All Island TSO Facilitation of Renewables Studies

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Foreword

EirGrid and SONI, as Transmission System Operators (TSOs) on the island, are pleased to present the findings from the Facilitation of Renewables studies.

Launched over 18 months ago as a joint venture between EirGrid and SONI the Facilitation of Renewables studies set out to examine the technical challenges with integrating significant volumes of wind power generation onto the power system of Ireland and Northern Ireland. The research consultants ECOFYS, Siemens-PTI and Ecar, were commissioned by EirGrid and SONI to examine different aspects of the overall study and this report brings together the core elements from this suite of studies in a single comprehensive document.

Ireland and Northern Ireland have set ambitious renewable energy targets up to 2020 and wind power is expected to form the largest component of these targets. Indeed, it has been estimated that at least 6000 MW of windfarms will need to be installed by 2020 to ensure our targets are achieved. This amount of windfarms will at times represent well in excess of 50% of the generation of the total power system in real time.

The technical characteristics of wind generation mean that this level of instantaneous penetration will alter the dynamic characteristics of the electricity power system. Understanding these changes therefore is fundamental to developing the operational strategies needed to manage the power system in a secure, reliable and consistent manner in the years ahead. These studies provide the first significant modelling of power system behaviour at these unprecedented instantaneous penetrations of wind, and the findings are a key element towards meeting our renewable energy targets.

The main findings of the study indicate that the integrity of the frequency response and the dynamic stability of the power system are compromised at high instantaneous penetrations of wind. The modelling used in the studies also suggests that the voltage and reactive behaviour of the system is directly related to the performance of all generators on the island as well as how the network is developed, and will require significant management over the coming years. Finally, the studies indicate that voltage disturbances could result in the temporary loss of windfarm output.

Nevertheless, the core message from the studies is positive. The findings indicate that subject to the fulfilment of a number of technical and operational criteria, Ireland and Northern Ireland can achieve our renewable energy targets securely and effectively by 2020. These technical and operational criteria are:

That the use of standard protection relays on the distribution network and the capability of all generators to ride through high rates of change of frequency is reviewed;

That compliance with the Grid Code standards is consistent and in particular conventional generators meet the standards of primary reserve that the dynamic models provided suggest; and

That all windfarms have the appropriate control, capability and response, particularly for voltage reactive support during disturbances that the Grid Code requires.

Understanding the implications of these findings and working towards their implementation will require the full engagement and support of all stakeholders in the electricity sector. It is with this process in mind that I look forward to fostering sector-wide support for these important next steps on the path towards meeting our 2020 renewable energy targets.

Dermot Byrne

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Chief Executive, EirGrid

Executive Summary

Background and Objective

The Republic of Ireland has set a binding electricity target of 40% from renewable resources by 2020 [Government of Ireland (2008)] [ENVIRON (2008)]. Northern Ireland is currently considering setting a similarly challenging policy target. Wind power will provide the dominant share of this renewable electricity generation and, hence, wind capacity will continue to grow significantly in the period up to 2020. This change in generation structure has implications for the real time operation of the power system. Related challenges have been acknowledged in the All Island Grid Study [DCENR (2008)].

The objective of the "All Island Facilitation of Renewables Studies" was to more fully understand the technical and operational implications associated with high shares of wind power in the All Island power balance. Consequently, building blocks for an operational strategy of the 2020 All Island Power System had to be developed allowing secure, safe and reliable power system operation.

Methodology

Based on data provided by EirGrid and SONI a 2020 All Island Power System scenario and model was derived. 63 dispatch cases distributed on the complete feasible operational range of the power system (combinations of instantaneous wind power and load) have been specified for the technical studies. For the 13 cases with no interconnector exchange (0X) see black dots in Figure 1. Both peak load and maximum output from wind power was assumed with 7,550MW.

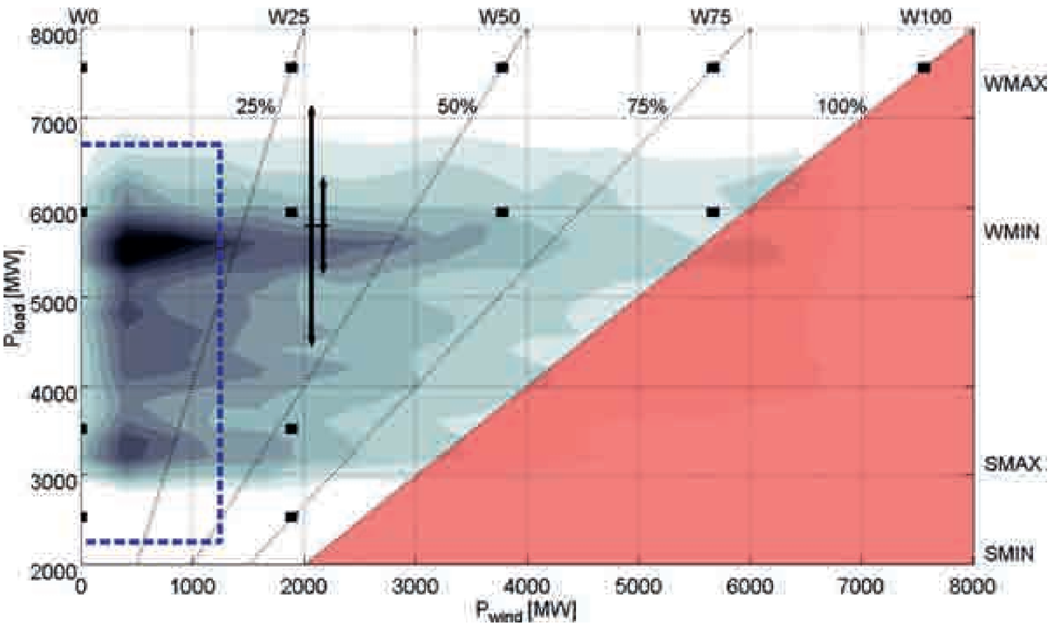

Figure 1: *Visualisation of the operational range of the 2020 All Island power system (area generated by the variables instantaneous wind power and load) compared to 2009 range (area indicated by blue dashed line). Black dots indicate cases with no interconnector exchange (0X).*

In Figure 1, dashed parameter lines indicate penetration of wind generation based on net load. Shaded area (red) with wind generation being higher than load is infeasible. Arrows indicate potential displacement of net load by interconnector export / import cases (± 550 / 1350 MW). Underlying contour is representative for probability of the operational condition as extrapolated from 2008 / 2009 monitoring data. Darker areas are more likely.

Modelling covered a variety of distinct technical issues. The results clearly show the potential impact of high instantaneous shares of wind power in the total generation and highlight specific technical issues associated with increasing levels of wind power.

Results

The analysis provided evidence that two key issues are limiting the acceptable level of instantaneous wind penetration in the 2020 All Island power system scenario:

- frequency stability after loss of generation;
- frequency as well as transient stability after severe network faults.

Modelling results suggested that technical measures exist to further mitigate transient stability issues.

Figure 2 gives an overview on these and other issues identified in the studies. Issues are classified into four categories: fundamental issues, fundamental issues that need further analysis, issues that can be mitigated, and non-issues according to modelling.

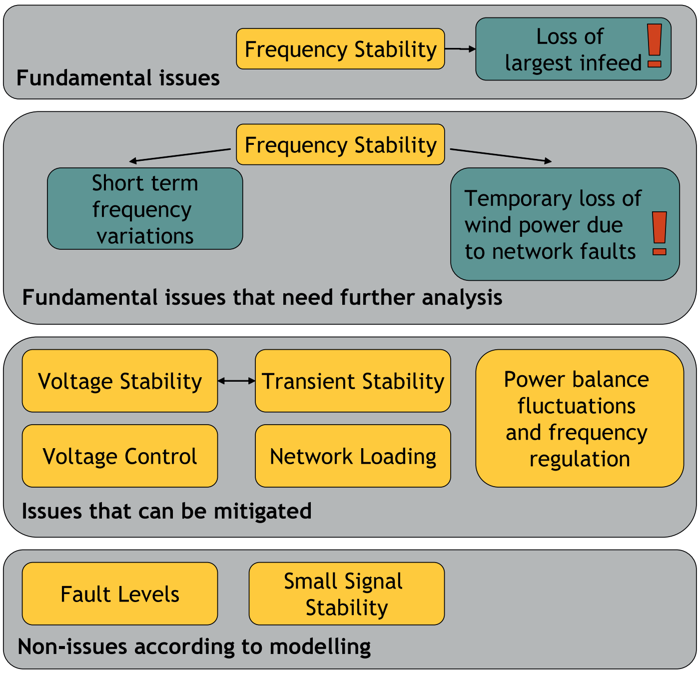

Figure 2: *Overview on issues arising from increasing wind power*

For some issues (frequency stability, small signal stability) model limitations and the applied methodologies did not allow for a comprehensive quantitative analysis. Nevertheless, evaluating the model limitations results are considered robust and the respective technical issues are less critical than those mentioned above.

For issues related to reactive power (i.e. fault levels, voltage stability) and voltage control, the network loading as well as power balance fluctuations and frequency regulation modelling showed minor problems or identified feasible mitigation measures.

Recommendations for an Operational Strategy

"Operational metric 1" has been identified as a suitable indicator for the operational ranges allowing stable operation of the system. Two other operational metrics have been analysed, too. "Operational metric 1" is the ratio of wind generation plus import and system load plus export. It could be regarded as the "**inertialess penetration**". Under the modelling assumptions – and following the precautionary principle with regard to the issues that may impose fundamental limits but need further analysis – the suggested maximum for this parameter in system operation is **60% ... 80%**.

Figure 3 illustrates the findings, indicating the allowable operational range as a green and yellowish area at the left side of the diagram.

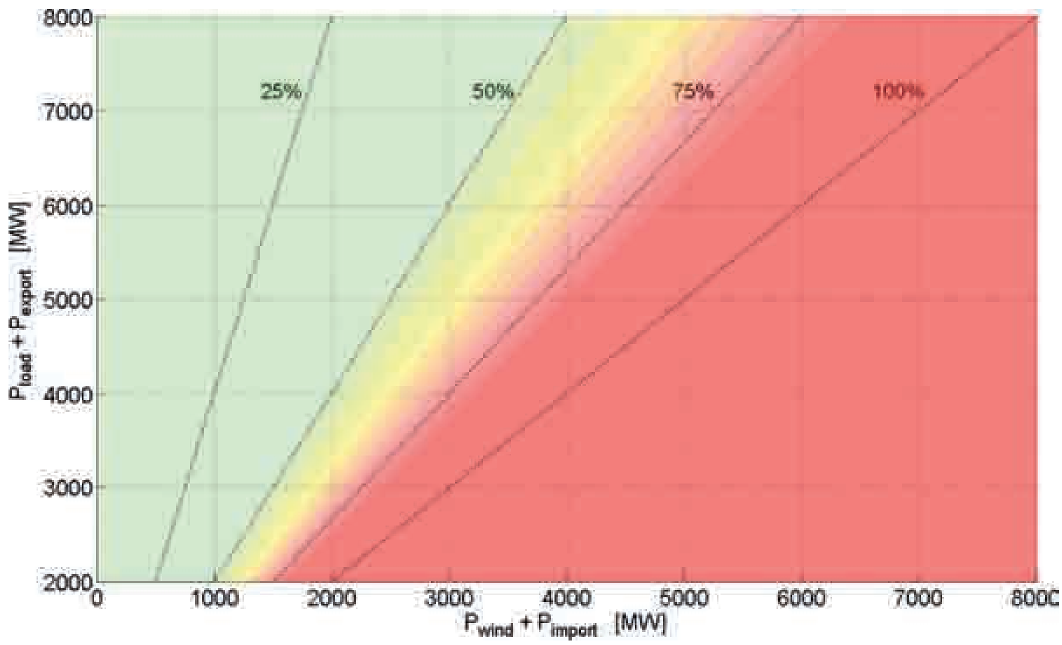

Figure 3: *Indicative illustration of the allowable operational range of the 2020 All Island Power System. Dashed parameter lines indicate penetration of wind generation based on net load. Left area (green): no relevant technical issues. Lower right area (red): technical issues jeopardising stable system operation. Range in between (yellow): transitional range, technical issues become increasingly critical. Ranges may be changed or reduced by future studies.*

The modelling suggested an even stronger restriction of "operational metric 1" to about 50% if ROCOF relays at distribution connected wind farms and other generators were not disabled and their threshold remained unchanged at the assumed value of ±0.6Hz/s. Also any actual limitations of generators, including transmission connected wind farms, to ride through ROCOF values of more than ±0.5Hz/s may restrict the acceptable value of "operational metric 1".

The identified acceptable range for "operational metric 1" of 60% ... 80% is only technically viable assuming major **additional adaptations** of the power system. The model provided by EirGrid and SONI was not optimised yet. Ongoing planning studies are currently investigating the optimum reinforcements required to accommodate the anticipated wind power up to 2025 [EirGrid (2008b)]. Examples of fundamental additional adaptations that were found necessary are:

- Extended static and dynamic sources for reactive power;
- Uncompromised grid code compliance of the complete wind portfolio and all other generators throughout the whole lifetime;
- Replacement of ROCOF relays in distribution networks by alternative protection schemes or increased ROCOF relays threshold;
- Monitoring of short circuit levels and adjustment of network capacity, in particular in 110 kV networks;
- Evolution of the power plant portfolio in line with the scenario, etc.

Respective measures are all applying state-of-the-art technologies and do not represent any technology risks. Implementation of future technologies and features, including (emulated) inertia from wind farms and other generators, may relax the acceptable range for "operational metric 1" but need to be further analysed.

The analysis does not allow drawing conclusions on system behaviour if these upgrades are not implemented neither is it possible to apply the findings straightforward to the current system topology.

Based on the study results some additional recommendations for system operation can be derived also with respect to a number of aspects which are not directly related to wind power:

- Imports via the interconnector should be limited to clearly less than the considered maximum value of 1350 MW. Modelling does not suggest that imports of 500 MW or less are critical. Definition of the allowable maximum requires dedicated modelling between these two distinct cases.
- Redispatch of conventional units is an important option of maintaining system stability with varying load, wind output or network topologies. Redispatch may be applied in order to assure ramping capability, flexibility and reserve provision of the conventional plant. Additionally, redispatch and dynamic allocation of must run units are effective measures for system wide voltage control and reactive power management.
- The risk level associated with the key issues often depends on the actual system condition (e.g. largest infeed, network topology and distribution of reactive power sources). Integration of the system conditions in the real time system monitoring tools (state estimator) will help to maximise the allowable value for "operational metric 1" during operation.

Impact of the operational strategy

The identified limitation for "operational metric 1" and instantaneous wind penetration, respectively, does not fundamentally conflict with the 2020 policy targets aiming at 40% electricity from renewables. According to Figure 4 the target could be overachieved in a scenario with 7,550MW peak wind generation and almost completely achieved by the use of wind energy in a scenario with 6,000MW peak wind generation – if limitations at the upper range (e.g. a value of 80% for "operational metric 1") were imposed. With a conservative approach (e.g. not more than a value of 60% for "operational metric 1") meeting the target will require increased contributions from renewable sources others than wind or higher installed capacity of the latter.

Nevertheless, the identified limitations clearly imply challenges for power system economics and project viability as well as regulation; this was out of the scope of the studies and needs further analysis.

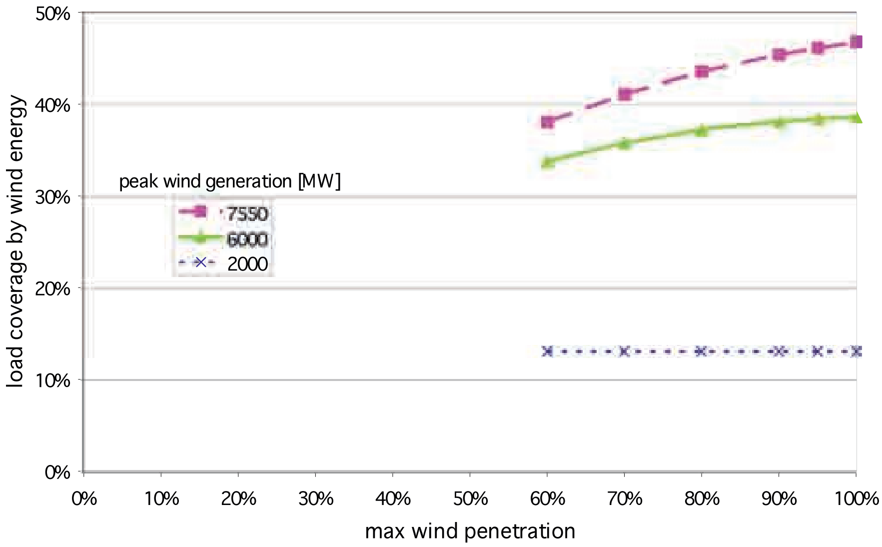

Figure 4: *Estimated total wind energy share in annual load coverage due to curtailment for different maximum allowable instantaneous wind penetrations.*

Recommendations for future work

The study process also identified potential to increase the accuracy of system modelling. Instantaneous values for "operational metric 1" and imports may be specified more accurately if more cases are analysed. In parallel, models should be further refined in order to overcome specific limitations of the applied methodologies. Key aspects are multi-bus models for the analysis of the system's frequency response as well as improved wind turbine and wind farm models representing a response completely in line with grid code requirements.

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Abbreviations

AC	*Alternating Current*
AIGS	*All Island Grid Study*
CCGT	*Combined Cycle Gas Turbine*
CCT	*Critical Clearance Time*
Controllable WFPS	*Controllable Wind Farm Power Station*
CSC	*Current Source Converter*
DC	*Direct Current*
DFIG	*Doubly fed induction generator*
EWIC	*East West Interconnector*
EWIS	*European Wind Integration Study*
FACTS	*Flexible Alternating Current Transmission Systems*
FCWTG	*Wind turbine generators with full converter*
HVDC	*High Voltage Direct Current*
NADIR	*Nadir (minimum value of frequency)*
NI	*Northern Ireland*
OCGT	*Open Cycle Gas Turbine*
PCC	*Point of Common Coupling*
POR	*Primary operating reserve*
ROCOF	*Rate of change of frequency*
RoI	*Republic of Ireland*
SFM	*System Frequency Model*
SOR	*Secondary operating reserve*
SVC	*Static Var Compensator*
TOR	*Tertiary operating reserve*
TSO	*Transmission system operator*
VSC	*Voltage Source Converter*
WTG	*Wind Turbine Generator*

1. Introduction

1.1 Background

The political objectives in Europe of tackling climate change while providing a secure and efficient energy system are challenging. Binding ambitious targets for energy from renewable sources have been set by the climate change and third energy package to be reached by 2020 [European Parliament and Council of the European Union (2009)]. The solution to these challenges will require co-ordinated and consistent approach across the European Union and the respective transport, heating and electricity sectors to resolve. There is an emerging consensus that the electricity sector will provide the back bone to resolution of these challenges.

Both Governments in Northern Ireland and Ireland have been aware of the advent of these binding targets and the central role that electricity will play in delivering on the energy policy objectives. There has been proactive policy in both jurisdictions consistent with these directives. In particular the Government in Ireland has set a binding electricity target of 40% from renewable resources by 2020 [Government of Ireland (2008)] [ENVIRON (2008)]. Northern Ireland is reviewing the target at present and is considering setting a similarly challenging target. In any case the penetration of significant wind farms has implications for the real time operation of the power system that need to be understood and managed to provide a secure, safe and reliable power system.

The behaviour of the power system will fundamentally alter with the addition of these wind farms. This has been previously acknowledged in the All Island Grid Study [DCENR (2008)] as well as a focus of electricity utilities and transmission system operators around the world. The degree of change that this introduces has the potential to materially reduce the reliability and security of the power system in Ireland and Northern Ireland if not deeply understood and appropriate operational mechanisms developed. The "All Island Facilitation of Renewables Studies" provide many of the answers required to understand how a power system behaves when there is a significant penetration of wind farms in real time and allows for a framework within which the appropriate operational tools can be developed.

The analysis contained in the three work packages of the studies also provides clarity for system operators in coping with the challenges imposed by the policy objectives. It is a significant step in identifying and ultimately reducing or bounding the risks associated with the operation of power system with high penetrations of wind farms. This has benefits not only for transmission system operators EirGrid and SONI but also policy makers, regulators and market participants in quantifying the benefits and risks in setting policy, defining market rules consistent with the policy objectives and ultimately successfully commercially operating in electricity power systems with high penetration of wind farms.

1.2 Objective

The objective of the "All Island Facilitation of Renewables Studies" was to understand the technical and operational implications associated with high shares of wind[1] in the All Island power balance and to develop a strategy for the operation of the 2020 All Island Power System. This report provides an executive overview of the findings.

1.3 Scope

The studies summarised in this report address various technical issues associated with the planning and operation of the All Island power system with large amounts of wind power. The horizon of the underlying development scenarios is 2020.

For optimum and timely delivery, EirGrid and SONI have divided the studies into three Work Packages tackling a variety of issues.

- Work Package 1. A series of detailed technical studies based on PSS®E modelling (undertaken by UK office of Siemens PTI)
  - Task 1.1: Dynamic, Transient and Small Signal Stability
  - Task 1.2: Fault Levels and Protection Operation and Philosophy

1 This report focuses on wind power because of its dominating role in the renewable energy portfolio in the 2020 Irish power system. The document refers to other renewable technologies only incidentally and in the technical studies they have not been considered in detail. Nevertheless, this simplification does not compromise results or conclusions. In the text, renewable generation and wind generation read as synonyms in most cases.

- Task 1.3: Network Loading
- Task 1.4: Reactive Power and Voltage Control
- Task 1.5: System Flexibility Requirements

- Work Package 2. A series of frequency studies based on a single-bus frequency model (undertaken by ECAR)
  - Task 2.1: Frequency Response
  - Task 2.2: Frequency Regulation
- Work Package 3. Operational Requirements (undertaken by Ecofys)
  - Detailed analysis of the results from Work Packages 1 and 2
  - Determination of impact on the operation and development of the power system
  - Identification of critical success factors
  - Recommendations for an operational strategy

The analysis is purely technical. Any assessment of economic implications of the considered issues or of supportive regulatory action as a precondition for successful implementation of required changes is out of the scope of this study.

1.4 Structure of the report

Section 2 defines the background of the studies by introducing critical changes of the All Island Power System related to the integration of large amounts of wind power.

In section 3 basic assumptions are explained and the applied methodology is summarised. The section also explains some relevant limitations of the applied models and tools.

Section 4 presents the key modelling results in an aggregated format. The critical issues related to the integration of large amounts of wind power in the All Island Power System are identified. Possible technical mitigation measures for the issues are discussed. Finally, the results are used to identify the allowable operational range for the system.

Based on these results, section 5 derives a set of recommendations for an operational strategy. Section 6 discusses potential implications of the operational strategy based on the estimated effects on the yield of the wind portfolio.

Section 7 and section 8 summarise the conclusions and some key recommendations for future activities, respectively.

2. Problem formulation

Compared to extended intercontinental power systems, such as the European ENTSO-E system the All Island Power System is of limited size only and can rely on interconnection capacity to a limited extent. The increasing share of wind power in the total instantaneous generation introduces new challenges for security and cost effectiveness of supply. These challenges can be related to the following categories of changes which, in fact, are the driving factors for the studies.

Structural changes of the All Island Power System

- *Electric location of generation:* The All Island Power System has been developed in a way to deliver electricity from large power plants connected at transmission level to customers connected at sub-transmission and distribution level. Renewable energy plants use resources with a relatively low energy density compared to conventional energy resources and have consequently a lower installed capacity per unit. In the Irish case, wind farms are distributed over the country and connected at sub-transmission and distribution level in large quantities. The electric location of generation is shifted to these voltage levels.

- *Spatial location of generation:* The spatial location of conventional plants was determined in the past either by the location of the energy resources (coal, gas, oil, peat) or – if resources had to be imported anyway – by distance to load centres (Dublin area, etc.). The electricity network was developed respectively to bring the electricity from those plants to the customers. However, renewable energy resources such as wind power are partly located in other parts of Ireland than conventional resources [ESBI Ltd (2008)]. Longer distances between generation and load centres are the consequence.

Operational changes in the All Island Power System

- *Reduced commitment and dispatch of conventional power plants:* Given the guaranteed priority dispatch of renewable generators as variable price takers throughout Ireland, in certain times the output from conventional power plants is either reduced or these units are not committed at all to cover the demand.

- *Increased variability of generation:* The infeed of power plants that use renewable energy sources can change significantly over time. This results in an increased variability of the power from renewable generators, especially wind farms. At the same time this leads to a reduced ability to control the power output of those plants (with certain exemptions for a reduction of their power output that results in a spill of renewable energy, "curtailment").

Technology changes in the All Island Power System

- *Different electrical characteristics of generators:* The generator technology that renewable generators are based on differs significantly from thermal power plants with synchronous generators.

  - *Fixed speed wind turbines:* Have been the dominant technology for wind power plants in the past. These wind turbines use induction generators, thus their ability to control reactive power flows and to contribute sustained short circuit power during grid faults is limited. Since the vast majority of wind farms in the 2020 All Island Power System will use variable speed wind turbines the impact of fixed speed wind turbines is not analysed in the studies.

  - *Variable speed wind turbines:* The dominant technology for wind power plants in 2020. These wind turbines use power converters.[2] Instantaneous values of active and reactive power can be controlled in a very flexible and fast way compared to the power values of synchronous generators. But power converters are vulnerable to extreme currents and voltages. Different technological concepts of wind turbines, i.e. doubly fed induction generator (DFIG) and full converter wind turbine generators (FCWTG) have different performance with respect to electrical characteristics.

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2 These devices convert alternating current (AC) to direct current (DC) and vice versa, and can be applied back-to-back for decoupling two AC circuits from each other. If placed in the generator's stator circuit, as it is the case for generators with a full scale converter (FCWTG), the electrical values at the stator and grid side of the power converter are fully decoupled; if placed in the generator's rotor circuit, as it is the case for doubly fed induction generator (DFIG), the power converter can control the electric field of the rotor independently from the electrical values at the grid side.

- *Decoupling of mechanical and electrical parts:* For variable speed wind turbines, the mechanical part of the prime mover (i.e. the wind turbine's rotor, shaft and gearbox) is effectively decoupled from the electrical part (the induction or synchronous generator) by the power converters. The physical laws inherent to synchronous generators do not apply. This leads to a reduction of power system inertia. Reduced inertia means that the power system frequency reacts faster to changes in the generation and load balance, e.g. showing faster decline of the system frequency in events of generation deficiency.
- *High inertia to energy ratio:* Due to the low capacity credit of wind power plants, significantly more wind capacity will replace conventional generation capacity. Whenever the wind speeds exceed the cut-in speed of wind turbines, their large amount of inertias is connected to the system, spinning and available for provision of inertia and frequency response. This potential capability, however, is not by state of the art wind turbines.
- *Increased complexity of control actions:* Similar to conventional power plants, renewable generators, e.g. wind turbines, have complex control systems with a large set of parameters. While this introduces a large number of new factors of influence into the power system, it also provides opportunities for dedicated control actions that might bring benefit to the power system operation.

3. Methodology and assumptions

3.1 General Remarks

The study criteria for the analysis were provided by EirGrid and SONI [Temtem and Dillon (2009)]. They reflected the Grid Code [EirGrid (2009)] requirements for voltage and frequency variations, short circuit levels, dynamic (transient) stability and others.

EirGrid and SONI acknowledged the inherent assumptions, simplifications and modelling characteristics of the studies. Generally, the study results only *suggest* how the power system performs and responds to contingencies *in reality*. Any generalisation of the study's results may be misleading or erroneous.

3.2 2020 Power Plant Portfolio and generation scenarios

The reference year for these studies was 2020. The general and base case assumptions including the 2020 power system configuration were provided by EirGrid and SONI [EirGrid and SONI (2009b)]. The study considered a single scenario, i.e. a fixed 2020 plant portfolio. In combination with lower forecasts for demand growth due to the recent economical crisis, the renewable energy share in this 2020 plant portfolio equals approx. 49% of total demand and losses.

Figure 3 - 1 shows a comparison of the chosen 2020 power plant portfolio with the today's (2010) power plant portfolio from EirGrid's Generation Adequacy Report 2009-2015 [EirGrid (2008a)] and SONI's Transmission Seven Year Capacity Statement [SONI (2006)] (left part).

The chosen 2020 power plant portfolios for conventional power plants assumed a significant evolution of the power plant portfolio compared to the status quo. Some important evolutionary steps to be mentioned are:

- **New CCGT:** About 1,800MW additional capacity of combined cycle gas turbine (CCGT) plants was assumed. Combined cycle gas turbine plants (both existing and new) have a maximum efficiency in excess of 50 %. New CCGT plants are assumed to reach ramp rates of about 11MW/min.
- **New OCGT:** About 2,000MW additional capacity of open cycle gas turbine (OCGT) plants was assumed. Open cycle gas turbines are inexpensive peaking plants with capacities close to 100MW but with maximum efficiency limited to 36 %. They ramp at 10MW/min.
- **Operation stopped:** Some gas plants that the All Island Grid Study had assumed to be decommissioned before 2020 were included in the portfolio (units at Aghada and North Wall); others were replaced by new CCGT power plants.

Definition and performance details for the other power plant types shown in Figure 3 - 1 can be found in [Ecofys (2008)].

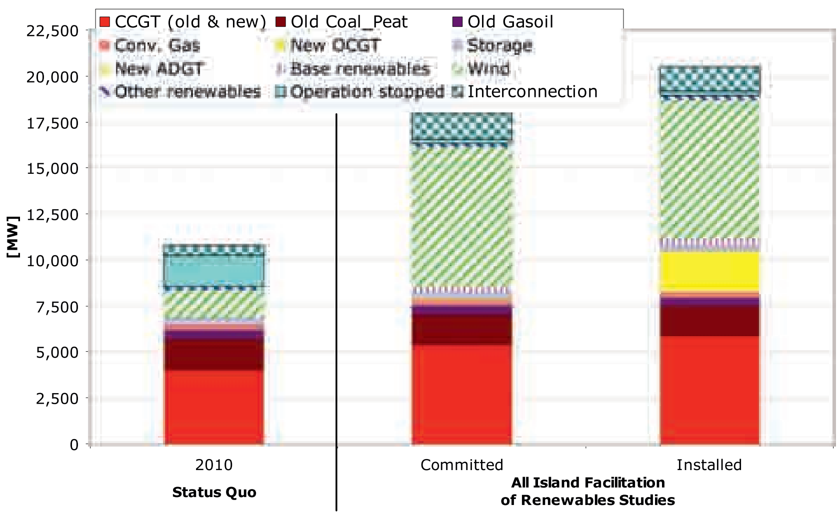


Figure 3 - 1: *Composition of 2020 generation portfolios (right) and comparison with Status Quo 2010 (left)*

The difference between the total "installed" capacity and actually "committed" capacity of the 2020 power plant portfolio in Figure 3 - 1 has to be read as follows:

- The "installed" power plant portfolio covers the total installed capacity of power plants listed in the assumptions [EirGrid and SONI (2009b)]. This portfolio includes significant amount of highly flexible new OCGT plants (2,210 MW) and was used in the analysis of flexibility requirements.
- The subset of "committed" power plants was included in at least one of the dispatches provided by EirGrid and SONI [Dillon (2009)]. This subset of the portfolio was used in the majority of the technical studies.

500 MW interconnection capacity (including 75MW for reserve power) is provided today by the Moyle interconnector connecting NI with Scotland. In 2020 it is assumed that three interconnectors (Moyle, EWIC I and EWIC II) provide interconnection of up to 1,350 MW in total (including 3x75MW for reserve power).

The study assumes a peak wind generation of 7,550 MW. Existing records suggest that peak wind generation in Ireland does not exceed 90% of the installed capacity. Hence, the 7,550 MW peak wind generation corresponds to an installed capacity of more than 8,000 MW. This capacity slightly exceeds portfolio 6 of the AIGS.

The 2020 power plant portfolio assumed the same amount of pumped hydro power plants as the portfolios of the All Island Grid Study. These plants are categorised as 'storage' in Figure 3 - 1. Biomass and tidal power plants are shown in the 2020 power plant portfolio as 'base renewables'. Run-of-river hydro power plants are named 'other renewables'.

3.3 Cases and naming conventions

Compared to previous studies, the scenario assumes a significantly lower demand growth according to most recent forecasts.

System operational scenarios ("sensitivity levels") were generated by defining a set of feasible load, (instantaneous) wind power and export/import combinations [EirGrid and SONI (2009a)]. EirGrid and SONI translated these combinations into 63 "feasible" system dispatches for the conventional plant [Dillon (2009)]. These dispatches were derived using a simple optimisation algorithm that considered the generators' merit order (i.e. the average heat rate) along with the generators' reserve characteristics and the reserve required. Composition of dispatches is presented in appendix A 1.

Of course, this snapshot approach using 63 distinct load/wind/interconnection combinations, with one unique dispatch each, does not support any statistical analysis. Consequently, the studies do not provide information on the likelihood or economic implications of a certain case. Even, drawing conclusions on the system behaviour *between* the distinct cases may be delicate. Still, the cases cover the complete operational range of the 2020 All Island System. Thus, they sufficiently indicate the operational ranges for that modelling suggests that the system is stable.

Table 3 -1 shows the 63 cases and the naming convention used throughout this report.

Table 3 -1: *Load, wind and export/import cases considered and presentation of feasible ("1") and non-feasible ("0") combinations.*

	Wind																								
	W0					W25					W50					W75					W100				
	0 MW					1,888 MW					3,775 MW					5,663 MW					7,550 MW				
	Export/Import																								
Load	EH	EL	OX	IL	IH	EH	EL	OX	IL	IH	EH	EL	OX	IL	IH	EH	EL	OX	IL	IH	EH	EL	OX	IL	IH
SMIN	1	1	1	1	1	1	1	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WMIN	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
SMAX	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0
WMAX	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0

Legend to Load:

Name	Label	Load (used in WP1)	load+losses -base renewables (used in WP2)
Summer Minimum	SMIN	2,535 MW	2,219 MW
Winter Minimum	WMIN	3,519 MW	3,253 MW
Summer Maximum	SMAX	5,938 MW	5,792 MW
Winter Maximum	WMAX	7,550 MW	7,485 MW

Legend to Export/Import:

Name	Label	Exchange	Name	Label	Exchange	Name	Label	Exchange
Export-high	EH	1,350 MW	Import-high	IH	-1,350 MW	Zero exchange	OX	0 MW
Export-low	EL	500 MW	Import-low	IL	-500 MW			

Further to the 63 dispatches, sensitivity of system behaviour to two parameters has been studied to a certain extent:

- percentages of wind power connected to the transmission / distribution level, respectively: 35%/65% (case T35) versus 20%/80% (case T20)
- share of wind turbine technology, i.e. doubly fed induction generator / full converter WTG, respectively: 80%/20% (case TSA) versus 50%/50% (case TSF).

The 2020 scenario represents a substantial change of the system with respect to the current situation as well as to a 2020 scenario without any generation from wind. The load duration curves in Figure 3 - 2 (derived from extrapolation of 2008/2009 load and wind data) illustrate this change. In the current system permanently about 2,000 MW of conventional generation is online (in a 2020 scenario without wind about 2,400 MW). In the 2020 scenario considered here the conventional generation required to provide active power to the load decreases structurally. The net load is zero or lower for more than 1,000 hours per year. A net load below zero is technically infeasible and means that the respective wind generation has to be curtailed.

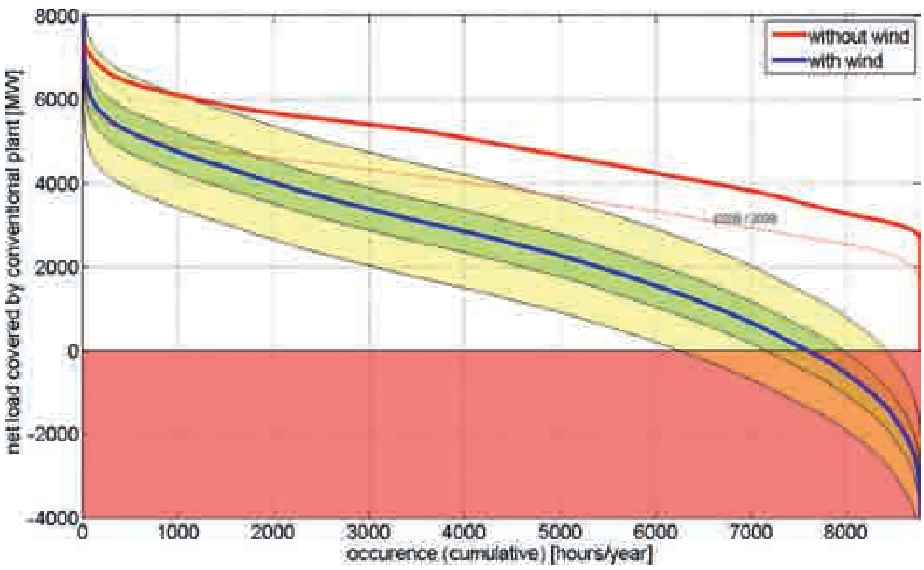


Figure 3 - 2: *Estimated 2020 load duration curve (red) and duration curve of remaining net load to be covered by conventional units (blue) assuming an installed wind plant capacity of >7550 MW. For comparison: duration curve of net load in 2008/2009 (dashed line). Area with negative load (shaded red) is infeasible. Ranges around net load indicate potential variations related to interconnector cases (550 MW / 1350 MW - import / export). Data source: Eirgrid / SONI 15 minute monitoring data.*

Figure 3 - 3 demonstrates that the cases cover the extreme ranges of system operation. The figure illustrates the position of the cases in the plane representing the load and wind power output combinations. Interconnector export and import may be interpreted as an offset of the system load moving the cases along the vertical axis (see arrows for illustration). In line with Figure 3 - 2 the red area in the lower right represents the infeasible operational range where wind generation exceeds load and needs to be curtailed.

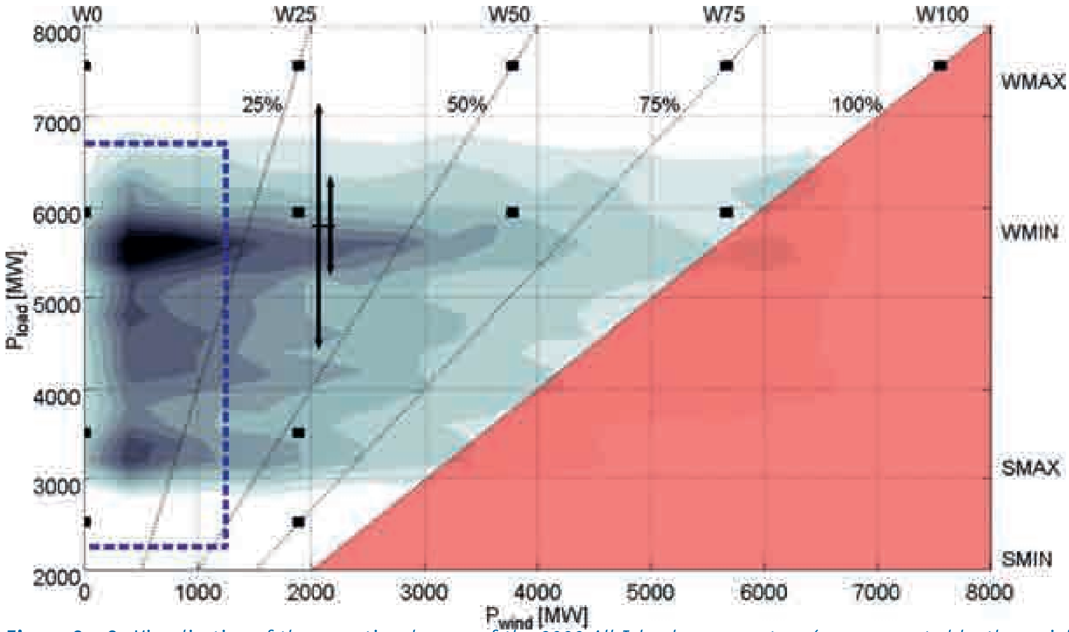


Figure 3 - 3: *Visualisation of the operational range of the 2020 All Island power system (area generated by the variables instantaneous wind power and load) compared to 2009 range (area indicated by blue dashed line). Black dots indicate cases with no interconnector exchange (0X). Dashed parameter lines indicate penetration of wind generation based on net load. Shaded area (red) with wind generation being higher than load is infeasible. Arrows indicate potential displacement of net load by interconnector export / import (± 550 / 1350 MW). Underlying contour is representative for probability of the operational condition as extrapolated from 2008 / 2009 monitoring data. Darker areas are more likely. Peak load and maximum output from wind power are 7,550MW.*

Figure 3 - 3 allows drawing some qualitative conclusions:

- Any wind power penetration beyond 100% of demand (indicated by red shading in Figure 3 - 3) inevitably has to be curtailed. Curtailment to 100% wind penetration in the figure results in yield losses of more than 10%.
- In this perspective, 8,000 MW installed wind capacity is an optimistic assumption. The associated yield losses might be commercially unacceptable. This will depend on the support scheme.
- The cases with lower wind output may be interpreted as the representation of a smaller installed wind capacity without fundamentally violating modelling assumptions. Hence, the 7550 MW wind scenario includes a more moderate development of wind power in the All Island system.

3.4 Modelling components

Power systems analysis – multi bus model (Work Package 1)

Siemens PTI applied their power system simulation package PSS®E v.31.1 together with its generic wind turbine generator (WTG) models [Siemens PTI (2010b)].

In modelling of **wind generation** two WTG types were distinguished:

- Doubly fed induction generators, DFIG (generic model with parameters based on a GE 3.6MW WTG);
- Full converter WTG, FCWTG (generic model with parameters based on an Enercon E70 2.3MW WTG).

The WTG models were tuned in their steady state reactive power *capability* for compliance with the Grid Code [EirGrid (2009)]. Performance of WTG models in the base case analysis was limited with respect to voltage support in normal operation and during faults [Siemens PTI (2010a)]. WTG models were also not suited for frequency studies [WECC (2009)]. Wind generation was lumped at the point of common coupling (PCC) with the transmission and distribution system buses. The principle of wind farm aggregation was similar to the methodology in the European Wind Integration Study (EWIS) [Lemmens and Winter (2008)] [Winter (2010)].

The **power system model** reflected reinforcements identified in the Grid 25 studies [EirGrid (2008b)] and in the NI network the North-West phase 1 studies which are required by 2020. This included all approved reinforcements as well as additional unapproved reinforcements which are required for the study cases to solve [EirGrid and SONI (2009b)]. But since the model provided was not optimised yet the 2020 scenario implied furthermore substantial adaptations of the system models as provided by EirGrid and SONI. The most relevant adaptations are related to:

- 2020 wind capacity;
- Network reinforcement, upgrading of transformers and reactive power capability;
- high voltage direct current (HVDC) voltage source converter (VSC) East-West Interconnectors (EWIC);
- user models for some conventional power plants.

Load modelling used constant impedance, current, power (ZIP) combination to represent voltage dependency and polynomial load models to represent frequency sensitivity. Base case analysis excluded large motor loads. In a sensitivity analysis for a single dispatch, 10% of motor load was modelled with an explicit induction machine load model from the PSS®E standard library.

Statistical Analysis (Work Package 1)

The statistical analysis focused on the operational power reserves required in the 2020 All Island Power System scenario. Parts of the statistical analysis were also used for estimating the robustness of network loading results and the adequacy of the transmission system for extreme geographical wind power distributions on the island of Ireland.

The assessment used 15 minute monitoring and forecast data (demand and wind generation) from a subset of 2007-2009 which were extrapolated to the 2020 scenario [Siemens PTI (2010b)]. Based on these data confidence intervals for extreme variations of demand, wind power and net demand were calculated for periods of 15min, 1h, 2h and 4h. The results were used to estimate the variability in demand and wind power that the 2020 All Island Power System has to deal with.

Frequency Studies – single bus model (Work Package 2)

Because of the previously mentioned limitations of the generic wind turbine models in PSS®E and other similar packages with respect to frequency excursions [WECC (2009)][3], frequency stability under normal operational conditions and the systems' response to disturbances has been investigated by ECAR using the System Frequency Model (SFM).

The model assumes a *single busbar* [Ecar Ltd. (2010b)] and represents the dynamic interactions of turbines, governors, boilers and load over the range of 0-15s following a loss of generation or load. Additionally, this model allows modelling of advanced WTG capabilities such as reserve provision in curtailed operation or inertia emulation.

The single busbar concept of the System Frequency Model (SFM) implies two important simplifications:

- The network supports unlimited load flows.
- All rotating masses connected to the system (e.g. large generators, motor loads) rotate in synchronism with each other permanently.

This means that transient oscillations between synchronous generators at different locations in the system are not represented in the model. The lumped representation of the generation capacity (conventional and wind) implies further that location specific parameters (e.g. voltage at PCC during a fault) cannot be included in the model directly. In the course of the analysis, a parametric adjustment of the wind portfolio response has been applied using approximate values derived from the power systems analysis in the multi bus model.

3 Cited: "[...] the WECC generic WTG models recently released in PSS®E and PSLF were not developed with the intent of being accurate for the study of frequency excursions. [...] the existing WECC generic models were not designed to reproduce the effect of advanced power management features that are imminently becoming available from some WTG manufacturers, such as programmed inertia and 'spinning reserve' by spilling wind."

Currently, wind farms connected to the distribution system are equipped with rate of change of frequency (ROCOF) relays as part of their G10 protection functions. ROCOF relays observe the frequency at the connection point of the wind farm. In order to prevent islanding they disconnect the wind farm in events when the rate of change of frequency exceeds ±0.40...0.55Hz/s over a period of 0.5s [Escudero (2010)].

For the modelling some optimistic assumptions regarding ROCOF response of generators and relays have been made. The threshold for ROCOF relays was set slightly higher to ±0.6Hz/s. And any limitations of generators, including transmission connected wind farms, to ride through significant ROCOF were neglected. This was in contrast to the grid codes of EirGrid [EirGrid (2009)], SONI [SONI (2010)] and ESB Networks [ESB Networks (2007)]. These indicate that all generators, including wind farms, only have to remain connected to the network during ROCOF values up to and including ±0.5Hz/s.

The SFM assumption that all distribution connected wind farms in the 2020 All Island Power System react identically to a frequency change, however, must be regarded as the worst case. Once activated the ROCOF relays in the SFM disconnect the complete wind capacity connected to the distribution system.

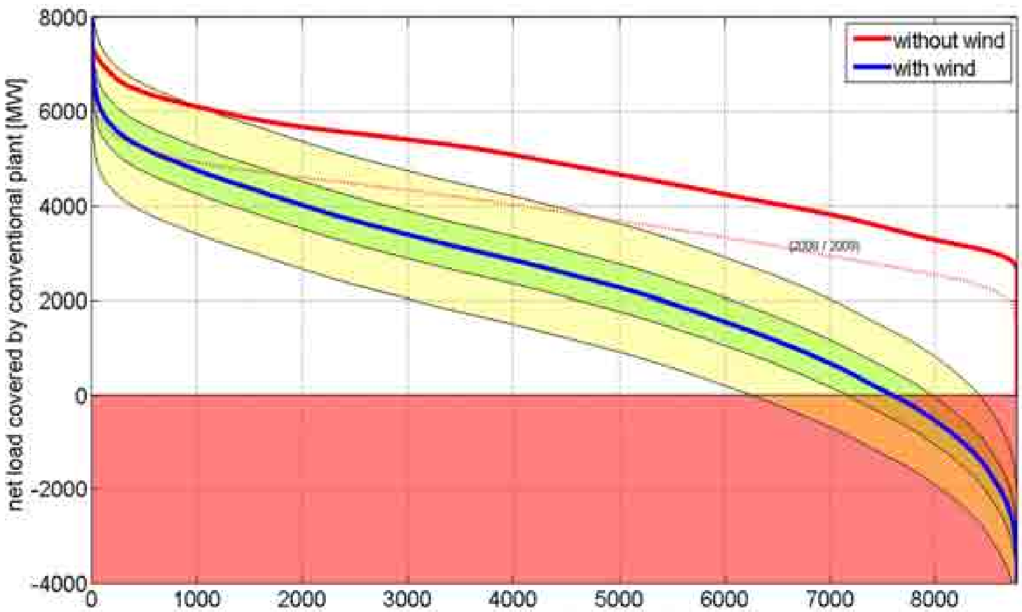
The load model used in the SFM assumed a steady state frequency sensitivity of the load of 2.5% (i.e. for 1Hz frequency drop the load reduces by 2.5%) [O'Sullivan and O'Malley (1996)]. For the kinetic energy of the load the model assumes that load provides an additional 50% of kinetic energy from the dispatched conventional generation units [Mullane (2010)].

System response to generation loss exceeding the primary control from conventional power plants together with primary reserves provided by wind turbines will be nonlinear. In such cases model accuracy may be insufficient.

The frequency response of the SFM is determined by the control settings of corrective actions taken at certain frequency levels in order to re-establish the supply demand balance. Four classes of actions are differentiated and shown in Table 3 - 2:

- Green: No corrective actions outside of normal governor response and utilisation of Turlough Hill and peaking of North Wall CCGT and MRC units.
- Yellow: Interconnector import increase necessary to stabilise the system frequency (<49.6 Hz)
- Red: Utilisation of interruptible load and or load shedding (<49.3 Hz)
- Black: Infeasible range of operation (<48.5 Hz)

Table 3 - 2: *Corrective actions taken in order to re-establish the supply demand balance.*



4. Key results

4.1 Classification of issues

In the following section modelling results are discussed. This discussion is aligned with the severity of the related issues for the All Island Power System. The following categories are distinguished:

Issues that impose fundamental operational limits: The results suggested that fundamental issues affect the secure operation of the 2020 All Island Power System if the system is operated beyond the identified operational limits. Possibilities for mitigation with state of the art technology are limited.

Issues that may impose fundamental operational limits but need further analysis: The results suggested that the secure operation of the 2020 All Island Power System may be compromised if the system is operated beyond certain operational limits. However, more analysis is required to fully understand the impact of these issues and the effectiveness potential mitigation measures.

Issues that impose operational limits but can be mitigated: The results have suggested that the secure operation of the 2020 All Island Power System is impacted if the system is operated beyond certain operational limits. However, these issues can be mitigated with appropriate investment in suitable network technologies and generator capabilities.

Issues that seem not to impose operational limits: The results suggested that these issues are not critical for the secure operation of the 2020 All Island Power System.

Figure 4 - 4 gives an overview on the issues identified in the studies.

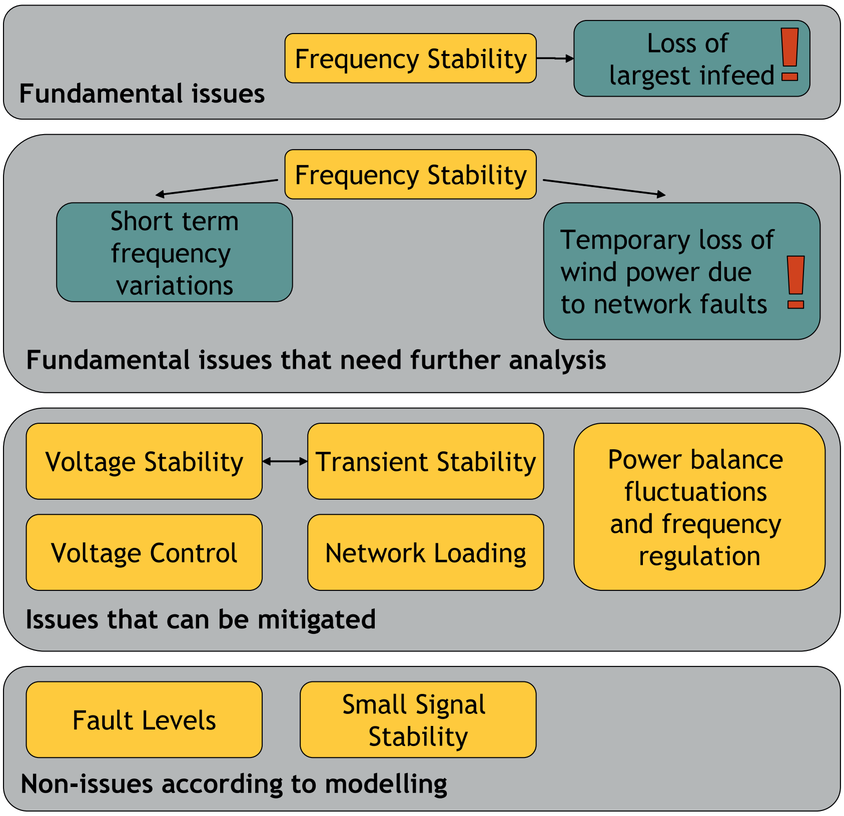


Figure 4 - 4: *Overview on issues arising from increasing wind power*

4.2 Operational metrics

The assessment of the operational limits beyond which the distinct issues impact the secure operation of the All Island Power System uses a number of operational metrics. These operational metrics reflect operation values showing a strong relationship with relevant system variables (e.g. critical clearance times or minimum frequency).

4.2.1 Operational metric 1

Power from wind turbines and imported via HVDC interconnectors does not contribute to system inertia. Both technologies rely on power electronics. Respective controls implement behaviour different than electromechanical machinery in conventional plants. When replacing conventional power plants, wind generation and imports reduce the total inertia in the All Island Power System. This affects the systems frequency response and, consequently, the following indicator proved to be helpful.

Operational metric 1	**Ratio of inertialess power from wind plus import and instantaneous load plus export**	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}}$

Figure 4 - 5 illustrates the trend of decreasing system inertia with increasing value of "operational metric 1". Figure 4 - 5 shows a significant dispersion of the observations. This is due the crisp character of the considered set of dispatches and the underlying variation of inertia constants *H* of the particular conventional units. Applying "operational metric 1" in further analysis the fuzzy character of the metric has to be reflected.

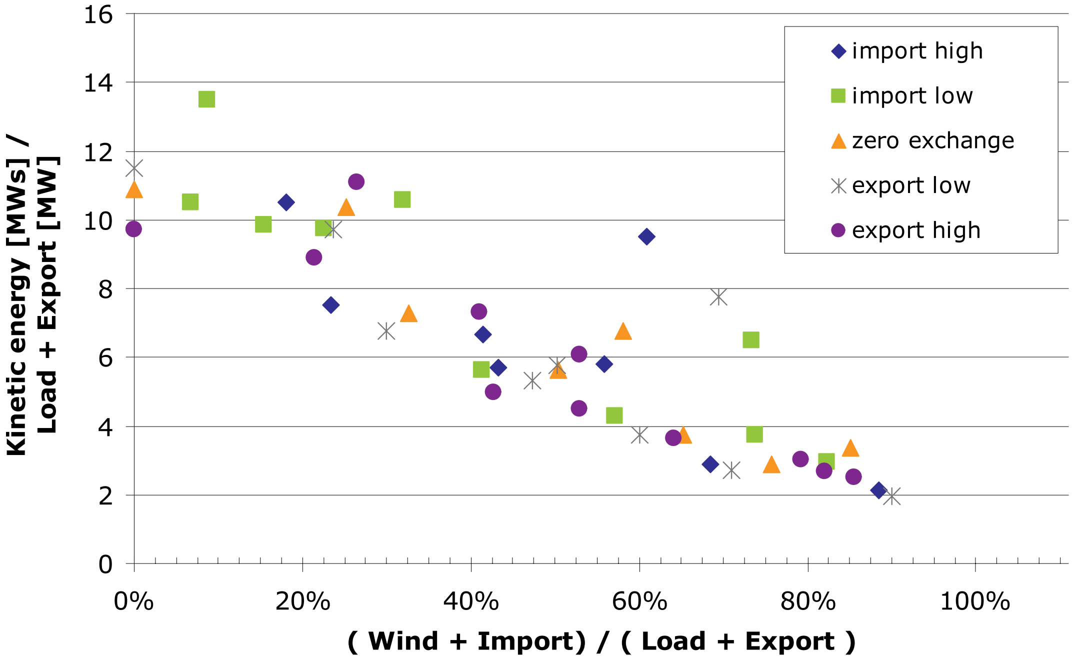


Figure 4 - 5: *System inertia constant (calculated as kinetic energy of the power system per sum of system load and export) as a function of "operational metric 1".*

4.2.2 Operational metric 2

Directly associated with the instantaneous system inertia illustrated in Figure 4 - 5, the kinetic energy stored in the rotating equipment (generators and load) has a strong impact on the frequency response to system disturbances (e.g. the loss of generation). Analysis showed that the ratio of kinetic energy and the dispatched power of the largest, potentially lost infeed seems to be a suitable indicator for frequency stability. Depending on the disturbance, largest infeed may also be temporary loss of wind power from many units simultaneously.

Operational metric 2	**Ratio of kinetic energy stored in conventional generators plus load and the dispatched power of the largest infeed;**	$\dfrac{KE_{convGen} + KE_{load}}{P_{largest\ infeed}}$

4.2.3 Minimum number of conventional unit online

Also the minimum number of online generation units larger than 100MW has been considered as an operational metric. Such an operational parameter might be useful for allocating must-run units. Figure 4 - 6 plots this operational parameter against the "operational metric 1". As the figure shows the 63 dispatch cases result in only seven distinct indicator values not revealing a clear relation. Modification of the indicator's definition (50MW threshold) did not improve the correlation. With the given, limited set of dispatches it is not possible to derive an applicable indicator reflecting the minimum number of online generation units and describing the stability of the system.

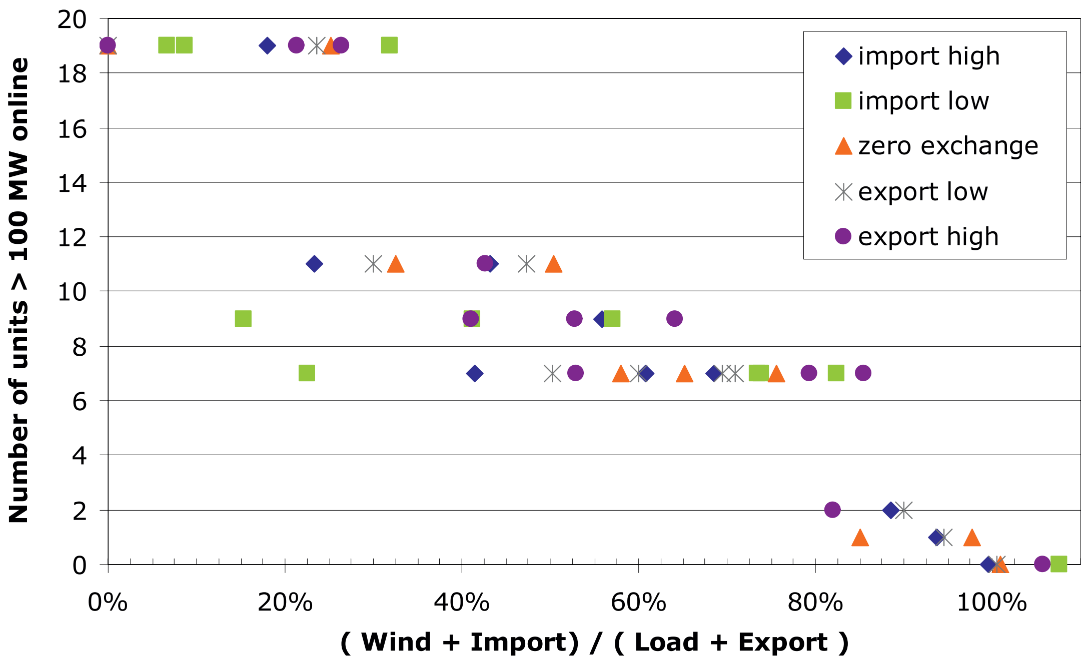


Figure 4 - 6: *Number of online generation units larger than 100MW as a function of "operational metric 1".*

4.3 Issues that impose fundamental operational limits

4.3.1 Frequency excursion following the loss of largest infeed

4.3.1.1 The Issue

Frequency Stability describes the ability of a Power System to return to an operating equilibrium following a severe system disturbance which did not result in separation of the system into subsystems. In line with common praxis voltage and reactive power issues were neglected [Kundur (1994)].

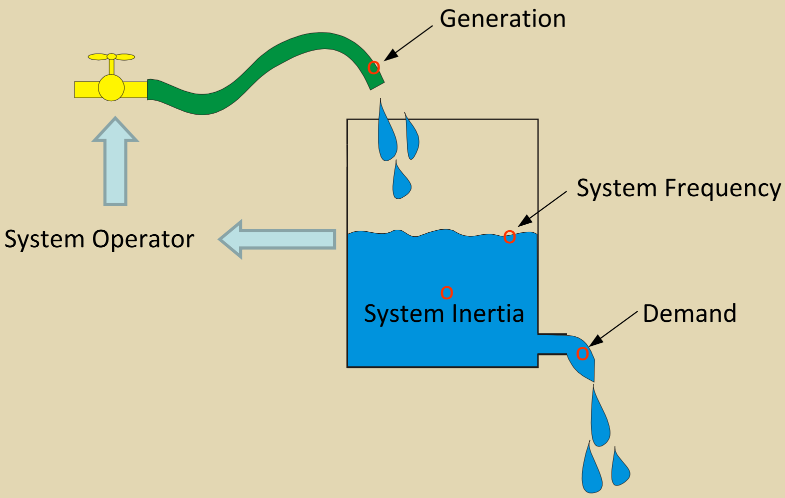


Figure 4 - 7: *Visualisation of the frequency control problem for power systems. The water level in the bucket stands for the system frequency and the water body for its inertia. The system operator monitors the water level and regulates the water inflow with the tap so that it meets the water outflow. Source: [Mullane (2009)]*

Operating a power system means balancing the active power of generation and loads at any moment (inflow and outflow in Figure 4 - 7). Any imbalance results in a change of the global system frequency (the water level). As the consequence of electromagnetic forces, the rotational speed of synchronous generators is an exact representation of the system frequency. In case of excess generation the generators are accelerated and system frequency increases (and vice versa in case of excess load).

Frequency excursions trigger corrective actions as load shedding (-0.7Hz) or immediate curtailment of wind power (+0.25Hz). The amount of corrective measures incrementally grows with the deviation and, in severe cases, may involve separation of subsystems. These actions are required because uncontrolled deviations from the 50 Hz setpoint lead to system instability and potentially system collapse.

The kinetic energy stored in the rotating masses of generators and loads, i.e. the power system's inertia, determines the sensitivity of the system frequency towards supply demand imbalances. The higher the power system's inertia, the less sensitive is the frequency to temporary imbalances.

In the very first moments after the loss of generation power the inertia of the rotating machinery helps to limit the drop of system frequency. The braking torques associated with decelerating of the generators release some of the rotational energy stored in the equipment. This results in additional instantaneous power output from the synchronous machinery supporting the system, even before primary reserve is activated. In the case of synchronous generators this power boost may amount up to a multiple of the nameplate capacity.

Wind power plants are equipped with electronic power converters. The torques are controlled by computer programmes and there is no strict relation between frequency of the system and the rotational speed of the generator. Hence, state of the art wind power plants (as well as imports via interconnectors) do not contribute to the inertia of the system. In fact, wind power and imports replacing synchronous machinery reduce the system inertia. An increasing wind share in instantaneous generation may make the system more vulnerable.

4.3.1.2 Results

The analysis used the minimum frequency after disturbance as the indicator for system stability[4]. Figure 4 - 8 illustrates the relationships between the minimum frequency after the loss of the largest infeed and "operational metric 1". The figure allows drawing the following conclusions:

- Interconnection has a strong impact on the frequency stability after disturbances with the loss of the largest infeed. Especially high import cases show very severe frequency drops (see ellipse in Figure 4 - 8). The reason is that imported power replaces conventional power plants in the All Island Power System.
- Ignoring high import cases, minimum frequency after loss of largest infeed hardly[5] drops down to 49.3Hz (activation threshold for tripping of interruptible load). For "operational metric 1" values lower than about 80% modelling suggests that minimum frequency stays within a range of 49.4...49.8Hz. For higher values of "operational metric 1" minimum frequency results become highly dispersed including values below 49.0Hz
- The figure shows many frequency excursions down to 49.6 Hz. The respective cases include also one configuration without wind power[6]. In modelling reserves from interconnectors are activated below a frequency of 49.6Hz. Hence, these reserves will play an important role for frequency control.
- Due to cascading effects, active ROCOF relays at distribution connected wind farms and other generators may increase frequency deviations and compromise system stability when the value of "operational metric 1" exceeds about 80%.

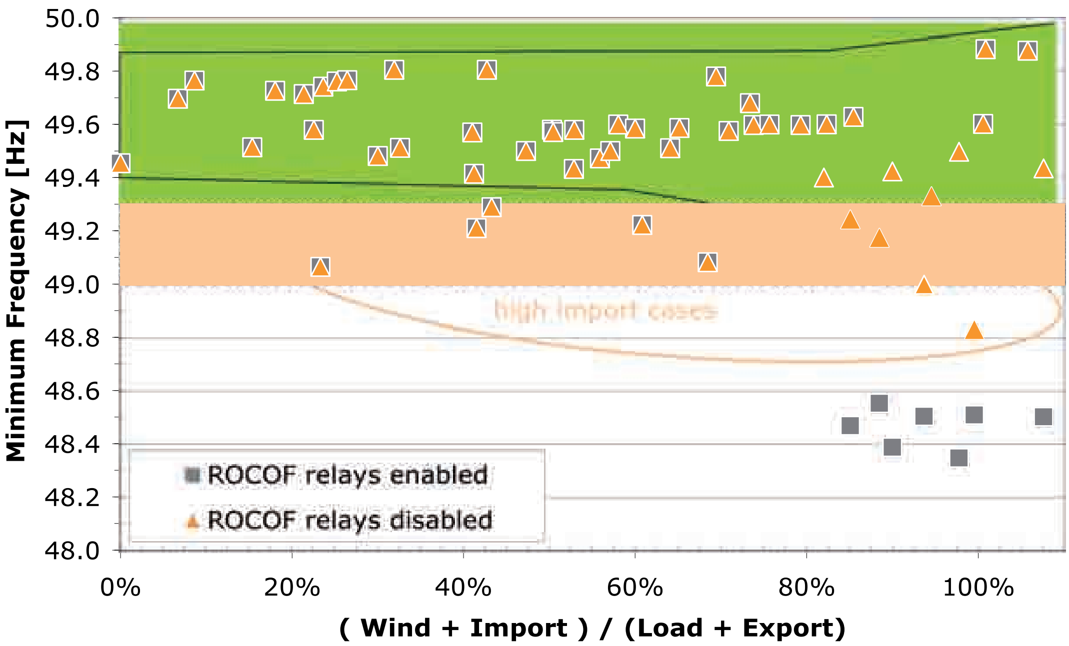


Figure 4 - 8: *Minimum frequency after loss of largest infeed as a function of "operational metric 1".*

Figure 4 - 9 shows a similar relation using "operational metric 2". Again ignoring high import cases, modelling suggests stable system behaviour for "operational metric 2" ratios above about 30MWs/MW. Above this ratio ROCOF relays do not impact frequency deviations.

4 For rate of change of frequency and time to nadir see [Ecar Ltd. (2010a)][Ecar Ltd. (2010a)].
5 Only the summer minimum (2,219MW) load case with 25% wind power (1,888MW) and zero exchange lead to a minimum frequency of 49.2Hz after loss of largest infeed.
6 Winter minimum load, export high, zero wind lead to a minimum frequency of 49.5Hz after loss of largest infeed.

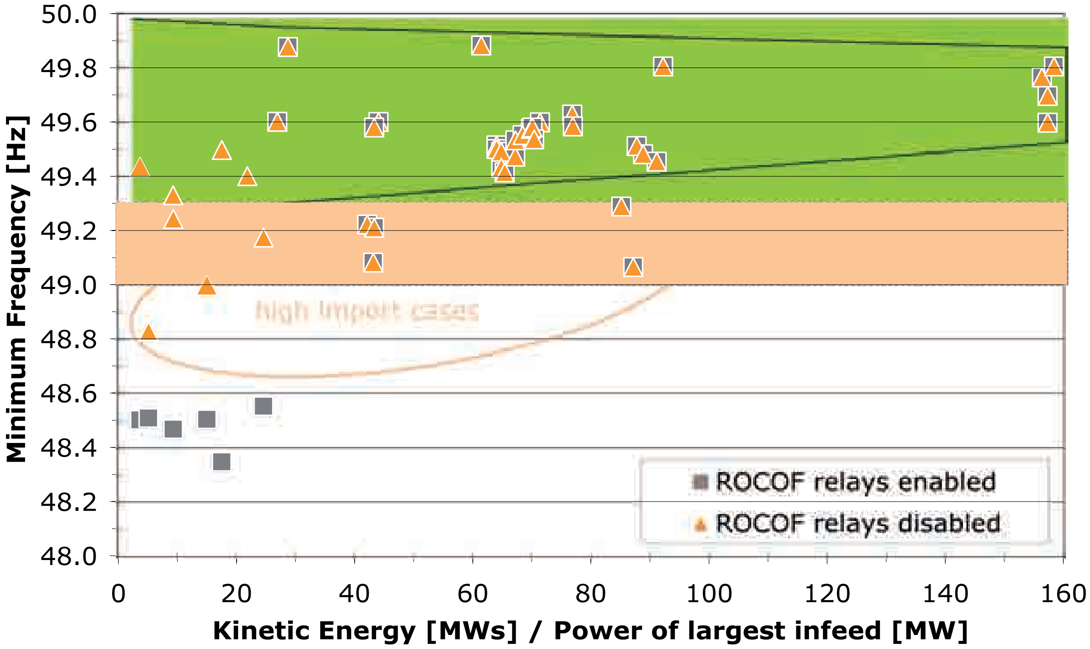


Figure 4 - 9: *Minimum frequency after loss of largest infeed as a function of the kinetic energy stored in conventional generators and the load divided by the dispatched power of the largest infeed.*

The results suggest that – simply by implementing a restriction on import - stable operation of the 2020 All Island System is possible with indicator values in the range of:

Operational metric 1	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < 70...80\%$
Operational metric 2	$\frac{KE_{convGen} + KE_{load}}{P_{largest\ infeed}} > 20...30\frac{MWs}{MW}$

The acceptable ranges for "operational metric 1" and "operational metric 2" might be further relaxed by disabling of ROCOF relays or increasing their threshold value. However, further studies are needed to assess the validity of the modelling for very high wind cases.

4.3.1.3 Technical mitigation measures

The only way to remove the 70% restriction on "inertialess penetration" is to add inertia to the system. The following two options are of potential interest but none of them is ready for immediate application.

Conventional plants providing inertia

Conventional plants dispatched in synchronous compensator mode potentially can provide inertia without generating active power. This mode will not be technical feasible for all plant types and may be subject to further operational restrictions.

As a check, frequency response with some units providing inertia only has been modelled with the System Frequency Model for a few cases. The results showed only very limited improvement of the frequency response. It may be concluded that an effective mitigation strategy would require substantial amounts of rotating equipment. To assess technical and economical implications of such a strategy a separate, dedicated analysis would be required.

Emulated inertia from wind turbines

In the rotating equipment of wind power plants much rotational energy is stored, even more than in the same capacity of conventional generation. By adopting the control programmes in the converters inertia might be 'emulated'. In case of a frequency drop the units might intentionally inject extra capacity into the network by decelerating. It is important to understand that this extra power does not come from the wind resource and, hence, does not rely on curtailment. On the other hand the available boost depends on the rotational speed and the actual generation level of the wind power plant.

The concept of emulated inertia from wind power plants draws growing attention in the industry. Recent publications of wind turbine manufacturers suggest that wind turbines could provide additionally 10% of nominal active power [Wachtel and Beekmann (2009)] or the equivalent energy (kW-sec) contribution of a synchronous machine with an inertia constant of $H=3.5s$ [Miller et al. (2009)] for 10 seconds.

Based on an indicative estimate Figure 4 - 10 illustrates this capability for the scenario with an installed wind capacity of 7,550 MW.

Potential benefits of inertia contribution of wind turbines have been investigated using the System Frequency Model. The results suggest that emulated inertia from wind power plants indeed promises improvement of system stability after loss of generation. The minimum amount of dispatchable generation might be further reduced compared to a system with no inertia from wind turbines.

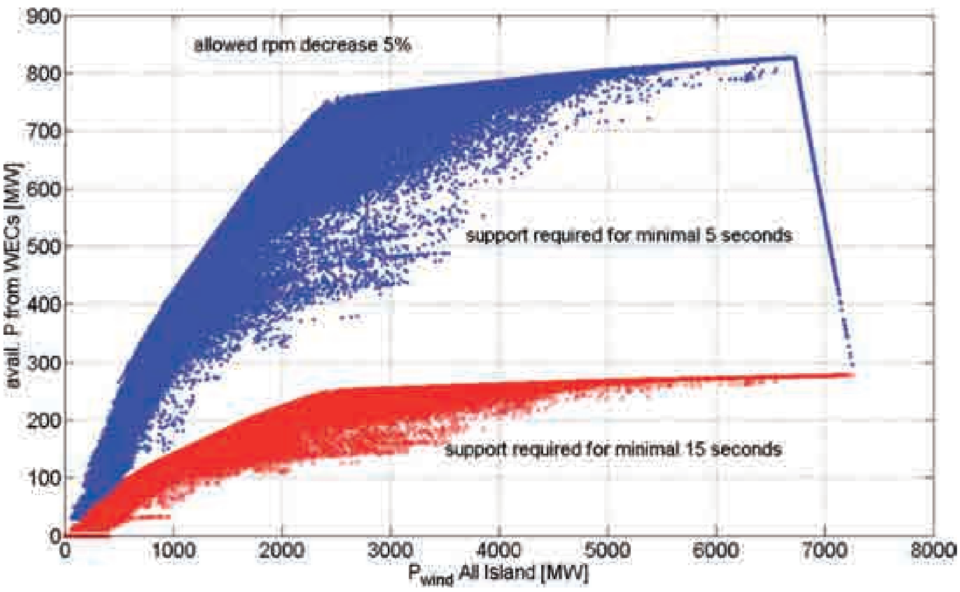


Figure 4 - 10: *Estimate of available power from wind turbines' inertia as a function of instantaneous wind power output for the 2020 All Island Power System. Data source: extrapolated 15 min wind and load monitoring data from Eirgrid and SONI*

However, a number of potential issues require further analysis in order to completely understand potential benefits and drawbacks of the concept.

- In contrast to synchronous machines, frequency changes have to be detected by wind turbine control systems first. Applied filtering might lead to time delays and reduce the performance of emulated inertial response.
- Depending on operating conditions inertia emulation will show a different response than a synchronous machine. If the wind turbine has been operating at rated power before the frequency dropped, the rotor's kinetic energy is not accessible for frequency support. Depending on ratings, the wind turbines' power electronic converters will limit the capability to provide additional power.
- As a consequence of rotor deceleration the aero-dynamic efficiency of a wind turbine decreases, resulting in a potential active power reduction until the units returned to normal operation conditions. This recovery process may interfere with system recovery and has to be managed carefully.
- The concept implies a highly distributed control hierarchy. Proper parameter settings will be crucial for achieving the intended performance.
- Due to the single busbar approach of the System Frequency Model current results do not reflect power flow congestions or voltage instabilities in the 2020 All Island Power System. Indeed, indicative checks with the PSS®E system model indicate that such aspects may jeopardize the benefits or may even result in adverse effects on system stability.

4.4 Issues that may impose operational limits but need further analysis

4.4.1 Frequency excursions after network faults

4.4.1.1 The Issue

The issue of frequency excursions is the same as discussed in the previous section. However, the specific mechanism causing frequency excursions in case of network faults is different.

Synchronous generators restore their active power output quickly after a short circuit has been cleared. Wind turbine generators may need more time to restore their active power to the pre-fault value in order to keep mechanical loads on the structure at acceptable levels (for an example see Figure 4 - 11).

With large wind capacity affected, delayed active power recovery and the associated system imbalance can put system frequency at risk.

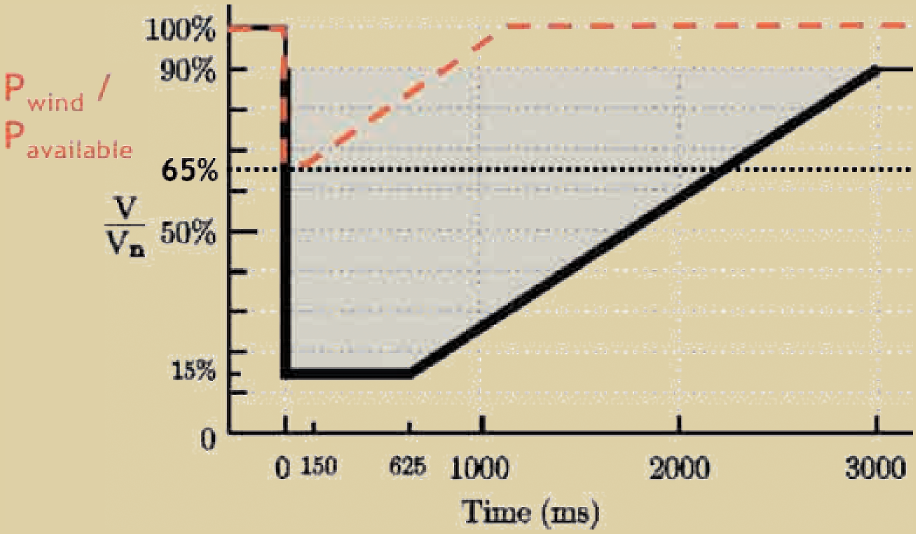


Figure 4 - 11: *Fault ride through curve in EirGrid grid code (black line) and assumed active power response for wind turbine generators to a 100ms fault with 65% retained voltage (red line)*

4.4.1.2 Results

The analysis with the Single Frequency Model assumed that all wind farms connected to the 2020 All Island Power System *actually complied* with WFPS1.4.2 of the grid code [EirGrid (2009)] requiring that wind farms

- shall provide active power in proportion to retained voltage during the transmission system voltage dip and
- shall provide at least 90% of its maximum available active power as quickly as the technology allows and in any event within 1 second of the transmission system voltage recovering to the normal operating range.

The decrease of wind power output due to voltage drops has been estimated based on the short circuit results obtained with the steady-state power systems analysis in the multi bus model. In this part of the study, however, wind turbine behaviour was not completely grid code compliant and, hence, assumptions are quite conservative.

Figure 4 - 12 shows the maximum decrease of wind power output for the worst case fault in different dispatches. Fault duration was 100ms and retained voltage typically was about 65% of nominal in an extended area. In certain cases, wind power output temporarily is decreased by 1,000-2,000MW. This exceeds by far the largest infeed. The percentage of faults that cause a power imbalance above 400MW is shown in Figure A - 20 of appendix A 6 for different load/wind cases.

Modelling assumed that interconnectors provide reserve below a frequency of 49.6Hz. However, because of the lacking location specific voltage information, validity of the Single Frequency Model also for import export cases is very limited. Voltage drops due to faults may cause blocking of the interconnector's power electronic converters or active power transfer may be reduced proportional to retained voltage [Siemens PTI (2010a)]. These effects have been ignored. In parts of the studies only cases with no interconnector exchange have been considered. Hence, the behaviour of interconnectors shortly after the fault clearance including the capability to provide reserve is subject to future analysis.

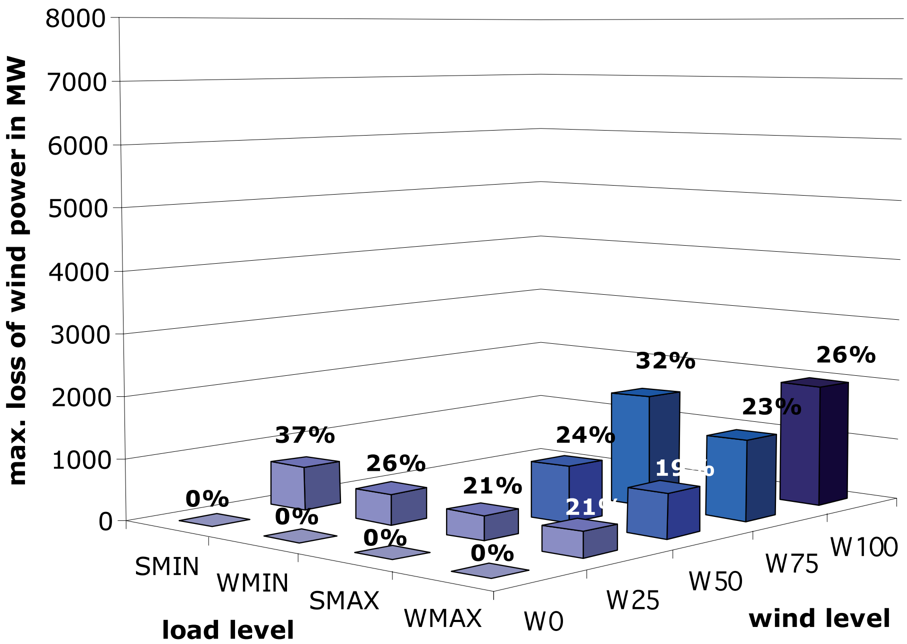


Figure 4 - 12: *Maximum temporary decrease of wind power output due to fault related voltage drop in different dispatches. The numbers above the bars indicate the percentage of total generation from wind and conventional power plants that is lost in the respective dispatch.*

Figure 4 - 13 shows the minimum frequency after the temporary decrease of wind power following severe network faults as a function of the "operational metric 1". Following observations are made:

- Minimum frequency values below 49.3Hz (activation threshold for tripping of interruptible load) are observed when the value of "operational metric 1" exceeds about 60% even if ROCOF relays are disabled.
- If the value of "operational metric 1" exceeds about 50% the ROCOF relays lead to cascading effects with a dramatic frequency drop as consequence.
- If ROCOF relays at distribution connected wind farms are disabled, the minimum frequency after temporary decrease of wind power following severe network faults reduces almost linearly with increasing values of "operational metric 1".
- Compared to the results from the loss of largest infeed analysis, the temporary decrease of wind power following severe network faults seems to be the larger risk.

Results plotted against "operational metric 2" are included in appendix A 6.

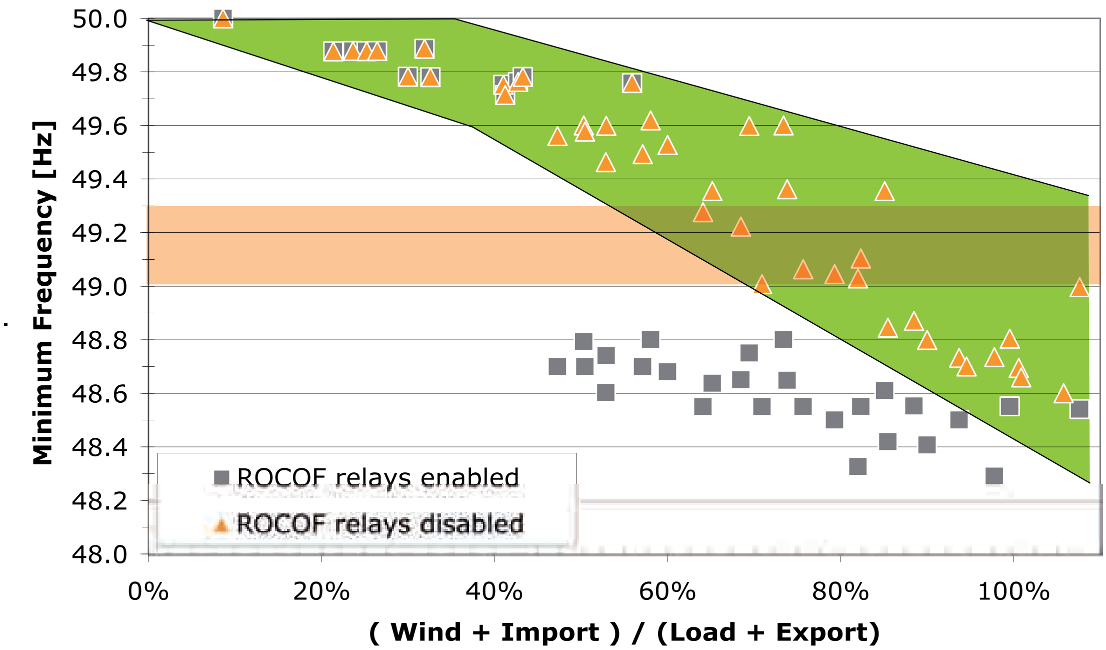


Figure 4 - 13: *Minimum frequency due to decreased wind power output after severe network faults as a function of "operational metric 1".*

Figure 4 - 14 shows the maximum ROCOF after the temporary decrease of wind power following severe network faults as a function of the "operational metric 1". It can be observed that cascading effects from ROCOF relays could be prevented for a value of "operational metric 1" of 60% … 70% if their threshold was changed to -1.0Hz/s … -2.0Hz/s.

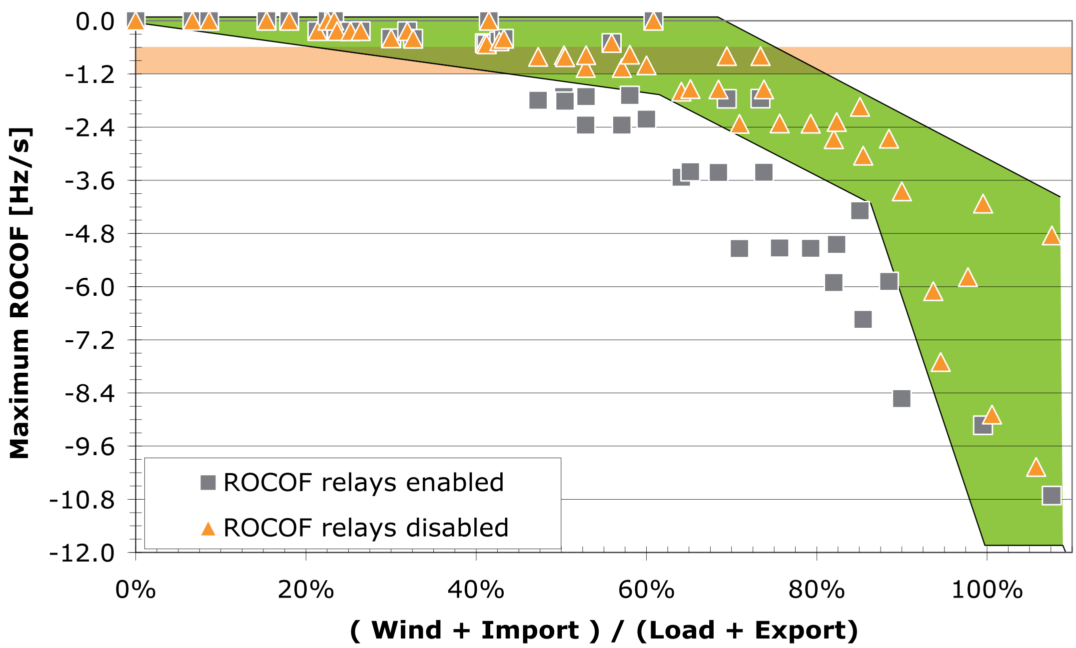


Figure 4 - 14: *Maximum ROCOF due to decreased wind power output after severe network faults as a function of "operational metric 1".*

The results suggest that – with *ROCOF relays disabled or with increased ROCOF relay threshold* - stable operation of the 2020 All Island System is possible with indicator values in the range of:

Operational metric 1	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < 60...70\%$
Operational metric 2	$\frac{KE_{convGen} + KE_{load}}{P_{wind\ lost}} > 20...30 \frac{MWs}{MW}$

With *ROCOF relays enabled at a threshold of ±0.6Hz/s* operation of the 2020 All Island System with a value of "operational metric 1" > 40...50% may be unstable. Also any actual limitations of generators, including transmission connected wind farms, to ride through ROCOF values of more than ±0.5Hz/s may restrict the acceptable value of "operational metric 1".

4.4.1.3 Technical mitigation measures

Work Package 2 studied a series of additional technical mitigation measures to improve the frequency regulation characteristics of the 2020 All Island Power System:

- provision of frequency regulating capability from wind generators;
- relaxation of frequency protection settings;
- minimum system inertial constraint.

The minimum system inertial constraint was analogous to imposing a constraint whereby a minimum number of synchronous generators must be online at all times ("must run units"). The constraint imposed was that the kinetic energy contribution from generators could never be below that provided by 9 x 150 MW synchronous generators having H constants of 4 s.

Model results suggested that:

- frequency regulating capabilities for wind generation are beneficial. The greater the curtailment of wind the greater the improvement of frequency stability. Of course, curtailment of wind power is associated with a yield loss.
- relaxing the frequency protection trip settings to the levels considered in this study has little impact.
- The minimum inertial response constraint considered in the study was found to be too small to have a significant impact on the results.
- The relevance of inertial response should nonetheless not be discounted as the inclusion of an inertial response from wind was found to bring significant benefit in the frequency excursion following the loss of largest infeed studies.

The additional technical mitigation measures did not promise a substantial increase of the 2020 All Island Power Systems' frequency stability after network faults.

Due to the limited validity regarding the voltage component, the effectiveness of inertial response from wind turbine generators could not be studied with the System Frequency Model. Another effect that was only observed in the power systems analysis with the multi bus model was that in depressed voltage conditions, additional injection of active power from a large number of wind farms could actually jeopardize the voltage stability of the All Island Power System.

A measure that has not been studied was an improved active power recovery of wind turbines after fault clearance that would be faster than required by the grid code. Some types of modern wind turbines are able to recover their active power in less than 1s after voltage recovery already today. Further technical development on this feature will very likely bring significant benefits for the operation of the All Island Power System.

Further studies of frequency excursions after network faults are recommended in order to detail the stability limits and to consider future technology trends.

4.5 Issues that impose operational limits but can be mitigated

4.5.1 Reactive Power and Voltage Control

4.5.1.1 The Issue

Voltage Stability describes the ability of a Power System to maintain acceptable voltages at all busbars in the system under normal operating conditions and after being subjected to a disturbance [Kundur (1994)].

Voltage stability is compromised when a disturbance (e.g. network fault), increase in load, or change in system conditions – including changes in wind power – cause a progressive and uncontrollable drop in voltage. The main factor causing voltage instability is the inability of the power system to meet the demand for reactive power.

A criterion for voltage stability is that, at a given operating condition for every bus in the system, the bus voltage increases as the reactive power injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus voltage decreases as the reactive power injection at the same bus is increased.

Unlike active power, reactive power can not be transported over long distances; the reactive power balance must therefore be maintained locally. Thus, voltage instability is also essentially a local phenomenon, although its consequences may have a widespread impact.

Voltage stability is to a large extent influenced by the reactive power capability of generation and the reactive demand of loads in different parts of the power system. The way bus voltages are controlled and the related interaction of transformer tap changers with the controls for generator terminal voltages are also of interest.

Voltage and transient stability issues are interrelated and same mitigation measures apply.

4.5.1.2 Results

Steady state analysis of voltage stability limits calculated active power versus voltage (PV) curves and reactive power versus voltage (QV) curves for dispatches with zero exchange over interconnector.

- PV curves determined *how close* the All Island Power System is *to voltage instability* at any of its busbars for different load/wind cases with respect to changes in the active power transfer. The analysis was done for normal and contingency system states.
- QV curves determined the *voltage values for all busbars* in the All Island Power System *at that voltage instability would occur* for different load/wind cases with respect to changes in the reactive power demand. The stability limit corresponds to the minimum of the QV curves.

The base case analysis assumed that tap changers of all transmission/distribution transformers were locked and that reactive power capability of wind farms was limited to unity power factor. The fact that transformers and wind farms did not participate in voltage control was regarded as the worst case.

While modelling results did therefore not allow for quantification of voltage stability limits and power transfer standards, they confirmed impacts of increasing wind power on voltage stability as expected and allowed to identify distinct voltage stability issues.

High amount of distribution connected wind farms decreases voltage stability

The results suggest that voltage stability of the All Island Power System decreases when large amount of wind power is fed into the system by distribution connected wind farms. Distribution connected wind farms (35% of all wind farms in the base case) are not capable to participate in voltage control unless they are equipped with additional reactive power compensation. But provision of reactive power at distribution level would also not effectively solve reactive power issues at transmission level. This underlines the importance of the grid code requirement, that at least transmission system connected wind farms must provide reactive power and have a continuously-variable and continuously-acting voltage regulation system [EirGrid (2009)].

Need for reactive power sources on transmission level

The reactive power capability of wind farms, in particular distribution connected wind farms, is lower than that of synchronous generators. When power infeed from wind farms replaces conventional power plants with synchronous generators, reactive power can become scarce in parts of the All Island Power System. It was found that significant amount of reactive power sources is needed to obtain feasible load flow solutions. These sources are needed at strategically important locations in the All Island Power System at 400kV, 275kV and 220kV transmission networks. Without sufficient reactive power sources at the right locations, the voltage stability of the All Island Power System deteriorates with increasing wind power.

Voltage instability close to nominal voltage

The analysis showed that voltage instability may occur already at voltages close to nominal voltage (minimum of QV curve). This finding is exemplified for one busbar (400kV Woodland) in Figure 4 - 15 assuming worst case reactive power capability of wind farms (solid coloured lines). The dashed black arrow shows the trend that minimums of QV curves move to higher voltages in dispatches with high wind power. If more realistic reactive power capability of wind farms was assumed (the improved capability did not fully reflect grid code requirements however[7]) the voltage stability was found to be significant improved (dashed coloured lines in Figure 4 - 15).

Figure A - 17 in appendix A 5 shows the QV curves for busbar 275kV Coolkeeragh. The results for that busbar also show that voltage instability can occur close to nominal voltage.

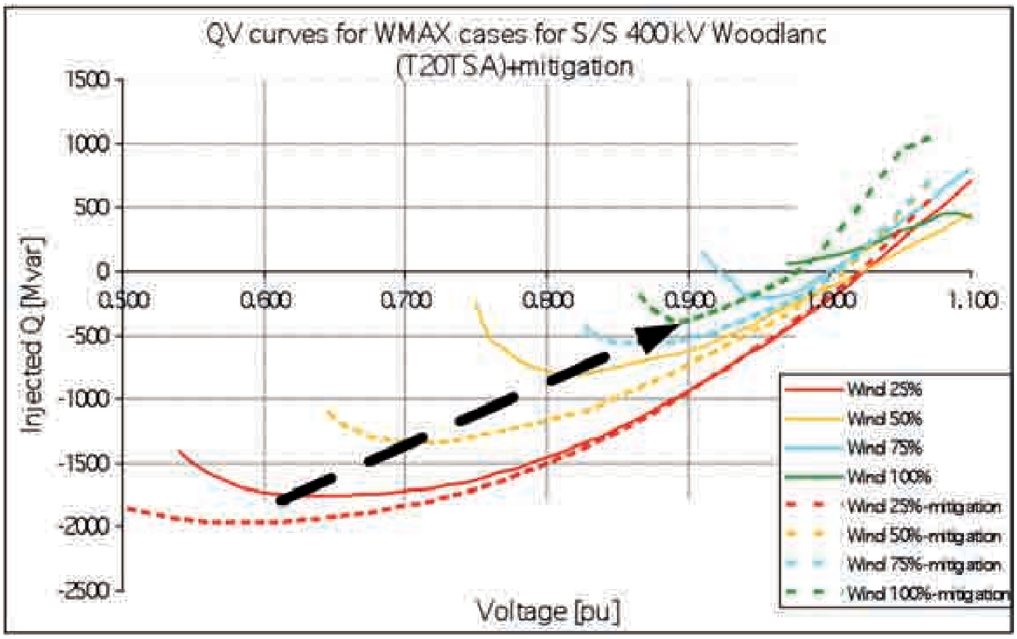


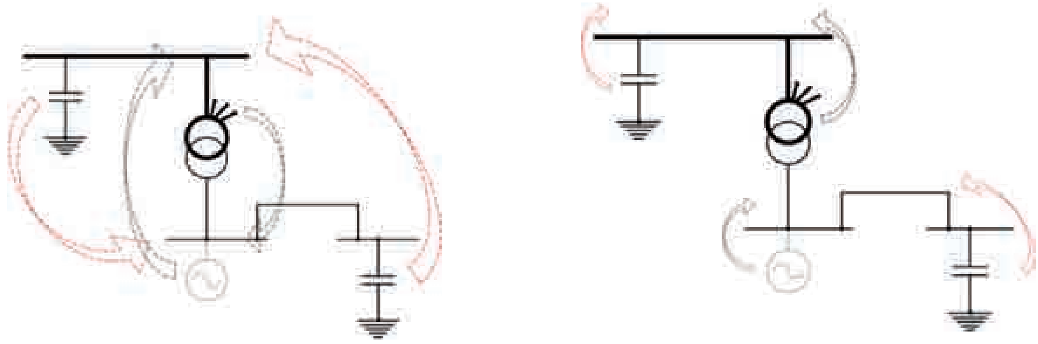
Figure 4 - 15: *Reactive power versus voltage analysis (QV curves) for 400kV busbar Woodland for winter maximum load and various wind power levels.*

Solid lines are results from worst case calculations and dashed lines from calculations with improved reactive power capability of wind farms. The dashed black arrow shows the trend that minimums of QV curves move to higher voltages in dispatches with high wind power. The minimum of QV curves represents the voltage stability limit at the respective busbar. Source: [Siemens PTI (2010a)]

Inappropriate voltage control

Figure 4 - 16 (a) shows a number of voltage control conflicts between elements connected to the transmission and distribution grid that were found in Work Package 1. The control logic of some switched shunts, transformers with tap changers and generators interacted in a non-optimal way [Siemens PTI (2010a)]. The observations underline the dynamic nature of the power system and its inherent control systems.

7 For the more realistic reactive power capability is was assumed that wind farms larger than 50MW injected reactive power up to a corresponding power factor of 0.96 in 25% and 50% wind cases and 0.98 in 75% and 100% wind cases. Smaller wind farms remained with a power factor of 0.99 leading close to unity power factor [Siemens PTI (2010a)][Siemens PTI (2010a)].



(a) (b)

Figure 4 - 16: *Example for voltage control conflicts (a) and how they are resolved (b)*

4.5.1.3 Technical mitigation measures

Analysis of voltage stability already assumed transformer reinforcements and a total of 1,520MVAr additional reactive power sources. In the dispatches with 75% and 100% of installed wind power online, these sources provided reactive power close to their design limits whereas in more moderate cases some of them were not in operation or operating at low reactive power values [Siemens PTI (2010a)]. Without these reinforcements voltage stability of the system probably will be even lower.

Results suggest that voltage stability issues can be mitigated in the following order by:

- Ensuring that transmission connected wind farms comply with the *current* grid code requirements for reactive power capability and power factor for different operation points (see Figure 4 - 17 and Figure 4 - 18).
- Placement of (even more) reactive power sources, e.g. static var compensators (SVCs) or similar equipment, at strategically chosen locations where necessary.
- Definition of conventional generation units in appropriate regions of the All Island Power System that should never be put offline ("must run units")[8].

Sensitivity analysis suggested that it makes little difference whether additional reactive power is provided by static var compensators (SVCs), similar equipment or large wind farms connected to the transmission system, because wind farms are dispersed throughout the All Island Power System. But if wind farms provided reactive power in a region where wind speeds suddenly fell, they would have to continue feeding reactive power into the transmission grid (even at zero active power) as long as conventional power plant with synchronous generators in that region are starting up.

With respect to "must run units", these units should be ideally conventional units with a minimum active power limit of close to zero, i.e. units that can be operated as synchronous compensators. Otherwise, the implications of "must run units" for wind power curtailment have to be further analysed.

The voltage control problems can be mitigated by a re-configuration of the control logic of switched shunts, transformers with tap changers and generators: always the voltage of the next or high voltage terminal should be controlled.

Further investigations are needed

- to optimise the magnitude of additional reactive power sources and – most importantly – the location of their placement and
- to determine "power transfer standards" between the distribution and transmission system with large amounts of wind power that include absolute min/max active power limits, absolute min/max reactive power limits (leading and lagging), active versus reactive power capability curve and active and reactive power duration guidelines.

8 Previous studies have suggested that at least one unit should remain in operation at sites in Aghada, Coolkeeragh and Dublin Bay even if they were not committed in the economic dispatch [TNEI Services Ltd. (2007)][TNEI Services Ltd. (2007)].

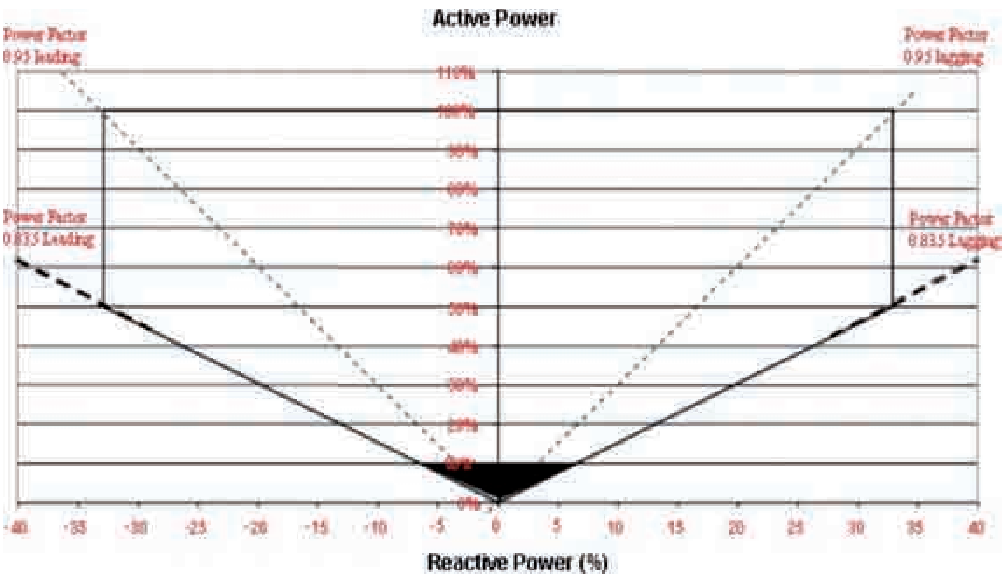


Figure 4 - 17: *Reactive power requirement for controllable wind farms in EirGrid's grid code for different operation points [EirGrid (2009)]*

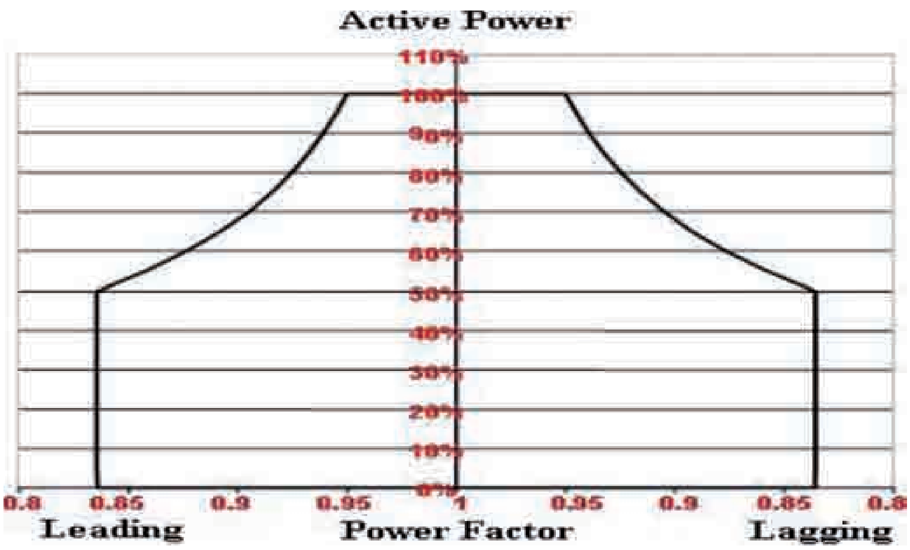


Figure 4 - 18: *Power factor requirement for controllable wind farms in EirGrid's grid code for different operation points [EirGrid (2009)]*

4.5.2 Transient Stability

4.5.2.1 The issue

Transient stability describes the ability of the All Island Power System to maintain synchronism when subjected to a severe transient disturbance such as a fault on transmission facilities [Kundur (1994)].

The principle is visualized in the figure at the bottom.

The yellow line in Figure 4 - 19 shows the active power response of a 400MW synchronous generator to a fault causing a significant voltage dip at the connection point of the plant. After fault clearance the machine returns to steady state operation - the generators remain transient stable.

The red line in Figure 4 - 19 shows the response of the same generator to a long-duration fault. As a consequence of the depressed voltage, the generator cannot feed the active power into the grid and accelerates. If the speed increased too much until fault clearance, the generator does not return to synchronous operation but trips after voltage recovery.

If large amounts of generation capacity are lost as a consequence of transient instability, the power system may collapse.

The time within a fault must be cleared to prevent any synchronous generators in the power system to become unstable is called *Critical Clearance Time (CCT)*. Decreasing transient stability of a power system is indicated by

- Decreasing CCTs for specific faults or
- An increasing number of faults with low CCTs.

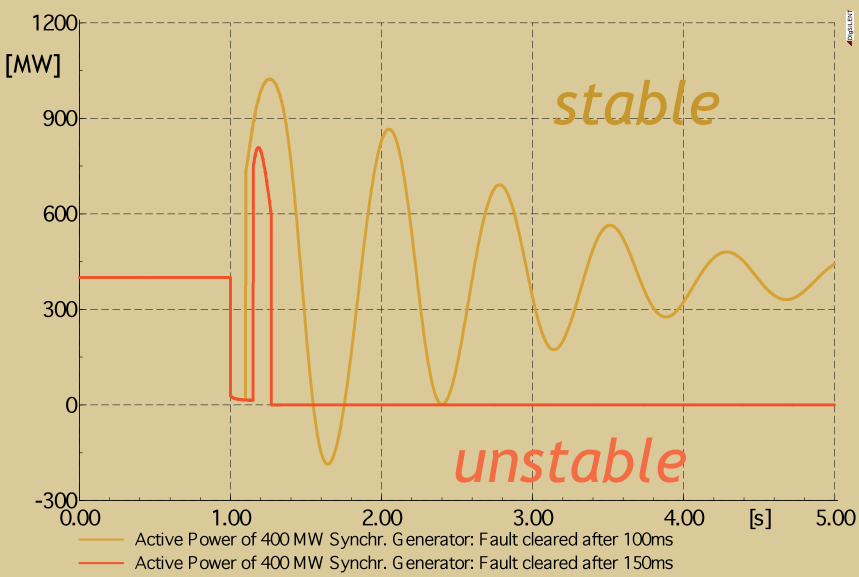


Figure 4 - 19: Active power response of a 400MW synchronous generator to a primary cleared fault – returning to steady state operation (yellow line) and a long-duration fault resulting in generator tripping (red line)

54.5.2.2 Results

In the Irish transmission system break times (including circuit breaker separation) are about 50-80ms [EirGrid and SONI (2009b)], [Rogers et al. (2010)]. EirGrid [O'Sullivan et al. (2010)] defined a share of 30%...40% of disturbances associated with critical clearance times of ≤150ms as tolerance range.

Figure 4 - 20 shows the percentage of disturbances with certain CCTs as a function of "operational metric 1" (see section 4.1 on page 18). Reactive power capability of the wind farms in the model was limited and, in fact, did not completely comply with current grid code requirements. On the other hand, any impacts from inductive motor loads were not explicitly modelled in the base case analysis.

As long as value of "operational metric 1" is below 70...80%, the 30% tolerance is respected for CCTs ≤150ms.

Appendix A 2 includes plots for critical clearance times of ≤100ms and ≤150ms detailing different import/export cases.

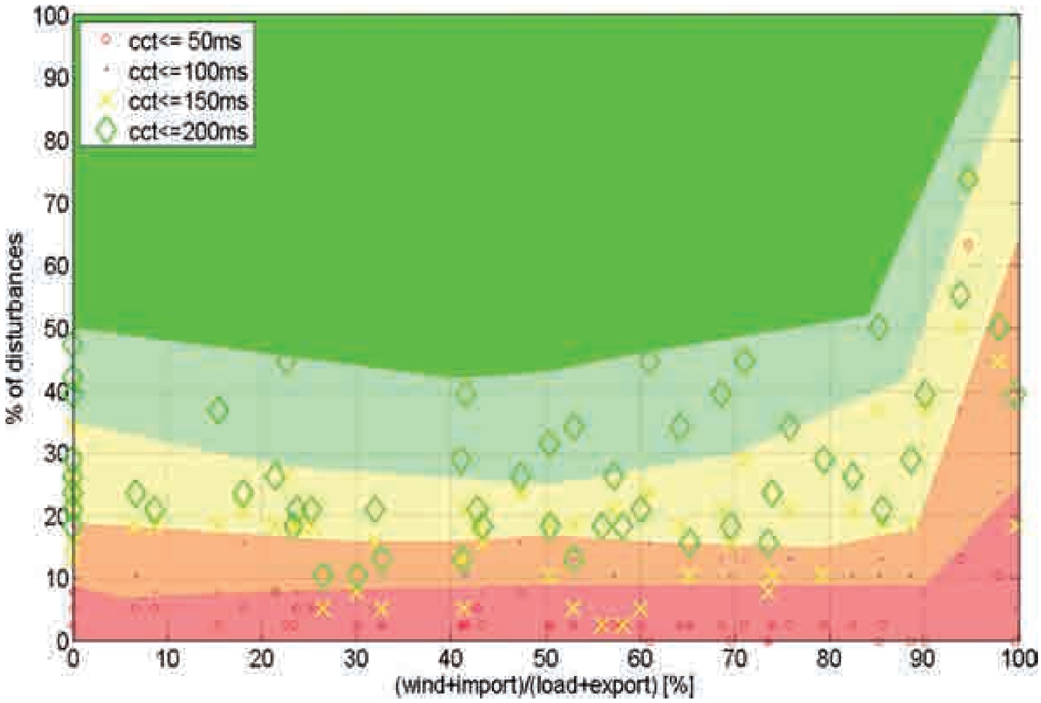


Figure 4 - 20: *Disturbances with critical clearance times as indicated in the legend as a function of "operational metric 1". (Wind farms were not fully grid code compliant.)*

For one specific dispatch the sensitivity to load composition was investigated by assuming 10% motor load. The results show a slight increase of CCTs ≤ 150ms and ≤ 100ms (see Figure 4 - 21). Hence, modelling based on ZIP loads and not considering explicit motor load models may result in a slightly optimistic assessment of transient stability.

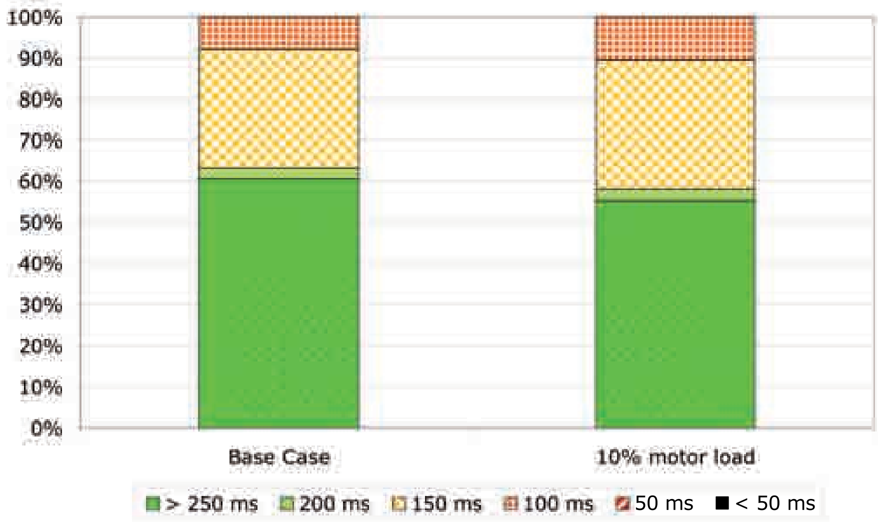


Figure 4 - 21: *Comparison of critical clearance times for load modelling with constant impedance, constant current, constant power load and 10% motor load for the summer maximum load, 75% wind power and low export case.*

The results suggest that the transient stability of the 2020 All Island Power System decreases significantly if the value of "operational metric 1" exceeds 70%...80%.

Operational metric 1	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < 70...80\%$

4.5.2.3 Technical mitigation measures

Analysis of transient stability already assumed transformer reinforcements and additional reactive power sources [Siemens PTI (2010a)]. Without these reinforcements transient stability of the system probably will be even lower.

Performance of additional technical mitigation measures was evaluated for one dispatch only (SMAX, W75, EL: T35TSA). This case showed an extreme electrical frequency drop for a transient fault at the Woodlands busbar as well as power oscillations of several units [Siemens PTI (2010a)].

Mitigation measures analysed were[9]:

- Operation of machines at Kilroot, Derry Irons and Tawnaghmore at very low active power output (approx. 1MW) as synchronous compensators.
- Voltage support by wind farms during faults according to grid code provisions. Wind farms – while providing active power in proportion to retained voltage - maximise reactive current up to generator ratings (compliant to requirement WFPS1.4.2 in [EirGrid (2009)]). Two cases were distinguished:
  - Only full converter wind turbine generators (15% of all wind farms) provided advanced voltage support;
  - Only wind turbines with doubly fed induction generator (85% of all wind farms) provided advanced voltage support.
- Advanced voltage support by wind farms during faults with priority to reactive current before active current. Wind farms respond to voltage drop by generating reactive power up to the thermal ratings of the equipment on cost of active power. Such behaviour deviates from the current requirements of WFPS1.4.2 in [EirGrid (2009)] but has been adopted in other countries, e.g. in Germany [German Government (2009)].

Figure 4 - 22 shows the impact of the mitigation measures on the number of faults that requiring a certain critical clearance time in order to maintain transient stability of all synchronous generators. In line with expectations,

9 Additionally, potential benefits of flywheel energy storage at five selected locations have been assessed. However, as a consequence of methodology limitations, the results do not allow to draw conclusions.

modelling results demonstrate the importance of the generators' reactive current capability during the fault and immediately after fault clearance for the system's transient stability. The most effective mitigation measure for transient stability issues is voltage support by wind farms according to *current* grid code requirements (maximisation of reactive current up to generator ratings while providing active power in proportion to retained voltage during faults). Deployment of synchronous compensators also shows benefits for CCTs.

Advanced voltage support with maximum reactive power *on cost of active power* lead to incidental tripping of units at Turlough Hill (in pumping mode for this dispatch), depending on fault location. This issue is particularly pronounced for faults close to Turlough Hill or if faults lead to significant temporary loss of wind power resulting in frequency deviations. For a full understanding of this interaction further analysis would be required.

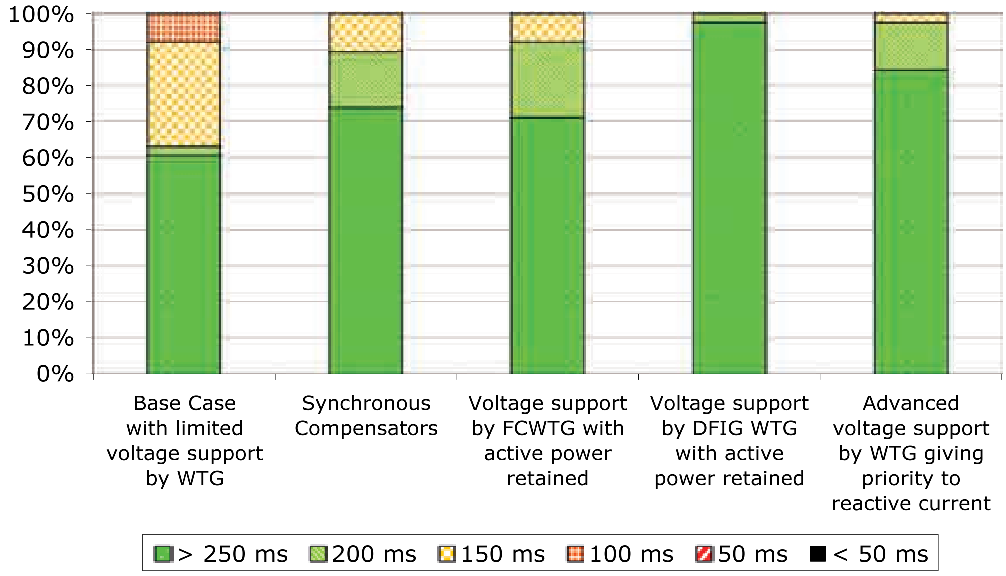


Figure 4 - 22: *Impact of different mitigation measures on the number of faults that require a certain critical clearance time to maintain transient stability of all synchronous generators. The results are shown for summer maximum and low export at 75% wind power output in the base case (T35TSA).*

Modelling suggests that application of the mitigation measures (including voltage support according to the *current* grid code) substantially improves transient stability. In this respect, the range of stability may be extended beyond a value of "operational metric 1" of 80%. Because this statement relies on analysis of a single dispatch, quantification of the additional range is not possible here.

Further investigations may be beneficial to determine

- to what extent wind power plants actually comply to requirement WFPS1.4.2 of the grid code [EirGrid (2009)];
- the impact of motor loads on transient stability;
- the impact of reduced active power provision of wind farms that give priority to reactive current injection during a fault on frequency stability.

As expected, modelling results showed a strong dependence of unit response on fault location. Due to the limited set of dispatches and faults, in most cases only a few units lost synchronism after faults.

For generalisation of the results as well as quantification of the additional range of stability the set of investigated dispatches and disturbances has to be extended.

4.5.3 Power balance fluctuations and frequency regulation

4.5.3.1 The Issue

The behaviour of the load is regular and well understood. Generation follows this pattern balancing the load in all time domains. Permanently updated load predictions support effective scheduling of generation units and adequate response to these changes in order to keep the system frequency constant.

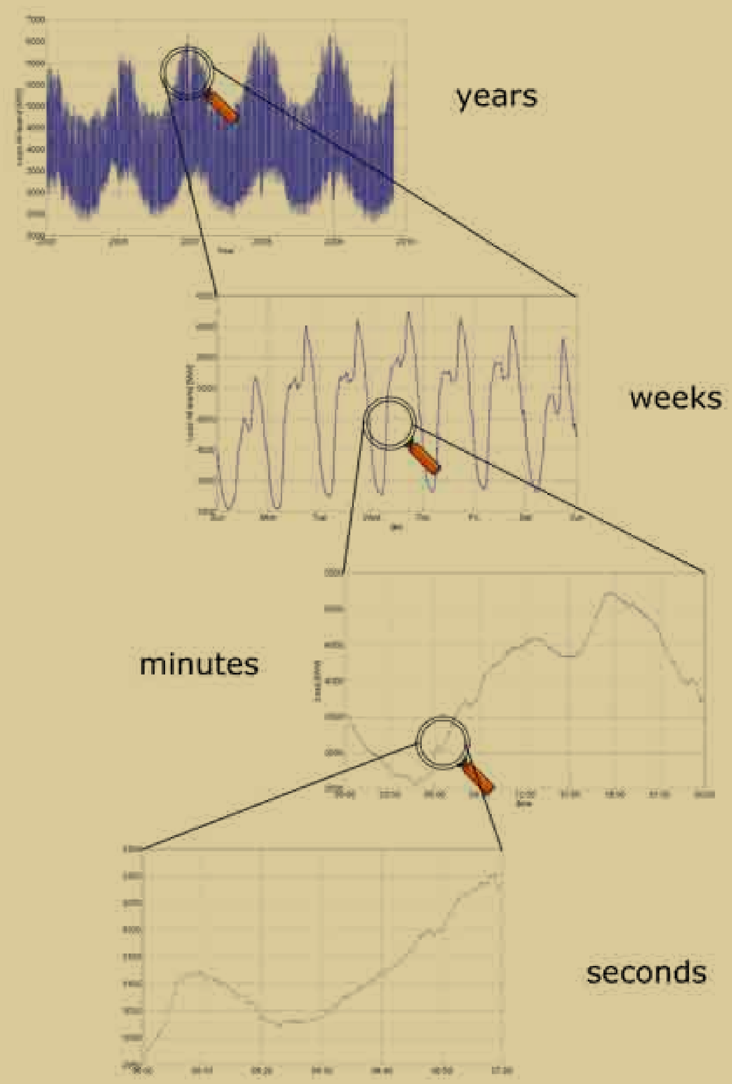


Figure 4 - 23: *Load variations over different timeframes (data source Eirgrid monitoring data).*

The wind pattern is not correlated with the load and not as cyclic. The combination of wind **and** load fluctuations now and then leads to steeper gradients of the net load. The required flexibility of the conventional units increases with the installed wind capacity. If, for example) the wind in the country is calming down while the load increases in the early morning much capacity has to be brought online in a few hours (see also Figure 4 - 24). As wind generation reduces the amount of conventional capacity online adequate response to this steeper gradient may be a challenge.

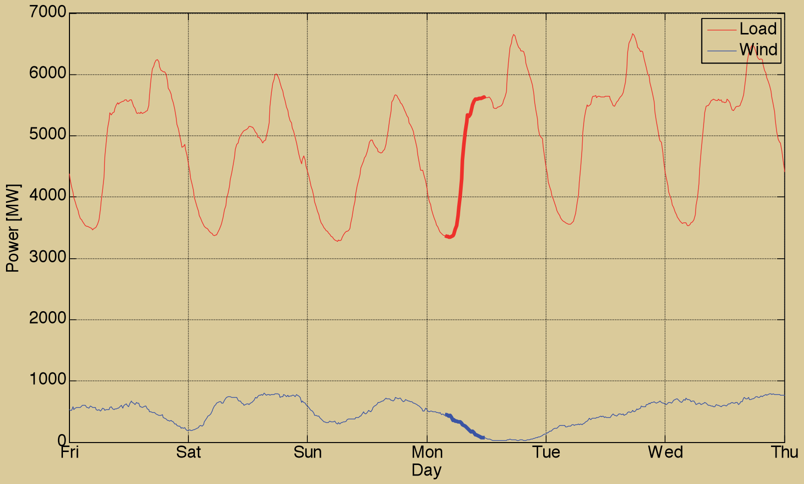


Figure 4 - 24: *Load changes and wind ramps during the week. On Monday the load increase in the morning coincides with a decrease of wind generation (bold line).*

The corresponding effect resulting in a negative gradient of net load occurs if a storm front is boosting wind power output while the load is decreasing, e.g. during night.

Because wind is also less predictable definition of the required amount of conventional generation is a complex exercise. Load shedding will be inevitable if the flexibility of the committed conventional plant is insufficient to follow steep net load gradients.

Additionally, solely the variations of the wind resource may introduce some additional fluctuations of the power balance in a very short time frame (seconds to a few minutes). These potential variations also have to be compensated by conventional generation. Control activity on conventional units may increase as well as component wear.

4.5.3.2 Results

The statistical analysis derived distributions and confidence intervals[10] for the change of 2020 wind generation and net load for various time frames. Based on these figures quantitative indicators for the required capability of the conventional plant to respond to changes of net load were calculated (see Table 4 -3).

Table 4 -3: *Upper and lower control requirement (source [Siemens PTI (2010a)]).*

		Wind and load variation period			
		15 min	1 h	2 h	4 h
Wind generation	Upper requirement	37 MW	88 MW	151 MW	261 MW
	Lower requirement	-37 MW	-86 MW	-147 MW	-254 MW
Load	Upper requirement	156 MW	584 MW	1100 MW	1892 MW
	Lower requirement	-153 MW	-552 MW	-985 MW	-1432 MW
Net load (load–wind)	Upper requirement	159 MW	590 MW	1108 MW	1902 MW
	Lower requirement	-157 MW	-559 MW	-996 MW	-1449 MW

10 By definition the confidence intervals were based on two times standard deviation.

The underlying data set covered less than two years and may be insufficient to comprehensively reflect extreme events. Additionally, refinement of the methodology would be required to achieve results of practical relevance for system operations.

Still, the results confirm important findings from previous studies and, in particular, of [Risø National Laboratory (2007)] and the AIGS focusing on dispatch and unit commitment[11]: even large wind portfolios hardly change the requirements to cope with net load fluctuations in a time frame up to 2 hours. Within 4 hours the additional requirements are quite moderate. The capability of the 2020 plant portfolio or of particular dispatches, respectively, to respond to the gradients of the net load is not questioned by the current analysis.

Physical limitations of the accuracy of the available dataset did not allow a quantitative assessment of power fluctuations caused by wind power on a very short time scale (15 seconds). The available information does not indicate issues related to an increase of those power fluctuations.

4.5.3.3 Technical mitigation measures

In case of extreme positive ramps of generation, the balancing the system can be supported by curtailing wind farms. To a certain extent demand response may help to reduce power gradients [DCENR (2009)].

11 The methodology of the AIGS did not allow evaluating flexibility requirements in 15 minute periods but the results of this study underlined that respective power fluctuations in fact are not influenced by wind power in a 2020 scenario.

4.5.4 Network Loading

4.5.4.1 The issue

The transmission and distribution systems have to transport the power from generation to load. The ratings of all components on this route have to be adequate for these power flows. In particular, in rural areas with strong wind power development often this is not the case – the network is congested. To solve this issue network reinforcements may be required.

Wind generation implemented at remote locations changes power flows and sometimes even reverses them. For that reason the impact of wind power on network loading may regionally differ and depends on local conditions.

4.5.4.2 Results

Power flows in the transmission network were studied for different instantaneous geographical distributions of the wind resource. The respective 2020 wind power patterns were derived from extrapolated 15 minute wind monitoring data covering a period of about two years[12]. The data set distinguished five regions (Figure 4 - 25).

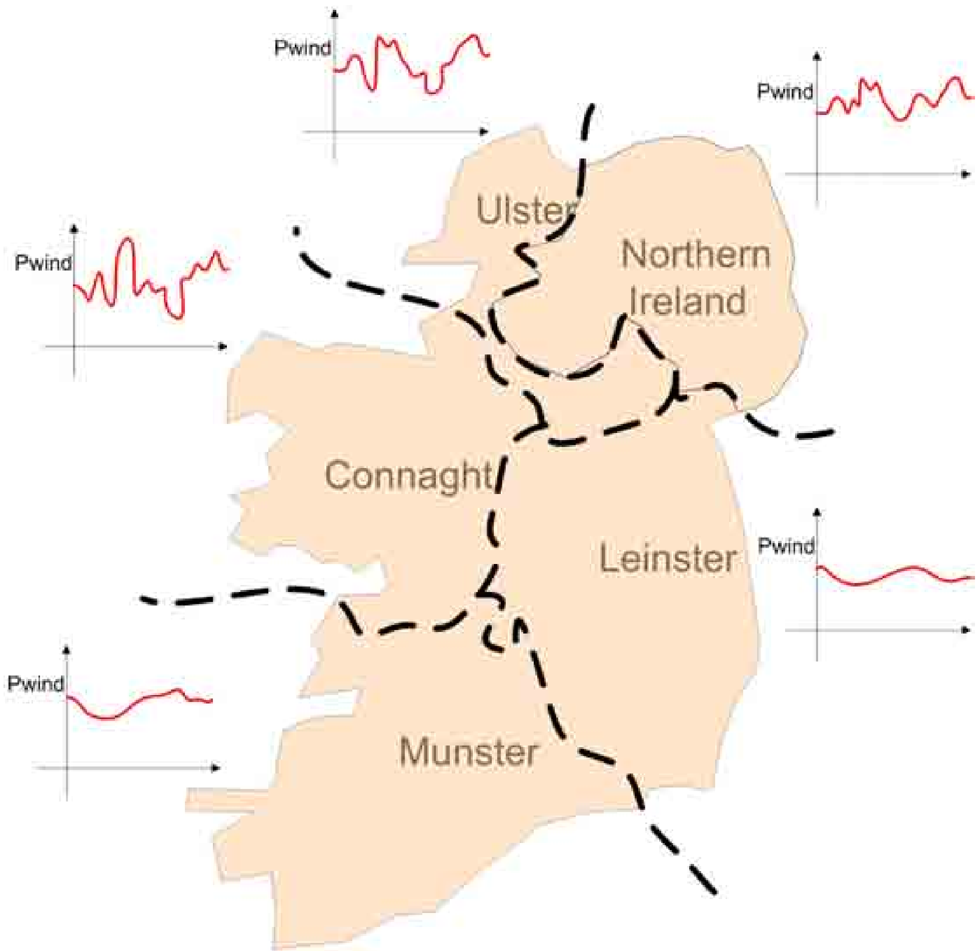


Figure 4 - 25: *Wind power regions used in the geographical wind distribution analysis in order to determine network loading. Source: [Siemens PTI (2010a)]*

12 For data processing reasons only 168 characteristic days from the dataset were analyzed.

In order to cover also extreme situations, variations of the extrapolated dataset were generated representing a fictive, imbalanced distribution of the wind resource across the island ("onerous wind pattern"). Analysed variations were:

- High wind generation in regions Connaught and East Leinster
- High wind generation in regions Ulster and Northern Ireland
- High wind generation in region Munster

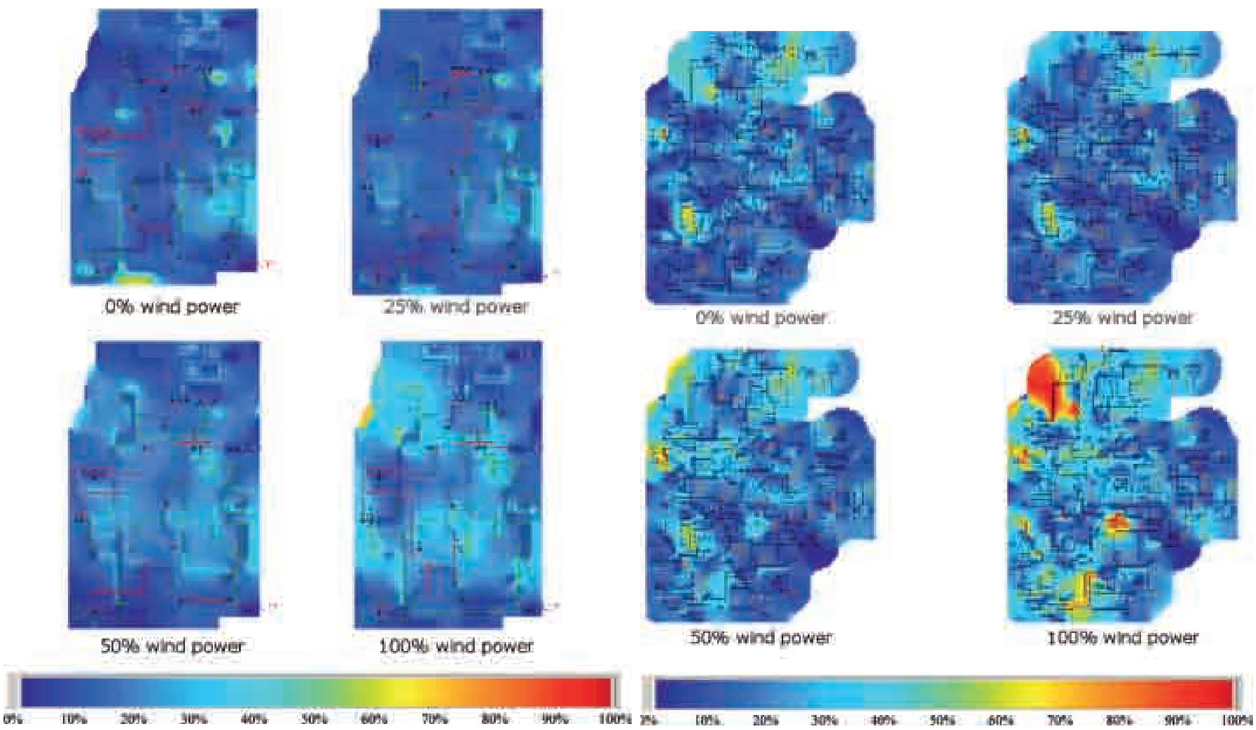
Figure 4 - 26 illustrates the loading of transmission network for the base case (35% of wind farms connected to the transmission system) at winter maximum load and 0%, 25%, 50% and 100% instantaneous wind power (75% of wind power is omitted here). The results suggest that even at high wind levels the network above 110kV is only lightly loaded (predominantly blue contours in the Figure 4 - 26a).

The power flows from distribution connected wind farms, however, caused congestion in parts of the 110kV network – as soon as instantaneous wind power exceeds 50% of installed wind capacity (orange and red contours in Figure 4 - 26b). Results showed large parts of the 110kV network being congested for 75% and 100% wind cases. Regions affected are Tawnaghmore, Bellacorrick, Letterkenny/Strabane, Trillick, Enniskillen/Omagh, Thurles, Tarbert, BootLiag, Arva, and Arigna [Siemens PTI (2010a)].

Figure 4 - 27 shows for the same load case the percentage of network branches with a certain loading. The results show a minimum of network loading for W25 cases (instantaneous wind generation is 25% of installed wind capacity). The improved critical clearance times found in the transient stability analysis for that case can be explained by the reduced transmission system loading.

The results showed that the share of transmission connected wind farms (20% versus 35% of total capacity) did not make a significant difference. Calculations showed also that "onerous wind patterns" can lead to more congestion in parts of the 110kV network but had no relevant impact on the loading of networks at voltages levels >110kV.

The results confirm the results of earlier studies, in particular [TNEI Services Ltd. (2007)].



(a) Networks at voltages levels >110kV (b) Network at voltage level 110kV

Figure 4 - 26: *Visualised loading of the >110kV network (top) and 110kV network (bottom) for the base case (35% of wind farms connected to the transmission system) at winter maximum load and 0%, 25%, 50% and 100% instantaneous wind power.*

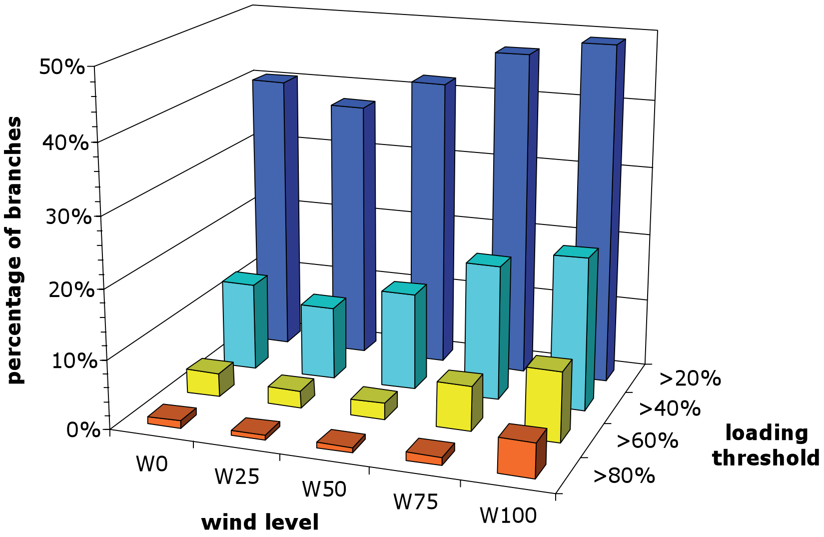


Figure 4 - 27: *Percentage of branches in the 110kV, 220kV, 275kV and 400kV networks above a certain loading (extremely heavy loading >80%, very heavy loading >60%, heavy loading >40% and light loading > 20%) for the base case (35% of wind farms connected to the transmission system) at winter maximum load and 0%, 25%, 50%, 75% and 100% instantaneous wind power.*

4.5.4.3 Technical mitigation measures

Reinforcement of the 110kV networks will be an important precondition for implementation of the 2020 scenario. Development of dedicated 220kV transmission stations for wind cluster power pick-up may also be considered.

Alternatively, temporary curtailment of wind farms connected to the 110 kV network may be applied during high wind periods. However, the impact of congestion on yield losses is site specific and may be severe.

Future work might focus on an macro economic analysis identifying the optimum balance between network reinforcement and temporary wind power curtailment, including appropriate allocation of costs and respective support mechanisms.

4.6 Issues that seem not to impose operational limits

4.6.1 Small Signal Stability

4.6.1.1 The issue

Small signal stability describes the ability of the All Island Power System to maintain synchronism when subjected to small disturbances [Kundur (1994)][13]. Oscillations with weakly dampened or even increasing amplitude do not only put stress on components, increase system losses and may lead to tripping of units. The wind portfolio has different characteristics than conventional generators. The dynamic system behaviour may change. The purpose of the small signal stability analysis was to asses the influence of increasing wind power on small signal stability.

4.6.1.2 Results

Small signal analysis focused on the dispatches with zero export. Export and import cases were not studied because HVDC interconnectors and wind power have a similar impact on small signal stability: both do not introduce any electromechanical oscillation modes but basically change the number of online synchronous generators with their corresponding controllers and modes.

Because of model limitations the analysis allowed for qualitative conclusions only. Additionally, the electromechanical modes observed varied fundamentally because of the small set of dispatches.

The modelling suggests that an increase of wind power tends to improve the damping of oscillations in the system. These findings are in line with results from latest research [Gautam et al. (2009)] [Wang et al. (2008)].

The improved damping can be explained by the fact that synchronous generation is replaced by wind power while the system's impedances do not change. Because wind generation is being controlled by power electronics, wind turbines do not induce new oscillatory modes, especially no electromechanical modes. The coupling of the remaining synchronous generators increases when either certain parts of the network become less loaded or the remaining synchronous generators are operated at lower loading [Slootweg (2003)]. Simultaneously to synchronous generators put offline, the number of modes decreases [Siemens PTI (2010a)].

The results showed that some local modes remain weakly dampened in the system for some load cases; concerned units were Tawnaghmore, Derry Iron and Kilroot [Siemens PTI (2010a)].

Inter-area modes were found to be less damped in the summer and winter maximum load cases, due to higher amount of conventional generation online than in summer and winter minimum load cases [Siemens PTI (2010a)].

Further investigations of the small signal stability are recommended in order to:

- overcome the limitations of the models provided by EirGrid and SONI and
- investigate the impact of alternative dispatches for the same load/wind cases.

Model results do not suggest that small signal stability becomes an issue with increasing wind power in the All Island Power System. Therefore, analysis of mitigation measures was obsolete.

13 The studies focused on rotor oscillations of insufficiently dampened or even increasing amplitudes due to lack of sufficient damping torque. Potential instability phenomena as a steady increase in generator rotor angle due to lack of synchronizing torque have not been considered.

4.6.2 Fault Levels

4.6.2.1 The issue

Fault levels quantify the maximum currents equipment may be exposed to in case of a short circuit. Of course, equipment ratings have to be selected in line with these expected levels and changes in the network have to respect ratings of existing equipment (upper limit for short circuit levels). On the other hand, protection schemes detect short circuits by monitoring the current and need a minimum current for reliable operation (lower limit for short circuit levels).

Wind power may affect short circuit levels in both directions. Adding generation capacity may increase short circuit levels locally. However, short circuit capability of wind turbines is significantly lower than that of synchronous generators. As a consequence, short circuit levels may decrease if conventional generation is replaced by wind power.

4.6.2.2 Results

Short-circuit calculations were carried out according to UK Engineering Recommendation G74 [National Grid (2008)]. Assumed break times (including circuit breaker separation) were about 50-80ms depending on voltage level [EirGrid and SONI (2009b)], [Rogers et al. (2010)]. Details on the modelling of wind farms are given in [EirGrid and SONI (2009b)].

During the assessment the upper limit was given by 90% of equipment ratings as defined in [ESB National Grid (1998)]. Slightly simplified this means that, for three-phase or single-phase-to-earth faults, the planned maximum short circuit fault levels shall not be greater than the values indicated in Table 4-4.

Table 4-4: *Planned maximum* *short circuit fault levels [ESB National Grid (1998)]*

	110 kV	220 kV	275 kV	400 kV
Short circuit fault level	23.4kA	36kA	N/A[1]	45kA

[1] Since no value was available for 275 kV networks in NI, the same maximum short circuit fault levels as in 220 kV networks in RoI were assumed.

In contrast to upper limits, it was not possible to define lowest operating limits of transmission network protection. Such limits are dependent on the considered substation [Conroy et al. (2010)] since load currents can be of the magnitude of short circuit currents. For the analysis of the fault level study results it was assumed that no major issues arise from increased wind power as long as fault levels remain equal or above the minimum fault levels with no wind power in the system (these occur usually during summer minimum load when only few synchronous generators are online).

Figure 4 - 28 and Figure 4 - 29 show the results from the short circuit studies on the base case (T35TSA) for three-phase faults and single phase faults, respectively. The figures illustrate the following effects:

- In general, short circuit levels decrease with increasing wind power. The buses most affected by increasing wind penetration are concentrated in the Dublin area [Siemens PTI (2010a)]. In case of high wind penetration short circuit levels can decrease down to 50%.
- Short circuit levels are unlikely to drop below the **minimum** levels that are experienced without wind power (i.e. during summer minimum). The only exception are busbars MNYPG1 380 in RoI and BAFD2 275 and BAFD1- 110 in NI. Table 4-5 specifies the minimum values plotted in the figures.

Table 4-5 Observed minimum short circuit fault levels

Minimum short circuit levels	110 kV	220 kV	400 kV / 275 kV
Three phase fault	3.5 kA	4.5 kA	8 kA
Single phase fault	2.5 kA	6 kA	9 kA

- The **maximum** short circuit current levels at the busbars FINGLAS 220, INCHICOR 220, LOUTH 220 in RoI and OMAH 110 in Northern Ireland – and also at further busbars specified in Table A -1 and Table A -2 of Appendix A 4 – have to be monitored carefully during the coming years when more wind farms are connected in their vicinity. Short circuit levels are already high at these busbars when no wind power is in the system. Although short circuit levels will also drop here with increasing wind power, lower wind generation levels at about 25% of installed wind capacity can have a higher risk of violating the allowable limits; in those cases, most of the conventional power plants will remain online and wind farms would contribute additionally to the short circuit current levels of the respective busbars.

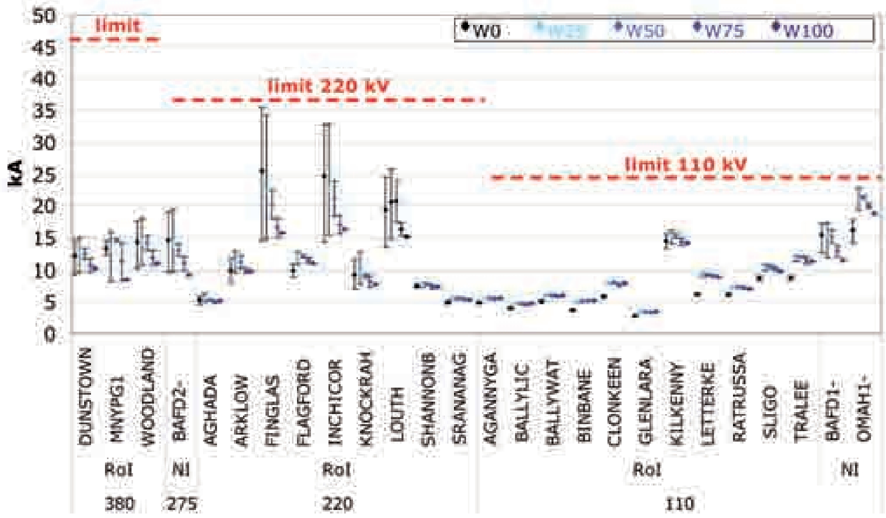


Figure 4 - 28: *Results from short circuit studies for **three-phase faults** at selected busbars for the base case (T35TSA). For each busbar the average short circuit current over all load cases and zero exchange is shown for different wind levels. Around each average value the minimum and maximum short circuit current over all load cases and zero exchange is indicated by the error bar.*

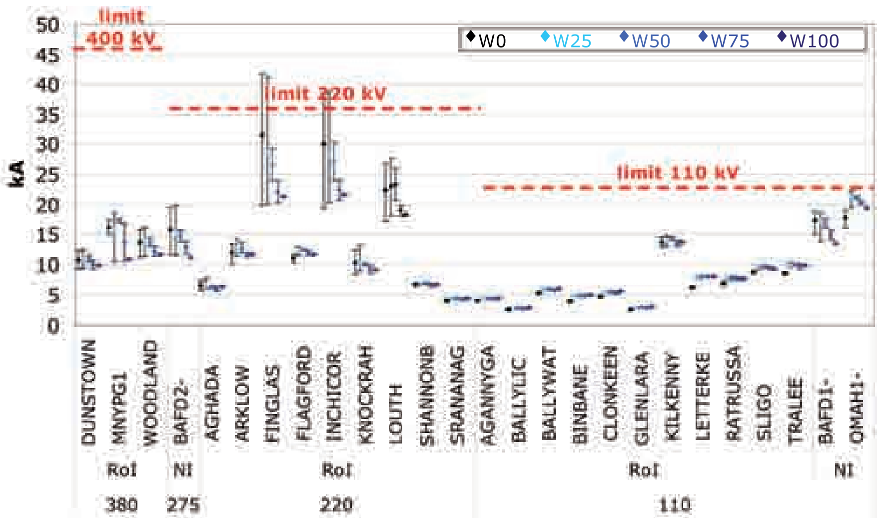


Figure 4 - 29: *Results from short circuit studies for **single-phase faults** at selected busbars for the base case (T35TSA). For each busbar the average short circuit current over all load cases and zero exchange is shown for different wind levels. Around each average value the minimum and maximum short circuit current over all load cases and zero exchange is indicated by the error bar.*

The results for a specific busbar are very sensitive towards the composition of the dispatches under study [Siemens PTI (2010a)]. The short circuit level of some buses close to large wind farms but remote from conventional generation increases with wind generation.

As a sensitivity check, the share of wind capacity connected to the distribution and transmission systems, respectively, was varied (80%/20% versus 65%/35%). Also the share of full converter WTGs in the total wind capacity was varied (15%/85% versus 50%/50%). In both cases, modelling results changed only insignificantly. These factors are of minor relevance for fault levels.

4.6.2.3 Technical mitigation measures

In case of *local* problems with critically low short circuit levels the following technical mitigation measures may be considered:

- Definition of "must run units" with synchronous generators in the vicinity of the affected busbars. Such units would not be switched offline and kept operating at their lower active power limits.
- Insertion of static var compensators (SVC) or similar flexible alternating current transmission systems (FACTS) devices in the vicinity of affected busbars. The preparation of the network model used in the present studies already considered a significant amount of new SVC or similar equipment in the transmission system[14].
- Upgrading of transmission lines between a region with low short circuit levels and a region with medium or high short circuit levels.
- Increased short circuit capability of wind turbines and respective amendment of the Grid Code. Such a measure will be associated with substantial extra cost and most likely will be economically less attractive than the alternatives.

14 Influence of these SVC on the base case short circuit level results cannot be analysed since this would require a reference scenario without reinforcements.

5. Recommendations for an operational strategy

The modelling results suggest that the **dominating issues** associated with an increase of wind power in the 2020 All Island Power System scenario are **frequency response to disturbances and transient stability**.

For some issues (frequency stability, small signal stability) model limitations and the applied methodologies did not allow for a comprehensive quantitative analysis. Nevertheless, evaluating the model limitations results are considered robust and the respective technical issues are less critical than those mentioned above.

For issues related to reactive power (i.e. fault levels, voltage stability) and voltage control, the network loading as well as power balance fluctuations and frequency regulation modelling showed minor problems or identified feasible mitigation measures. Often a single measure mitigates more than one issue at a time.

Table 5-6 summarises the issues and the findings of the analysis.

Table 5-6: *Technical issues associated with the 2020 All Island Power System scenario and limitations of the operational range as identified in the technical studies*

Category	Distinct Technical Issue	Resulting limitations of operational range
Issues that impose fundamental operational limits	• Frequency excursions following the loss of largest infeed	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < 70...80\%$
Issues that may impose operational limits but need further analysis	• Frequency excursions after network faults associated with a temporary decrease of wind power output	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < 60...70\%$
Issues that impose operational limits but can be mitigated	• Reactive Power and Voltage Control	./.
	• Transient Stability	$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < 70...80\%$
	• Power balance fluctuations and frequency regulation	./.
	• Network loading	./.
Issues that seem not to impose operational limits	• Small Signal Stability	./.
	• Fault Levels	./.

Issues related to reactive power and voltage control (section 4.5.1) and network loading (section 4.5.4) can be regarded as “modelling issues” since the power system model provided by EirGrid and SONI was not optimised yet in terms of reinforcements.

“Operational metric 1” has been identified as a suitable indicator for the operational ranges allowing stable operation of the system. Under the modelling assumptions – and following the **precautionary principle** with regard to the issue that may impose fundamental operational limits but needs further analysis – the suggested maximum value for this parameter in system operation is **60% … 80%**. The 60% value is related to the frequency response following severe network faults with an associated temporary drop of wind power output.

For this particular aspect, a few modelling cases even suggested critical system conditions at values of "operational metric 1" slightly above 50%. However, due to model limitations this particular set of results is considered being conservative. The modelling suggested a similar restriction if ROCOF relays at distribution connected wind farms and other generators were not disabled and their threshold remained unchanged at ±0.6Hz/s. Also any actual limitations of generators, including transmission connected wind farms, to ride through ROCOF values of more than ±0.5Hz/s may restrict the acceptable value of "operational metric 1".

Figure 5 - 30 illustrates the findings, indicating the allowable operational range as a green and yellowish area at the left side of the diagram.

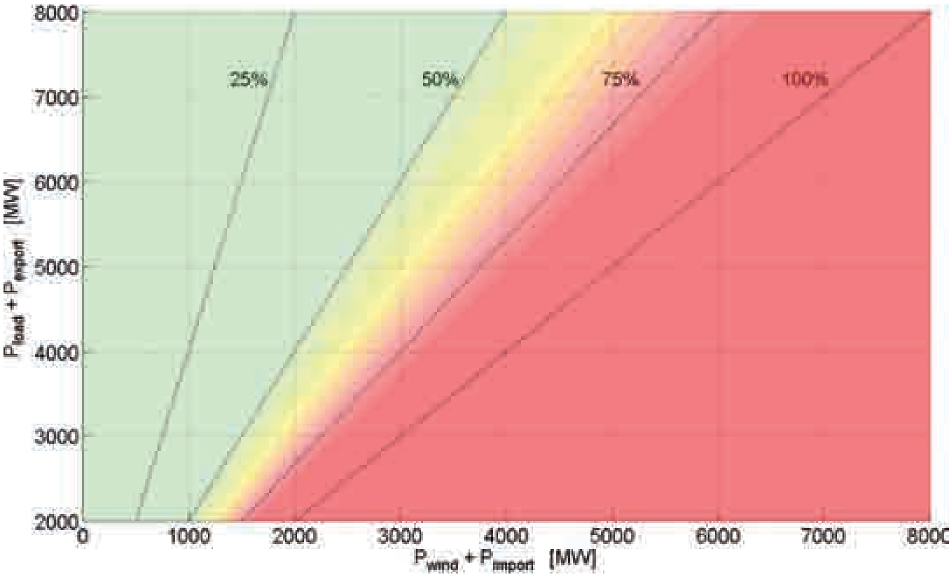


Figure 5 - 30: *Indicative illustration of the allowable operational range of the 2020 All Island Power System. Left area (green): no relevant technical issues. Lower right area (red): technical issues jeopardising stable system operation. Range in between (yellow): transitional range, technical issues become increasingly critical. Transitional range may be reduced by future studies.*

Based on the study results some **additional recommendations for system operation** can be derived also with respect to a number of aspects which are not directly related to wind power:

- Imports via the interconnector should be limited to clearly less than the considered maximum value of 1350 MW. Modelling does not suggest that imports of 500 MW or less are critical. Definition of the allowable maximum requires dedicated modelling between these two distinct cases.
- Redispatch of conventional units is an important option of maintaining system stability with varying load, wind output or network topologies. Redispatch may be applied in order to assure ramping capability, flexibility and reserve provision of the conventional plant. Additionally, redispatch and dynamic allocation of must run units are effective measures for system wide voltage control and reactive power management.
- The risk level associated with the key issues often depends on the actual system condition (e.g. largest infeed, network topology and distribution of reactive power sources). Integration of the system conditions in the real time system monitoring tools (state estimator) will help to maximise the allowable value of "operational metric 1" during operation.

Some of the findings indicate needs to be reflected in **strategic planning of system development** rather than in system operation.

Aspects deserving attention in addition to the studies assumptions are:

- Monitoring of short circuit levels and adjustment of network capacity, in particular in 110 kV networks;
- Monitoring of grid code compliance of all generators and further elaboration of grid code provisions; and
- Guiding investments and further development of the conventional power plant portfolio. Important aspects are the flexibility of the plant mix, sufficient peaking capacity and granularity of the portfolio. Construction of inflexible and large units (multiple 100 MW range) might be discouraged by the regulative framework.

6. Impact of the operational strategy

In an unconstraint situation the scenario represented by the considered power plant portfolio facilitates a renewable energy share of nearly 50% in the annual load coverage. This figure is higher than the 40% target set by the Irish government in October 2008 [Government of Ireland (2008)].

Based on the modelling results the operational strategy proposed limiting the instantaneous inertialess generation from wind plus import to 60...80% of the instantaneous load plus export balance. This implies that wind power exceeding this limit has to be curtailed.

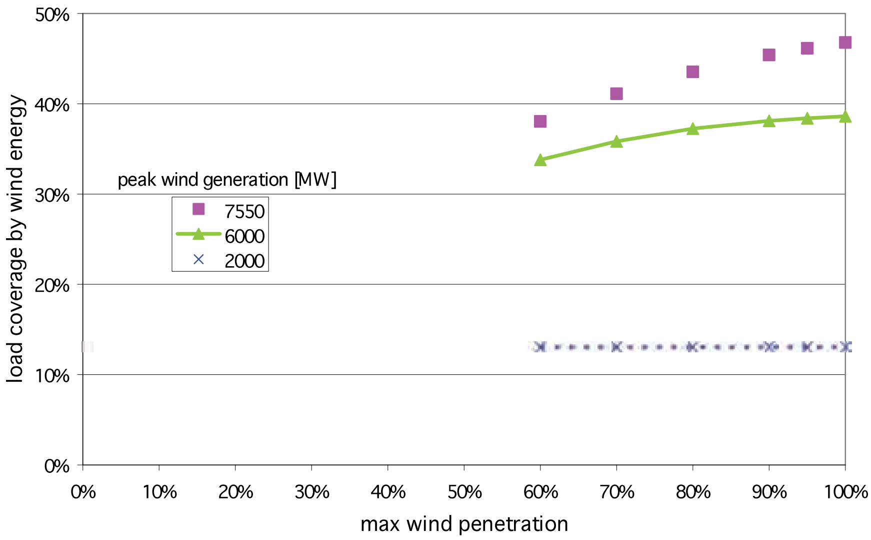


Figure 6 - 31: *Estimated total wind energy share in annual load coverage due to curtailment for different maximum allowable instantaneous wind penetrations.*

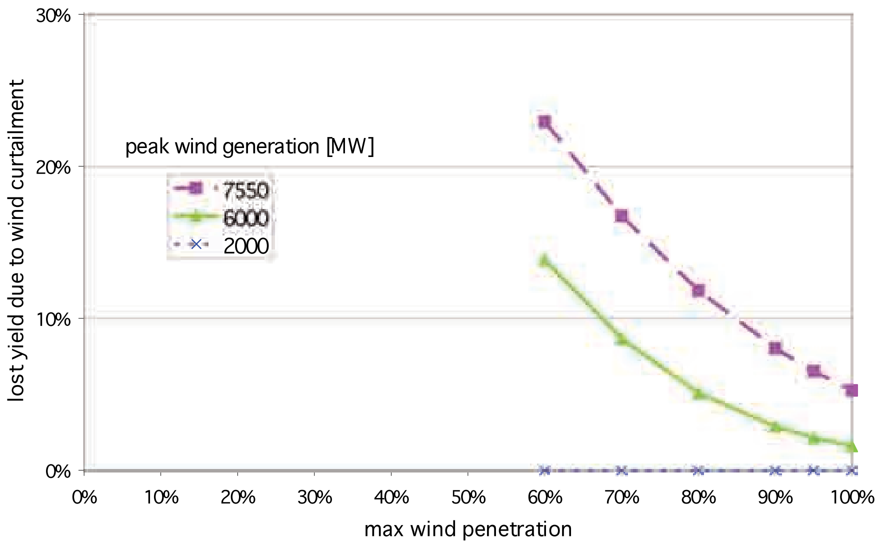


Figure 6 - 32: *Estimated lost wind yield due to curtailment for different maximum allowable instantaneous wind penetrations.*

Figure 6 - 31 shows an estimate of the impact of such operational strategies on the total renewable energy share in annual load coverage. Figure 6 - 32 shows the amount of lost wind yield. The analysis allows drawing following conclusions[15]:

15 EirGrid and SONI have performed a more comprehensive analysis with the Plexos market simulation model that has generally confirmed these findings.

- If wind penetration was limited to 60...80% in the considered 7550 MW wind scenario, the 40% renewable energy target could still be achieved. However, 10% of wind energy yield would be lost as a consequence of curtailment with the 80% limit. The respective loss may increase to more than 20% of the potential generation applying a 60% limit.
- With 6,000MW installed wind capacity, the 40% renewable energy target could still be achieved as long as 80% instantaneous wind penetration is technically feasible. Less than 5% of wind energy yield would be lost. With a limitation to 60% instantaneous wind penetration the yield losses would increase to more than 10% and the share of renewable energy in electricity supply would be reduced to values between 30% and 40%. With such constraints it may become difficult to meet the policy target, depending on the contributions from other renewables.

Of course, also other impacts as, for example, limitation of imports have to be evaluated in dedicated studies.

Conclusions

The study represents the most comprehensive and detailed analysis of the All Island Power System ever undertaken. The results clearly show the potential impact of high instantaneous shares of wind power in the total generation and highlight specific technical issues associated with increasing levels of wind power.

The analysis provided evidence that two key issues are limiting the acceptable level of instantaneous wind penetration in the 2020 All Island power system scenario:

- **frequency stability** after loss of generation;
- **frequency** as well as **transient stability** after severe network faults.

Modelling results suggested that technical measures exist to further mitigate transient stability issues.

The ratio between **instantaneous wind generation plus interconnector imports and load** has been defined as "operational metric 1". "Operational metric 1" appeared to be a suitable parameter to define limits of stable system operation. Modelling results suggest – while following the precautionary principle with regard to the issue that may impose fundamental operational limits but needs further analysis – that the value of "operational metric 1" has to be restricted to values below **60% ... 80%**. The penetration limit is determined by frequency stability issues while limitations related to transient stability are less restrictive.

Modelling suggests that further issues might exist related to frequency stability after severe network faults already at values of "operational metric 1" above 50%. However, in this particular aspect the analysis was subject to obvious data limitations and model imperfections. As a consequence, the 50% limit is considered being extremely conservative. In order to remove this relevant uncertainty further modelling with refined methodologies is required.

The modelling suggested a similar restriction if ROCOF relays at distribution connected wind farms and other generators were not disabled and their threshold remained unchanged at ±0.6Hz/s. Also any actual limitations of generators, including transmission connected wind farms, to ride through ROCOF values of more than ±0.5Hz/s may restrict the acceptable value of "operational metric 1".

According to modelling results imports via the interconnectors have to be restricted to a maximum between 500 MW and 1350 MW. This applies even to cases with moderate wind generation, in order to avoid frequency instability after loss of generation. Extension of the dataset in future modelling exercises will allow a more accurate specification of the limit.

The limitations for instantaneous wind penetration do not fundamentally conflict with the 2020 policy targets aiming at 40% electricity from renewables. The target could be overachieved in a scenario with 7,550MW peak wind generation and almost completely achieved by the use of wind energy in a scenario with 6,000MW peak wind generation – if limitations at the upper range (e.g. a value of 80% for "operational metric 1") were imposed. With a conservative approach (e.g. a value of 60% for "operational metric 1") meeting the target will require increased contributions from renewable sources others than wind or higher installed capacity of the latter.

Nevertheless, the identified limitations clearly imply challenges for power system economics and project viability as well as regulation; this was out of the scope of the studies and needs further analysis.

The identified acceptable range for "operational metric 1" of 60% ... 80% is only technically viable assuming major **additional adaptations** of the power system. The model provided by EirGrid and SONI was not optimised yet. Ongoing planning studies are currently investigating the optimum reinforcements required to accommodate the anticipated wind power up to 2025 [EirGrid (2008b)]. Examples of fundamental additional adaptations that were found necessary are:

- Extended static and dynamic sources for reactive power;
- Uncompromised grid code compliance of the complete wind portfolio and all other generators throughout the whole lifetime;

- Replacement of ROCOF relays in distribution networks by alternative protection schemes or increased ROCOF relays threshold;
- Evolution of the power plant portfolio in line with the scenario, etc.

Respective measures are all applying state-of-the-art technologies and do not represent any technology risks. Implementation of future technologies and features, including (emulated) inertia from wind farms and other generators, may relax the acceptable range for “operational metric 1” but need to be further analysed.

The analysis does not allow drawing conclusions on system behaviour if these upgrades are not implemented neither is it possible to apply the findings straightforward to the current system topology.

8. Recommendations

System planning and operation

The generic limits defined for "operational metric 1" are conservative following the precautionary principle. They reflect the potential system response to the most severe faults not considering potential operational mitigation measures as redispatch of conventional generation. During extended periods throughout the year, depending on the actual dispatch and associated load flows, system robustness may be higher. Dynamic system operational metrics, possibly more sophisticated than "operational metric 1", can be derived from real time monitoring and can be integrated in operational tools (e.g. state estimators). This will enable the TSOs to realistically asses the specific risks associated with possible outage or fault scenarios during operation. This might allow a temporary relaxation of the limits for "operational metric 1" which in turn reduces the need for curtailment as well as an optimisation of the dispatch. Hence, such a measure will contribute to the fulfilment of the policy target.

In parallel, the experience gained with monitoring and dynamic operational limits will support validation and refinement of further modelling. This will contribute to an improved understanding of the key issues and their interaction (e.g. voltage and frequency excursions).

The conclusions emphasised the importance of grid code compliance of wind farms and other generators throughout their complete operational life. In the current situation developers provide initial evidence that their projects meet the requirements based on manufacturers declarations and testing reports. Implementing cost effective methods to verify and monitor grid code compliance of projects during their operational phase is required to completely deploy the operational range of the 2020 All Island power system with increased wind capacities.

Further extension of knowledge base

The ranges for the allowable values of "operational metric 1" and the tolerated import via the interconnector derived from modelling are wide. They leave significant uncertainties or potential for optimisation, respectively. The wide ranges are due to the sparse character of the 63 cases used in the analysis to represent the operational range in combination with a reasonable but limited selection of additional sensitivity parameters. Increasing the density of modelled cases, in particular along the critical value of "operational metric 1" and with varying dispatches will help to reduce the range and respective uncertainties[16].

For methodology reasons and due to model limitations interconnector exchange has been ignored in parts of the study. However, modelling suggests that the interconnectors have a strong impact on system behaviour. Variation of the dispatch cases may focus on this aspect.

Models should be further refined in order to overcome specific limitations of the applied methodologies. Key aspects are multi-bus models for the analysis of the system's frequency response as well as improved wind turbine and wind farm models representing a response completely in line with grid code requirements.

Anticipating future developments

Potential for pushing the limits of "operational metric 1" even beyond the specified range may exist when new technology concepts are applied (e.g. 'fast active power recovery after faults' and 'emulated inertia' provided by wind turbines). For a comprehensive analysis of respective benefits and drawbacks further model refinement alone is insufficient. Close interaction with manufacturers and system providers is a precondition for a realistic evaluation of those unproven technologies, their characteristics and market opportunities.

16 A 'repeatable study process' has been dedicatedly set up by the project team in course of the project. This framework effectively supports a future extension of the data set.

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Appendix A: *Additional plots and data*

A1 Composition of dispatches

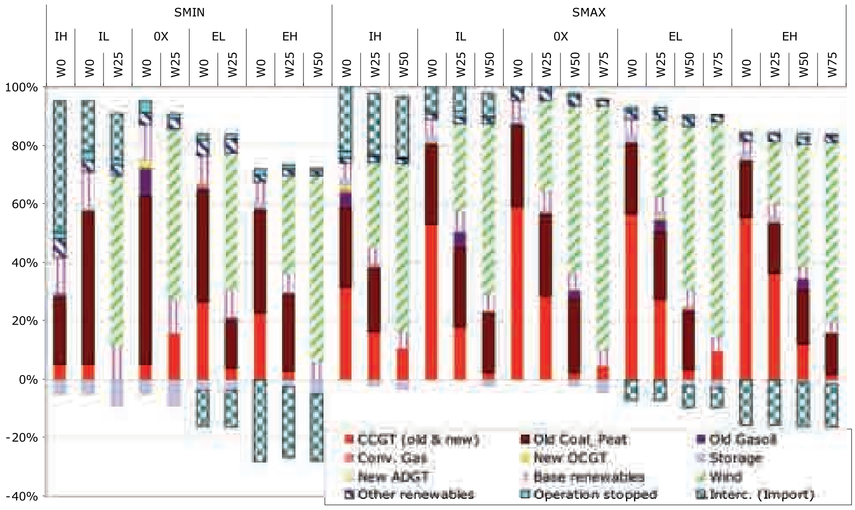


Figure A - 1: *Composition of summer minimum (SMIN) and summer maximum (SMAX) dispatches for various export/import and wind levels. Units Aghada and North Wall are labelled "operation stopped" since the All Island Grid Study (2008) had assumed them to be decommissioned before 2020.*

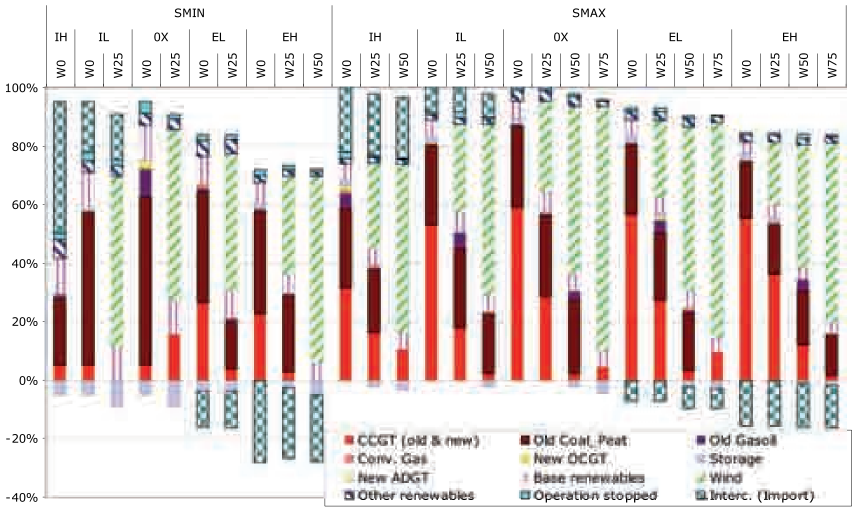


Figure A - 2: *Composition of winter minimum (WMIN) and winter maximum (WMAX) dispatches for various export/import and wind levels.*

Transient Stability (Task 1.1)

Figure A - 3 plots the number of CCT ≤ 150ms against “operational metric 1” detailing import/export cases. As long as the value of “operational metric 1” is below 70%...80%, the 30% tolerance is respected.

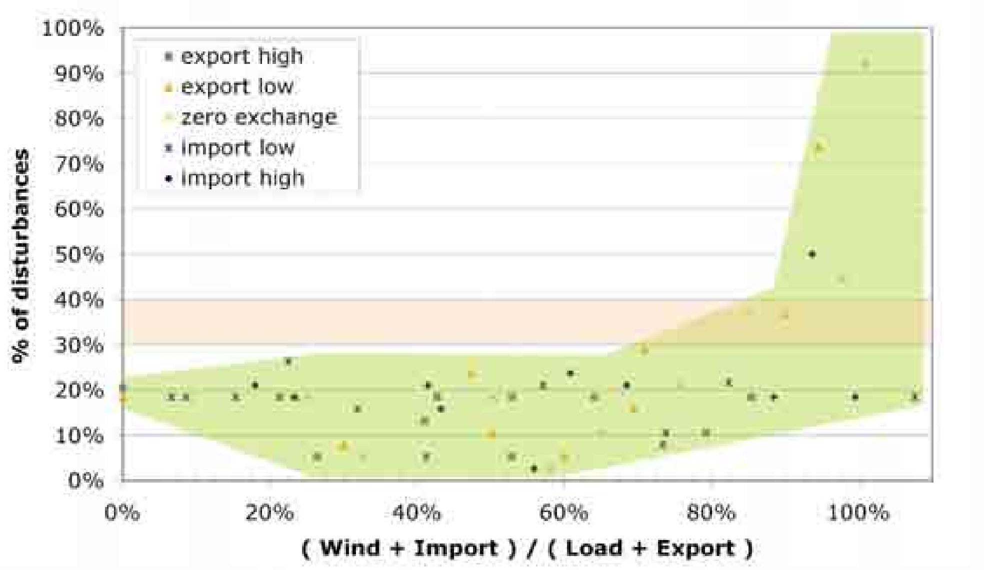


Figure A - 3: *Disturbances with critical clearance times ≤ 150ms as a function of “operational metric 1”. (Wind farms were not fully grid code compliant.)*

Figure A - 4 plots the number of CCT ≤ 100ms against “operational metric 1” detailing import/export cases. As long as the value of “operational metric 1” is below 85%...95%, the 30% tolerance is respected.

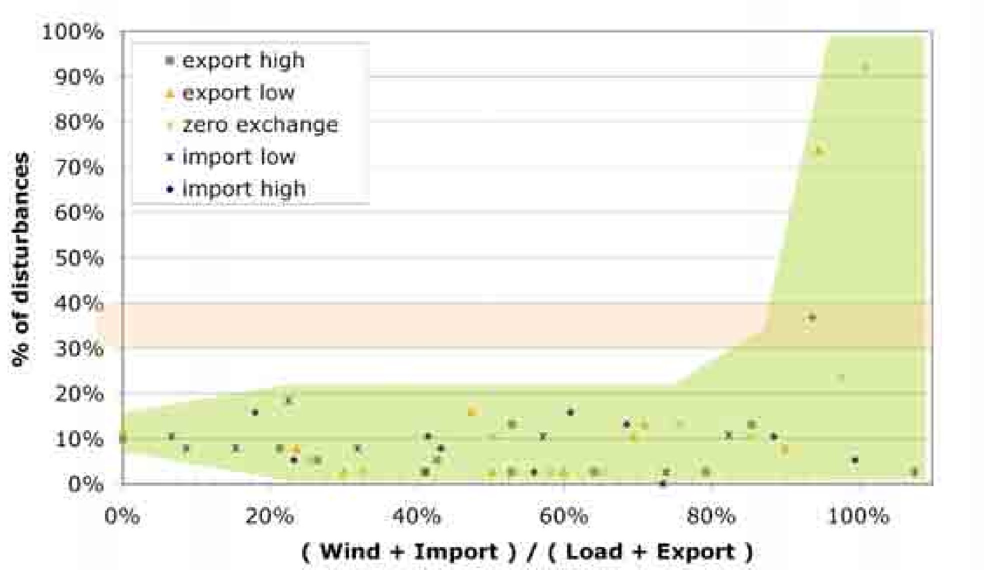
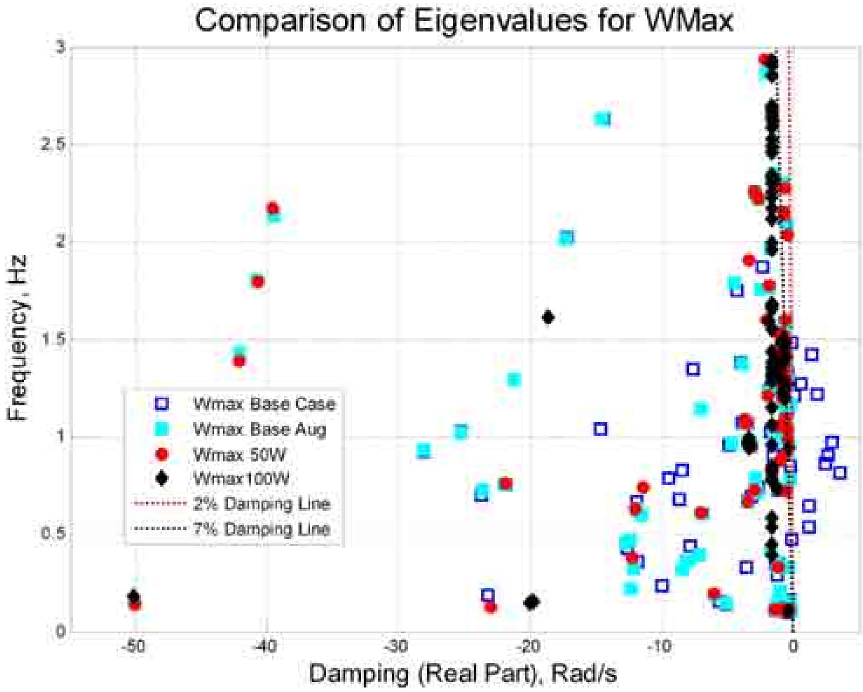


Figure A - 4: *Disturbances with critical clearance times ≤ 100ms as a function of “operational metric 1”. (Wind farms in the base case were not fully grid code compliant.)*

A3 Small Signal Stability (Task 1.1)



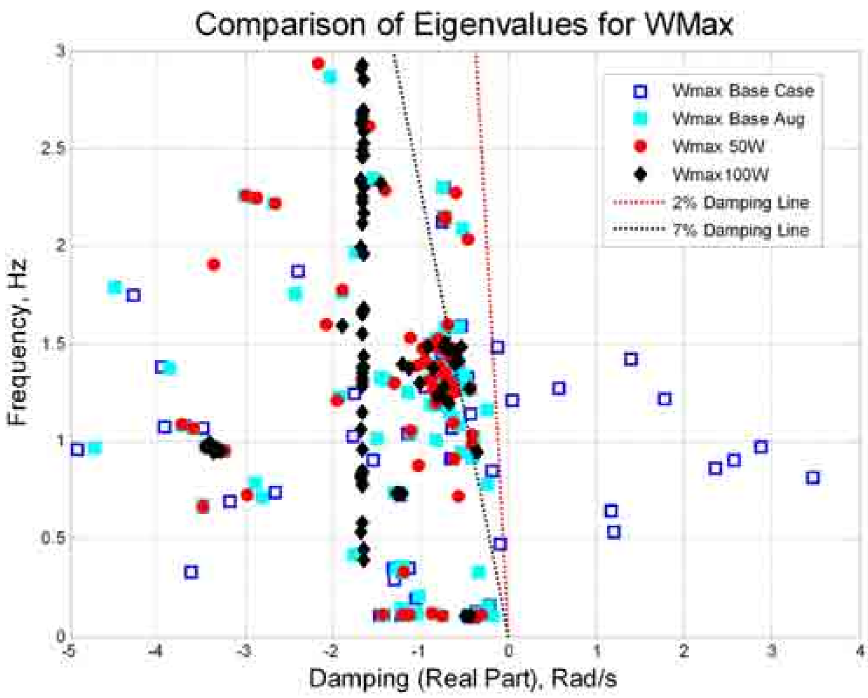


Figure A - 5: *Eigenvalues for winter maximum load and zero exchange case for two different wind power levels. The figure at the bottom is a zoom into the real axis focussing on damping values of -6…4 rad/s. In the base case models specific governors that introduced unstable modes were turned off; this augmented case ("base aug") was used for generating the results of the shown wind 50% and 100% cases.*

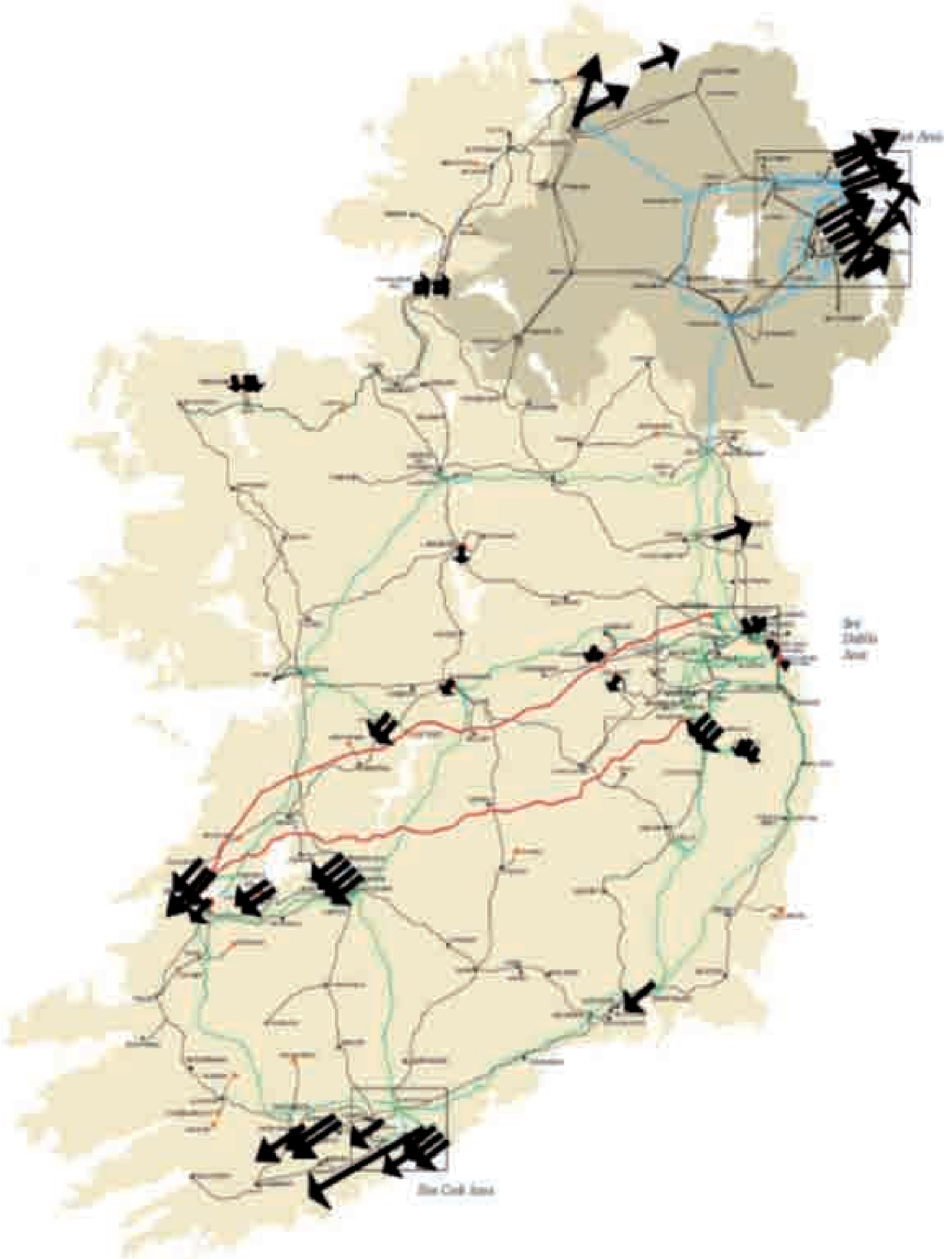


Figure A - 6: *Example for oscillations of groups of generators in Northern Ireland against groups of generators in the Republic of Ireland for the winter maximum load and zero exchange case* without any wind power. *The mode shape visualized corresponds to the Eigenvalue -0.23544 ± 0.78002(Hz) which proves to be an inter-area mode between Northern Ireland and Republic of Ireland.*

A4 Fault Levels (Task 1.2)

For each busbar the average short circuit current over all load cases and zero exchange is shown for different wind levels (0% wind in black, 25% wind in turquoise, 50% wind in light blue, 75% wind in blue and 100% wind in dark blue). Around each average value the minimum and maximum short circuit current over all load cases and zero exchange is indicated by the error bar.

Three-phase faults

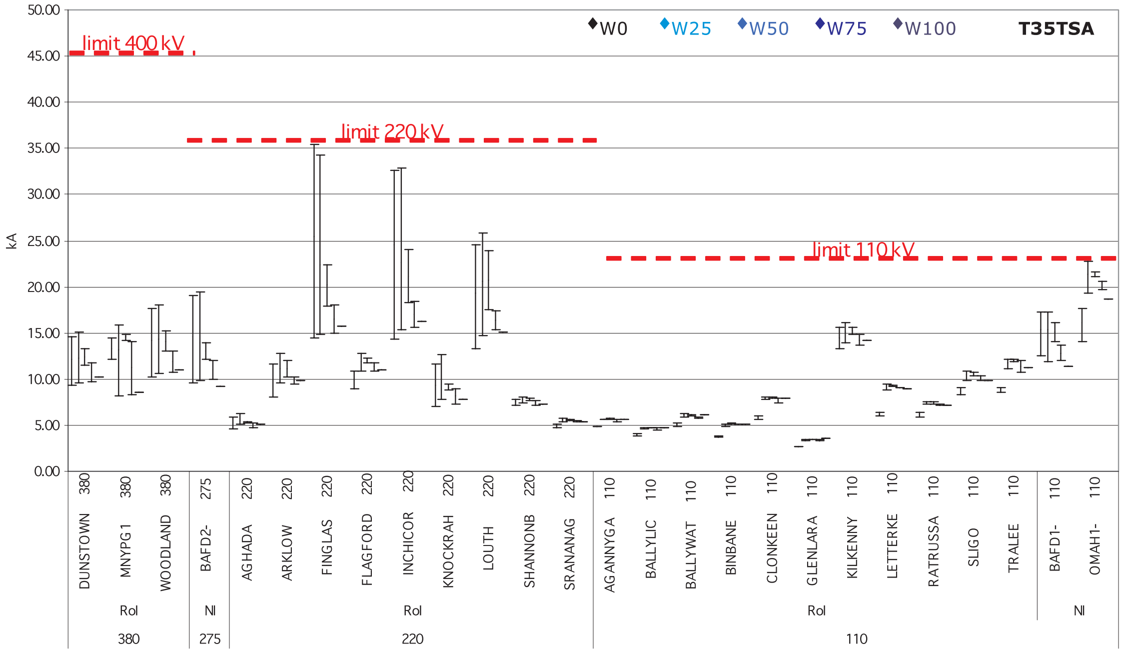


Figure A - 7: *Results from short circuit studies for **three-phase faults** at selected busbars for the base case (T35TSA).*

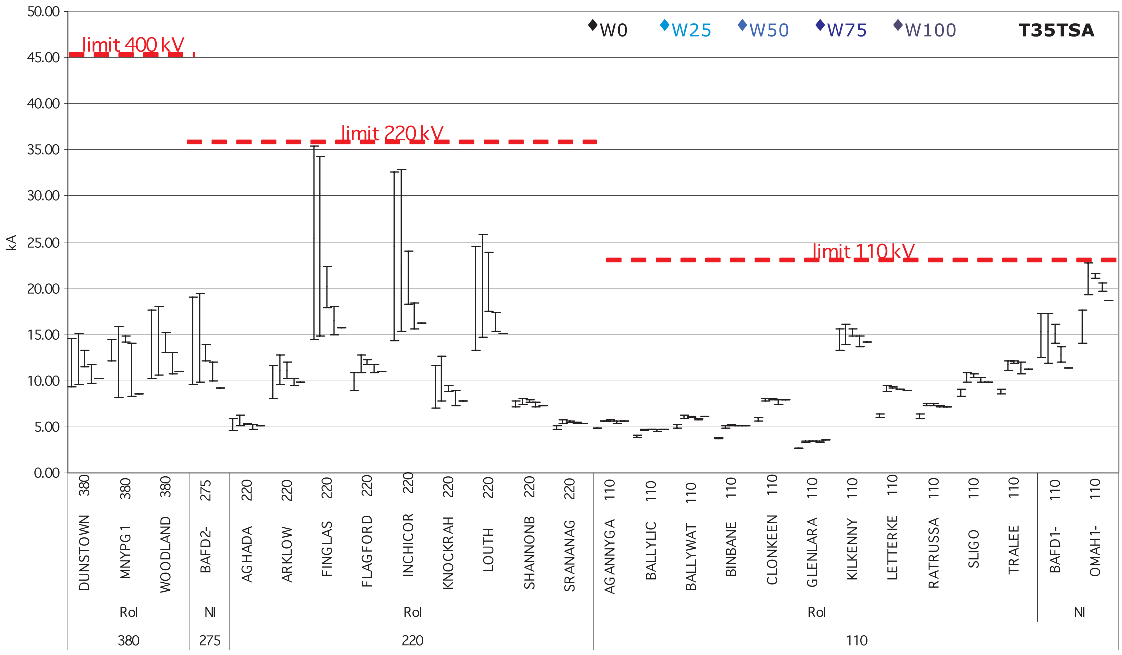


Figure A - 8: *Results from short circuit studies for **three-phase faults** at selected busbars for the case with 20% transmission connected wind farms and 85% DFIG wind farms (T20TSA).*

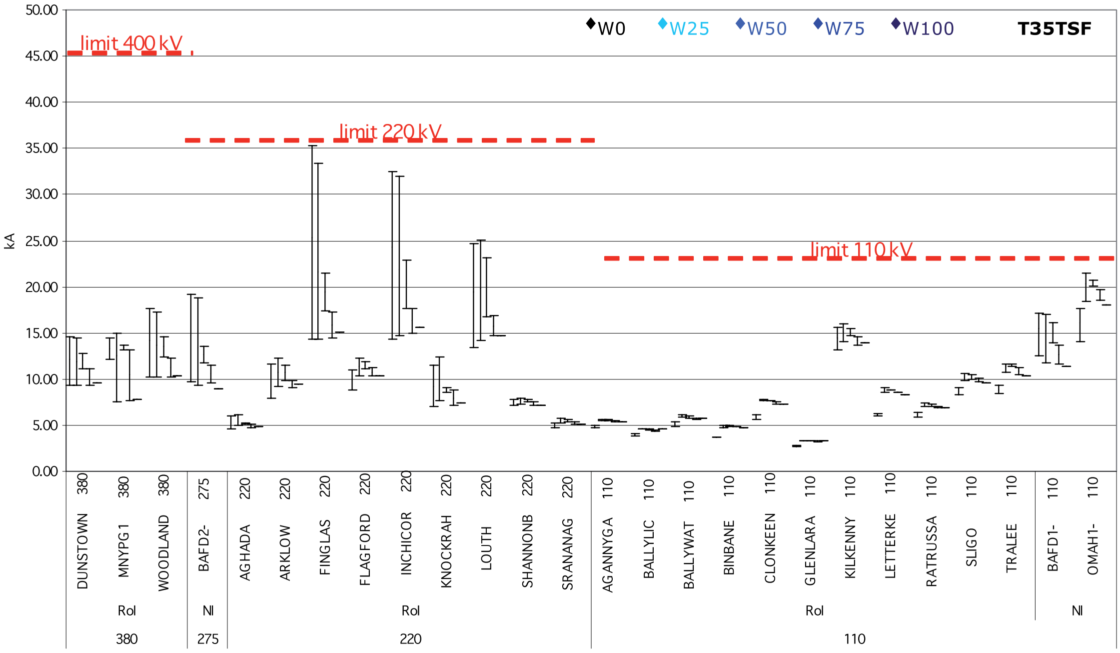


Figure A - 9: *Results from short circuit studies for* ***three-phase faults*** *at selected busbars for the case with 35% transmission connected wind farms and 50% DFIG wind farms (T35TSF).*

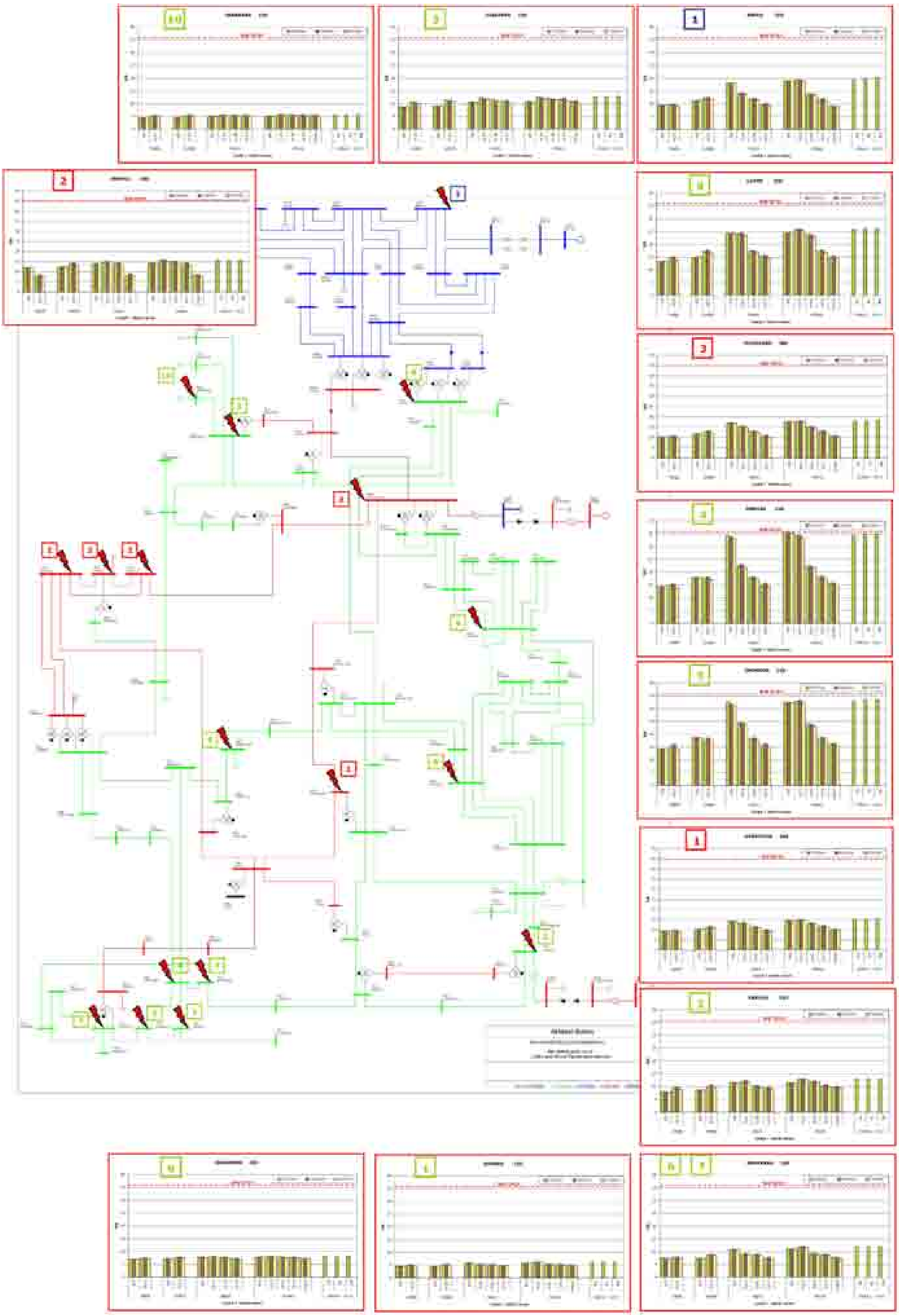


Figure A - 10: *Results from short circuit studies for **three-phase faults** at selected > 110kV busbars localised in the single line diagram for different cases of transmission connected wind farms and technology split.*

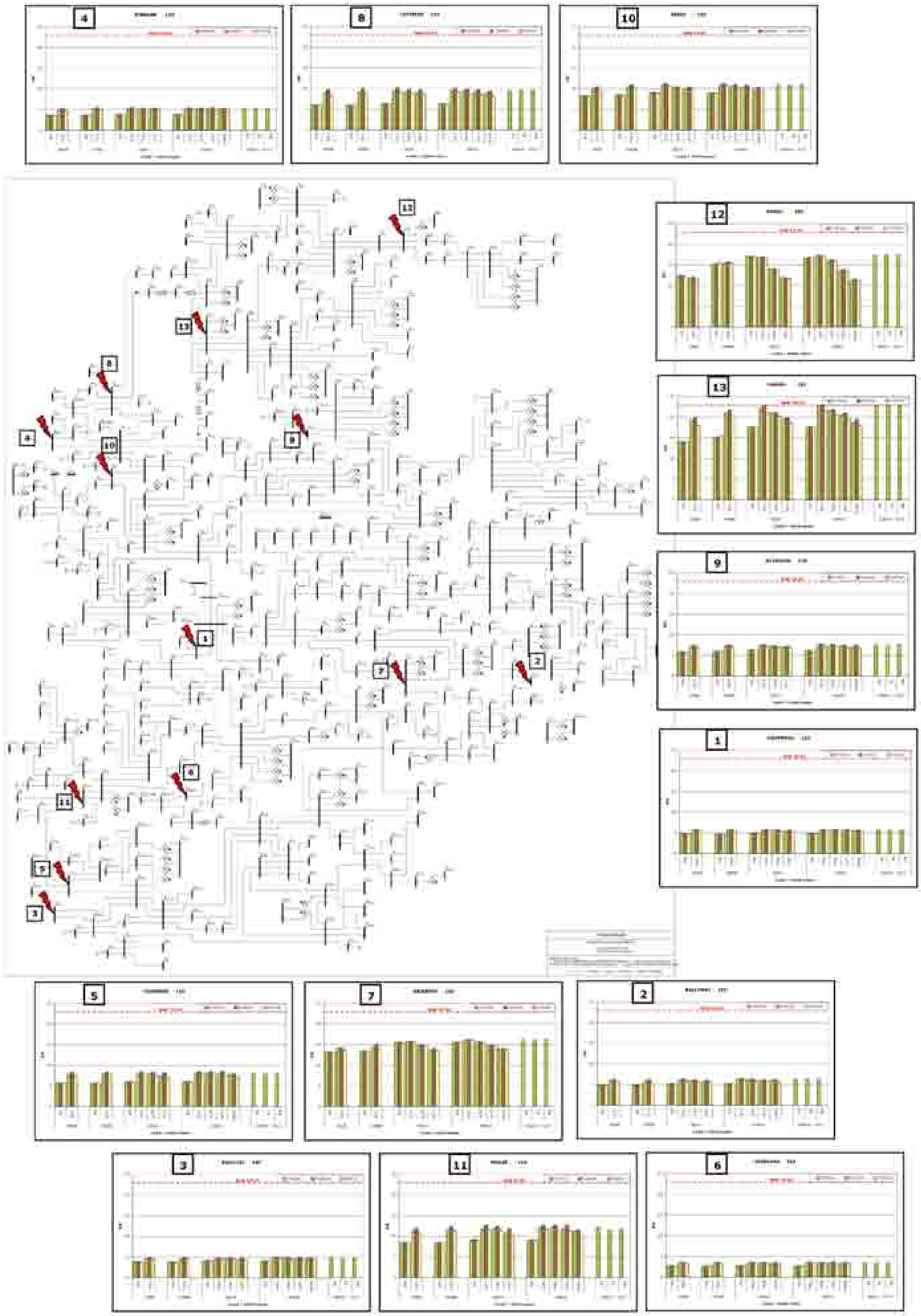


Figure A - 11: *Results from short circuit studies for* ***three-phase faults*** *at selected 110kV busbars localised in the single line diagram for different cases of transmission connected wind farms and technology split.*

Table A -1: *List of busbars where short circuit levels exceed maximum allowable limits for three-phase faults.*

Voltage Level	Bus number	Bus name	Max. short circuit current [kA]	Selected busbar
220	3122	IRISHTOW	36.28	no
	5122	SHELLYBA	36.20	no
110	1741	CARRICKM	23.58	no
	51319	CENTRAL	23.41	no
	3359	CLONBURRIS	23.56	no
	3349	CLONDALKIN	23.90	no
	75010	COLE1-	23.76	no
	75011	COLE1C	23.76	no
	75510	COOL1-	25.62	no
	75514	COOL1C	25.62	no
	2531	FINNSTOW	24.69	no
	2861	GRANGE C	25.29	no
	3081	INCH_CIT	26.79	no
	3091	INCH_COU	23.94	no
	3201	KNOCKRAH	24.73	no
	3211	KNOCKRAH	24.73	no
	3871	MILLTOWN	23.54	no
	4281	NANGOR	23.90	no
	3329	PARK WEST	25.05	no
	9993	RATHFARNHAM	23.56	no
	89510	STRA1-	24.94	no
	90011	TAND1A	24.41	no
	90012	TAND1B	24.41	no
	5141	TARBERT	23.63	no

Single-phase faults

For each busbar the average short circuit current over all load cases and zero exchange is shown for different wind levels (0% wind in black, 25% wind in turquoise, 50% wind in light blue, 75% wind in blue and 100% wind in dark blue). Around each average value the minimum and maximum short circuit current over all load cases and zero exchange is indicated by the error bar.

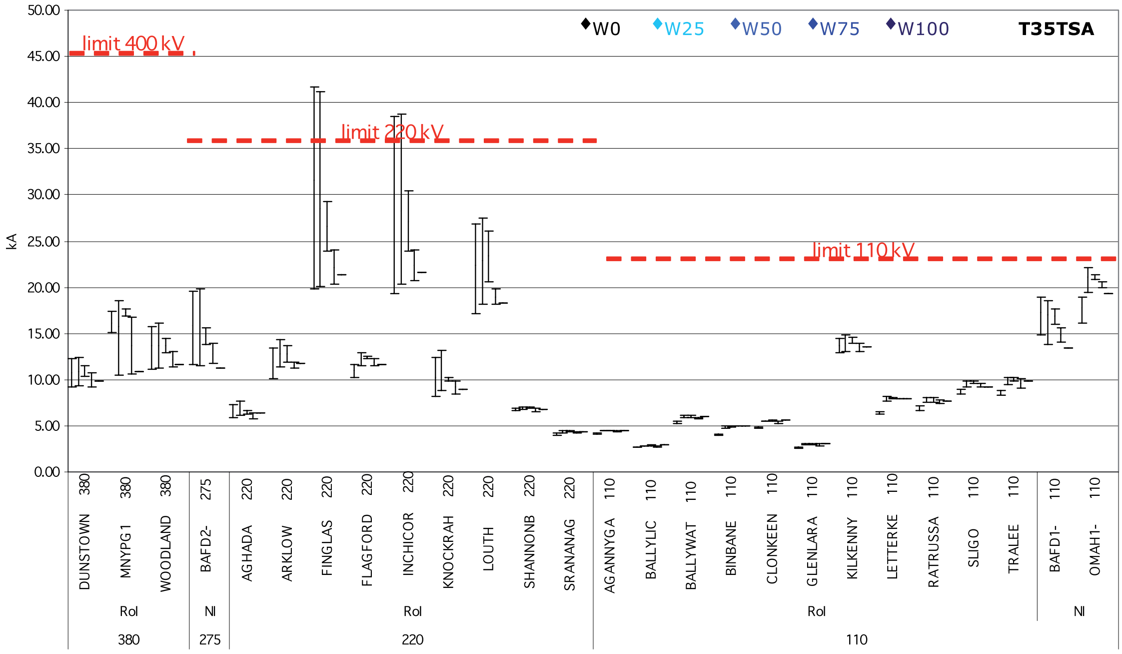


Figure A - 12: *Results from short circuit studies for **single-phase faults** at selected busbars for the base case (T35TSA).*

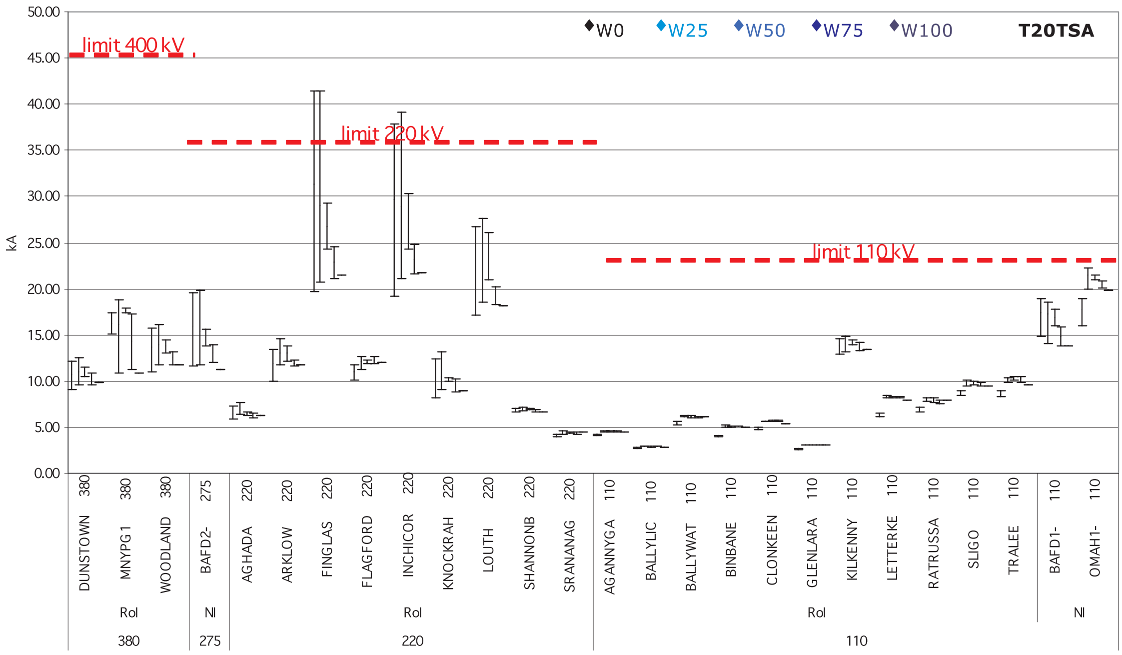


Figure A - 13: *Results from short circuit studies for **single-phase faults** at selected busbars for the case with 20% transmission connected wind farms and 85% DFIG wind farms (T20TSA).*

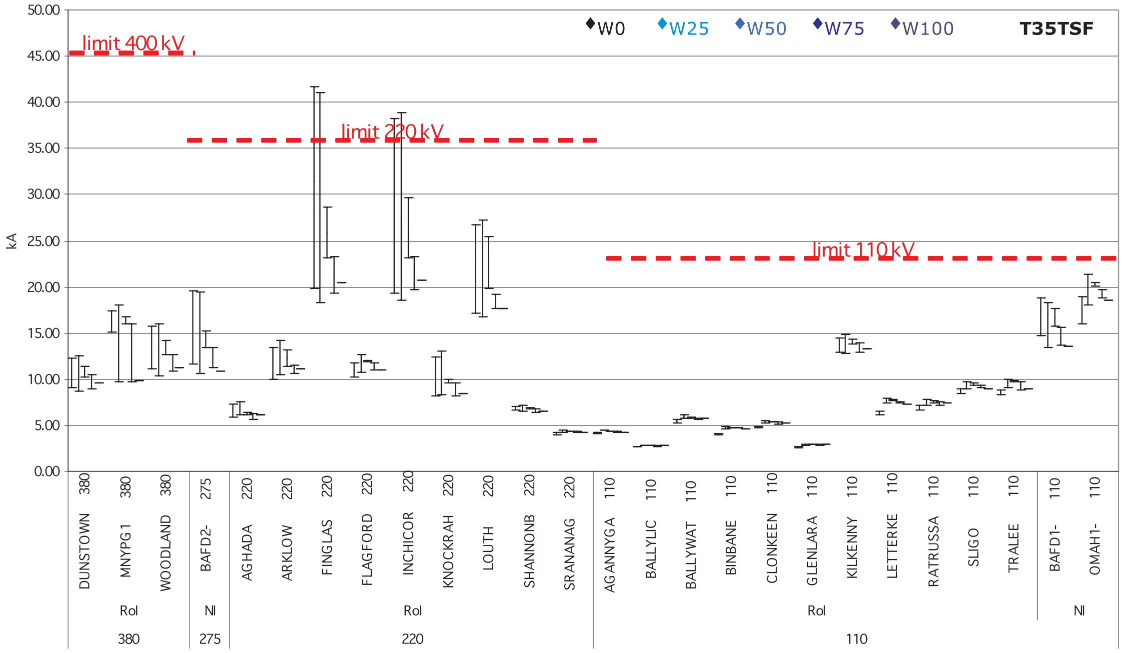


Figure A - 14: *Results from short circuit studies for **single-phase faults** at selected busbars for the case with 35% transmission connected wind farms and 50% DFIG wind farms (T35TSF).*

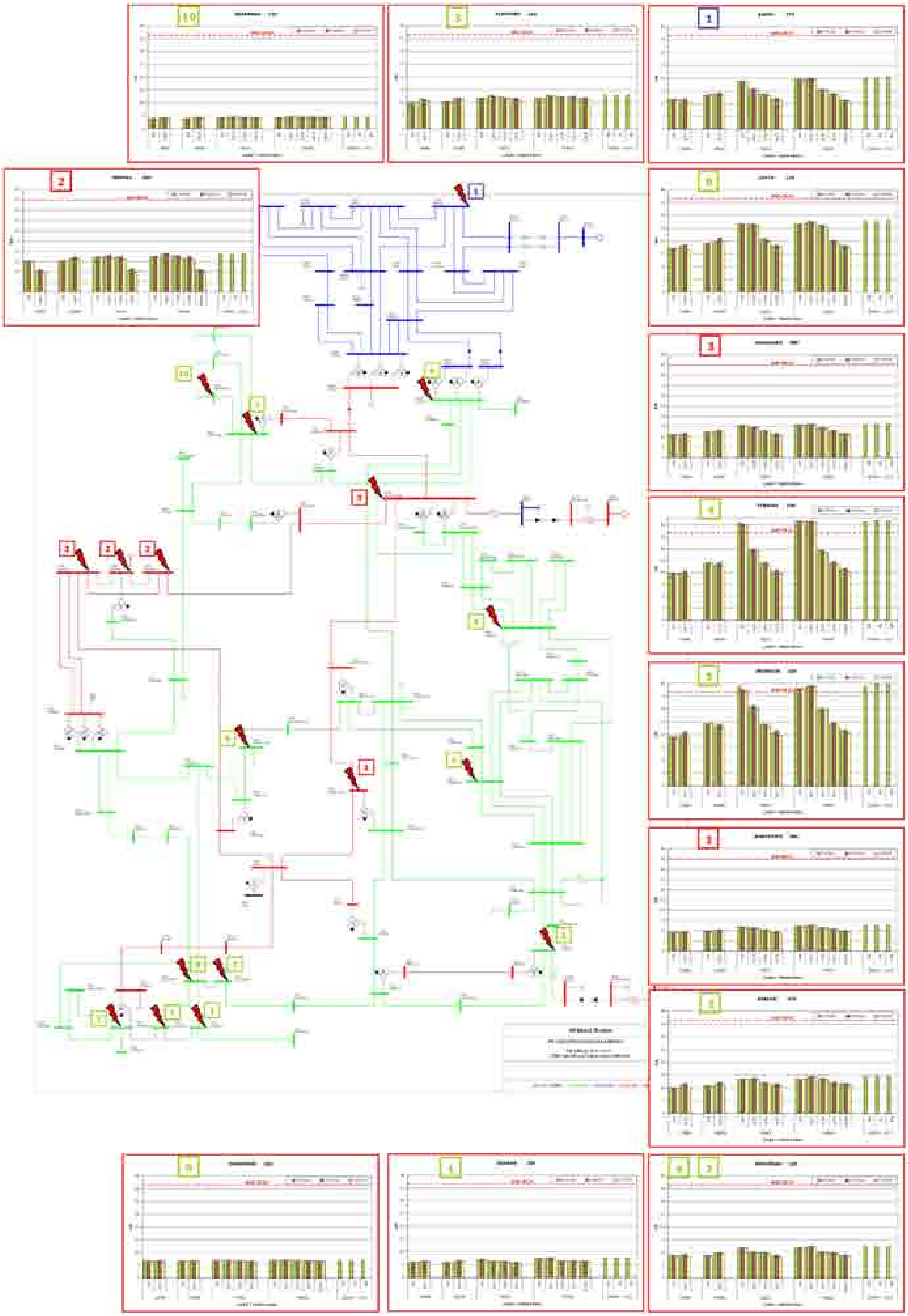


Figure A - 15: *Results from short circuit studies for **single-phase faults** at selected > 110kV busbars localised in the single line diagram for different cases of transmission connected wind farms and technology split.*

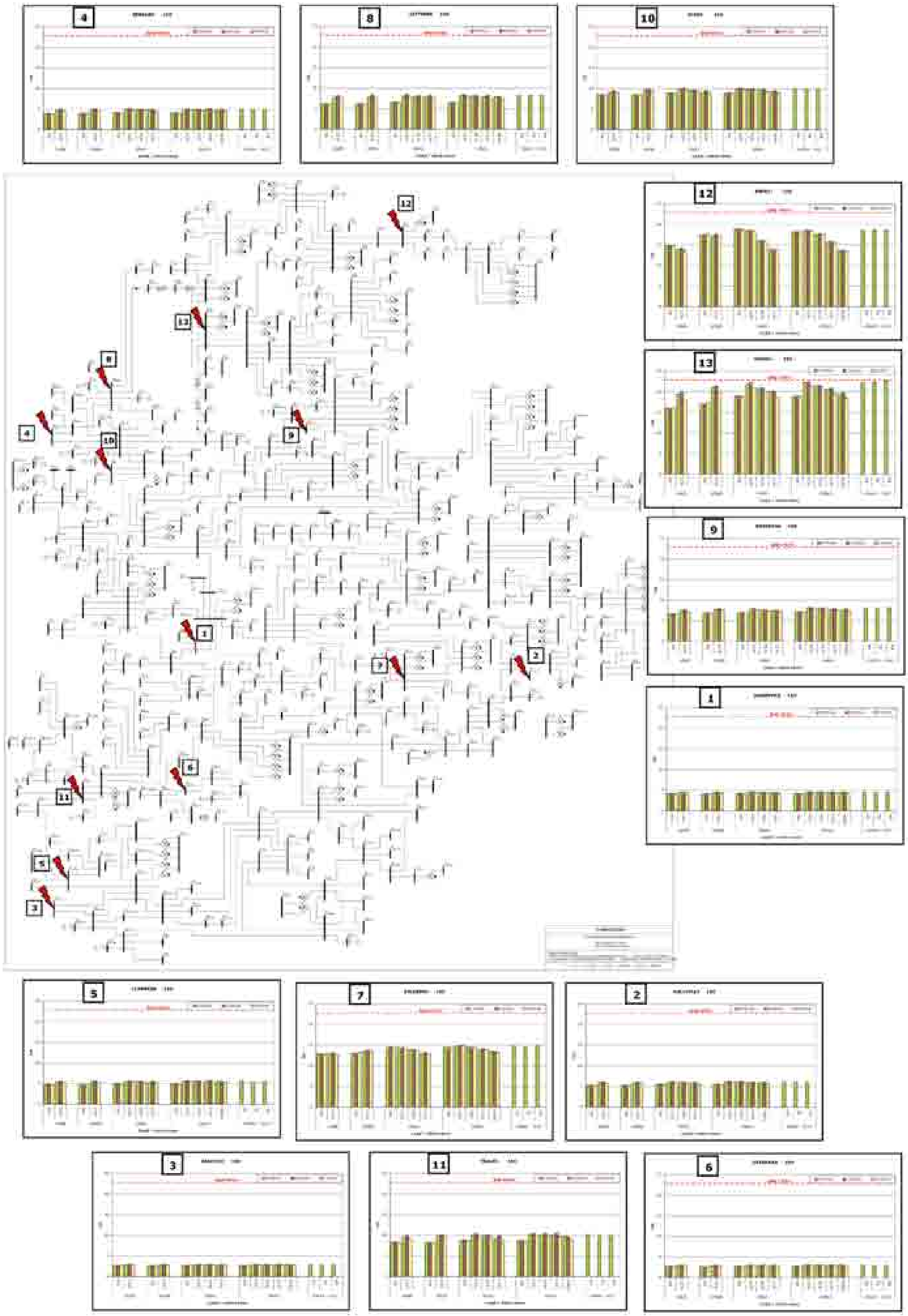


Figure A - 16: *Results from short circuit studies for* ***single-phase faults*** *at selected 110kV busbars localised in the single line diagram for different cases of transmission connected wind farms and technology split.*

Table A -2 List of busbars where short circuit levels exceed maximum allowable limits for single-phase faults.

Voltage Level [kV]	Bus number	Bus name	Max. short circuit current [kA]	Selected busbar
220	CARRICKM	1742	36.33	no
	CKM_SR	17462	36.33	no
	CORDUFF	2042	37.81	no
	FINGLAS	2562	41.87	yes
	HUNTSTOW	2962	41.15	no
	HUNTSTOW	2972	41.15	no
	INCHICOR	3082	39.74	yes
	IRISHTOW	3122	43.32	no
	SHELLYBA	5122	43.17	no
110	ADAMSTOW	1091	27.59	no
	CARRICKM	1741	26.36	no
	CAST1A	74511	25.19	no
	CAST1B	74512	25.19	no
	CENTRAL	1691	24.77	no
	CENTRAL	51319	25.85	no
	CLONBURRIS	3359	28.75	no
	CLONDALKIN	3349	29.27	no
	COOL1-	75510	25.95	no
	COOL1C	75514	25.95	no
	CORDUFF	2041	23.98	no
	CORDUFF	2051	23.98	no
	DRUM1-	77010	24.21	no
	FINNSTOW	2531	29.69	no
	FRN ST B	2551	24.44	no
	GRANGE C	2861	30.63	no
	HANA1A	81010	24.52	no
	HEUSTON	2951	25.83	no
	INCH_CIT	3081	32.84	no
	INCH_COU	3091	28.98	no
	KELS1-	81510	23.74	no
	KILLONAN	3281	24.36	no
	KILMAHUD	3431	27.83	no
	KIMMAGE	3319	26.57	no
	KNOCKRAH	3201	23.67	no
	KNOCKRAH	3211	23.67	no
	LAOIS	3551	25.44	no
	LAOIS_ST	35511	25.44	no
	LOUTH	3521	26.18	no
	LOUTH_CAP	35261	26.18	no
	MILLTOWN	3871	27.85	no
	NANGOR	4281	28.78	no
	PARK WEST	3329	30.86	no
	RATHFARNHAM	9993	28.03	no
	SANDYFORD	9994	24.27	no
	TAMN1-	90310	24.24	no
	TAND1A	90011	27.18	no
	TAND1B	90012	27.18	no
	TANEY	5131	24.42	no
	TARBERT	5141	24.70	no

Reactive Power and Voltage Control (Task 1.4)

Table A -3: *Additional reactive power sources (static var compensators or similar reactive power equipment) assumed in the All Island Power System model for the simulation runs.*

Voltage level	Busbar	Capacity of SVC or similar reactive power equipment
400kV	Aghada	±250Mvar
	Turleenan	±250Mvar
275kV	Coleraine	±100Mvar
	Magherafelt	±250Mvar
220kV	Finglas	±250Mvar
	Bellacorick	±120Mvar x 2
110kV	Cathleens Fall	±120Mvar
	Thurles (upgrade of switched shunt)	±60Mvar
Sum		**1,520Mvar**

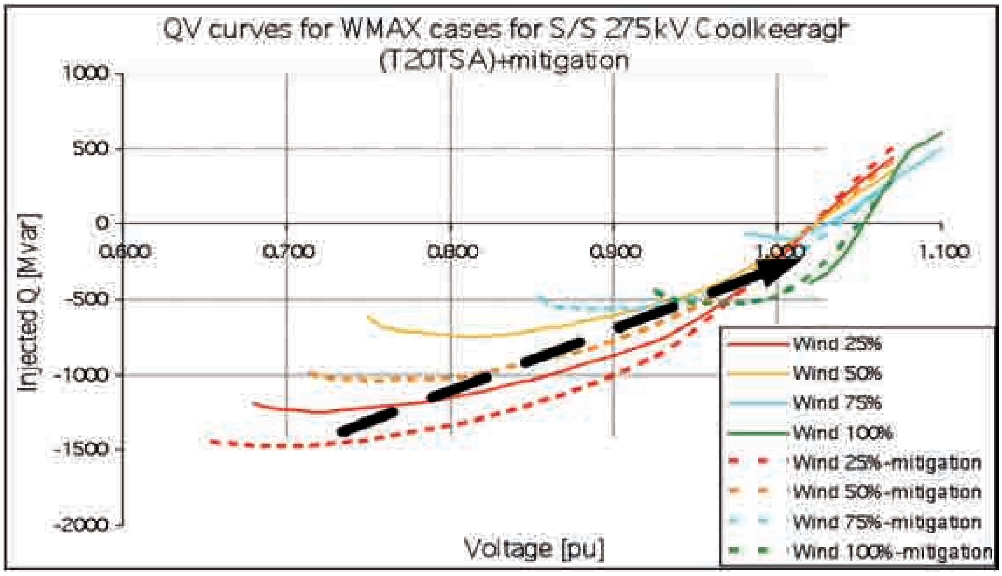


Figure A - 17: *Reactive power versus voltage analysis (QV curves) for 400kV busbar Coolkeeragh for winter maximum load and various wind power levels.*

Solid lines are results from worst case calculations and dashed lines from calculations with improved reactive power capability of wind farms. The dashed black arrow shows the trend that minimums of QV curves move to higher voltages in dispatches with high wind power. The minimum of QV curves represents the voltage stability limit at the respective busbar. Source: [Siemens PTI (2010a)] [Siemens PTI (2010a)]

A6 Frequency Stability (Task 2.1)

Loss of largest infeed with inertia from wind turbines

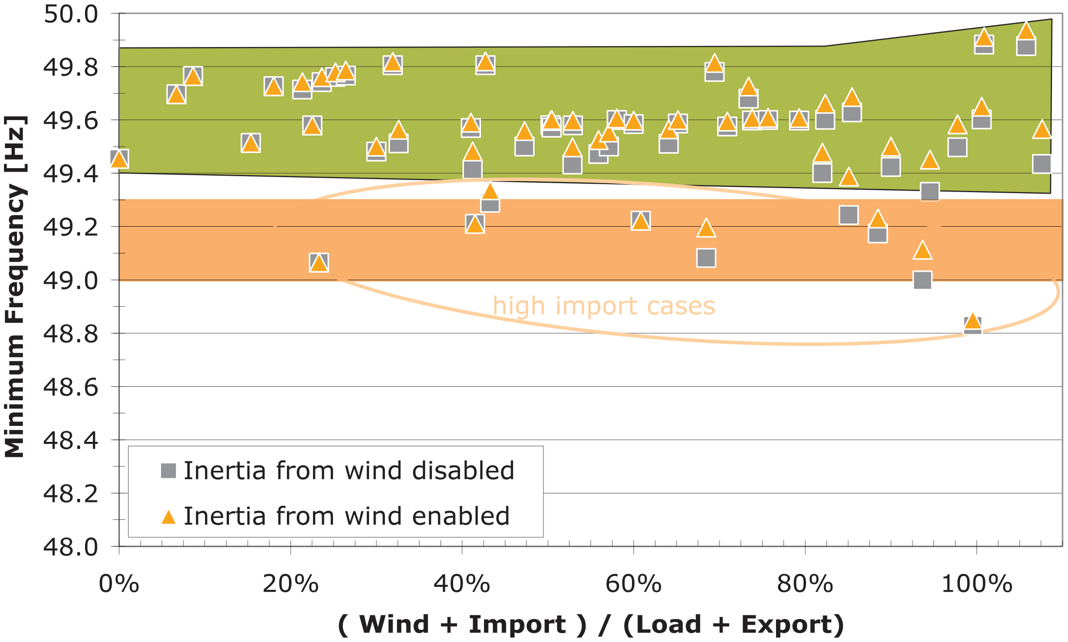


Figure A - 18: *Minimum frequency after loss of largest infeed as a function of the ratio between inertialess power from wind plus import and the instantaneous load plus export balance. Results for two operational strategies are shown: rate of change of frequency (ROCOF) relays at distribution connected wind farms are disabled (grey triangles) and inertia contribution from wind turbines is enabled (tangerine triangles)*

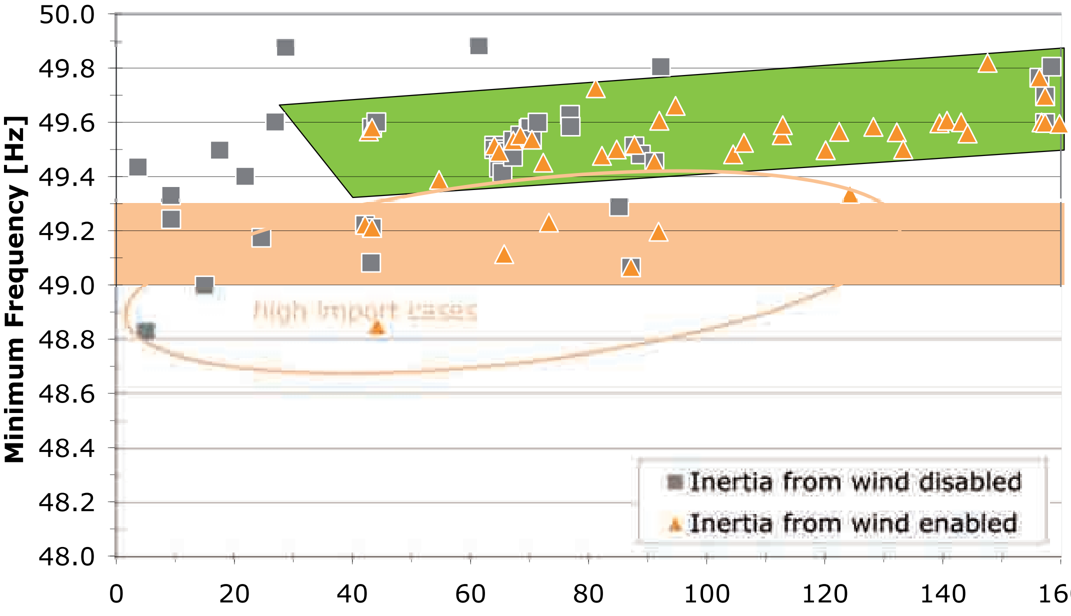


Figure A - 19: *Minimum frequency after loss of largest infeed as a function of the kinetic energy stored in conventional generators and the load divided by the dispatched power of the largest infeed. Results for two operational strategies are shown: rate of change of frequency (ROCOF) relays at distribution connected wind farms are disabled (grey triangles) and inertia contribution from wind turbines is enabled (tangerine triangles).*

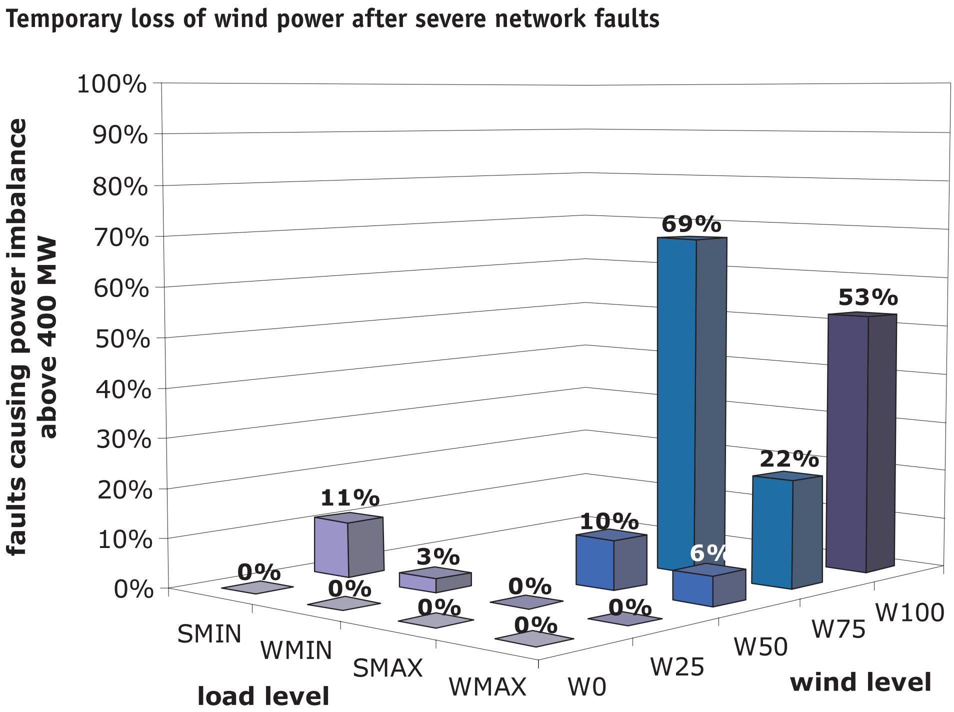


Figure A - 20: *Percentage of faults that cause a power imbalance above 400MW for different load/wind cases.*

Figure A - 21 shows the impact of the "operational metric 2" on minimum frequency with the temporary loss of wind power representing the maximum infeed. For "operational metric 2" ratios below about 30MWs/MW the minimum frequency is hardly predictable indicating a critical system state.

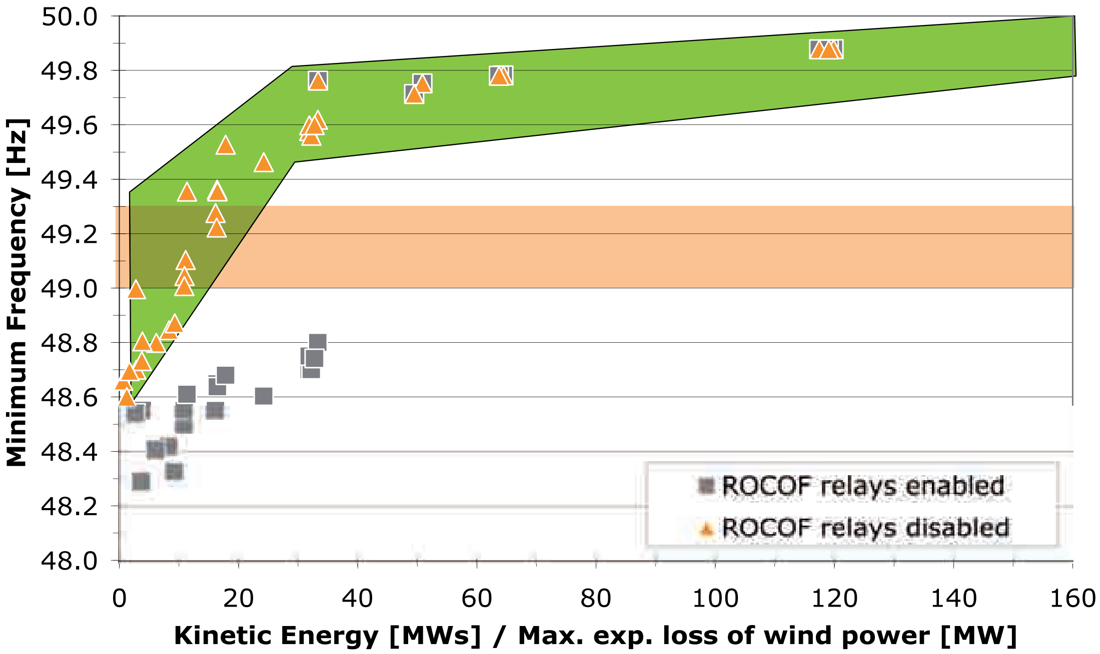


Figure A - 21: *Minimum frequency due to temporary loss of wind power output after severe network faults as a function of "operational metric 2" for the respective dispatch.*