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<b>Authors(s)</b>	Ruttledge, Lisa, Flynn, Damian
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# System-wide Contribution to Frequency Response from Variable Speed Wind Turbines

Lisa Rutledge, *Student Member, IEEE* and Damian Flynn, *Senior Member, IEEE*

**Abstract**—Due to the differing electromechanical characteristics of modern variable speed wind turbines to conventional generators, the provision of ancillary services from wind generation is likely to change the nature of the frequency response of power systems to contingency events. This paper explores the aggregate contribution from wind turbines to the frequency response of future power systems, considering both emulated inertial and governor controls. In particular, the potential issues that may arise as a result of the changing nature of the system frequency response due to the uncertainty over the distribution of ancillary services from embedded generation on the network, are examined in the context of future power system requirements.

**Index Terms**— Frequency control, wind power generation, emulated inertial response, governor control.

## I. INTRODUCTION

In the coming years, synchronous generators along with the ancillary services they inherently contribute to power systems will be displaced as wind penetration levels increase on power systems worldwide. As a result, the dynamic characteristics of these systems, and hence the protocols for maintaining frequency control are changing [1]. One of the most prominent issues regarding the increased penetration of wind generation is its impact on short-term frequency stability following a contingency event, particularly on small isolated systems, which have naturally lower synchronous generation online and hence lower levels of ancillary services from conventional sources [2]. In the event of an imbalance between the generation and demand, the system frequency experiences a deviation and conventional generators respond to restore the frequency to nominal. The short-term frequency responsiveness of a generator can be characterised by its inertial response from the stored energy of the turbine rotor, which is inherently provided by synchronous generation, and the governor response achieved by changing the power set point. As more wind generation is incorporated onto the

system, the level of traditional sources of these ancillary services is depleted, thus potentially making future power systems more vulnerable to contingency events. Wind turbines, the majority of which operate at variable speed, can be configured to contribute a frequency response and hence improve the short-term flexibility of the system. Due to their differing electromechanical characteristics, however, these ancillary services are fundamentally different to those provided by synchronous generators.

In the context of these increasing concerns, many grid codes are being or have been adapted, requiring that wind turbines offer a partial solution to the uncertainty and variability they introduce, through the inclusion of control structures to provide frequency responses similar to those from conventional generators. The particular grid code requirements for wind turbines to contribute frequency support services vary depending on system size, wind penetration levels, synchronous generation levels and underlying plant portfolios. National Grid in the UK currently requires modern wind turbines to 'operate so as to provide primary response and/or secondary response and/or high frequency response' similar to that of conventional generators [3]. In Ireland, wind turbines are not currently required to contribute an emulated inertial response but must be capable of being curtailed and comply with a droop response characteristic specified by the system operator [4]. The European Network of Transmission System Operators for Electricity (ENTSO-E) are also considering that individual transmission system operators (TSOs) shall have the right to require a wind power generating facility to deliver an equivalent performance to conventional generation through an increase of active power related to the rate of change of frequency [5]. Hydro Quebec is currently the only system which requires an emulated inertial response capability from wind turbines. In addition to a response similar to the governor droop of conventional generators, wind turbines must be capable of providing an emulated inertial response equivalent to that of a synchronous machine with an inertial constant of 3.5 s for a period of 10 s [6]-[7]. Against this background, a number of wind turbine manufacturers have developed governor droop and emulated inertial response products to respond to significant frequency events [8]- [9].

Due to the geographical diversity and variability of wind farm outputs and the likely variation in the number of turbines online in systems with significant wind penetration levels, the potential for wind turbines to enhance the short term flexibility of the power system could vary greatly with different regional

L. Rutledge (lisa.rutledge@ucdconnect.ie) and D. Flynn (damian.flynn@ucd.ie) are both with the School of Electrical, Electronic and Communications Engineering, University College Dublin, Dublin, Ireland.

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weather patterns and implementation methods of frequency response control strategies. The resulting impact on factors such as conventional plant commitment, and, therefore, assessment of the system wide governor droop and inertial response capability becomes probabilistic in nature. The analysis carried out in this study examines the frequency response capability that could be relied upon in future power systems with high wind penetration levels, including wind generation with short-term frequency response capability. The frequency response capability of a projected Ireland and Northern Ireland 2020 system was considered as a test case in this study.

Section II describes the state of the art of emulated inertial and governor response capabilities of variable speed wind turbines and the potential system-wide consequences and issues related to harnessing an active power response from wind generators. Section III outlines some operational policies associated with high wind penetration levels and describes the unit commitment tool and dynamic power system model employed, as well as the assumptions made in assessing the frequency response capability of the combined Ireland and Northern Ireland system. Section IV illustrates the potential for variable speed wind turbines to contribute to system frequency response, in both high and low frequency events. Section V considers the implications of the results of this study on power system operation and suggests considerations which should be taken into account in the implementation of such control mechanisms in future systems, while Section VI highlights the conclusions of this work.

## II. FREQUENCY RESPONSE FROM WIND TURBINES

Modern variable speed wind turbines can be enabled to respond to changes in system frequency through the inclusion of supplementary control structures which allow the turbine to provide responses similar to the inertial and governor responses of conventional generation. However, due to fundamental differences in the operation of wind turbines and the uncertainty and variability associated with the wind energy resource, these response capabilities cannot be considered identical to those from synchronous generators.

Variable speed wind turbines are decoupled from the system frequency through power electronic converters and therefore do not contribute an inherent inertial response to sudden deviations in system frequency, as synchronous generators do. Such wind turbines can, however, be fitted with a control loop which can temporarily increase the torque set point and hence the power exported by the turbine to harness the stored energy of the rotor. A number of distinct control mechanisms have been proposed to create such a response which can broadly be split into those depending on an input proportional to the rate of change of frequency and those proportional to the deviation in frequency from nominal. Unlike conventional generators, this is an active control and is limited by the turbine rating as well as the converter limits. Below rated wind conditions, this emulated inertial response is followed by an energy recovery period as the energy donated during the initial event must be recouped, while above rated wind conditions, the blades can be pitched to harness

previously untapped energy, thus reducing or even eliminating the energy recovery period in such cases [10]- [11].

In order to provide a governor droop response, similar to that from conventional generators, wind turbines must first be curtailed so that some energy is held in reserve, thus spilling a certain portion of the available wind energy in normal operating conditions. The differing electromechanical characteristics of wind turbines from conventional generators can prove advantageous in over frequency events however, as, due to the decoupling of the rotor from the power system through power electronics, the wind turbine power can quickly be ramped down, thus providing a fast, effective frequency response. The droop characteristic of wind turbines is often intentionally asymmetric so as to take advantage of wind turbines' superior ability to reduce their output, in the case of an over frequency event [12]-[13]. The governor response capability of a wind turbine is dependent on the wind conditions present while the power set point is curtailed, the deadband applied to the frequency signal in the control loop, the amount by which the turbine has been curtailed and the droop response characteristic it follows. This response characteristic can be adjusted to meet specific grid code requirements.

Unlike conventional synchronous generators, the aggregate frequency response capabilities of wind generation are dependent on a number of stochastic variables, including regional wind speeds and the implementation of frequency response on wind turbines across the system. At very low power (15 to 20% of rated), in order to avoid rotor stall, wind turbines can neither provide an emulated inertial response nor be curtailed to provide a governor response. Above these low levels, the energy which can be delivered is dependent on the degree of their initial curtailment, the available wind power at the time of the event, the tuning of the inertial response control structure and the shape of the droop characteristic.

In a power system with synchronous generators only, a system dispatch is capable of determining those units that are connected, their output level and are therefore able to contribute to the frequency response of the system during a contingency event. However, assuming that wind generation is capable of contributing a frequency response, a system dispatch will not specify the exact number, or the loading, of wind turbines which can contribute to the frequency response of the system. If significant uncertainty exists over the active power response available on a system, at a time of high wind generation and low load, there is a risk of frequency excursions greater than normal. Assuming that variable speed wind turbines have an emulated inertial response capability, the number of wind turbines online is a key factor in determining the aggregate fast-acting frequency response capabilities of wind generation. Variable speed wind turbines can only contribute an emulated inertial response if operating above their minimum speed. Using 15 minute historical data from all metered wind farms in Ireland and Northern Ireland for 2009, Fig. 1 illustrates the proportion of variable speed wind turbines operating above a minimum operational speed, and thus are capable of contributing an emulated inertial response to the system, as a function of the system-wide wind generation [14]

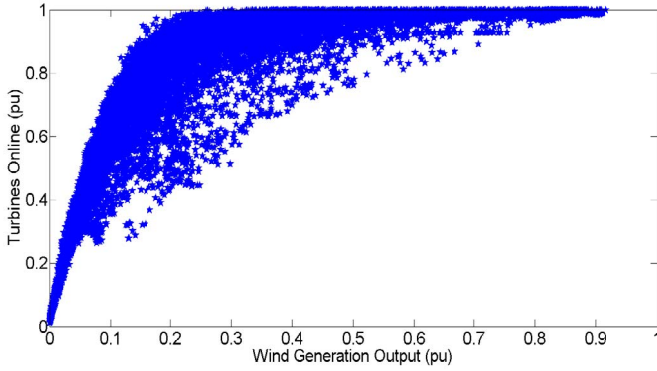


Fig. 1. Variable speed wind turbines operating above minimum speed

While the number of turbines online is relatively deterministic at very low and very high wind generation levels, at mid-range levels there is much less certainty. For example, at a generation level of 0.2 pu the number of turbines online may range from 0.4 pu to greater than 0.9 pu. The potentially large variation in the number of turbines online in the low and mid generation region of 0.05 pu to 0.6 pu, the most probable generation output range [14], highlights the uncertainty in the emulated inertial response which could be available to the system operator. This is further compounded by the fact that the available stored energy, which is therefore available to provide an emulated inertial response, will vary with wind speed. In addition, at certain times, wind may be curtailed or constrained, leading to further variations in the frequency response capability. In the case that wind generation is curtailed due to very high wind levels on the system, the aggregate governor response capability from wind is less vulnerable to such variability as most turbines are likely to be online and capable of contributing to the response. Fig. 2 demonstrates the impact that different distributions of the overall wind generation level may have on the aggregate frequency response capability of wind generation whereby the aggregated inertial response is obtained as the combination of the responses at different wind speed levels. A similar aggregated response is determined for the combined governor responses. As illustrated, the inertial response from fixed speed wind turbines (FSIGs) is independent of wind speed [15].

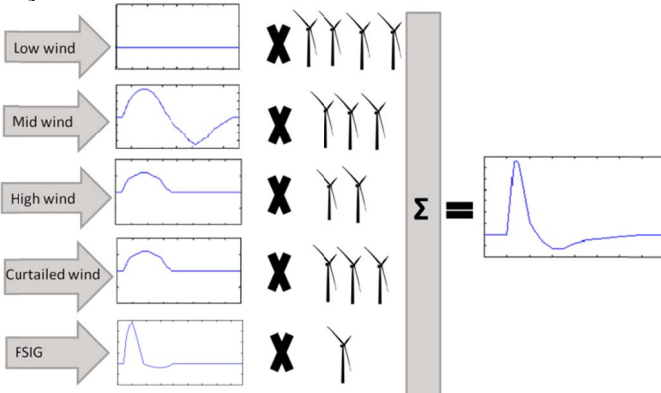


Fig. 2. Aggregate inertial frequency response from wind

In order to determine the aggregate frequency response capability of wind power, the system operator would need to be able to predict how many variable speed turbines are

operating above their minimum operating speed and so are capable of contributing a frequency response, as well as the operating conditions of the turbines online, and the potential depth and duration of any energy recovery period following the disturbance. While the energy recovery of a single wind turbine is not likely to impact the overall frequency response capability of the system, a large aggregate energy recovery following a contingency event could potentially result in a second frequency nadir, lower than the original.

### III. OPERATIONAL POLICIES AND SYSTEM MODELING

The combined Ireland and Northern Ireland system in 2020 was considered as an example in this study. The system currently has a peak demand of about 6955 MW, and comprises conventional generation (coal, gas and peat), a HVDC interconnector with Great Britain and approximately 1800 MW of wind generation. The largest generator on the system is 480 MW against a minimum demand of approximately 2500 MW. In 2008, in anticipation of the challenges facing power system operation with high wind penetrations, the Irish Governments commissioned the All Island Grid Study (AIGS) to examine the ability of the 2020 combined Ireland and Northern Ireland power system to handle various generation portfolios from renewable sources [16]. Subsequently, the Ireland government set a target of 40% of electricity to come from renewable sources by 2020 (37% from wind generation), which corresponds to approximately 6000 MW installed wind capacity, of which it is anticipated, 10% will be fixed speed and 90% will be variable speed wind turbines. Following on from the AIGS, the transmission system operators of Ireland and Northern Ireland conducted a comprehensive study to better understand the technical and operational implications associated with high shares of renewable energy, called the 'All Island TSO Facilitation of Renewables Studies' (FOR). The frequency, voltage, transient and small signal stability of the system were analyzed for a wide range of system demand, interconnection (import/export) and wind generation levels [17]. An important metric developed through the FOR studies was the system non-synchronous penetration (SNSP) ratio, defined as:

$$SNSP = (P_{wind} + P_{hvdc(import)}) / (P_{demand} + P_{hvdc(export)})$$

where,  $P_{wind}$  refers to the wind power on the system,  $P_{hvdc(import)}$  is the power imported through HVDC interconnection,  $P_{demand}$  is the system demand and  $P_{hvdc(export)}$  is power exported through HVDC. Currently, the maximum operational SNSP limit for the combined system is 50%. This threshold has been reached on a number of occasions in recent years, leading to wind curtailment at those times, although the overall energy reduction has been low. It is the intention of both TSOs to increase this instantaneous limit to 75% within the next decade through a sequence of planned steps [18].

#### A. Unit Commitment

In order to assess the impact of wind turbine active power controls on system performance, the Wilmar Planning Tool [19] was used to create a stochastic unit commitment for a

combined Ireland and Northern Ireland 2020 test power system. Wilmar is a stochastic, mixed integer unit commitment and economic dispatch model, originally developed to model the Nordic electricity system but later adapted to the combined Ireland and Northern Ireland system as part of the All Island Grid Study. There are two main branches to the Wilmar Planning Tool, namely the Scenario Tree Tool (STT) and the Scheduling Model. The STT, which represents possible future wind and load, generates the scenarios that are used in the Scheduling Model. Each branch of the scenario tree corresponds to a unique forecast of wind and load, and the probability of occurrence of that scenario. The Scheduling Model consists of a mixed integer, stochastic optimization model. The objective function being minimized is the expected cost of the system, including fuel costs, carbon costs and startup costs over the optimization period, covering all scenarios. It was assumed that a minimum of 8 units (5 units in Ireland and 3 units in Northern Ireland) must be kept online, in accordance with current system operational policies. The units included must provide network voltage support, fault level, etc. in addition to synchronous inertia and so open cycle gas turbines (OCGTs) and small scale hydro plants were not considered to contribute to this requirement. In line with the FOR studies, a maximum SNSP of 75% was permissible.

### B. Dynamic System Model

A dynamic model, developed in Matlab/Simulink, has been used to model the system frequency response of the 2020 Ireland and Northern Ireland combined system. It comprises of a single busbar model, consisting of dynamic models for each type of generating unit and a representative dynamic load model. The model incorporates all conventional generation on the system, comprising predominantly steam, OCGT and combined cycle gas turbine (CCGT) generators and two HVDC interconnectors to Great Britain. Static sources of reserve include pumped storage, HVDC interconnection, interruptible load and load shedding. This model has been validated and extended over many years and full details are available in [20]-[21]. The system is assumed to be in steady state at nominal frequency prior to an event on the system and the change in power output from each unit due to a frequency disturbance is calculated in the model components. The inertia of individual conventional generators, as well as load, are combined together to form a single inertia term, which then determines the rate of change of system frequency following a contingency event. This simplification is possible by assuming that the frequency at all points on the system is the same, and thus any change in inertial energy is seen uniformly throughout the network [20]-[21].

The model incorporates two separate dynamic models of wind generators, one based on fixed speed induction generators, FSIGs, and the other based on doubly fed induction generators, DFIGs. The DFIG wind turbines are fitted with an active control loop allowing them to contribute an emulated inertial response as well as a droop response [22]. All frequency responses from wind, including the inherent inertial response from FSIGs and the active control from DFIGs are fed through the model as changes in generation and do not contribute to the combined inertia value of the system. Recognizing that the frequency response of variable speed

wind turbines will vary depending on their operating conditions, models of DFIG wind turbines at varying operating conditions, incorporating emulated inertial response and governor droop control structures, were included in the system model. The system frequency is calculated by integrating the power imbalance between the load and generation, while taking the system inertia into account.

It is assumed that all conventional generators perform as expected (with a 4% governor droop) in accordance with the expectations in [18], islanding protection does not mal-operate following a generator trip, and wind generation is assumed to conform to grid code requirements. In line with [17], it is also assumed that transient stability, voltage stability, and network restrictions do not limit the instantaneous wind penetration.

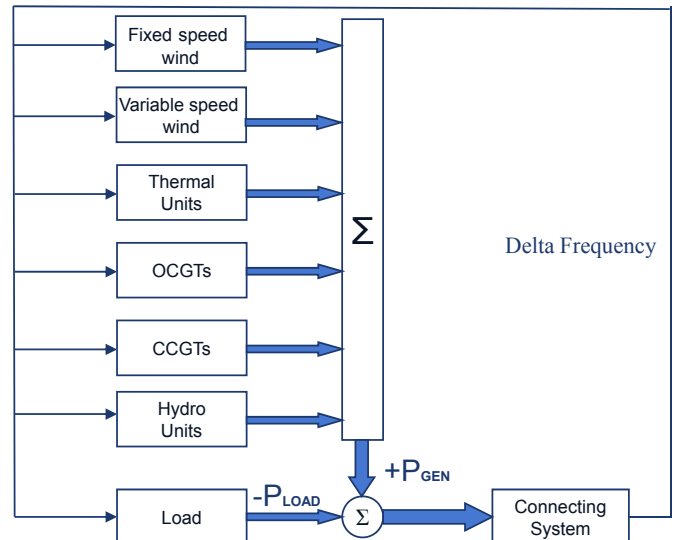


Fig. 3. Schematic of dynamic model

As implied by Fig. 1, for a given system-wide wind generation profile, power could be supplied by a small number of turbines operating at close to rated power or perhaps a large number of turbines at low output. Fig. 4 illustrates the potential difference in wind power from individual variable speed wind turbines for a wind generation level of 0.25 pu, for a low and high number of turbines online, based on analysis of 2009 wind data. It should be noted that turbines included in the bin between 0 and 0.1 pu represent all those not capable of contributing an inertial response, including turbines not generating, while those included in the bin above 0.99 pu represent those operating at rated power. It was assumed here that only turbines operating above 0.3 pu were capable of contributing a governor response as curtailing turbines at such low power set points could force them towards stall conditions. In the case when a low number of turbines are contributing to the overall system wind generation, the proportion of those turbines operating at high generating levels ( $> 0.7$  pu) is greater (approx. 0.06 pu) compared to the case when a high number of turbines are contributing to the overall wind power (approx. 0.02 pu). In the latter case, more turbines are seen to operate at mid-generation levels.

Distributions of the number of turbines operating at different wind generation levels, similar to that in Fig. 4, were determined and then applied to the 2020 test system model to represent the aggregate system wind profile. The responses

from variable speed and fixed speed wind turbines on the system were examined for two different wind distribution scenarios assuming a high and low number of turbines online contributing to the overall generation output and capable of contributing a frequency response. A similar methodology was employed to model the number of fixed speed wind turbines (FSIGs) online, less the minimum speed requirement, assuming a 10% penetration of FSIGs within the wind generation fleet.

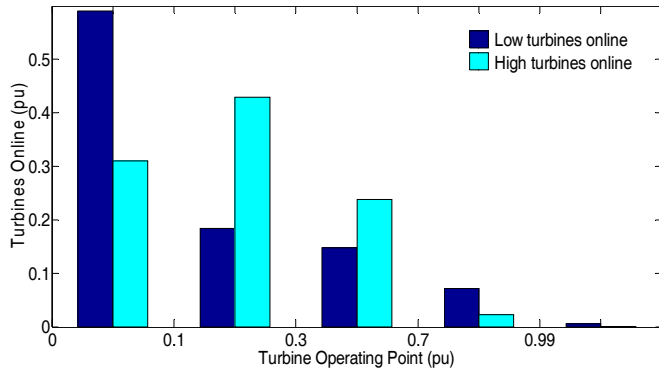


Fig. 4. WTG operating point distribution for wind generation level of 0.25 pu

As illustrated in Fig. 5, the stochastic economic dispatch conducted through Wilmar resulted in numerous instances during the year when the wind available on the 2020 test system would cause the 75% SNSP limit to be exceeded and wind production is therefore curtailed at these times. In these cases it is assumed that all DFIG wind turbines operating above 0.3 pu are curtailed by the same proportion of their operating point.

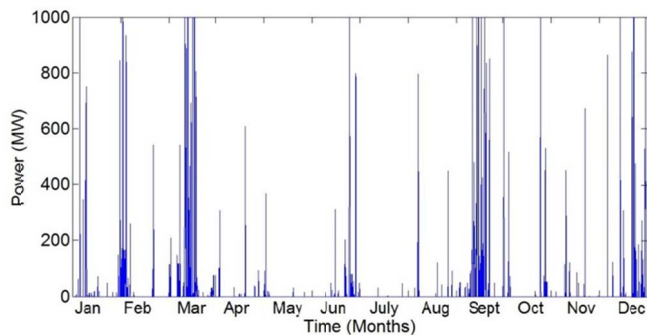


Fig. 5. Wind curtailed on test system

Drop values for wind turbines ranging between 2% and 8%, based on available power, were considered for both over and under frequency events. An example of one of the droop response characteristics considered is illustrated in Fig. 6. The droop characteristic resembles that of a conventional generator, including a high frequency cut off point to protect the system from exceedingly high frequencies and a deadband to limit the response to significant frequency deviations only.

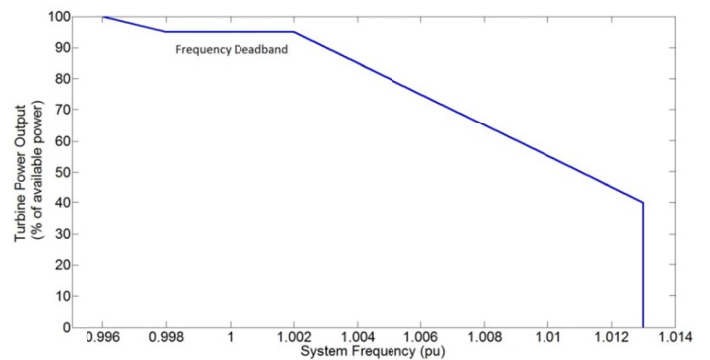


Fig. 6. Representative wind droop characteristic

It should be noted that, unlike the droop response of conventional generators which is based on the unit rating, the droop characteristic of variable speed wind turbines is typically based on the active power available from wind at the time of the event [4]. As a result, the effective droop of a wind turbine, i.e. equivalent to that of a conventional generator of the same rating, may vary considerably with wind conditions, as illustrated in Fig. 7. For a turbine operating at 0.2 pu with a 4% droop based on the wind power available, the effective droop of an equivalent conventional generator is actually 20%, based on the wind turbine rating. Thus, for a given system frequency deviation, turbines operating at higher outputs contribute more energy than those at low operating levels.

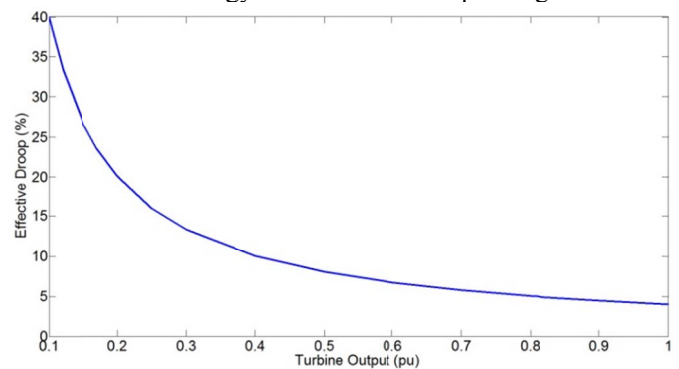


Fig. 7. Effective wind turbine droop as a function of unit output

#### IV. SYSTEM FREQUENCY RESPONSE

Due to reduced levels of synchronous inertia, the system frequency response of the test system to a contingency event is likely to vary substantially, depending on the aggregate response provided from wind generation.

##### A. Under Frequency Response

Fig. 8 illustrates the distribution of the frequency nadir over the 2020 year assuming a contingency event of the loss of the largest single infeed at every hour of the year, both including and excluding an emulated inertial response capability from wind generation. The system dispatch is based on the unit commitment outlined in the previous section. In the case including wind generation with an inertial response capability, the lower of the two frequency nadirs (high and low number of turbine distributions) is plotted in each case. The three peaks in both traces are due to the tripping of static reserve sources at these thresholds. When the system frequency falls below

49.6 Hz and 49.5 Hz, 50 MW static reserve is released from the HVDC interconnection on the system. The impact of the emulated inertial response is to shift the distribution to the right, raising the frequency nadir, and greatly reducing the number of instances when interruptible load is activated (threshold at 49.3 Hz).

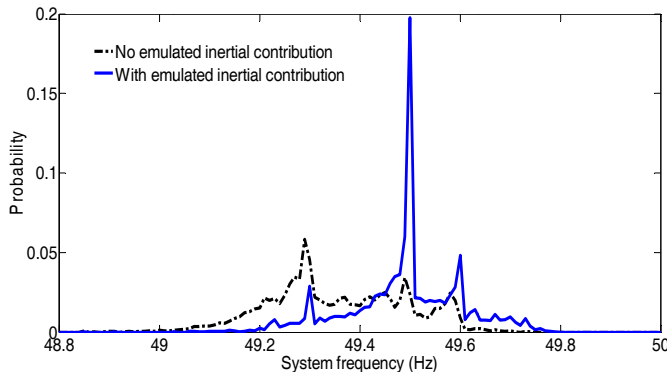


Fig. 8. Frequency nadir distribution

While the effect of the emulated inertial response characteristic is to improve the system frequency nadir, the extent to which this occurs is dependent on a number of other variables. For example, the frequency nadir and recovery of the system frequency varies with the number of turbines on the system capable of contributing an emulated inertial response and their operating conditions. Fig. 9 illustrates the frequency response of the system to the loss of the largest generating infeed on the system at that time, of 443 MW, with a demand of 5401 MW, an SNSP of 28%, HVDC import of 752 MW and wind generation of 776 MW. In this case, the system frequency drops to 49.48 Hz after approximately 5 s and begins to recover following the tripping of the second static reserve threshold frequency (49.5 Hz). However, assuming an inertial response capability from all wind turbines on the island, only one of these threshold values is now exceeded (at 49.6 Hz). While the frequency nadir is improved by the inclusion of the emulated inertial response, the initial rate of change of frequency remains unaffected and the recovery of the frequency to steady state is somewhat delayed due to the energy recovery period associated with the emulated inertial response and the fact that less static reserve has been activated.

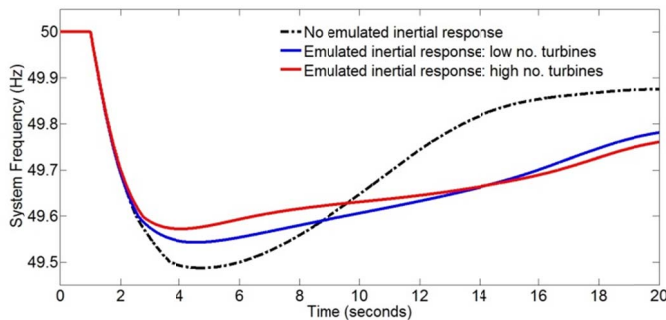


Fig. 9. Frequency response: mid-level load, mid-level SNSP

It can also be observed that when the response from wind is obtained from a large number of turbines online, the nadir is better than when fewer turbines are contributing to the response. While the nadir is improved in the former case, the recovery is slightly slower due to the deeper aggregate

recovery period associated with more turbines operating below rated speed and fewer operating above rated.

The case represented in Fig. 10 and Fig. 11 has a demand of 4420 MW plus a 1000 MW export, an SNSP of 72%, 4254 MW available wind generation of which 465 MW is curtailed, with all online turbines curtailed in equal proportion of their output. In Fig. 10, the frequency response of the system is illustrated assuming an emulated inertial response capability from the system. Two sub cases were considered in this scenario: in one, wind is curtailed such that the curtailed energy enables an enhanced inertial response with reduces the energy recovery period and, in the second, wind is not curtailed whereby wind power is limited to 4254 MW but the untapped wind energy is not utilised, resulting in a larger energy recovery period. It can be observed that, while both scenarios improve the frequency nadir, in the absence of curtailment the initial frequency recovery is followed by a deeper second dip due to the energy recovery phase of the wind turbines. When the curtailment of wind turbines across the system is considered, however, this frequency dip is reduced as the energy recovery phase of the curtailed wind turbines is eliminated.

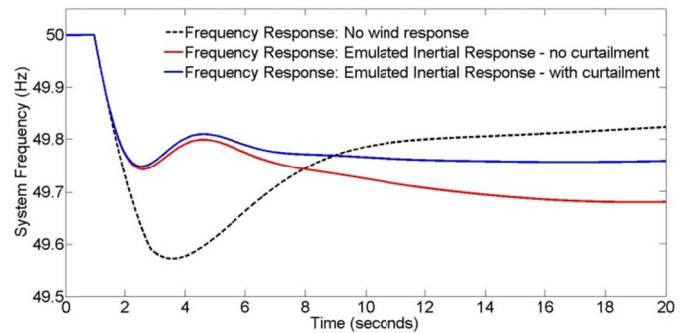


Fig. 10. Frequency response: mid-level load, high SNSP

The frequency response of the system with emulated inertial control is compared to that when wind also incorporates a governor response (4% and 8% droop considered) in Fig. 11. It can be observed that the double dip in frequency, which systems with high wind penetration levels contributing an emulated inertial response can be particularly vulnerable to, can be avoided by the inclusion of a governor response capability, assuming sufficient untapped wind energy.

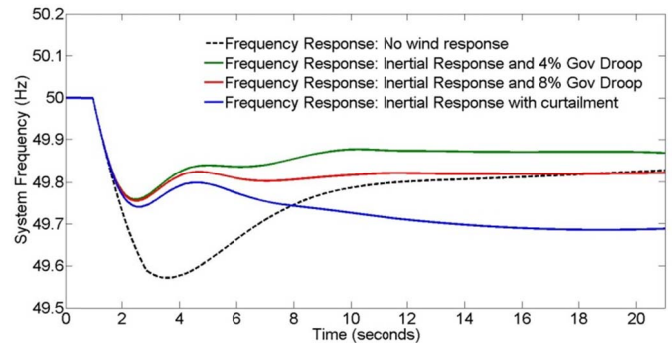


Fig. 11. Frequency response: mid-level load, high SNSP

### B. Over Frequency Response

While the loss of the largest infeed has traditionally been the contingency event of most concern on small isolated power systems, like Ireland, increased interconnection levels

could potentially result in significant over frequency events due to the loss of an exporting interconnector. It should be noted that on small systems with high wind generation levels power would be exported at high wind penetrations and thus conventional generators would be close to their minimum output. As a result, high frequency reserve would need to be scheduled to guard against the loss of major loads, including exporting interconnectors. In such cases the downward governor response capability of wind can act to prevent over frequency trip thresholds from being activated. Fig. 12 illustrates the frequency response of the system with a demand of 4015 MW, an SNSP of 51%, 1000 MW HVDC export and 2513 MW from wind generation, for the loss of a 500 MW export. It can be observed that while conventional plant on the system provide some over frequency reserve, as illustrated in Fig. 12, the response can be significantly improved by the inclusion of a governor response from wind.

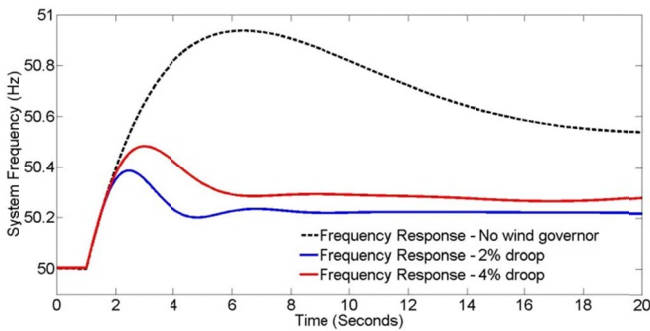


Fig. 12. Frequency response to loss of largest load: high export, mid SNSP

In order to achieve the 75% SNSP objective on the 2020 power system a number of operational issues will have to be resolved. These include confirmation of adequate conventional generator reserve performance and proven controllability from wind farms including frequency response, fault ride through capability and reactive power provision. In addition, the Ireland Grid Code, at present, only requires all generation to remain connected to the system for rates of change of frequency (ROCOF) less than 0.5 Hz/s. For rates of change of frequency greater than this threshold the stability and performance of individual units must be considered uncertain. Due to the high proportion of wind connected at the distribution level (approximately 50%), anti-islanding protection exists in the form of ROCOF relays with a threshold value of 0.55 Hz/s. As a result, for a significant contingency event causing a significant ROCOF, a large proportion of the wind generation could trip, thus exacerbating any initial contingency, potentially leading to a cascade event. In addition to the system frequency, the dynamic model of the Ireland and Northern Ireland system also outputs the rate of change of frequency following a system imbalance. Fig. 13 illustrates the maximum rate of change of system frequency which was experienced by the test system and unit commitment described in Section III following loss of the largest single infeed or loss of the largest load for every hour in the test system dispatch, as a function of wind generation level. It can be observed that, for an under-frequency contingency event, the maximum rate of change of system frequency experienced exceeds -0.5 Hz/s in less than 7% of

cases and -0.55 Hz/s in just over 1% of cases. In the case of an over frequency excursion following the loss of the largest load the respective figures are 9.31% and 2.17%. While the proposed methods of frequency response from wind generation could potentially improve the nadir or zenith of a frequency deviation, these capabilities, relying on active controls do not currently compare with the ability of synchronous inertia to reduce initial rates of change of frequency. In order for the system to operate securely with high SNSP, those cases when the system ROCOF is at risk of exceeding these thresholds should be identified and operational strategies to prevent such scenarios should be introduced [18].

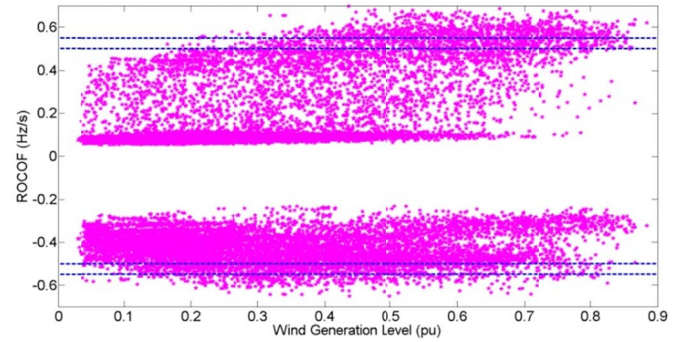


Fig. 13. ROCOF as a function of wind generation level

## V. DISCUSSION

The frequency response characteristics shown in the previous section demonstrate that the short-term frequency response capability of future power systems, with both inertial and governor controls, will vary with a number of stochastic variables, with possible implications for the manner in which such systems are operated. While active power controls on wind turbines can improve wind turbine responsiveness to system under-frequency and over-frequency events, considerable uncertainty exists over the aggregate response available to the system due to the potential variability of the wind generation profile. This implies that even if wind turbines are configured to contribute an active power response in the case of a frequency deviation from nominal, the nature of that capability may vary due to wind turbines operating across a range of wind speeds and varying degrees of curtailment and governor droop responsiveness. Although the emulated inertial response ultimately relies on the stored energy of the rotor, it may be more appropriate to describe the such a response from DFIGs as being a tunable 'fast-acting' response, as distinct from synchronous inertia which inherently increases the stiffness of the system. A prudent system operator may, therefore, wish to distinguish between the two categories, particularly during periods of low system inertia and /or high SNSP. While a system dispatch and enhanced load modeling will identify the inertia of the system, regional wind forecasting could play a pivotal role in quantifying the emulated inertial response capability of wind generation on the system and how it may change in the near future as the geographical wind profile changes.

Variable speed wind turbines offer the opportunity to tune or shape the frequency response to suit the dynamic response requirements of a particular system, such as delaying the time to minimum frequency or improving the frequency nadir. It is vital that both the emulated inertial response and governor droop response of wind turbines are appropriately tuned for the system they are connected to, particularly at high wind penetration levels [13]. For example, in the absence of curtailment, attempting to enhance the magnitude of the inertial response may actually result in a deeper or extended energy recovery phase which could potentially lead to a second frequency dip, lower than the original transient. As such, in advance of wind controls being required through the grid code or incentivized through a market mechanism it is advisable that a system operator carefully analyzes its own system's specific dynamics in order to optimize the tunable response from wind. Similarly, the balance between droop and emulated inertial response requirements in the development of frequency control strategies for individual systems should be carefully considered in light of the overall system dynamics.

In conjunction with the uncertainty surrounding the obtained inertial and governor responses, increased reliance on active control, involving the detection of significant frequency deviations and communication of control requests within multi-turbine wind farms will affect the reliability of providing a frequency response service. Consequently, a prudent system operator may wish to balance wind turbine frequency capabilities against those obtainable from conventional generation sources. It should also be noted that a reduction in synchronous inertia due to increased wind penetration levels will result in a higher initial rate of change of frequency following a contingency event. Consequently, on small isolated systems, like Ireland, it is more challenging for the introduction of frequency response capability in wind turbines to improve the initial system ROCOF due to the high speed of such transients on small systems.

## VI. CONCLUSION

The short term flexibility of power systems have traditionally been governed by ancillary services provided by conventional generators and static sources only. As wind power continues to increase its share in the plant portfolio, the nature of the frequency response of the system will evolve. In turn, system operators must adapt their methods of quantifying this capability on future systems with high wind penetration levels. The frequency response capability of systems including wind turbines with emulated inertial response and governor droop response are likely to exhibit uncertainty due to variations in regional wind conditions, synchronous generation and load portfolios, as well as non-synchronous penetration levels. While many system operators are currently investigating the role that wind generation should play in frequency control, a prudent operator should consider the potential for profiling the geographical distribution and dynamic nature of aggregate wind generation in the assessment of the frequency response capability of the system. Additionally, it should be ensured that the implementation of any such active controls from wind generation respond synergistically with the rest of the dynamic system.

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