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Frequency Response of Power Systems with Variable Speed Wind Turbines

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***Abstract*— As wind penetration levels on power systems increase worldwide and synchronous generation is displaced, the dynamic characteristics of these systems, and hence the protocols for how they are operated, are changing. One issue, of particular concern, is the resulting reduction in system inertia since modern variable speed wind turbines do not inherently contribute to the inertial response of the system. Such devices can, however, be fitted with a control loop which provides an active power response to significant frequency deviations, similar to the inertial response of fixed speed wind turbines and synchronous generation. Unlike conventional machines, however, the response of variable speed turbines is dependent on local wind speeds and so cannot be quantified deterministically by system operators. As a result, it is likely that uncertainty will exist over the inertial response capability of the system at high wind penetration levels. In this paper the frequency response capability is assessed on a test system and the effectiveness of wind turbines' contribution to system inertial response is evaluated in the context of future system requirements.**

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

I. Introduction

As wind penetration levels increase on power systems worldwide, conventional generators, along with the inherent ancillary services they contribute will be displaced while the system requirement for such support services grows, due to the increased variability on the system [1]. One of the more prominent concerns regarding the increased penetration of wind power, particularly on island systems, is its impact on frequency stability [2]-[4]. Immediately following a contingency event, the system frequency will fall at a rate dependent on the combined inertia of connected generators and loads. Synchronous generators and fixed speed wind turbines (FSIGs) intrinsically contribute to power system inertia. However, this does not occur with the addition of variable speed wind turbines due to their differing electromechanical characteristics [5]. Direct drive (DD) and doubly fed induction generator (DFIG) wind turbines are not electrically coupled to the system frequency due to their power electronic control mechanisms. While variable speed wind turbines do not inherently contribute to the system inertial response, the torque set-point of such machines can be modified by an input dependent on system frequency to extract stored rotational energy from the turbine, creating an emulated inertial response for a time period in the order of 10 s [6]-[8]. 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 [9]-[10] and those proportional to the deviation in frequency from nominal [11].

In light of concerns for the operation of systems with high wind penetration levels many grid codes are being adapted, requiring that wind turbines offer a partial solution to the uncertainty they introduce [12]-[13]. The specific grid code requirements of different systems for frequency support from wind power plant are likely to vary depending on the system dynamics due to varying wind penetration levels, synchronous generation levels and underlying plant portfolios. For example, in the Hydro Quebec system it is required that, in the case of a significant frequency deviation, wind turbines provide an active power response equivalent to that of a synchronous machine with an inertial constant of 3.5 s for a period of 10 s. 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 by an increase of active power related to the rate of change of frequency [14]. Against this background, a number of wind turbine manufacturers have developed emulated inertial response products to respond to significant frequency events. While implementation strategies differ between manufacturers, inertial response controls can be implemented which cause the power output of a wind turbine to temporarily increase in the range of 5 to 10% of the rated turbine power, following a significant under-frequency excursion [15]-[17].

In systems with significant wind penetration levels, due to the geographical diversity and variability of wind farm outputs and the variation in the number of turbines online, the combined stored rotational energy of variable speed wind turbines could vary greatly with different regional weather patterns. The resulting impact on conventional plant

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commitment, and, therefore, assessment of the system inertial response capability becomes probabilistic in nature. While it is noted that an emulated inertial response is only available when wind is contributing to the system generation portfolio and that other technologies, such as flywheel energy storage, may also contribute to the fast acting frequency response in future power systems, these isues are not considered in this paper [18]. The analysis carried out in this study examines the frequency response capability that could be relied upon with high wind penetration levels, including wind generation incorporating an emulated inertial response capability. The frequency response capability of a projected Ireland and Northern Ireland 2020 system was considered as a test case here. Section II describes a series of full-scale field tests which were performed at an operating wind plant to test control function performance. Section III describes the potential system-wide consequences and issues related to harnessing an inertial response from wind generators, while Section IV highlights the potential synchronous inertia available on future power systems. Section V describes the dynamic power system model employed and assumptions made in assessing the frequency response capability of the combined Ireland and Northern Ireland system. Section VI highlights the results and illustrates the potential for variable speed wind turbines to contribute to system frequency response. Section VII considers the implications of the study's results on power system operation, and Section VIII summarises the conclusions of this work.

II. Modeling Emulated Inertial Control

Unlike conventional synchronous generators, the emulated inertial response of a wind turbine is dependent on a number of stochastic variables. The resultant response from a wind turbine is a function of the wind speed, but this is unlikely to remain constant during the transient period following a significant frequency deviation. Additionally, due to the priority given to the load management functions of the wind turbine control, the inertial behaviour is also dependent on the wind turbulence and mechanical states of the drive train and tower. For example, an individual turbine might transiently be running at a speed greater than the steady-state condition associated with a particular power level, because of a gust, at exactly the time that a grid event occurs. Under this condition, the power delivered in the immediate post-event time-frame would be greater than that for a steadier wind condition. Therefore, the inertial performance of an individual wind turbine is significantly stochastic in practice. However, a valid indication of the aggregate inertial performance of a wind farm, composed of many turbines equipped with an emulated inertial response control, each experiencing slightly different wind speed and turbulence conditions, may be obtained from the averaged response of many trials on an individual turbine.

As the emulated inertial response performance of variable speed wind turbines is dominated by control, rather than Park's equations, substantial variations in performance are thus possible, depending on system design. As an example, the control performance of the inertial response control product, GE WindINERTIA™ is considered, based upon a series of full-scale tests performed at an operating wind plant with GE wind turbines. It should be noted that the actual control characteristics will vary to a certain degree with different specific commercial products, however, many of the concepts remain relevant across a broad range of emulated inertial response designs. While some approaches operate at a wind farm level, this design is fitted at the turbine level. The control philosophy of WindINERTIA is to sense significant grid frequency depressions, as observed at the terminals of individual wind turbine generators (WTGs) [19]. A deadband suppresses the controller response until the deviation exceeds a threshold, which limits the response to large events only.

Given that it is not feasible to alter the frequency of a large grid in order to perform field testing, a secondary injection testing technique was used whereby an artificial frequency deviation was imposed on the input control. Fig. 1 shows the averaged inertial control response of a tested wind turbine. A total of 141 trials were performed, with results grouped into wind speed buckets near 5, 8, 10, 11.5 and 14 m/s. This performance is for a specific set of tuned control parameters which have been found to provide superior performance, in terms of improved frequency nadir, when displacing MW-for-MW the inertia of conventional machines [19]. The controls can be made more or less aggressive, depending on the control objective and specific system details, subject to the physical limitations of the wind turbine.

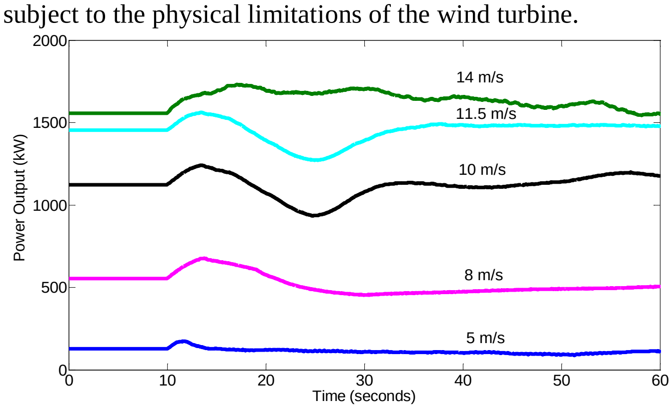

Fig. 1. WindINERTIA Field Test Results

At very low power (15 to 20% of rated), in order to avoid rotor stall, very little stored rotational energy can be made available to the system from wind turbines. Above these low levels, the energy which can be delivered is, on average, relatively independent of wind speed - roughly 0.5 MJ/MW of turbine rating in the first 10 s. A key aspect of the aero-mechanical rating of a wind turbine is its maximum mechanical loading. Below rated wind speed, the emulated inertial response is followed by an energy recovery period, meaning that the power output of the turbine is temporarily reduced below the original operating point. While the energy recovery of a single wind turbine is not likely to impact the overall frequency response of a power system to an event, a large aggregated energy recovery following a contingency event could potentially result in a second frequency nadir, lower than the original. When the wind speed is greater than rated, the turbine controls reduce lift by decreasing the angle of attack through pitch control. Under these conditions, the available wind power is greater than the rating of the turbine and it is possible to increase the captured wind power, using pitch control, to temporarily exceed the steady-state rating. Thus, at higher wind speeds, say 14 m/s, turbines with an emulated inertial response capability can transiently provide extra power for frequency response through pitch control - increasing wind power to the rotor, rather than only extracting stored inertial energy by slowing the rotor. Similarly, if wind power has been curtailed in the period before the contingency event, more energy can be exported to the grid from curtailed turbines without subsequently requiring a recovery period. Under these conditions, the decline in rotor speed is reduced and the energy recovery period is minimal.

III. Aggregate Inertial Response from WTGs

System inertia is a crucially important parameter in small and synchronously isolated power systems, since the largest infeed may represent a significant fraction of the generation capacity online. As an example, the combined Ireland and Northern Ireland system currently has a peak demand of about 6800 MW, and comprises conventional generation (coal, gas and peat), a HVDC interconnector with Great Britain and approximately 2000 MW of wind generation. The largest generator on the system is 500 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 [20]. Subsequently, the Ireland government set a target of 40% of electricity to come from renewable sources by 2020 (37% from wind generation). 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 analysed for a wide range of system demand, interconnection (import/export) and wind generation levels [21]. 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, $P_{hvdc(import)/(export)}$ is the power imported/ exported through HVDC interconnection and P_{demand} is the system demand. 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. Both TSOs intend to increase this instantaneous limit to 75% within the next decade through a sequence of planned steps [22].

In a power system with synchronous generators only, a system dispatch is capable of determining those units that are connected, spinning and therefore contributing to the stored energy of the system. 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 system stored energy resource. If significant uncertainty exists over the stored inertial energy available at a time of low synchronous inertia on the system, 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. 2 illustrates the proportion of variable speed wind turbines operating above their 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 [23].

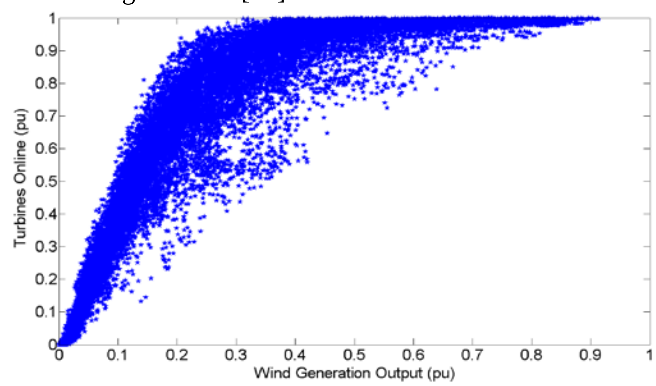

Fig. 2. Variable speed wind turbines operating above minimum speed

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 0.25 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 [23], highlights the uncertainty in the emulated inertial response which could be available. This is further compounded by the fact that the available stored energy will vary with wind speed while, at certain times, wind may be curtailed or constrained, leading to further variations in inertial response capability. In order to determine the aggregate inertial response capability of wind power, the system operator would need to be able to predict how many variable speed wind turbines are operating above their minimum operating speed and so are capable of contributing an inertial response, as well as the operating condition of those turbines online and the potential depth and duration of the energy recovery period following the disturbance.

Currently, on the combined Ireland and Northern Ireland power system, if the frequency drops to 49.3 Hz interruptible load will activate. It can be calculated that conventional generators will contribute approximately 3% of their stored energy for a change in steady state system frequency from 50 Hz to 49.3 Hz. In [23], it was shown that if wind turbines were to contribute similarly, the estimated stored energy from wind generation could vary by almost 40% of the minimum inertial response capability requirement of the combined system. This range is equivalent to the inertial contribution of over 3 medium-sized conventional generating units, resulting in considerable uncertainty over the frequency response capability of a system with significant wind generation levels.

IV. SYSTEM SYNCHRONOUS INERTIA

In order to assess the impact of emulated inertial controls on system performance, the Wilmar Planning Tool [24] 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, carbon and startup costs over the optimization period, covering all scenarios.

A. Minimum Synchronous Inertia Constraint

The synchronous inertia on the test system was investigated under the assumption 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. Fig. 3 illustrates the maximum and minimum daily values of synchronous inertia for the test system. Traditionally, power systems in temperate climates in the northern hemisphere would experience their minimum inertia levels in July and August when the demand is low, however it can be seen that the issue of low synchronous inertia is likely to be relevant at all times of year**,** at instances when the demand is low, HVDC imports are high and/or wind generation is high.

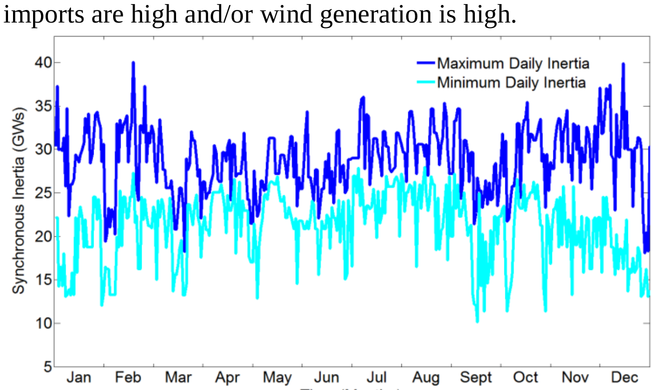

Fig. 3. Maximum/minimum daily synchronous inertia on 2020 test system

As wind displaces conventional generation, synchronous inertia on the system will reduce. Fig. 4 illustrates the synchronous inertia duration curves for the combined Ireland and Northern Ireland system in 2009 and the projected 2020 case, which is in general agreement with [22]. While system wide synchronous inertia forms a similar characteristic in both years, the magnitude of the synchronous inertia is greatly reduced in the 2020 case, despite an increased demand to 7550 MW. Large amounts of synchronous inertia are displaced as a result of increased wind generation from 1500 to 6000 MW and an additional 500 MW of HVDC interconnection. It is clear that any fast-acting frequency response capability supplied by wind turbines, or other sources, is likely to play a key role in maintaining acceptable inertia levels in future power systems.

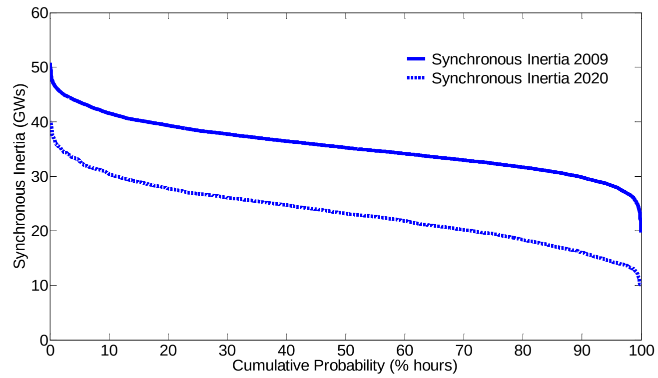

Fig. 4. Synchronous inertia duration curves for the combined system

B. Operational Issues on Systems with Reduced Inertia

In order to achieve the 75% SNSP objective 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. Beyond this threshold the stability and performance of individual units must be considered uncertain. Due to the high proportion of wind generation connected at the distribution level (approx. 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 and potentially leading to a cascade event. Fig. 5 illustrates the maximum rate of change of system frequency which would be seen by ROCOF relays following the loss of the largest single infeed for every hour in the test system dispatch, including the potential loss of a HVDC link, as a function of the wind generation level. These calculations were determined using the single bus model of the test system as described in Section V. It can be observed that 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 order for the system to operate securely with an SNSP of 75%, 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 [22].

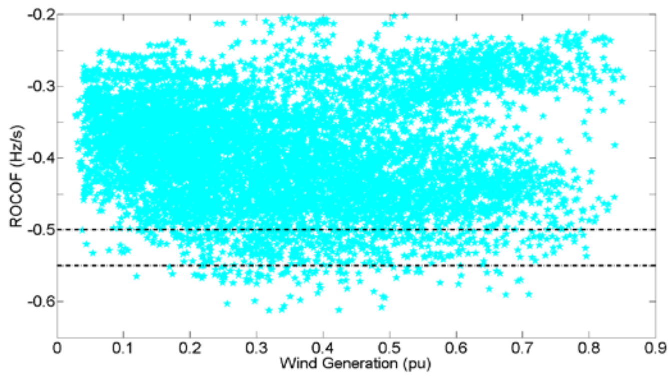

Fig. 5. ROCOF as a function of wind generation level

V. Single Bus Model

A dynamic model, developed in Simulink, has been used to model the system frequency response of the 2020 Ireland and Northern Ireland combined system. It incorporates all conventional generation on the system, comprising predominantly steam, OCGT and combined cycle gas turbine (CCGT) generators, two HVDC interconnectors to Great Britain, fixed speed wind turbines and variable speed wind generation, with and without an inertial response capability. Static sources of reserve include pumped storage, HVDC interconnection, interruptible load and load shedding. The model has been validated and extended over many years and full details are available in [25]-[26]. It is assumed that all conventional generators perform as expected (with 4% governor droop) in accordance with the expectations in [22], islanding protection does not mal-operate following a generator trip, and wind generation is assumed to conform to grid code requirements. In line with [21], it is also assumed that transient stability, voltage stability, and network restrictions do not limit the instantaneous wind penetration. The system frequency, assumed uniform across the system, is used as an input to generator and load models and is calculated by integration of the power imbalance between generation and demand.

Recognizing that the emulated inertial response of variable speed wind turbines will vary depending on their operating conditions, models of DFIG wind turbines at varying operating conditions, incorporating a control structure similar to that of GE WindINERTIA were employed [27]. As implied by Fig. 2, 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. 6 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 operating at levels capable of contributing an emulated inertial response, 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. 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. 6, were determined and then applied to the 2020 test system model to represent the aggregate system wind profile. The response of variable speed wind turbines was 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 an emulated inertial response. A similar methodology was employed to model the number of FSIGs online, less the minimum speed requirement, assuming a 10% penetration of FSIGs within the wind generation fleet.

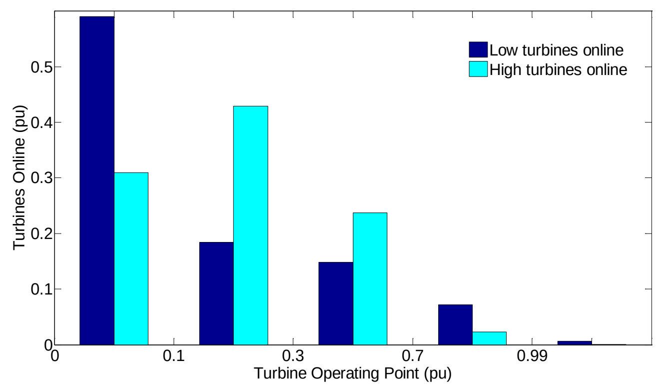

Fig. 6. WTG operating point distribution for wind generation level of 0.25 pu

VI. System Frequency Response

The system frequency response of the test system to a contingency event is likely to vary depending on the response provided from wind generation, due to the reduced levels of synchronous inertia. Fig. 7 illustrates the distribution of the frequency nadir over the 2020 year period 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. In the case including wind generation with an inertial response capability, the lower of the two frequency nadirs (high and low wind turbine distributions) is plotted for each case. It should be noted that an initial frequency of 50 Hz was assumed for these scenarios. In reality, the pre-event frequency would vary around 50 Hz, resulting in a slightly different frequency nadir distribution. 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. 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). 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.

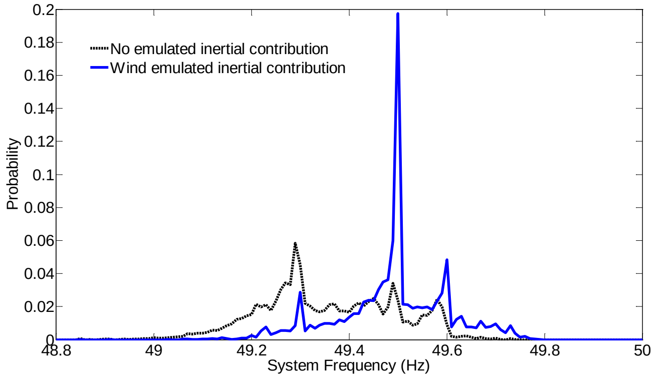

Fig. 7. Frequency nadir distribution

Fig. 8 illustrates the frequency response of the system to the loss of the largest generating infeed on the system at that time, of 443 MW (as is the case for the following two scenarios), 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 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. 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.

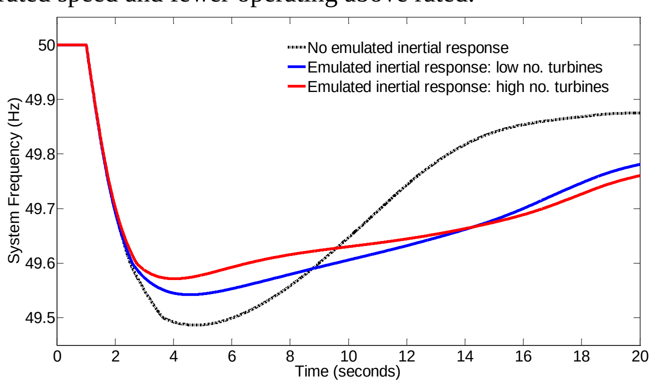

Fig. 8. Frequency response: mid-level load, mid-level SNSP

At higher wind penetration levels the impact of the emulated inertial response becomes more pronounced. Fig. 9 illustrates the system frequency response for a demand of 6079 MW, an SNSP of 63%, 1000 MW HVDC export and wind generation of 4440 MW. In this case, without an emulated inertial response from wind, the frequency drops through the first two static reserve thresholds. When emulated inertial control is included for all variable speed wind turbines the nadir is greatly improved from 49.31 Hz to 49.55 Hz. The shape of the frequency recovery is somewhat different in this case as, while the emulated inertial response contribution increases with wind penetration, so too does the depth of the recovery of the aggregate wind response, leading to a double dip scenario. As a result the minimum frequency following the loss of the largest infeed occurs 21 seconds subsequent to the event, during the wind turbine energy recovery phase.

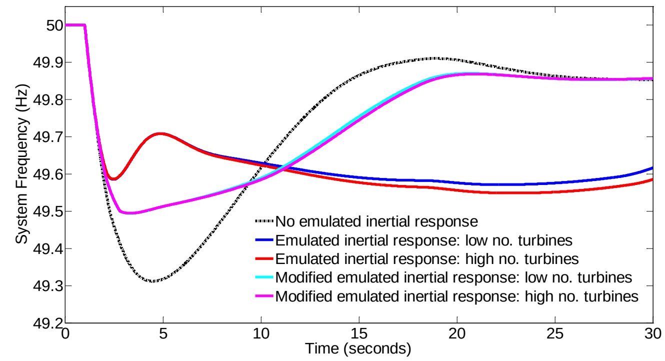

Fig. 9. Frequency response: high-level load, high SNSP

While it may intuitively seem desirable to maximize the emulated inertial response as is physically possible from variable speed wind turbines, on small, isolated systems with high wind penetrations, a more damped response may be more suitable. If the emulated inertial control is modified, as illustrated in Fig. 10, to reduce the response contributed by each turbine, and hence reduce the depth of the recovery phase the double dip phenomenon can be avoided whilst still improving the frequency nadir from the no wind contribution case. It should also be noted that the wind generation in this case is high as a proportion of the total installed capacity (0.74 pu). Therefore, in agreement with Fig. 2, the range of variability in the number of turbines online is low, thus minimizing the difference between the system response for different wind distributions. The difference seen in the steady-state frequency reached depends on whether or not the 49.5 Hz static reserve threshold has been breached.

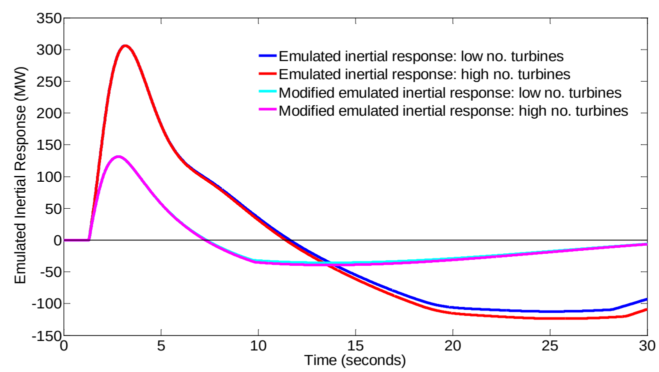

Fig. 10. Emulated inertial responses: high-level load, high SNSP

Another method of reducing the impact of the energy recovery phase is to reduce the number of turbines equipped with an emulated inertial response capability. In the case illustrated in Fig. 11 the system demand is 5588 MW, the SNSP is 70%, 1000 MW HVDC export and the wind contribution is 4634 MW, and cases are considered when

100%, and only 50%, of wind turbines are fitted with emulated inertial response control. Without an emulated inertial response from wind generation the frequency passes through three static reserve thresholds to 49.27 Hz. When only 50% of turbines on the island contribute an inertial response, the initial frequency nadir is not improved to the same degree as if all turbines were contributing, however, the subsequent recovery of the frequency is improved due to the reduced energy recovery phase. It can also be observed in the 100% case that, for both the low and high number of turbines, the system frequency briefly recovers at approximately 12 s before beginning to fall again. In both scenarios when the 49.5 Hz threshold is reached, 50 MW of static reserve is released. However, the subsequent frequency rise only brings forward the energy recovery phase of the combined turbine response.

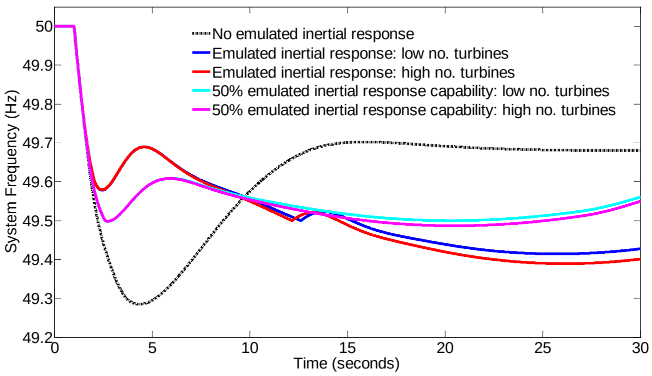

Fig. 11. Frequency response: mid-level load, very high SNSP

VII. Discussion

Given that the frequency response capability of future power systems will vary with a number of stochastic variables, as seen in the previous section, there are likely to be implications for the way such systems are operated. While emulated inertial response controls on individual wind turbines or wind farms can improve the minimum frequency reached following the loss of the largest infeed, uncertainty remains over the aggregate response available to the system due to variations in the number of turbines contributing to the response and the individual operating conditions of those turbines. Even for a given wind speed, the response of two identical turbines may vary depending on wind turbulence and the mechanical states of the drive train and tower, and so it is difficult to accurately predict. The implication is that even if wind turbines are fitted with an emulated inertial response capability that capability may vary greatly in magnitude in systems with high wind penetration levels, due to wind turbines operating at a range of wind speeds, including those that have been curtailed.

Unlike synchronous machines, variable speed wind turbines offer the opportunity to tune or shape the inertial response to suit the dynamic response requirements of a particular system, such as increasing the time to minimum frequency or improving the frequency nadir. It is important that the emulated inertial response of wind turbines is appropriately tuned to improve the total system response and ensure that it is not diminished by their addition. For example, attempting to enhance the inertial response by making it as large as physically possible may result in a deeper or extended energy recovery phase which could potentially lead to a secondary frequency dip, potentially lower than the original transient [13]. The energy recovery phase occurs as turbines attempt to recover to the optimal rotor speed for the given wind condition. Consequently, the emulated inertial response from wind turbines operating below rated is slightly net energy negative, since turbine speed is perturbed from optimal. The energy recovery of synchronous machines is tied to the system frequency, thus their stored energy is only reclaimed when the frequency has fully recovered to nominal. Wind turbines operating above rated, or in a curtailed state may also act as net energy contributors, as their blades can be pitched to access a previously untapped resource.

While the inertial response from a synchronous machine is a passive process relying on the fact that its rotational speed, and hence stored energy is synchronized to the system frequency, the response from variable speed wind turbines is active in nature, requiring a measurement of system frequency, or ROCOF, before a response is activated. Although the response ultimately relies on the stored energy of the rotor, it may be more appropriate to describe the emulated inertial response from DFIGs as being a tunable 'fast-acting' response. A prudent system operator may, therefore, wish to distinguish between the two categories, particularly during periods of low system inertia and/or high SNSP. Regional wind forecasting could play a 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.

Results here suggest that there could be limited occasions when the rate of change of frequency exceeds the current thresholds of 0.5 Hz/s for generation and 0.55 Hz/s for anti-islanding relays. However, the simulation results assume uniform system frequency across the network, ideal generator behavior and correct operation of anti-islanding protection relays. Measurement of the rate of change of frequency is not straightforward in a noisy environment, and mal-operation of relays is inevitable, with devices from individual manufacturers likely to display different operational behavior. Since the emulated inertial response will contain an activation deadband it is challenging for approaches based on frequency deviation to reduce the maximum ROCOF seen, although the frequency nadir can be noticeably improved, as illustrated in Section VI. It has also been assumed here that the worst case scenario follows from loss of the largest system infeed, but network faults may actually result in larger temporary generation-demand imbalances at high wind penetration levels [21]. In addition, the load has been modeled with a fixed inertial constant, and a fixed sensitivity to frequency deviations. In reality, both quantities will likely vary with time of day and time of year [28], which may alter the frequency response, particularly during periods of low synchronous inertia. While an emulated inertial response from wind generation has only been considered here, active power governor controls can offer further support to the system frequency following a contingency event if wind output has been previously curtailed. As variable speed wind turbines are decoupled from the system frequency, a very fast acting droop response could also offer effective amelioration of ROCOF and maximum frequency during an over frequency event.

The nature of the inertial response capability of power systems with high wind penetration levels is likely to be very dependent on the framework of individual systems for ensuring adequate system ancillary services. While retrofitting of existing wind turbines with an emulated inertial response capability may be technically possible, the number of turbines with this capability in future power systems will be dependent on the financial incentives or penalty structures in place for the system in question. If an emulated inertial response is introduced as a grid code requirement for new wind farms, it is highly unlikely that such an investment would be made for existing wind farms. However, if the capability is provided through an ancillary services market, depending on the incentives defined for fast acting frequency response capability, the aggregate system response capability may be higher.

VIII. Conclusion

Traditionally, system inertia has only been viewed as a concern at particular times of the year, and only for small and/or isolated systems. However, if high wind penetrations are assumed, low inertia periods may result at any time of the year, i.e. low demand, high wind or high HVDC import, depending on any seasonal correlation between system demand and wind generation output. The inertial response capability of systems including wind turbines incorporating an emulated inertial response are likely to exhibit significant uncertainty due to variations in regional wind conditions, synchronous generation and load portfolios. As a result, when considering the frequency response capability of a system with variable speed wind generation, a prudent operator should consider the potential for detailed profiling of the geographical distribution of turbine technologies, local wind forecasts and load dynamics in addition to the conventional plant portfolio.

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