# Studying the Maximum Instantaneous Non-Synchronous Generation in an Island System – Frequency Stability Challenges in Ireland

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***Abstract*—Synchronous island power systems, such as the combined Ireland and Northern Ireland power system, are facing increasing penetrations of renewable generation. As part of a wider suite of studies, performed in conjunction with the transmission system operators (TSOs) of the All-Island system (AIS), the frequency stability challenges at high and ultra-high wind penetrations were examined. The impact of both largest infeed loss and network fault induced wind turbine active power dips was examined: the latter contingency potentially representing a fundamental change in frequency stability risk. A system non-synchronous penetration (SNSP) ratio was defined to help identify system operational limits. A wide range of system conditions were studied, with results showing that measures such as altering ROCOF protection and enabling emulated inertia measures were most effective in reducing the frequency stability risk of a future Ireland system.**

***Index Terms*—Power system dynamics, Power system control, Power system stability, Wind power generation.**

## I. INTRODUCTION

SIGNIFICANT amounts of non-synchronous wind generation capacity are presently being connected to many electrical power systems around the world. There are, however, a number of technical and economic challenges of varying complexity associated with ambitious wind energy integration targets [1-3]. For example, the deployment of sufficient new transmission network capacity in the system planning timeframe [4-6], the development of advanced wind forecasting and power system scheduling tools for the system operational timeframe [7-8], and the necessary re-evaluation of electricity market structures [9-11] are to name but a few. It might be argued though that with appropriate industry adaptation and the provision of adequate investment capital, many of these issues may not comprise 'hard limits' to the level of non-synchronous wind generation. On the other hand, the radically different electrical and mechanical characteristics of wind turbine technology, and its negative impact on some aspects of dynamic stability [12-14], may represent a more fundamentally limiting integration constraint.

It is imperative from a security perspective to maintain frequency deviations within small tolerances of nominal operating frequency in order to avoid customer interruption, additional generator trip events, and in extreme cases the risk of cascading system blackout. Increasing the amount of non-synchronous wind penetration (be it with traditional squirrel-cage induction generators, contemporary doubly-fed induction generators (DFIG) or advanced full-converter wind turbine generators (FCWTG)) will effectively displace traditional synchronous generation in the system dispatch [15]. Despite the availability of a relatively large stored rotational energy resource in wind turbines [16-17], the decoupling of the mechanical rotating mass of power-electronic-based DFIGs and FCWTGs from the synchronous system dynamics impacts the overall inertial response characteristic. While inertial 'emulation' using turbine control functionality has been proposed as a possible mitigating factor [18-20], it is yet to be widely applied in practice. It is known that a reduction in synchronous inertia will have significant frequency stability implications for smaller synchronous-island systems with respect to loss of the largest generation in-feed contingency and its resultant generation/demand imbalance [21-23]. Furthermore, analogous non-synchronous and zero-inertial characteristics of additional HVDC interconnection will likely have a similar effect, as categorized in Fig. 1.

An emerging, yet potentially more critical, risk to synchronous frequency stability is the relatively slow active power recovery response of wind turbine generators to short-circuit-fault related voltage dips in order to avoid excessive mechanical forces. This delay is typically of the order of 1-4 s [24]. Depending on the fault location, the instantaneous wind generation level and the spatial clustering of wind farm locations, then at high wind penetration levels this temporary active power supply interruption may result in even more serious frequency stability implications.

Non-synchronous capacity integration is arguably more challenging in standalone synchronous-island power systems, where there is already a lower synchronous inertial basis to start from, and less access to back-up resources. A very important question arises therefore – to what extent can the instantaneous penetration of an existing standalone synchronous area be made up of non-synchronous generation (e.g. wind power and/or HVDC imports), and still be operated in a safe, secure and reliable manner with respect to frequency stability? Enforcing maximum instantaneous non-synchronous generation limits obviously implies curtailment of any additional wind power available. In addition, therefore, what are the precise technical challenges and how can they be

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mitigated (using inertia emulation, system re-dispatch, advanced system control and protection strategies) to have minimal economic and renewable energy policy implications?

With such an objective, this paper reports on a detailed dynamic stability study, as carried out on the Irish All-Island standalone synchronous power system projected for the year 2020. Important indices of frequency stability such as the maximum rate-of-change-of-frequency (ROCOF) and the minimum frequency reached (frequency nadir) following system contingencies are studied using a combination of a transient stability tool, Siemens PSS/E®, and an advanced single-bus frequency model [21]. Ultra-high instantaneous non-synchronous generation levels of up to 100% are considered. Section II describes characteristics of the Ireland power system, Section III presents the study methodology and frequency stability case study details, with important results, discussion and conclusions outlined in Sections IV, V and VI.

## II. 'ALL-ISLAND' POWER SYSTEM OF IRELAND

The All-Island system (AIS) comprises a single synchronized power system, spanning Ireland and Northern Ireland. Coincident with EU policy directives, significant renewable generation expansion is a political and therefore regulatory priority in the sector. Ireland, and separately Northern Ireland, have set renewable electrical energy targets of 40% of demand by 2020, the vast majority of which to be supplied from wind power. New generation developments are being facilitated by a network expansion plan [6] and streamlined transmission access queue [25]. Aside from wind power, by 2020 the conventional generation portfolio is expected to mainly comprise of combined cycle gas turbines (CCGTs), open cycle gas turbines (OCGTs), a few indigenous peat-fueled steam turbine stations, a relatively small amount of conventional hydro power, and a 292 MW pumped storage power station. This contributes to approximately 8000 MW conventional synchronous generation capacity overall. There is currently +/- 1000 MW of HVDC interconnection with the much larger Great Britain system. It was assumed in these studies that by 2020 there would be additional interconnection leading to a total of ± 1350 MW in either direction. The largest generation in-feed security contingency is currently 500 MW. Peak load demand (winter day) for the year 2020 is approximately projected at 7800 MW, and minimum load (summer-night) is expected to be 2600 MW.

There is the planning potential for up to 7500 MW of wind generation connection by the year 2020, the mainstay of which will likely be DFIG or full-converter turbine technology. From analysis of multiple years of historical wind power data, it can be concluded that even at relatively low instantaneous system wind power production levels, most of the turbines across this region are spinning online and thus have stored rotational energy available [22-23], assuming that an inertial response characteristic were able to access it.

A detailed grid code for generation performance with respect to voltage and frequency deviations has been formulated [26]. Contracted interruptible load is tripped for system security reasons when the frequency dips to 49.3 Hz, with emergency unscheduled customer load tripping applied at staggered frequency levels below this. As later illustrated in Section IV, it is critical to note that a significant proportion of the wind capacity (up to 80% of total) may be connected at the distribution system level. Protection relays based on measured ROCOF are traditionally used to trip such distributed generation following detection of abnormal system conditions and prevent local system islanding effects [27]. ROCOF values exceeding ~ ± 0.6 Hz/s measured over a period of 0.5 s would presently be considered abnormally extreme.

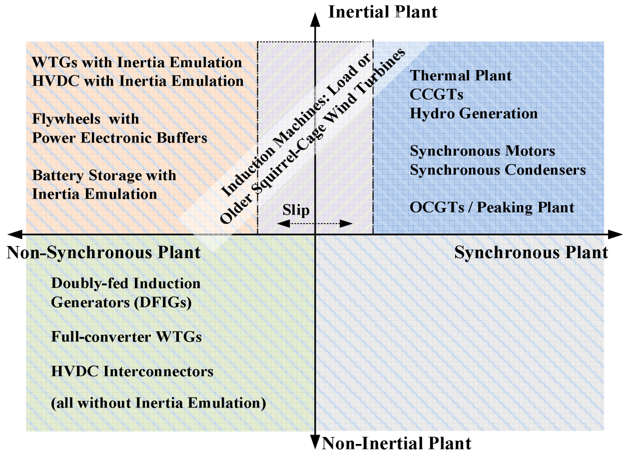


Fig. 1- Classification of power generation sources according to whether they are synchronized to the system and/or provide inertia

The relative scale of the projected non-synchronous wind capacity and HVDC interconnection levels with respect to the size of the power system (i.e. sometimes available wind may far exceed the total demand requirement) would suggest a number of challenges in the near future. Some of these issues have been analyzed as part of a detailed wind integration study (the 'All-Island Grid Study' [28], which estimated that up to 42% of annual electricity demand on the AIS could be met by renewable generation sources. However, dynamic stability constraints during instantaneously high non-synchronous generation penetrations were identified as one technical area that required further investigation to confirm this feasibility. Subsequent frequency stability studies have been guided by the 'All-Island TSO Facilitation of Renewables Studies' programme [29], the objectives, methodology and principal results of which are reported herein.

## III. METHODOLOGY AND CASE-STUDY DETAILS

### *A. AIS Dispatch Cases for 2020*

The addition of a highly variable source of generation, such as wind power, necessitates the study of a much greater diversity of system operating conditions than might have previously been the case with conventional plant, as the most challenging situations may no longer occur at the extremities of maximum or minimum system load demand. Year-long 8760-hour dispatch studies are becoming common in a wide variety of steady-state wind production-costing study applications [30-31]. Hence, a number of representative instantaneous wind/load case combinations were analyzed here. Load was varied in 4 steps from minimum to peak demand, with wind power output simultaneously varied in 5 steps from zero to an assumed maximum generation peak level of 7550 MW, Fig. 2. Each wind/load combination was furthermore analyzed for a number of additional sensitivities with regard to 5 different instantaneous HVDC interconnector dispatch levels – 0, ± 500 and ± 1350 MW. Maximum wind output and HVDC interconnection import would not be feasible to ensure power balance at minimum load, as indicated by the hatched area in Fig. 2 – such inapplicable (37) cases are thus disregarded.

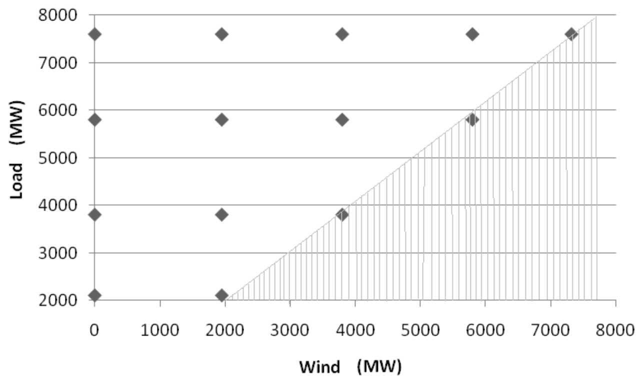


Fig. 2 – Instantaneous wind/load case combinations studied

The remaining 63 deterministic snapshot cases are worthy of detailed dynamic system investigation, and are generally representative of the wider set of possible operational extremities. For each individual case, conventional power generators were economically dispatched on the basis of a merit order ranking approach, with projected 2020 fuel costs applied and appropriate reserve characteristics included. Consistent with current operational policy, it was assumed that total primary reserve of at least 81% of the largest possible in-feed contingency (be it HVDC interconnector or conventional generation) should be carried.

### *B. Single Bus Frequency Model – Loss of Largest In-Feed*

A 'single-bus frequency model' (SFM) of the AIS has been developed, using MATLAB® and Simulink®, over a number of years, to study primary system-frequency dynamics during the initial 0-15 s post-contingency timeframe [21, 32]. The model is based on the principle that the difference between the combined active power of the generation and the load, following the loss of a large generation in-feed, is fed to a connecting system block which calculates the system frequency based on the system power imbalance and the kinetic energy accessible to the system from the rotating masses, before being fed back to the individual generator and load models. Within Ireland, the comparatively short transmission lines separating the loads and generators allow the SFM to apply a single busbar lumped-mass concept. The frequency sensitive dynamic characteristics of the system load demand [33] and each generator are included. The individual generator models are based on the structures defined in [34] for thermal steam plant, incorporating a multi-stage turbine, boiler, and governor controls, and for hydro-electric based plant [35]; open cycle and combined cycle gas turbine models [21] incorporate both governor droop and gas exhaust temperature controls; while a user-defined model is introduced for the pumped storage plant representing pumping, generating and spinning modes of (static reserve provision) operation. HVDC interconnection is a further source of static reserve, and is simply represented as a multi-stage response triggered at a number of defined frequencies. In the primary reserve timeframe, the wind generation output is assumed invariant, and so the wind turbines are not explicitly modeled, excepting the governor droop and emulated inertia mitigation control measures introduced in Section III-D. The required proportion of contracted interruptible load is allowed to trip below frequencies of 49.3 Hz (additional emergency load tripping is also modeled for lower frequencies) and the relevant proportion of distribution connected wind farms is tripped following ROCOF values greater than -0.6 Hz/s. As it is a lumped-representation single bus model, it cannot model network-separated inter-unit transient oscillations, and does not directly allow for voltage-related dynamic issues. It has, however, been validated based on manufacturer data and real event traces to provide accurate traces of the overall system frequency response in the first 15 seconds following significant generation/demand imbalance events [21, 23]. The SFM was initialized for the 63 dispatch cases as outlined in Section III-A, and the frequency response following loss of the instantaneously largest in-feed simulated, with the frequency nadir, time to minimum frequency and maximum rate of change of frequency all recorded.

### *C. Transient Stability Issues – Voltage Disturbance Impact*

There is concern that the delayed active power recovery of modern wind turbine control technology with respect to short-circuit-fault related voltage dip conditions will present a significant risk to frequency control performance in isolated synchronous power systems - as any reduction in power output following a voltage dip will cause the system frequency to correspondingly reduce. While the active power recovery of a conventional synchronous plant takes only the order of some milliseconds in duration, grid codes for wind plant generally allow a much longer recovery period in order to prevent excessive physical stresses on the wind turbine mechanical components [24]. Depending on the location and spread of the voltage dip in a transmission network following a short-circuit fault, a large number of wind turbines could potentially be affected. Critically, at instantaneously high wind power production levels, the magnitude of the resultant active power imbalance between total generation and load demand could in fact be larger than the traditional extreme case of the largest conventional generation contingency. Furthermore, with high instantaneous wind power production levels, it is likely that many synchronous conventional plant will already have been displaced in the system dispatch. So, while the potential contingency may be enlarged, the system inertia levels will tend to be reduced, exacerbating the resultant frequency excursion. Such combined effects are of great concern to a system operator in a small isolated synchronous area.

A multi-bus model of the AIS was investigated for each of the 63 dispatch cases with regard to transient stability and short-circuit levels following network fault contingencies, using PSS/e® v31.1 and its industry-standard generic wind turbine dynamic models. It is noted, however, that the active power output response of wind farms during some disturbances is under study using such models [36]. Therefore, in order to more realistically assess the potential frequency control implications of this issue, a combination of the PSS/e transient stability and SFM studies was performed. Given that approaching 8000 frequency transients were to be considered (based on mitigation strategies, and combinations of strategies, for each dispatch case and each event type) the SFM was strongly viewed by the TSOs within Ireland as a pragmatic and efficient testbed, as compared to the complexities of the detailed multi-bus model.

As discussed in Section III-B, the SFM cannot directly model the impact of faults on bus voltages. Instead, the results from the PSS/e model were analyzed to determine the aggregate reduction in wind power output caused by network faults. The magnitude and spatial-spread of voltage dips following each possible three-phase short-circuit fault contingency was recorded for the various dispatch cases. The instantaneous wind power output at each network bus was scaled by the magnitude of the voltage dip seen (assuming that the wind turbines are grid code compliant and that the wind power retained was directly related to the fault voltage dip), and then summed to determine the collective system wind power response. It should be noted, of course, that this constitutes a temporary active wind power reduction, rather than an extended outage trip event – the wind power active power recovery trajectory was assumed to precisely bound (i.e. neither exceed nor fail to meet) the grid code standards of recovering to 90% of pre-fault active power output within 1 second of fault clearance [26]. This collective wind power response was then fed into the SFM to allow the impact on system frequency stability to be analyzed.

The combined modeling approach provides the maximum active power reductions shown in Fig. 3 for the given winter and summer min/max load dispatch scenarios. Analysis of the PSS/e transient stability results indicated that the worst-case instantaneous wind power output reduction following a large selection of single- and three-phase network fault disturbances was typically around 35% of the system-wide pre-fault level. It is noteworthy that the power imbalance is associated with the post-fault active power recovery of the turbines rather than wind farm disconnection. Clearly, at higher wind power production levels, although such cases are less common, the maximum active power temporary dip (≈2000 MW) could be much greater than the existing largest conventional generator or interconnector in-feed contingency level of 500 MW.

## D. Possible Mitigation Strategies

As will be illustrated in Section IV, the magnitude of the frequency deviations that could result with instantaneously high non-synchronous generation contributions requires alternative system operational strategies to mitigate frequency stability risk. In order to mitigate an extreme frequency deviation, obviously either the magnitude of the initial power imbalance must be reduced by limiting the worst-case single outage (such as constraining wind down), or the subsequent emergency active power increase of the system must be made more instantaneous, or both. A number of different and possibly complementary solutions were explored to improve the post-contingency system frequency stability. Some of the most influential options considered are detailed as follows:

### 1) Relaxing Distribution System ROCOF Relay Settings

Given that wind capacity connecting at distribution level will in future be an essential contributor to system power balance, then for contingencies that cause frequency changes to exceed the 0.6 Hz/s ROCOF benchmark, subsequent additional (ROCOF relay) tripping of distribution-connected wind capacity would clearly exacerbate the frequency excursion. The impact of relaxing distribution-connected wind power ROCOF relay protection settings (assuming alternative local islanding protection schemes could be devised) was thus considered as a possible frequency control mitigating step. Moving some wind generation from the distribution system to the transmission system would have a somewhat analogous effect, though at potentially greater infrastructural cost.

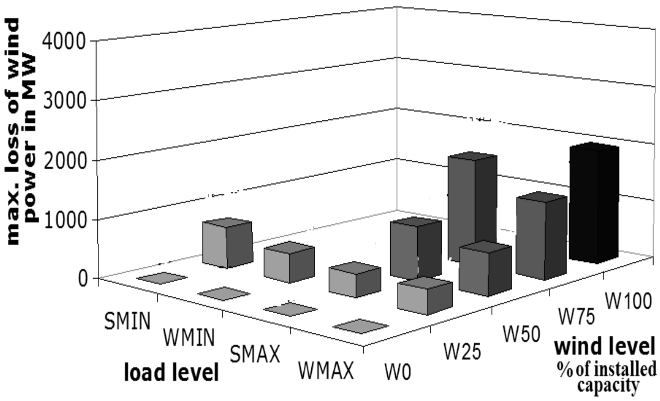


Fig. 3 – Maximum wind power contingency size following widespread voltage dip of 35% of nominal value

### 2) Wind Turbine Inertia Emulation

It is well known that variable speed wind turbines operate at variable speed primarily to enable smoother power capture from the wind. However, their ability to actively control speed also enables a speed reduction in response to a system frequency dip, and thus emulate the inherent inertial response displayed by conventional generators. Within the study, it was viewed to examine the benefit that inertia emulation might bring to the AIS with two scenarios examined:

1. 'base-case' scenario where wind generation provides no inertial response to the power system, and
2. wind generation provides an inertial response to the power system similar to synchronous generators.

While the actual inertial contribution of wind turbines at scale has not been proven in practice, examining both theoretical extremities allows the best and worst cases to be considered. When calculating the stored rotational energy of wind generators an inertial constant, $H$, of 3.5 s was assumed, which was combined with the total online wind generation in each scenario to arrive at the rotational energy contribution from system wind generation. This rotational energy was added to the rotational energy provided from conventional generation including a contribution from the load.

### 3) Additional Control Actions

The benefit of applying additional frequency control related dispatch constraints was also explored:

- Constraining a minimum amount of synchronous inertia to be online at all times (the equivalent of nine units of 150 MW size, and *H* constant of 4 s).
- Curtailing wind generation below its maximum availability in certain situations will reduce the wind-power-related contingency size for network faults, as well as allowing a frequency-responsive governor-type spinning reserve capability to be effected to aid system recovery.

## IV. Results

A simple operational metric was helpful in the analysis and reporting of results to reflect the range in operating conditions evaluated. The instantaneous system non-synchronous penetration ratio (SNSP) is defined as follows:

$$SNSP = \frac{P_{wind} + P_{HVDC(import)}}{P_{load} + P_{HVDC(export)}} \tag{1}$$

where, $P_{wind}$ refers to the system wind power, $P_{load}$ is the system demand, and $P_{HVDC(import)}$ and $P_{HVDC(export)}$ are the power imported / exported through HVDC interconnection.

### A. Impact of Wind Penetration on Synchronous Inertia

The effect of increasing instantaneous wind power output and the corresponding reduced level of synchronous inertia of the AIS is indicated by Fig. 4. While acknowledging that the load will have some inertial contribution, in addition to that of any dispatched synchronous units, Fig. 4 nevertheless highlights the radically different future system operating situations with respect to the projected 2020 generation portfolio.

### B. Conventional Contingencies at Ultra-High SNSP

The implications of reduced synchronous inertia can be clearly observed in Fig. 5. A higher SNSP will generally result in more extreme frequency deviations, from a secure operating range, if there is a contingency outage of a large conventional in-feed at the same time. However, a more detailed investigation of the conditions contributing to the particularly extreme frequency nadir deviations suggests some useful operational principles that could be introduced in future. Two common factors were found to primarily contribute to the worst cases in Fig. 5. Cases that had both relatively high wind power output and HVDC interconnection import levels were disproportionately represented in the worst case scenarios. In a ‘business-as-usual’ operational rules paradigm, reliance on a significant amount of non-synchronous generation to cover load balance will inevitably lead to more insecure frequency stability conditions. Future operational situations may lead to the need to constrain down the admissible wind energy or HVDC import level for system security reasons.

Even more prevalent to the most extreme frequency deviation conditions were those cases when the initial ROCOF measured at the instant of the generation in-feed trip was greater than -0.6 Hz/s. This led to the cascaded tripping of distribution system connected wind capacity, thereby severely compounding the magnitude of the initial generation/demand imbalance. As the frequency exceeded 49.3 Hz in all of these cases, then load shedding of at least some customer demand would likely have occurred in reality. As Fig. 5 suggests, however, when the distribution connected wind farm ROCOF relays were disabled (assuming that all other conventional generators could ride through the ROCOF values experienced), the frequency stability of the system was much improved.

### C. Voltage Disturbance Impacts at Ultra-High SNSP

The impact of network short circuit faults on frequency stability performance is evidently very significant from the illustrations of minimum nadir and maximum ROCOF in Fig. 6 and Fig. 7 respectively (for the worst case scenario of a fault causing a voltage dip of 35% over an extended area). ROCOF relay de-activation is again highlighted as a useful pre-emptive frequency control strategy. A comparison of Fig. 5 and Fig. 6 suggests some important effects. At lower SNSP levels, the most severe contingency remains as a conventional generation outage. However, at high wind power availability levels the impact of a widespread voltage disturbance on wind farm active power output could potentially be a more onerous constraint on the maximum permissible SNSP level. For the AIS (and similar systems) this would represent a fundamental change in the nature of the frequency instability risk.

### D. Combined Potential of Mitigation Strategies

From the trends evident in Fig. 5 and Fig. 6, a future AIS with high levels of instantaneous wind power output will be at significant risk of frequency instability with respect to generation outages and severe widespread network fault related voltage dips. Fig. 8 illustrates the combined potential benefit that wind inertia emulation and a resolution of distribution connected wind ROCOF protection relay issues could achieve when implemented in a complementary manner. If both mitigation strategies could be applied together, then the worst case frequency nadir values (from either a generation trip or network fault) could be maintained much closer to the desired safe operational region above 49 Hz, whereby involuntary load shedding is avoided. One caveat, however, is that the provision of reserve, and an inertial response, from wind generation is likely to be less effective than expected during severe network faults, when the ability of wind farms to export power is limited.

### E. Other Important Observations

For all 63 dispatch cases, it was possible to propose mitigation actions that avoid severe emergency conditions and limit load shedding to 5.9% of system demand (corresponding to the first stage of involuntary load shedding at 48.85 Hz). Controllable smart metering infrastructure could, however, allow such load tripping events, if they must occur, to be of a more customer-discretionary nature. Additional observations include:

- Disabling ROCOF protection relays was found to be the single most effective mitigation strategy, followed by the case of wind inertia emulation.
- Network faults which result in under frequency load shedding may further lead to high frequency events as wind turbines ride through and recover their output, particularly (but not conditionally) if ROCOF protection is deactivated.

- Shifting wind farms from the distribution system to the transmission level can improve the frequency nadir, particularly for higher SNSP levels.
- Implementing a wind curtailment and governor response also has a positive effect on frequency stability, at least in those cases when the frequency excursion is caused by a conventional generation trip. In the case of a network fault, its potential may be limited somewhat by the recovery and stability of voltage levels at affected wind farm buses
- Constraining the minimum number of conventional plant online was less effective than would have been expected.

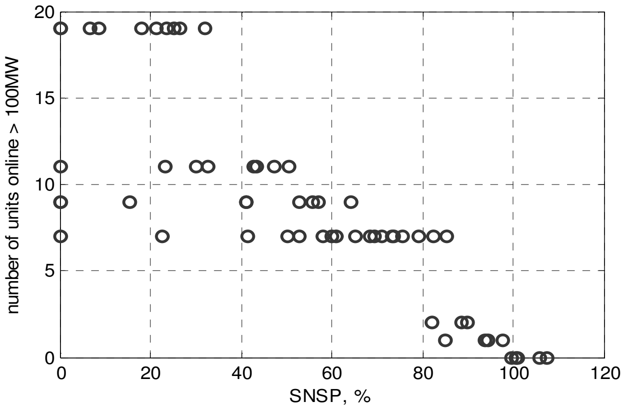


Fig. 4 – Number of conventional synchronous plants > 100 MW online with respect to instantaneous SNSP

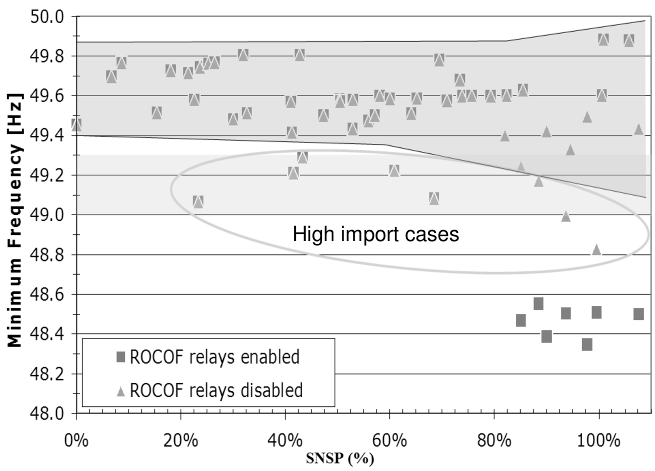


Fig. 5 – Frequency nadir with respect to SNSP for largest generation in-feed outage contingency – with distributed wind ROCOF relays enabled/disabled

## V. DISCUSSION

There are a myriad of issues arising from very high wind integration levels in small or isolated systems. Precise frequency control, however, is an issue of fundamental importance in conventional power system management, and at present would appear to represent a notable impediment to ultra-high instantaneous wind energy penetration levels. Wind development in small isolated synchronous areas, such as the AIS, often challenges fundamental power system operational constraints sooner than might be experienced in large synchronous interconnections. In some ways, the operational intricacies developed in these smaller systems to manage a low synchronous inertia system with very high non-synchronous generation levels may be akin to prototype strategies to other larger systems later. The fact that the case studies were performed here on a real power system scale only serves to accentuate the significance of the results.

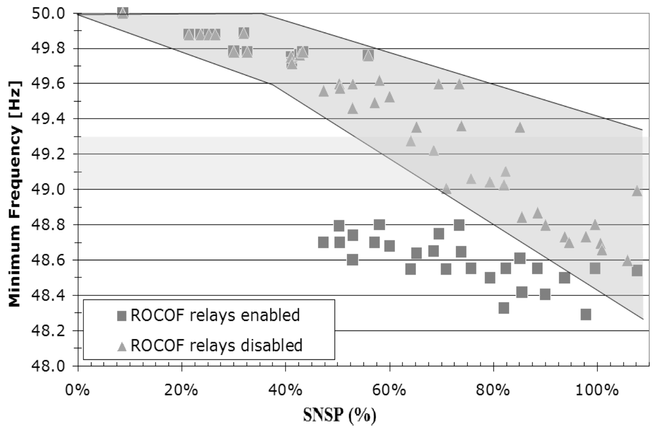


Fig. 6 – Impact of transient voltage disturbances (35% dip of nominal voltage) on frequency nadir

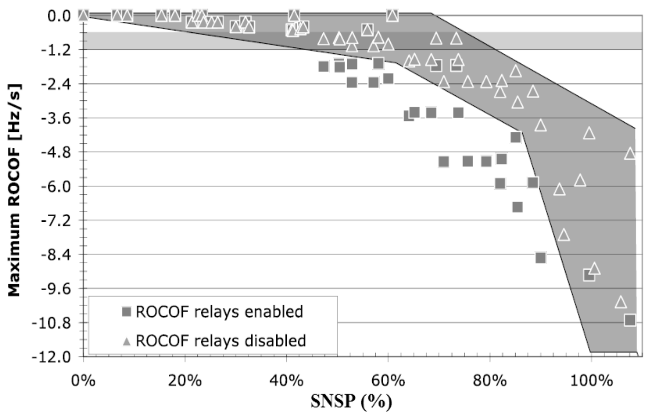


Fig. 7 – Corresponding impact of voltage disturbances (35% dip of nominal voltage) on maximum ROCOF

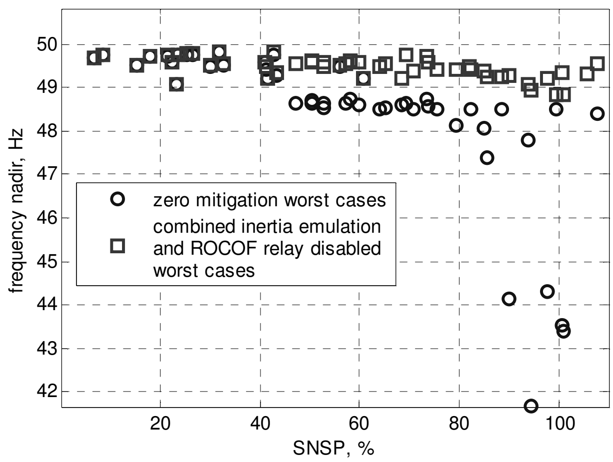


Fig. 8 – Potential benefits of combined wind inertia emulation and ROCOF relay relaxation on frequency nadir for different values of SNSP

A key outcome of this study is an understanding of the effect that instantaneously high wind power output has on the displacement of synchronous conventional plant in the economic dispatch, while coincidentally creating a situation where the magnitude of the worst-case power imbalances may be accentuated if caused by a voltage dip seen widely across the network. Furthermore, while greater interconnection using HVDC may be of appreciable benefit to general system economics and wind variability management, if it tends to displace local synchronous generation in the economic dispatch then it will exacerbate any frequency stability issues. Placing an operational limit on the maximum instantaneous non-synchronous generation level may have commercial implications for both wind power investment and for HVDC interconnection infrastructure cost recovery. An emerging and far-reaching topic for power systems that might approach levels of completely non-synchronous power supply in the decades ahead is whether the necessity for very precise synchronous frequency control would be as critical as it is now, and how system operational principles and market implementation might be impacted if it were not.

This study also provides an enhanced understanding of distribution system connected ROCOF protection relays and their influence on cascading generation outages following the type of severe frequency deviations to be expected in a low synchronous inertia system. A lower synchronous inertia system will inevitably experience greater initial ROCOF values, particularly if the initial power imbalance contingency may be higher than traditionally would be the case. Assuming all generation sources (both wind, HVDC and conventional) can physically cope with more extreme ROCOFs, then increased ROCOF relay thresholds must be set or alternative distribution islanding protection schemes, not based on ROCOF detection, may need to be developed to aid system frequency management. This is an important issue of co-operation that spans the traditional distinction between transmission and distribution system operator responsibilities.

The judicious use of the transient stability and single frequency models as a combined modeling approach is of course an approximation, but nevertheless allows exploration of the growing coincidence between network voltage and system frequency stability issues with high wind power penetration. While all dynamic models are approximations to some extent, the primacy of fault-related temporary wind generation interruptions on the future AIS frequency stability underlines the ongoing need for accurate frequency-responsive generic wind turbine models to be developed for commercial power system study tools. Only then can the post-fault voltage stability impacts of wind turbine inertia emulation and spinning reserve capabilities be fully understood. Conventional generation governor response capabilities (and indeed their simulation models) must also be precisely validated to ensure that their impact will be sufficient to arrest such severe ROCOFs and frequency deviations expected in the near future.

A further aspect for future modeling work is the requirement to efficiently account for geographic spatial diversity of wind power production in dynamic frequency stability studies, particularly for network-related issues such as the spatial spread of voltage dips that will increasingly contribute to worst-case frequency excursion contingencies. The 63 dispatch cases introduced in Section III-A implied a totally correlated wind power regime across the AIS, which is not an unreasonable assumption in such a small geographical area. Future work requires more granularity of wind resource cases considered, accounting for spatial wind power diversity with alternative deterministic case studies. Techniques introduced in [37] to analogously account for spatial wind power diversity while reducing the scale of optimized transmission access models may have promising application.

The results of this frequency analysis study have shown the challenging nature of ensuring safe, secure and reliable operation of the AIS in the near future. System operation with ultra-high SNSP levels is, of course, quite removed from traditional TSO operational experience, and much work must yet be completed to ensure that the mitigation strategies can actually be put into practice. EirGrid and SONI are now leading the DS3 (Delivering a Secure and Sustainable Electricity System) programme [38], with advanced modeling, planning and operation of the power system dynamic stability control strategy a key task underpinning the ambitious renewable energy integration targets set for the next decade.

## VI. Conclusions

This paper outlines the methods and results of a detailed industry-level technical study on ultra-high non-synchronous generation levels and their impact on dynamic system stability in an isolated synchronous-island area. While many power systems have proposed renewable energy targets they have largely been based on unit commitment based studies and assumed operational procedures: dynamic stability addresses have not been directly addressed. So, for example, the future Western Wind and Solar Integration Study (Phase 3) will introduce reliability and stability issues into its analysis. There are several key conclusions concerning the ultimate limits for the AIS and many other systems with high wind power targets:

1) At higher instantaneous non-synchronous generation penetrations, network faults, leading to a depressed system voltage and a reduced ability of wind farms to export power, are likely to represent a more severe frequency stability contingency compared to the traditional loss-of-the-largest conventional unit or interconnector. This represents a major step change in the risk to power system security.
2) De-activation of distribution-connected wind farm ROCOF relays, combined with wind turbine inertia emulation, was found to be the most influential alternative system control strategy to ensure mitigation of frequency stability risk at ultra-high non-synchronous generation levels.
3) Alternatives to ROCOF protection schemes for embedded generation, or modifications to existing protection devices, should be sought with some urgency.
4) Wind farms represent a potential source of governor droop and inertial response, although less so for severe network faults. Modeling effort, supported by ongoing demonstration trials [38], is required to fully understand the implications of widescale implementation of such technology.
5) Network faults can ultimately lead to over-frequency events, particularly if load shedding occurs, as affected wind turbines ride through the fault and recover their output.
6) Even with ultra-high instantaneous wind power penetration, a mitigation strategy (or combinations of) can be devised in the majority of operational situations encountered to prevent

emergency system frequency conditions, and limit customer load tripping to a reasonable level.

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## VIII. References

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