g. synchronous compensators or windfarms) during voltage disturbances could be used to mitigate many, if not all, of these issues (Figure 33). The figure shows the impact of the mitigation strategies on the critical clearance times of the contingencies studied. These results suggest that application of the mitigation strategies substantially improves transient stability by increasing the critical clearance time of the most onerous faults.

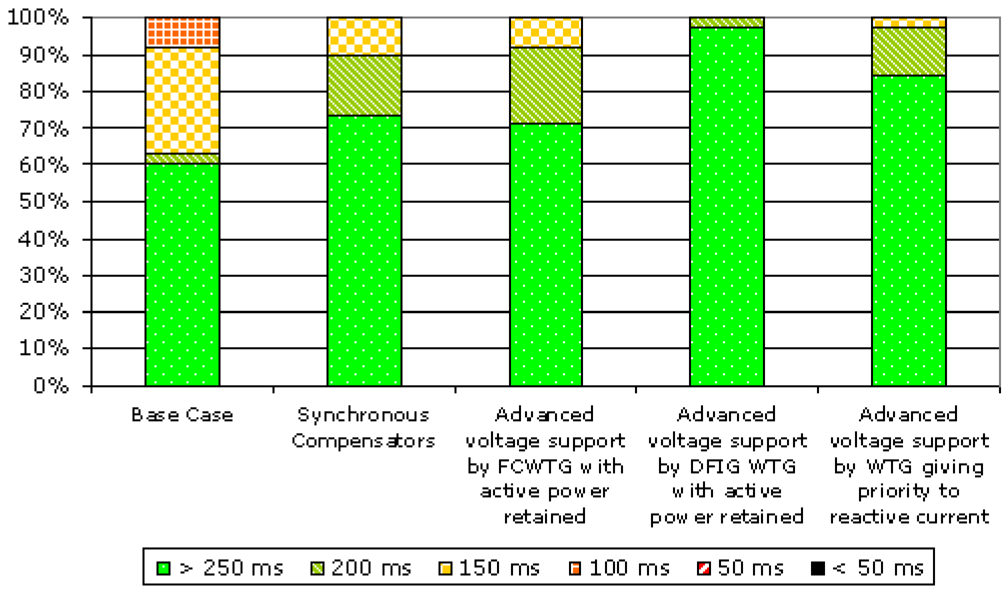

Figure 33: Impact of mitigation strategies for improving transient stability issues on Critical Clearance Times (FoR Studies EirGrid/SONI, 2010)

These mitigation strategies relied on generators and windfarms being able to provide significant reactive current during voltage disturbances. Synchronous generators inherently provide this type of response. . However, it is not clear from the Grid Code exactly what capability is required in this regard from transmission connected windfarms. In addition, there is no definitive requirement for any such response from type B, C, D and E windfarms connecting to the distribution system in Ireland. Without clarity in this regard with respect to windfarms, it will not be possible to efficiently manage the operation of the power system. This also has a material impact on the long term design and planning of the transmission network. This would result in a lower maximum SNSP level that can be accommodated while maintaining system security – Figure 34 below illustrates the potential impact on the secure SNSP limit.

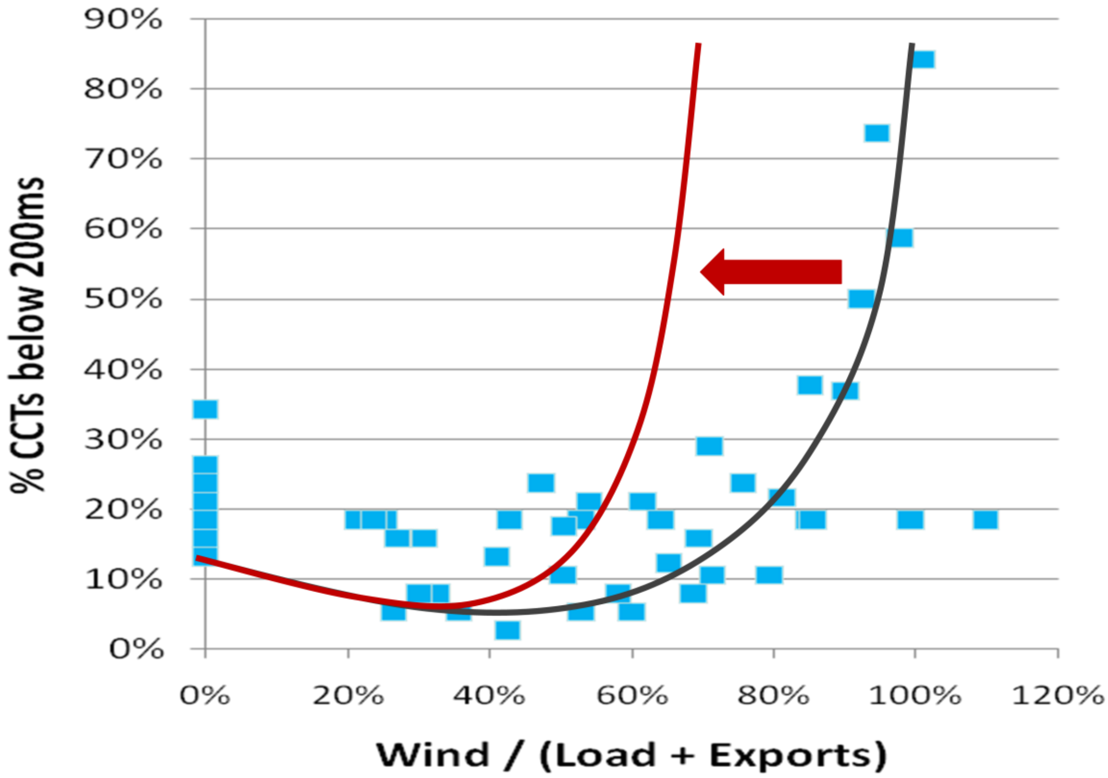

Figure 34: Potential impact (red curve) on transient stability if windfarms' dynamic reactive power capability is not clarified (EirGrid, 2011)

6 EXPERIENCE AND LEARNING

6.1 Operational Experience – Recent Examples

The analysis presented here, together with the results of the FoR studies, has enabled the identification of system issues and operational challenges in the next 10 years. Recent operational experience corroborates these findings as some of the issues are already evident.

For example, there have been two transmission faults in the last six months that resulted in the loss of over 100 MW of wind generation (which should have remained connected per the Grid Code standards). The implications of this, when scaled up to the levels of wind expected in 2020, are very serious.

The importance of generator performance, particularly in respect of operating reserve, was illustrated in a recent low frequency event. A large CCGT tripped and the remaining on-line generation increased output as their reserves were activated. However, less that 15 seconds later another generator, which had provided a significant reserve response, also tripped. This "sympathetic tripping" of the second generator caused the frequency to fall to 48.86 Hz, resulting in load shedding.

The importance of synchronous reactive power was evidenced when on a day during the cold weather last winter the voltage in Donegal began to fall as the evening peak approached. The falling voltages meant a reduction in the reactive power output of the static devices and windfarms in the area, which exacerbated the voltage decline. Swift corrective action by the system operator meant that the incipient voltage collapse was avoided.

6.2 Operational Experience – Wind Curtailment

Of the 1,050 MW of controllable windfarms, just over half has registered in the SEM as Variable Price Taker Generators (VPTGs). The remainder are either not registered or are classified as Autonomous. This is illustrated in Figure 35 below.

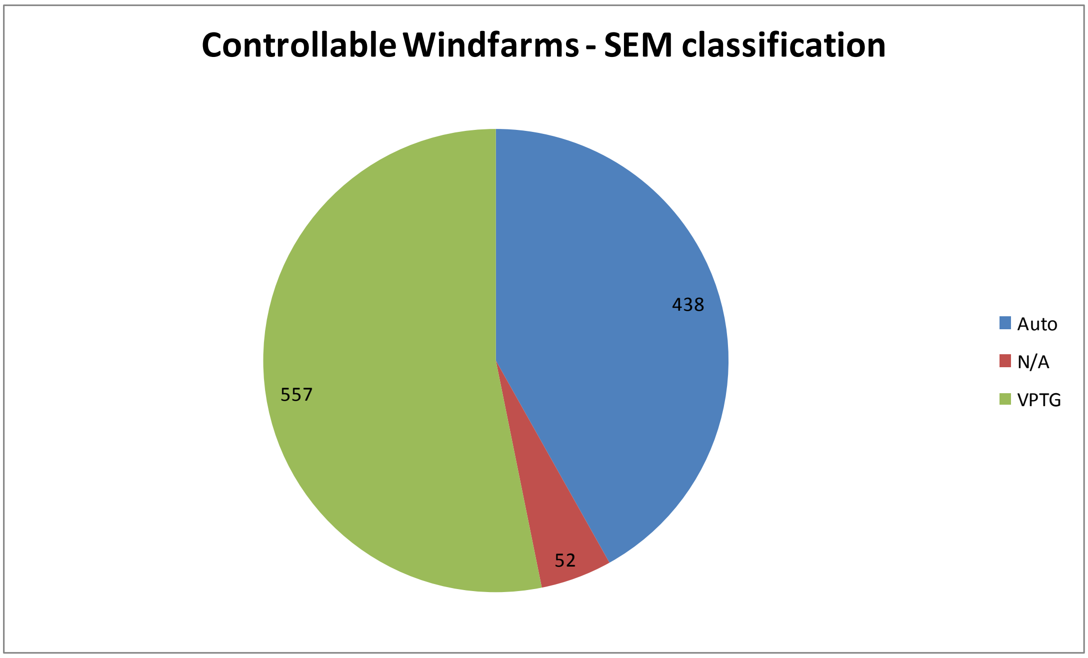

Figure 35: SEM classification of controllable windfarms registered data in the SEM (SEMO, 2011)

It is necessary for wind generation to be turned down at times to maintain system security. The reasons for this can be system-wide (e.g. maintaining a minimum level of synchronous inertia) resulting in "wind curtailment", or localised (e.g. to avoid overloading a transmission line) resulting in "wind constraint". The unused wind energy, based on SEM data, for both constraint and curtailment reasons from 2010 (Jan-Nov) is shown in Figure 36. The data presented is for Variable Price Taker generators (VPTGs). Autonomous wind generators do not have proven control capability (nor receive compensation via the SEM if dispatched down) and are therefore generally not dispatched down.

During this period, the total unused wind energy of VPTGs was 26 GWh, which is equivalent to 2.8% of the available wind energy from these windfarms. Since the VPTGs comprise ⅓ of the installed wind generation, the amount of unused wind generation is approximately 1% of the total available wind energy.

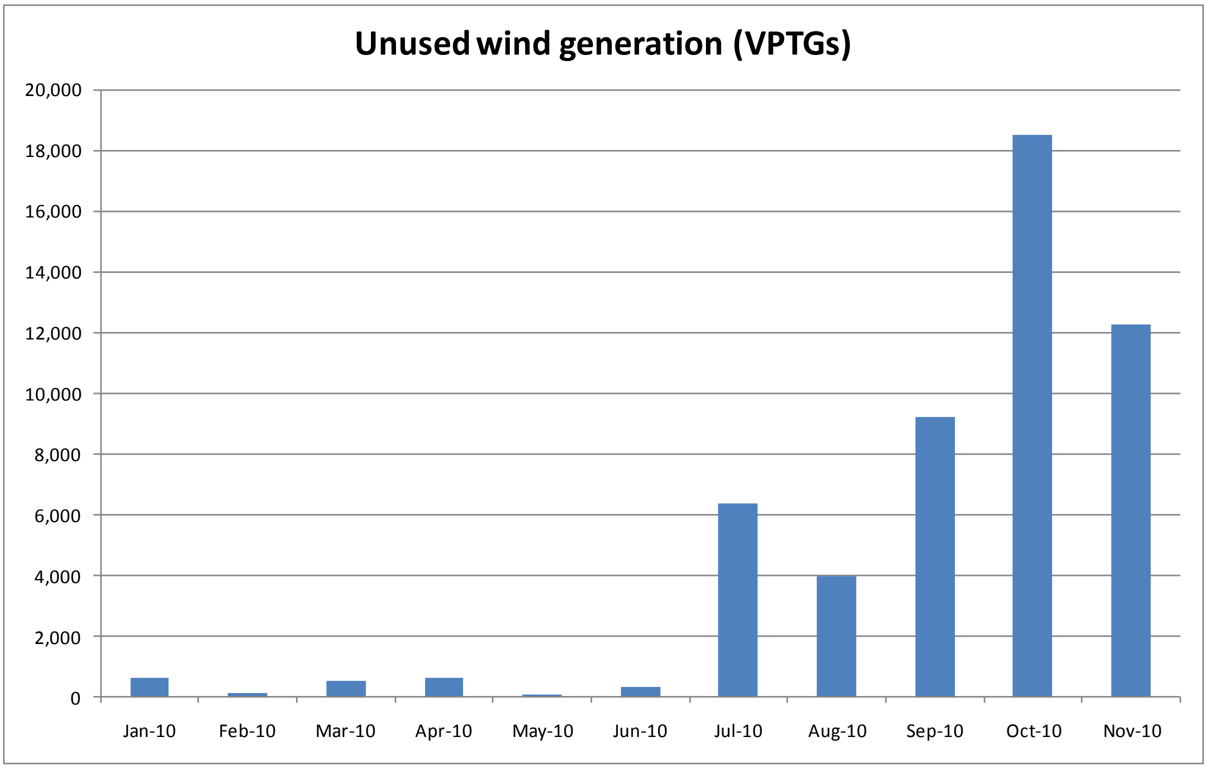

Figure 36: Unused wind generation (MWh) - Jan-Nov 2010 based on actual data (EirGrid, 2011)

The level of curtailment and constraint has increased over the year. There are three main reasons for this:

- The capacity factor for VPTGs was higher in the second half of the year (25%) than the first half of the year (20%).
- The level of installed wind increased over the year by approximately 200 MW.
- The Turlough Hill pumped storage station became unavailable from July 2010, resulting in lower night valleys (less "room" for wind) and lower system load factors (i.e. larger relative gap between peak and valley).

The modelling carried out for this paper, along with previous studies carried out by EirGrid and SONI including the FoR studies, indicates that the level of wind curtailment will rise as the installed capacity of wind increases. With this in mind, the TSOs are actively seeking to increase the amount of wind with active power control so that curtailment is shared equitably.

6.3 Minimum Generation

Although not a service, the minimum generation of the portfolio has a significant impact on its ability to deliver the services necessary for the secure operation of the power system. The Irish Grid Code specifies minimum generation levels of 50% for CCGTs and 35% otherwise. Minimum load levels in Northern Ireland are individually specified for each generator.

Current Portfolio Capability

The current portfolio has been assessed using the Technical Offer Data submitted via the SEM. The total minimum generation of the 2010 conventional generation portfolio (dispatchable) is 3,450 MW, which is equivalent to an aggregate minimum generation of 38%. Some generators do not comply (or have derogations) against the Grid Code requirements, which increases the aggregate minimum generation by 265 MW. If all were consistent with the Irish Grid Code requirements, the system aggregate minimum generation would reduce to 35%.

Projected Portfolio Capability and Resultant Issues

A significant amount of the "flexible" portfolio (i.e. with a wide operating range between minimum and maximum generation) is nearing the end of its useful life and is expected to have been retired by 2020. If new generation is compliant with the Irish Grid Code standards (50% for CCGTs and 35% otherwise), then the aggregate minimum generation of the 2020 conventional portfolio (8432 MW) will rise to 42%.

Some services, such as inertia and reactive power, can be provided by synchronous generators at any output level. Other services can only be provided by a synchronous generator once it reaches a certain output level (sometimes referred to as minimum load). In the case of operating reserve, this can be up to 50% of the maximum generation.

Since many of the operational security constraints involve minimum required levels of various services, higher minimum generation levels will mean that those generators providing services must operate at higher outputs, leaving less "room" for other generators. Therefore, the likely increase in minimum generation needs to be addressed if the required services are to be obtained efficiently and without necessitating significant increases in wind curtailment.

6.4 Generator Performance Incentives and Performance Monitoring

With the establishment of the Harmonised Ancillary Services arrangements, Generator Performance Incentives were introduced on an all-island basis. The GPIs were based on the existing incentives in place in Northern Ireland through the Generating Unit Agreements. Historically, these incentives were observed to have delivered improved generator performance.

The initial tranche of GPIs implemented in 2010 included incentives on the declared capabilities of generators in respect of the following:

- Minimum generation
- Operating Reserve
- Reactive Power
- Governor Droop

Of particular relevance to this paper are the GPIs for declared availability of Ancillary Services. The impact of GPIs has been largely positive. Several generators have sought to improve their contracted capabilities for AS in a number of areas. Following testing, contract values have been amended. The most significant improvements are summarised in Table 5.

Table 5: Improvements to declared operating characteristics since introduction of GPIs

Characteristic	*Improvement*
Reactive Power (Leading)	100 Mvar
Reactive Power (Lagging)	100 Mvar
Primary Operating Reserve	25 MW
Secondary Operating Reserve	40 MW
Minimum load for reserve provision	50 MW

Further improvements have been sought by generators that will be implemented upon completion of successful testing. In addition, the benefit for the TSOs is that there is much more accurate knowledge of plant capabilities.

The GPI for minimum generation has also had significant positive benefits. As of December 2010, based on Technical Offer Data submissions, the total minimum generation of the conventional portfolio was 3450 MW, which is equivalent to a system average minimum generation of 38%. When compared to October 2009, prior to the introduction of the GPIs, this represents a reduction[23] of 170 MW, or 1.9% of installed capacity. This net reduction of 170 MW consists of total reductions of 245 MW, across seven generating units, and increases of 72 MW, across two units which have recently re-registered in the market.

In parallel with the Harmonisation of Ancillary Services, a formalised, systematic generator performance monitoring process has been introduced in Ireland. Although still in its infancy, the new processes and systems have enabled the identification of performance issues, including deficiencies against the required Grid Code standards. A similar process has been in place in Northern Ireland for a number of years but may need to be expanded to include additional metrics relevant to the future needs of the power system.

By being better informed about generator performance, the system operators can operate the system more securely, while generators have improved information to help them address performance deficiencies. This has resulted in a lowering of contract capabilities (particularly in respect of operating reserve) for a number of generators. While this has tended to increase constraint costs in the short term, it should in the longer term, when combined with appropriate performance incentives, result in improved capabilities.

6.5 A Review of the Incentivisation of Performance

It should be noted that the generation with reserve capabilities that exceed the Grid Code minimum is generally concentrated in Northern Ireland and in the older part of generation portfolio in Ireland. This can be attributed, at least in part, to the importance of reserve (particularly prior to the interconnection of the all-island system) and the centrally planned nature of the system prior to deregulation. In addition, there appears to be a relationship between the introduction of energy

[23] To avoid distortion, generator additions and retirements have been excluded from this comparison.

markets (1999 in Northern Ireland and 2000 in Ireland with the IME and TESS systems respectively) and the relative decline in performance (Figure 37).

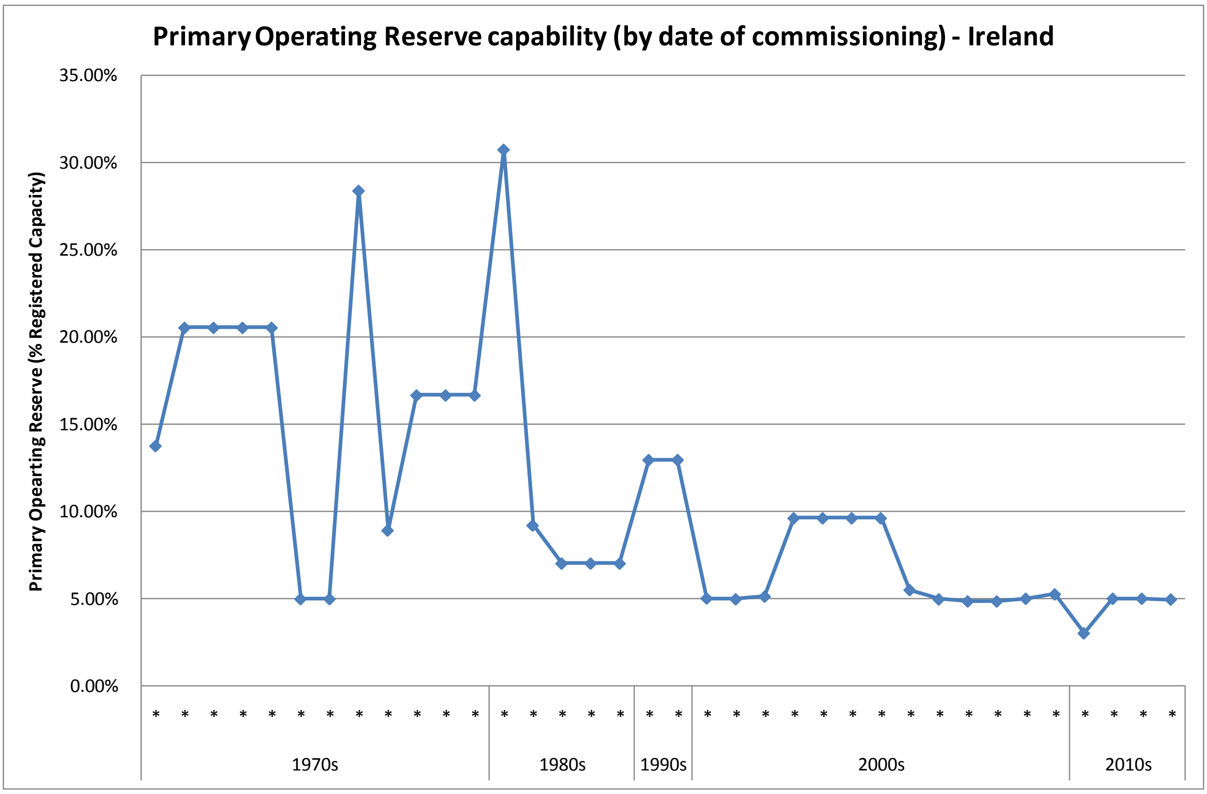

Figure 37: Primary Operating Reserve capability at date of commissioning in Ireland (EirGrid, 2011)

This is partly attributable to the available technology at the time. However, it is also likely to be due to the relative weightings of payments for energy, capacity and system service performance. With the introduction of the SEM in 2007 the energy markets in Ireland and Northern Ireland were combined into a mandatory gross pool in which there was an energy value of €2.6 billion (in 2008) with a capacity payment pot of €545 million. A harmonised ancillary service product was subsequently introduced with a total payments valued at almost €60 million for performance and system services. Ancillary Services represent approximately 2% of the wholesale electricity payments to generators. In the previous bilateral markets in the two jurisdictions – the Transitional Electricity Settlement System in Ireland and the Interim Market for Electricity (IME) in Northern Ireland – the payments for ancillary services were of a similar relative size. In the TSOs' view it is unlikely that any investors will materially consider ensuring performance levels as the revenues received for providing these play an insignificant role in the decision to build a unit. Without significantly altering the percentage allocation between energy, capacity and ancillary services, this practice is unlikely to change in the future. Given the changing needs of the power system this has potential implications for system security and generation adequacy into the future.

The TSOs consider that an industry review of the needs of the future power systems and the appropriate level and structure of payments for ancillary services should be conducted as soon as possible. This review should consider the payments for specific services to ensure that they are at a level that will incentivise plant, account for the likely reduction in energy market value with increasing renewable resources, allow for the greater operational efficiencies from having improved and more reliable plant performance, and consider the reduced need for capacity arising from the demand growth projections in recent years. While it has yet to be analysed in detail, the TSOs consider it likely that a scheme of targeted payments can be constructed that will incentivise the necessary system performance capability, improve the operational efficiency and lead to a more secure, reliable and efficient power system for the end consumer. This can be achieved without changes to the design of SEM or the Capacity Payments but may require a reallocation of the regulated monies allocated to these revenue streams.

7 KEY FINDINGS

Area	Finding
	Frequency Response
Reduced Synchronous Inertia	On line synchronous inertia will fall as the SNSP level increases. In the absence of mitigation measures, additional wind curtailment will be necessary to maintain system security.
Conventional Generators Reserve Performance	Over 30% of generators have contracted values less than the Grid Code requirement. A majority of generators are not consistently performing according to their declared operating reserve characteristics.
RoCoF Protection Relays	RoCoF distribution relays limit the ability of the power system to ride through significant frequency deviations at high wind levels.
	Ramping Services
Forecast and Variability	Wind will increase the variability and uncertainty in the portfolio output over different time horizons. There appears to be up to a 20% variability relationship with installed windfarms in one hour time period.
Ramping Requirement	Increasing ramping requirements (defined by ramping duty and forecast errors) will drive a need for increased ramping capabilities. Portfolio analysis indicates that pumped storage plant can play an important role in providing these services.
Windfarm Active Power Control	Over 400 MW of windfarms do not have the appropriate active power control to the control centres. This is leading to higher duty on compliant windfarms and will challenge system security in the future if allowed to continue.
	Voltage Control
Aggregate Volume of Portfolio Reactive Power Capability	The current reactive power capability (leading) is 30% less than the required Grid Code standard. In 2020 with significant windfarm penetration (and less synchronous thermal plant) on average there will be 25% less synchronous reactive power.
Type of Reactive Capability	The nature of the reactive support provided by wind farms is not as valuable to the system during voltage disturbance and collapse scenarios.
Controllability	Only 27% of connected wind farms can currently provide reactive power capability and control to the Control Centres.

Implications of not addressing issues:

- Increased system operation costs
- Increased curtailment levels over and above FoR predicted levels
- Reduced system security
- Increased operational complexity
- Increased network development costs

8 PROGRAMME FOR A SECURE SUSTAINABLE POWER SYSTEM

The results of the Facilitation of Renewables study and the subsequent analysis that was carried out on portfolio performance have been considered and a programme of work has now been developed. EirGrid and SONI consider that this programme addresses the issues highlighted in the preceding sections of this report. The programme is fundamental to ensuring the continued security of supply on the island and is required to deliver the 2020 renewable policy targets in an efficient and sustainable manner. This programme of work spans a three year timeframe and covers multiple industry stakeholders, including the TSOs, the DSOs, the Regulatory Authorities, conventional and renewable generators and the wider electricity industry.

The programme focuses on three key work areas which underpin the programme for sustainable power system development over the next decade: enhancing Portfolio Performance, the development of appropriate System Policies and Tools, and Infrastructure Development. These work packages are described at a high level in this section. An indicative timeline has been shown against specific tasks within the programme. This timeline is subject to change particularly with respect to external dependencies.

The major components of the programme address the fundamental need to have long term certainty about portfolio performance and capability. Delivering that certainty will require ongoing objective and accurate performance monitoring against clear and unambiguous standards which meet the long term needs of the power system. The TSOs will continue to monitor and to report regularly on the performance of the entire portfolio. The Facilitation of Renewables studies, and future studies and analysis will continue to inform on the long term needs of the system and provide guidance on the required direction of the portfolio capability.

The key issues for the DSOs are focused on ensuring the appropriate infrastructure is in place in a timely fashion. In addition, the DSOs need to ensure embedded generation is not only controllable by the TSO but that this is co-ordinated to meet both the needs of the power system and respect the security requirements of the local network. The key deliverable for conventional plant is to provide a reliable and consistent performance at least to the standard of the current Grid Code. In particular, these generators should provide the required operational reserve capability and performance. Transmission and distribution connected windfarms need to provide the necessary active and reactive control to the Control Centres.

The delivery of this programme for a secure sustainable power system will only be achieved with the full engagement and support of stakeholders across the electricity sector. EirGrid and SONI will be actively engaging with stakeholders throughout the execution of this programme.

The first three sections of this chapter outline the primary components of the three main work streams of the programme. These are portfolio performance, system policies and system tools. There is a short section highlighting the importance of infrastructure in delivering on the overall renewable policy targets. Additionally there is a section on the communications within the programme. Finally, a tabular overview of the programme is provided.

The indicative timelines outlined in this section have been developed by the System Operators in advance of the detailed scoping of the tasks and deliverables required under each action. The TSOs' project team will work with the RAs' project team (and where relevant, the DSOs) to develop and agree a full and detailed programme of work, including project plans for each work package (key actions), timelines, key deliverables in each area and dependencies.
It is important to note that these actions are indicative and the final agreed programme will outline in greater detail what each key action will involve. While the key actor(s) has, in each instance, been identified in the tables, there may also be interactions and cooperation with other parties, including, where appropriate, decisions by the Regulatory Authorities.

8.1 Portfolio Performance

Portfolio performance refers to the performance of all plant and technologies connected to the power system in Ireland and Northern Ireland. This includes demand side, interconnection and all types of generation. Accurate knowledge of the performance and capability of the entire portfolio is central to managing the power system in the long term with high levels of variable renewable generation. Credible enforcement of the Grid Code (or derogated performance where applicable) is a fundamental requirement in terms of the system operators having a clear picture of the capabilities of the portfolio.

Section 2 provided an overview of the types of generation connected to the power system and its characteristics, and the capacity of renewable generation connected at transmission and distribution level. The expected needs of the power system have been informed by the "All Island Facilitation of Renewables" studies which were completed last June. An assessment of the expected performance capability of an assumed 2020 plant portfolio has also been completed.

Sections 3, 4 and 5 highlighted areas where there are predicted deficiencies in system performance capability in terms of frequency and voltage control. In terms of frequency control, analysis showed that the levels of available synchronous inertia were less than needed in 2020. The Facilitation of Renewables studies also showed that at high instantaneous wind penetration levels, there was a risk to frequency stability on the system due in part to the presence of RoCoF protection relays. A key recommendation was to replace the RoCoF protection relays on the distribution networks by alternative protection schemes or increased RoCoF thresholds. All of these issues have been factored into the work programme and are outlined.

The controllability and availability of reactive power from wind farms is a key requirement for managing voltage performance securely. The results from the Facilitation of Renewables studies also highlighted that enhanced sources of static and dynamic reactive power were needed on the system.

The next step for the TSOs following the examination of current and projected portfolio performance is to identify the required system/ancillary services. Following this identification of system services requirements, the services will have to be designed, financially valued and corresponding commercial mechanisms decided upon. This will involve substantial stakeholder consultation around the commercial arrangements and appropriate market design.

It is important that any design balances the need for regulatory certainty within SEM with the provision of adequate commercial signals to reflect the long term system operational needs.

Portfolio performance is a central work area within the programme where there will be a need for significant stakeholder involvement and in particular, input from the Regulatory Authorities. The key areas of work within Portfolio Performance are developing and enhancing portfolio performance capability and the design of appropriate commercial mechanisms that align with the long term system needs.

8.1.1 Portfolio Performance Capability

The objectives of this work area within the programme are to continually measure portfolio performance through performance monitoring and enforcement of Grid Code/Distribution Code standards and to ensure that the Grid Code is developed to allow for new technologies. EirGrid introduced a new performance monitoring process last year and initial results have already provided valuable information to the TSOs on real plant performance capability. Some of the results from the performance monitoring were shown in the analysis presented above. EirGrid and SONI will build on this over the coming years and enhance the performance monitoring capability where possible. Where there is lack of clarity in the Grid Code around performance standards, this will be examined and any appropriate modifications will be brought forward to the Grid Code Review Panel. It is important to note that the Facilitation of Renewables studies assumed Grid Code compliance (or better) of the entire portfolio. Any reduction in this performance standard will have a material impact on the maximum secure system non synchronous penetration levels. Tied in with this, the credible enforcement of the Grid Code and Distribution Code is important to ensure that the TSOs have a realistic baseline against which to measure performance and resultant future system needs.

This part of the programme is essentially about ensuring the delivery of the required power system performance from the portfolio in terms of frequency and voltage control capability.

Programme	Key Actions	Timeline	Actor (s)
Portfolio Performance Capability	Enhance capabilities for performance monitoring on an all-island basis Report on portfolio performance	Ongoing	EirGrid & SONI
	Extension of Generator Performance Incentives for all plant	2011	EirGrid & SONI
	Review standards of performance of all plant	2011	EirGrid & SONI
	Clarification of existing Grid Code standards (all-island) • Clarification of reactive power standards	2011	EirGrid & SONI
	Development of standards for new technologies e.g. Electric Vehicles, offshore wind	2012/2013	EirGrid & SONI
	Input into European Grid Code development	Ongoing	EirGrid & SONI
	Investigate other technology types that can provide system services e.g. flywheel technology	2011	EirGrid & SONI
	Performance monitoring against relevant technical standards and provision of supporting information to Regulatory Authorities	Ongoing	EirGrid & SONI

8.1.2 Commercial Design

This part of the programme will investigate the commercial aspects of the development of suitable ancillary services to meet the long term needs of the power system. This work will include ensuring that the market mechanisms and standards are appropriate to incentivise plant performance and provide the correct plant investment signals.

Results from section 3 showed areas where there is a potential deficiency in system performance capability in 2020. For example, based on the assumed plant portfolio for 2020, there will be a sizeable reduction in the synchronous inertia capability available at high levels of wind generation. This reduction in inertia could impact on the frequency stability of the system. It is therefore important that long term market mechanisms incentivise the provision of inertia.

Programme	Key Actions	Timeline	Actor(s)
Commercial Design	Examine current plant portfolio, expected plant portfolio in 2020 and the long term power system operational needs	2011	EirGrid & SONI
	Investigate mitigation methods for managing potential long term system portfolio deficiencies.	2011	EirGrid & SONI
	Identify the system services required to meet the long term system needs against the current and projected performance capability of all plant	2011	EirGrid & SONI
	Draft a consultation paper for industry engagement outlining the ancillary services required and potential funding options.	2011	EirGrid & SONI
	Financial valuation of system services	2011/12	EirGrid & SONI
	Design the commercial mechanisms to match the system services requirement.	2011/12	EirGrid & SONI
	All island consultation on proposed ancillary services payment structures	2012	EirGrid & SONI
	Decision on future ancillary services funding (total ancillary services pot)	2012	Regulatory Authorities
	Decision on ancillary services implementation methods	2012	EirGrid & SONI / Regulatory Authorities
	Implementation of new ancillary services arrangements	2013	EirGrid & SONI

8.2 System Policies

This part of the programme focuses on the development of appropriate system operational policies to assist in securely managing a power system with high levels of variable renewable generation.

The TSOs already have many system operational policies in place. In some cases these policies will need to evolve and be updated over time as the levels of renewable generation increases. In other cases, new system policies will need to be created to manage specific issues that have arisen due to the management of variable renewable generation.

This work area has taken into account the results from sections 3, 4 and 5 of this paper and will investigate and manage the issues which have been raised. The two key areas of focus are frequency control and voltage control. For example, analysis of the current portfolio capability has shown that the levels of available primary operating reserve have fallen over time and will fall further as more non synchronous generation is accommodated onto the system. This has implications in terms of management of system frequency response and needs to be considered in terms of the development of reserve policies. A key area within Frequency Control is also the review of RoCoF protection settings as highlighted in the Facilitation of Renewables studies. This is shown in the Programme below.

8.2.1 Frequency Control (Frequency Response and Ramping)

System Frequency Control hinges upon ensuring sufficient reserve capability in the short term (seconds), in the medium term (minutes) and in the long term (hours). The development of policies associated with frequency control will include a review of RoCoF protection settings (as highlighted in the Facilitation of Renewables studies).

Programme	Key Actions	Timeline	Actor(s)
Frequency Control	Review of RoCoF protection settings and capability (information gathering)	2011	EirGrid & SONI
	Engagement with the DSO on RoCoF protection settings	2011	EirGrid & SONI / DSOs
	Agree new settings for RoCoF relays/Agree to disable RoCoF relays	2011/2012	EirGrid & SONI / DSOs / Regulatory Authorities
	Implementation of changes to RoCoF settings	2012	Industry
	Review system reserve policy for Control Centres in the context of high levels of variable renewable generation	2012	EirGrid & SONI
	Investigate the system ramping requirements (long term reserve) and associated policy	2012	EirGrid & SONI
	Investigate unit commitment and scheduling and any changes needed in the long term	2012	EirGrid & SONI
	Review the technical and commercial aspects of maintenance outages.	2011/12	EirGrid & SONI/ Regulatory Authorities

8.2.2 Voltage Control

Ensuring adequate voltage control capability across the entire power system is a fundamental requirement to operating a power system securely. Voltage control capability has traditionally been provided by thermal plant. In the face of increasing renewable energy sources dispersed around the system (and embedded on the system), it is important that voltage control capability is also provided by wind generation. The results in section 5 show that there is substantial non-compliance of the wind portfolio against the Grid Code requirements in terms of voltage control. There are also many windfarms where there is no reactive power controllability available to the Control Centres. These voltage control issues have been factored into the work programme. A key piece of work in this area will also include reviewing governance arrangements for the TSO and DSO in terms of reactive power control of wind farms.

Programme	Key Actions	Timeline	Actor(s)
Voltage Control	Investigate reactive power controllability of current wind portfolio	2011	EirGrid & SONI
	Enhance controllability of wind portfolio (develop incentives)	2012	EirGrid & SONI
	Review of current reactive power standards and requirements in Grid Codes and Distribution Codes (All island)	2011	EirGrid & SONI
	Develop modifications to the Grid Codes for appropriate reactive power standards on all plant	2011/12	EirGrid & SONI
	Decision on Grid Code and Distribution Code reactive power standards	2012	Regulatory Authorities
	Investigate a TSO/DSO reactive power management strategy	2011/2012	EirGrid & SONI / DSOs
	Agree a reactive power management strategy	2012	EirGrid & SONI / DSOs
	Implementation of reactive power management strategy in Control Centres	2012/2013	EirGrid & SONI / DSOs

8.3 System Tools

As more wind power stations connect to the system, the operation of the power system will become even more complex. Improved system operational tools will assist in the management of this complexity. The aim of the tools is to provide the system operator with more accurate real-time information and also greater control and monitoring facilities.

These tools include the ability to dispatch wind, to forecast wind output accurately and to assess the stability of the power system (Wind Security Assessment Tool, WSAT) in real-time. Some of these tools are already in place in the Control Centres while other tools will need to be developed or enhanced over time. One of the key results from section 4 is the need for greater active power control of renewable generation from the Control Centres. Other tools will also need to be developed over time to tie in with updated system policies. The key areas of work within system tools are wind dispatch, control centre tools and capabilities and further system studies.

8.3.1 Wind Dispatch

A wind dispatch tool is already in place in the Control Centres, this tool allows the operator to constrain wind generation in real-time if there is a transmission constraint or to curtail wind generation if there is a risk to system security. Over time, as more wind generation connects to the system this tool will have to be enhanced to allow for greater functionality.

Programme	Key Actions	Timeline	Actor(s)
Wind Dispatch	Implement enhancements to current Wind Dispatch Tool	2012	EirGrid & SONI
	Development of Next Generation Wind Dispatch Tool	2013	EirGrid & SONI
	Reporting on Wind Curtailment/Constraints as part of National Renewable Energy Action Plan	Bi annually	EirGrid & SONI

8.3.2 Control Centre Tools & Capabilities

This part of the programme focuses on enhancing the tools and capabilities available to the operators in the Control Centres. Due to the changing nature of the generation portfolio and the increased work in the area of infrastructure development, a review of resourcing in the Control Centres will be required and this has been factored into the programme. Additionally, the results from the System Policies work package will feed into the development of system tools. Managing the variability of wind generation will be assisted by continuing to use the best in class forecasting methods.

Programme	Key Actions	Timeline	Actors
Control Centre Tools & Capabilities	Examine roles, responsibilities and resources within Control Centres	2012	EirGrid & SONI
	Investigate the long-term EMS requirements	2012	EirGrid & SONI
	Extension of Wind Security Assessment Tool	2012	EirGrid & SONI
	Continue to use best in class forecasting tools Input into analysis on probabilistic distribution factors	Ongoing	EirGrid & SONI
	Implement greater active and reactive power controllability of Distributed generation from Control Centres	2012	EirGrid & SONI / DSOs
	Update system tools to include system policy developments (e.g. reserve)	2013	EirGrid & SONI

8.3.3 System Studies

This part of the programme outlines the additional studies that need to be carried out over the coming years to review system performance capability and the associated security of the power system. The studies will be similar in scope to the studies which were carried out as part of the Facilitation of Renewables studies. However, a refinement of system models will be carried out over the next two years to improve the accuracy of the studies.

One of the recommendations from the Facilitation of Renewables studies was to refine system models; this will include using a multi bus model for the analysis of the system's frequency response as well as improved wind turbine and wind farm models.

Programme	Key Actions	Timeline	**Actors**
Studies	Update dynamic models with current performance capability for all generators	2011/12	EirGrid & SONI
	Develop a multi – bus model for the analysis of the system's frequency response	2011/12	EirGrid & SONI
	Carry out further frequency stability analysis with refined dynamic models and investigate and review secure system non synchronous penetration levels	2013	EirGrid & SONI

8.4 Infrastructure

The delivery of the required transmission and distribution infrastructure forms a major part of the programme of work to deliver on the 2020 renewable policy targets. The Grid25 implementation plan, the delivery of the Gate 3 connection offers and the Northern Ireland Grid Development plan all form major parts of this work. The delivery of Grid25 and the Northern Ireland Grid Development plan will provide the necessary capacity to reliably transport the future anticipated power levels from renewable and conventional generators and interconnectors to the cities and towns where the power is required. The delivery of the East-West Interconnector (EWIC) is under construction and on target to be delivered by 2012.

The infrastructure implementation programme is well underway and is being reported to the Regulatory Authorities via the CAPEX mechanism. The delivery of the required infrastructure to support the delivery of the renewable policy targets will therefore not be discussed in detail as part of this paper.

8.5 Communications

A major part of the programme of work for a secure, sustainable power system will include communications management. Given the wide scope of work and range of stakeholders involved in the programme, it is important that there is early and active stakeholder engagement. This will be facilitated by EirGrid and SONI by hosting information seminars throughout the delivery of the programme. In addition, EirGrid and SONI intend to set up an advisory council comprising representatives from across the industry in order to facilitate input on the direction of the programme. It is important to note that the advisory council will not be a decision making or a policy formulation body.

8.5.1 Overview of Programme

Portfolio Performance

	Programme	Key Actions	2011	2012	2013	Actor (s)
Portfolio Performance	Portfolio Performance Capability	Enhance capabilities for performance monitoring on an all island basis. Report on portfolio performance	√	√	√	EirGrid & SONI
		Extension of Generator Performance Incentives for all plant	√			EirGrid & SONI
		Review standards of performance of all plant	√			EirGrid & SONI
		Clarification of existing Grid Code standards (all island) Clarification of reactive power standards	√			EirGrid & SONI
		Development of standards for new technologies e.g. Electric Vehicles, offshore wind		√	√	EirGrid & SONI
		Input into European Grid Code development	√	√	√	EirGrid & SONI
		Investigate other technology types that can provide system services e.g. flywheel technology	√	√		EirGrid & SONI
		Performance monitoring against relevant technical standards and provision of supporting information to Regulatory Authorities	√	√	√	EirGrid & SONI
	Commercial Design	Examine current plant portfolio, expected plant portfolio in 2020 and the long term power system operational needs	√			EirGrid & SONI
		Investigate mitigation methods for managing potential long term system portfolio deficiencies.	√			EirGrid & SONI
		Identify the system services required to meet the long term system needs against the current and projected performance capability of all plant	√			EirGrid & SONI
		Draft a consultation paper for industry engagement outlining the ancillary services required and potential funding options.	√			EirGrid & SONI
		Financial valuation of system services	√	√		EirGrid & SONI
		Design the commercial mechanisms to match the system services requirement.	√	√		EirGrid & SONI
		All island consultation on proposed ancillary services payment structures		√		EirGrid & SONI
		Decision on future ancillary services funding (Ancillary Services Pot)		√		Regulatory Authorities
		Decision on ancillary services implementation methods		√		EirGrid & SONI / Regulatory Authorities
		Implementation of new ancillary services arrangements			√	EirGrid & SONI

System Policies

Programme	Programme	Key Actions	2011	2012	2013	Actor (s)
System Policies	Frequency Control	Review of RoCoF protection settings and capability (information gathering)	√			EirGrid & SONI
		Engagement with the DSO on RoCoF protection settings	√			EirGrid & SONI/DSOs
		Agree new settings for RoCoF relays/Agree to disable RoCoF relays	√	√		EirGrid & SONI/DSOs
		Implementation of changes to RoCoF settings		√		Industry
		Review system reserve policy for Control Centres in the context of high levels of variable renewable generation		√		EirGrid & SONI
		Investigate the system ramping requirements (long term reserve) and associated policy		√		EirGrid & SONI
		Investigate unit commitment and scheduling and any changes needed in the long term		√		EirGrid & SONI
		Review the technical and commercial aspects of maintenance outages.	√	√		EirGrid & SONI/ Regulatory Authorities
	Voltage Control	Investigate reactive power controllability of current wind portfolio	√			EirGrid & SONI
		Enhance controllability of wind portfolio (develop incentives)		√		EirGrid & SONI
		Review of current reactive power standards and requirements in Grid Codes and Distribution Codes (All island)	√			EirGrid & SONI
		Develop modifications to the Grid Codes for appropriate reactive power standards on all plant	√	√		EirGrid & SONI
		Decision on Grid Code and Distribution Code reactive power standards		√		Regulatory Authorities
		Investigate a TSO/DSO reactive power management strategy	√	√		EirGrid & SONI/DSOs
		Agree a reactive power management strategy		√		EirGrid & SONI/DSOs
		Implementation of reactive power management strategy in Control Centres		√	√	EirGrid & SONI/DSOs

System Tools

Programme	Programme	Key Actions	2011	2012	2013	Actor (s)
System Tools	Wind Dispatch	Implement enhancements to current Wind Dispatch Tool		√		
		Development of Next Generation Wind Dispatch Tool			√	EirGrid & SONI
		Reporting on Wind Curtailment/Constraints as part of National Renewable Energy Action Plan	√	√	√	EirGrid & SONI
	Control Centre Tools & Capabilities	Examine roles, responsibilities and resources within Control Centres		√		EirGrid & SONI
		Investigate the long term EMS requirements		√		EirGrid & SONI
		Extension of Wind Security Assessment Tool		√		EirGrid & SONI
		Continue to use best in class forecasting tools Input into analysis on probabilistic distribution factors	√	√	√	EirGrid & SONI
		Implement greater active and reactive power controllability of Distributed generation from Control Centres		√		EirGrid & SONI/DSOs
		Update system tools to include system policy developments (e.g. reserve)			√	EirGrid & SONI
	Studies	Update dynamic models with current performance capability for all generators	√	√		EirGrid & SONI
		Develop a multi – bus model for the analysis of the system's frequency response	√	√		EirGrid & SONI
		Carry out further frequency stability analysis with refined dynamic models and investigate and review secure system non synchronous penetration levels			√	EirGrid & SONI

9 CONCLUSIONS AND RECOMMENDATIONS

This report has quantified the degree of system change that will occur with increasing windfarm penetration on the Ireland and Northern Ireland power system over a range of key operational and plant portfolio metrics. In particular it has found that:

System Frequency Response

On-line synchronous inertia will potentially fall by 25% on average in 2020 with resultant impacts on the ability of the system to securely withstand sudden energy imbalances in short time periods. New operational polices will be needed that address the greater impact on the minimum frequency reached and the rate of change of frequency experienced following a disturbance and there will be an increased reliance on fast-acting reserve provision from all plant.

Ramping Services

New operational practices are needed to manage the increased variability and uncertainty that wind generation brings. Specifically, it has been found that there is a 20% correlation with installed wind and the average change in output of windfarms in one hour. In addition, the absolute MW in wind forecast error will increase with installed windfarms. New operational policies are needed to ensure sufficient ramping capability to manage this increased duty (combined with forecast errors) over multiple time horizons. The effectiveness of these policies will be dependent on the level of controllability of all windfarms, the accuracy of wind forecasts, and the portfolio ramping capability and performance.

Voltage Control

A co-ordinated approach to voltage control across the system is required to allow for the changing nature and location of reactive power sources. This will need to account for: a potential decrease of over 25% in on-line synchronous reactive capability, that the nature of windfarms steady state reactive capability is different from conventional generation, that the control of windfarm reactive output is critical to enable secure system operation and the performance of windfarms' reactive output during voltage disturbances has implications for the stability of the power system.

Portfolio Performance

In addition, the reliable performance of generators to expected standards further complicates the operation of the power system. Mechanisms to reduce this uncertainty will improve the efficiency of operation today and enable the system operators to securely manage the power system in the long run.

EirGrid and SONI have proposed a three-year multi-stakeholder "Programme for a Secure, Sustainable Power System". This programme systematically addresses the identified challenges.