THE IMPACT OF WIND FARMS WITH FIXED SPEED INDUCTION GENERATORS ON GRID DAMPING IN NORTHERN IRELAND

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Abstract – The study reported in this paper was prompted by a discovery that oscillations at the output of a Fixed Speed Induction Generator (FSIG) farm in Northern Ireland power system can reach about 6-10% of the farm output. The oscillations were mostly due to 1P and 3P effects. The analysis was performed by detailed time and frequency-domain modelling of the NIE power system with the Republic of Ireland power system represented by an equivalent generator. The study found that fixed-speed induction generators were interacting with the dynamics of the power system and were shown to have a negative influence on the stability. The results indicate that 1P and 3P oscillation may interact with system modes, and especially the inter-area mode. As long as the system modes are well damped, 1P and 3P effects should not present a significant risk. However if the system is subject to a periodic force at a frequency that is close to a mode that is marginally stable, the effect could be significant.

Keywords: Power system dynamic stability, wind power generation

1 INTRODUCTION

Wind power is increasing its penetration in modern powers systems and therefore studying the effects it has on power system characteristics is of utmost importance. Wind generators are predominantly of two types: Fixed Speed Induction Generators (FSIG) and Double Fed Induction Generators (DFIG). The former are simpler and therefore cheaper while the latter offer better energy capture and better control characteristics. This paper concentrates on FSIG. Although the share of FSIG is decreasing relative to other wind power technologies, FSIG still constitute a significant proportion of installed wind generators worldwide.

It is well known that the output of a wind turbine dips when a blade passes the tower, due to the wind shadow created by the tower. Furthermore, there is a slight rise in power as a blade sweeps the top part of the cycle, where the wind speed is highest due to the windshear effect. For a typical turbine with three blades those effects occurs with frequency proportional to triple the rotational speed and they are therefore referred to as 3P oscillation. There is additionally so-called 1P oscillation which occurs with the frequency corresponding to the rotational speed and it is related to the static and dynamic imbalance of the turbine [11]. Static imbalance relates to the centre of mass not being coincident with the centre of rotation in the plane of the disk. Dynamic imbalance comes from angular momentum vector not being aligned with the axis of rotation due to blade centres of mass not being in a plane perpendicular to the axis of rotation.

1P and 3P oscillations tend to be quite small. According to [1], 1P pulsations were between 1 kW and 3 kW for a 180 kW single wind turbine while 3P pulsations were about 1 kW. According to [2], the maximum pulsations were only about 0.4% of the steady-state torque. On the other hand [3] reported that the amplitude of 1P oscillations, and its multiples, could be as high as about 20% of output for a single isolated FSIG with cases of unstable operation when the oscillations were close to 100% of the output. In the latter case the oscillation frequency was lower than 1P. Another paper reported 3P fluctuations reaching 10% for a two-machine windfarm [4].

Generally 1P/3P oscillations present no problem in DFIG farm as they can be filtered out by the DFIG control system. Even though FSIG has no such controls, 1P and 3P oscillations tend to be smoothed in larger FSIG windfarms with many turbines due to a random relationship between the angles of turbines in a windfarm. The momentary dips are therefore randomly distributed, and the combined effect of oscillations from the whole farm is a lesser proportion of the windfarm output than it would be in the case for an individual turbine. Assuming that the individual oscillations are uncorrelated, the overall effect can be expressed as:

$$\Delta P_{wf} = \sqrt{\sum_{i=1}^{N} \Delta P_{wt,i}^{2}} \tag{1}$$

where ΔP_{wf} is the amplitude of wind farm oscillations, $\Delta P_{wt,i}$ is the amplitude of individual wind turbine oscillations and n is the number of turbines in the farm.

The study reported here was prompted by a report [5] that oscillations at the output of FSIG farm with 20 turbines in Northern Ireland Electricity (NIE) power system can reach about 6-10% of the farm output, see Fig. 1. NIE power system has a relatively large proportion of wind generation connected and there is a grid code requirement that the low frequency spectral content of the active power injected by a windfarm should be less than 1% of the power level. Observations of low frequency power oscillations at a windfarm approaching 10% were therefore unexpected.

There were also recorded instances of undamped oscillations at the Tandragee interconnector between Northern Ireland and the Republic of Ireland – see Fig. 2. Those results indicate that the system could be small-signal unstable (i.e. it could exhibit negative damping) as it was experiencing limit-cycling oscillations. The large-signal stability was maintained because the oscillation amplitude was limited by non-linear characteristics of the system. If this was indeed the situation, there was some risk to the system, as controllers were not operating as they were designed. There is also a possibility that the stable limit cycles can be overtaken by unstable limit cycles and grow to a much larger amplitude [12]. It is therefore of interest to understand what is causing or influencing this behaviour, either to ensure that the problem does not escalate or to resolve the underlying issues by design.

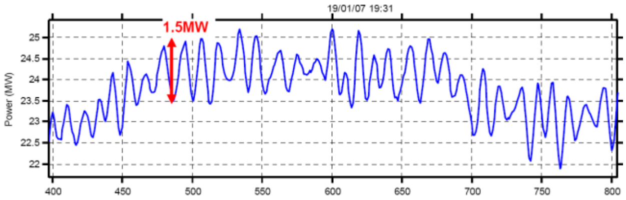


Fig. 1 Example of oscillations at a wind farm output. Time samples on x-axis are at 10 Hz.

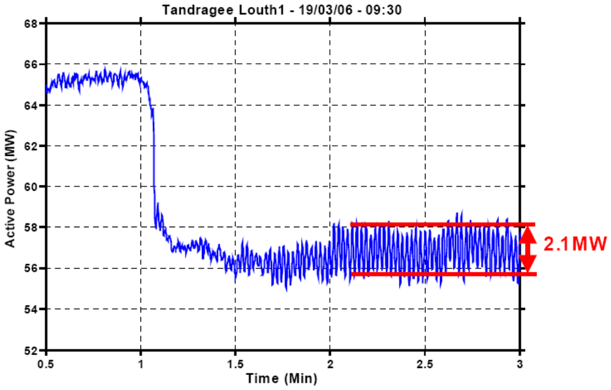


Fig. 2 Example of undamped oscillations in interconnector power flow.

Influence of wind farms equipped with FSIG on system stability has been investigated by many authors. It is well-known that FSIG are coupled to the grid less stiffly than synchronous generators [6] hence any variations in the prime mover input are attenuated before appearing as variations in the output power. Torque changes in an induction machine are related directly to speed changes. Hence torque variations produced are largely in phase with speed variations providing natural damping [7] with the result that FSIG based wind farms can contribute significantly to grid damping [8]. [9] confirmed that view and additionally reported that the impact of wind generators on intra-area oscillations is not significant and that wind power itself does not induce new oscillatory modes.

This paper does not challenge the general view that FSIG exhibit inherently better damping that synchronous generators but shows that under certain specific conditions FSIG based wind farms may actually have detrimental effect on grid damping. 1P and 3P effects may interact with system modes resulting in undamped or poorly damped oscillations explaining the observed 6-10% oscillations at the wind farm output power.

The analysis was performed by detailed modelling of the NIE power system. Both eigenvalue analysis using a linear power system model and non-linear time-domain simulation was attempted. The results indicate that 1P and 3P oscillation may interact with system modes. As long as the system modes are well damped, 1P and 3P effects should not present a significant risk. However if the system is subject to a periodic force at a frequency that is close to a mode that is marginally stable, the effect could be significant.

2 NORTHERN IRELAND ELECTRICITY POWER SYSTEM AND ITS MONITORING

The Northern Ireland power system is relatively small, with the installed capacity of about 2 GW and a 275 kV AC interconnection at Tandragee to the Republic of Ireland (ROI) and a DC interconnection to the Great Britain (GB) system. In 2008, the installed wind power capacity was 168 MW and minimum demand was around 550 MW. During periods of low load, wind power can supply a large proportion of the load, although in practice there are operational rules to ensure that a certain amount of conventional generation runs for stability reasons. This small system provides a very useful reference for wind power penetration issues that could well arise in future elsewhere in the world.

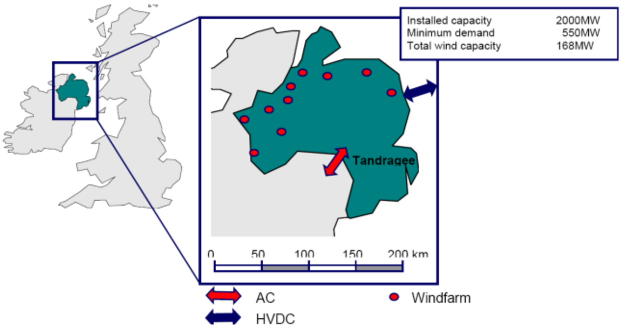


Fig. 3 Windfarm and interconnector locations in NIE power system.

The NIE power system was monitored using phasor measurement units (PMU) installed at the interconnector between NEI and ROI at Tandragee, and two of the windfarms shown in Fig. 3. In this paper only one dual-speed FSIG-based farm is considered. For reasons of confidentiality this farm will be referred to as Farm A.

The measurements were acquired by a system installed and operated by Queens University Belfast (QUB) for research purposes. The devices used were Hathaway IDM disturbance recorders with GPS time stamping and phasor measurement capability, and these were installed with Hathaway Local Storage Units (LSU) to capture a 2-week buffer of data.

Since there was no high-speed data links available at the time of the project, it was necessary to acquire data either by GSM modem or by physical access to the site. This meant that there was a practical limit to the volume of data that could be retained for analysis. Consequently, it was not possible to obtain simultaneous data at the windfarms and interconnector for periods of particular interest. Nevertheless, analysis of the available data provided valuable insights of the long-term dynamic performance of the system that was useful for identifying periods of degraded damping, and developing and validating a dynamic model.

3 RESULTS OF DYNAMICS ANALYSIS OF NIE DATA

The data acquired from the monitors in the NIE system was processed using proprietary methods, developed by Psymetrix Ltd [10], to extract the frequency, amplitude, phase shift and damping of the dominant modes of from continuous measurements of a signal (power, frequency or voltage angle), as illustrated in Fig. 4. The changes in the signal are assumed to be from small perturbations of the system due to random load variations.

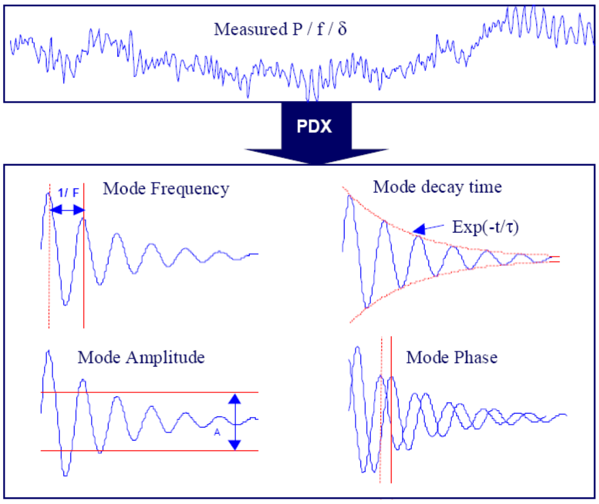


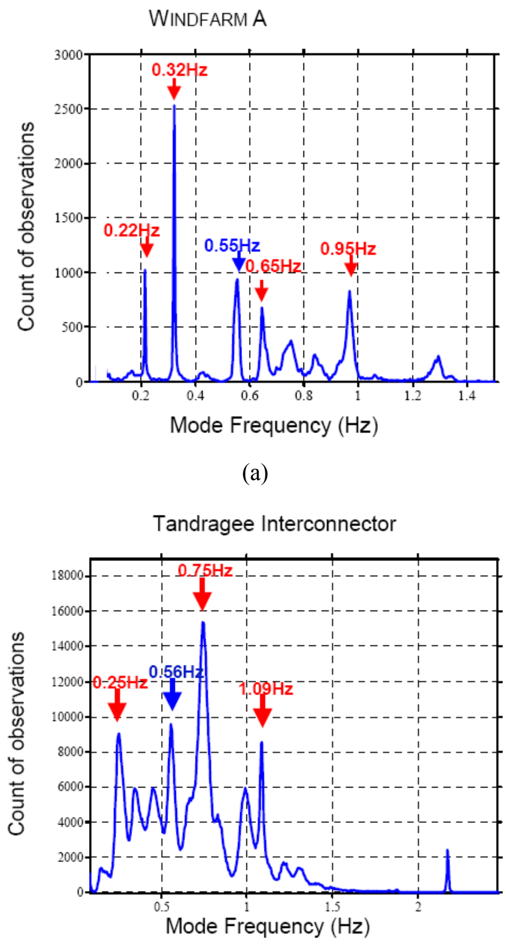
Fig. 4 Illustration of Psymetrix' Power Dynamics Extraction (PDX) method

Table 1 Modes excited by wind turbine

	Rotational frequency (1P)	Blade-passing frequency (3P)
Low gear ratio (low wind speed)	0.22 Hz	0.66 Hz
High gear ratio (high wind speed)	0.32 Hz	0.96 Hz

The dynamics analysis applied to the Northern Ireland data revealed the patterns of modes observable at the interconnector and windfarm A. Table 1 shows the expected modes due to 1P and 3P effects while Fig. 4 shows the actual dominant modes at each location. At windfarm A, both 1P and 3P modes are clearly seen. There is also a system mode seen at 0.55 Hz and indication of a mode at around 0.75 Hz.

At the Tandragee interconnector, there are four modes clearly observable, including modes at 0.56 Hz and 0.75 Hz. There are also modes at 0.25 Hz, 1.09 Hz and a smaller peak around 0.95 Hz.



(a)

(b)

Fig. 5 Histograms of observed mode frequencies at: (a) windfarm A ; and (b) Tandragee Interconnector

There is therefore an evidence of interaction between the system modes and the windfarm as the modes of 0.55 Hz, 0.75 Hz and 0.95 Hz can be seen both at the interconnector and at windfarm A. This observation suggests that the windfarm is participating in system oscillations at these mode frequencies. Conclusive proof that the oscillations observed at the two locations are part of the same mode would be possible with continuous storage of synchronised data, but unfortunately this was not available.

The results of the oscillation damping analysis are summarised in Fig. 6 showing colour-coded instances of poorly damped oscillations. The interarea mode is clearly seen at around 0.75 Hz. It is regularly observed with decay time greater than 10 seconds, and on occasion it is significantly more resonant. The mode at 0.55 Hz can also be seen, and is particularly poorly damped on one occasion in July.

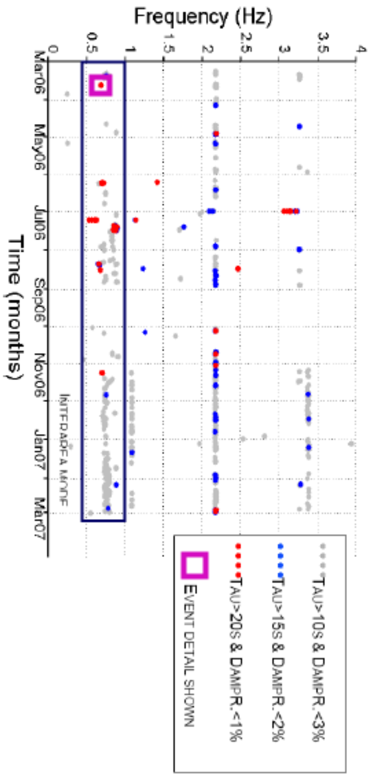


Fig. 6 Mode frequencies and damping observed at the interconnector. Tau is the damping time constant in seconds while DampR is the damping ratio.

An example of the power output at windfarm A is shown in Fig. 1 at the point in time indicated in Fig.6. In this case the amplitude of oscillation was about 1.5 MW, or about 6% of the total windfarm capacity. There were four occasions over the 1-year period of observation on which continuous undamped power oscillations were observed at the interconnector. One example is shown in Fig. 2, and details of the others are provided in Table 2. Three of the four events occurred at the interarea mode frequency of about 0.7 Hz. It is not unusual for poor damping of a mode to coincide with a lower mode frequency than normal – this can be a result of a weakened network or the participation of more generators than usual. Note that the undamped mode frequency is approaching the low-speed 3P mode of 0.66 Hz at windfarm A.

Table 2 Undamped oscillation events detected in interconnector power flow

Mode Frequency	Mean Amplitude	Duration (hours)
0.69 Hz	1.2 MW	2.5 h
0.70 Hz	0.9 MW	2.5 h
0.53 Hz	1.9 MW	11.5 h
0.67 Hz	0.9 MW	1 h

Note also that the fourth event occurred at 0.53 Hz, consistent with the 0.55 Hz mode observed at both the interconnector and at windfarm A. This fourth event had the highest amplitude of all of the events and had the longest duration.

As noted in the Introduction, the results indicate that the system could be small-signal unstable (i.e. it may exhibit negative damping) as it was experiencing limit-cycling oscillations.

4 DEVELOPMENT AND VALIDATION OF A DYNAMIC MODEL OF THE NIE SYSTEM

4.1 Model of the NIE Power System with ERIN Equivalent

In order to investigate the dynamics of the Northern Ireland system in detail, a dynamic model of the power system was developed. This model was based on the operational PSS/E model, but implementing it in Matlab allowed more detailed modelling of components, and in particular, it was possible to include detailed windfarm models.

In that model the NIE generators were modelled individually, the HVDC link was modelled as a constant power source, and the Republic of Ireland (ERIN) system was modelled as a single generator equivalent. The wind generators could be modelled either as a constant power source or with detailed site network configuration and turbine/generator models.

Each power station model included standard 5th-order GENROU generator model and standard models of AVR, PSS and Turbine Governor, all taken from the library of standard models in PSS/E. Detailed parameters of the units cannot be disclosed due to confidentiality reasons.

A practical constraint on the modelling aspect of this project was that only the Northern Ireland system was modelled in detail, due to availability of data. There could well be influences from the Republic of Ireland system that did not appear in the model.

4.2 Dynamic model of the windfarm

Five windfarms were modelled, both FSIG and DFIG. All of the models included detailed models of individual WTGSs. The model of a windfarm consisted of:

- wind variation model to allow introduction of a constant input value of wind velocity, wind gusts (with defined amplitude and period), wind velocity harmonics (with defined amplitude and period) and step changes (with defined slope) of the wind velocity,
- wind turbine model,
- mechanical eigenswing model to introduce 1P/3P effects,
- drive-train model (two-mass model),
- asynchronous generator model based on Siemens 1.3 MW model or DFIG model based on GE 1.5 MW model taken from PSS/E library.

The model of DFIG additionally included models of wind turbine and generator control systems.

4.3 *Small-signal frequency-domain analysis of linear NIE model: windfarm dynamics neglected*

A base case analysis of the small-signal stability of the linear NIE model was carried out without including dynamic models of the windfarms. It is noted from the eigenvalue analysis results in Table 3 that all of the simulated modes were well damped while the real system was in fact less stable. Note that the 0.76 Hz inter-area mode observable at Tandragee is reflected in the model.

Table 3 Modes in the power system model without wind farms. Modes observable at: windfarm A – yellow (lighter), Tandragee – cyan (darker). ξ is the damping ratio and T is the damping time constant.

Re(λ)	Im(λ)	f [Hz]	ξ [–]	T [s]
-1.57	11.20	1.78	0.14	0.64
-1.09	8.68	1.38	0.12	0.92
-7.56	6.60	1.05	0.75	0.13
-3.20	8.21	1.31	0.36	0.31
-2.18	8.04	1.28	0.26	0.46
-0.96	7.91	1.26	0.12	1.04
-1.88	6.59	1.05	0.27	0.53
-1.03	4.75	0.76	0.21	0.97
-5.06	2.99	0.48	0.86	0.20
-0.51	2.70	0.43	0.19	1.96
-0.25	1.96	0.31	0.12	4.07
-2.20	1.23	0.20	0.87	0.45
-2.01	0.69	0.11	0.95	0.50
-0.96	0.87	0.14	0.74	1.04
-0.42	1.08	0.17	0.36	2.37

The results also show at least four system modes (highlighted) close to the 1P and 3P frequencies of windfarm A. The coincidence of the system modes with the 1P and 3P effects can directly lead to self excitation of electromechanical oscillation of those frequencies.

The model was validated and the sensitivity of the system modes to various parameters was investigated but the details are not reported here for confidentiality reasons. These experiments were carried out for two reasons. Firstly, it was of interest to identify issues that could be causing the more resonant behaviour of the grid, that was not replicated in the base case analysis. Secondly, the impact of wind generation on system stability of a model that reflects the actual system conditions was of particular interest.

Generally validation of the model was undertaken by using the mode frequency and damping measures from the measurement-based analysis to adapt the dynamic model.

A sensitivity study attempted to indicate particular generating units at which there may be problems with the control systems, or incorrect dynamic modelling of the plant (these problems were not at windfarm A). In general terms, it was noted that the modes of interest were sensitive to the AVR gain settings at certain generating units.

It was noted that there could be influences on the stability of the system from the ERIN system in the Republic of Ireland. This external system was only modelled as a simple equivalent, and the influences were not apparent in this modelling work.

5 IMPACT OF WINDFARM DYNAMICS ON SYSTEM STABILITY

The effect of the wind generation on the stability of the system was investigated by studying the difference in behaviour between modelling the windfarms as constant currents and as detailed dynamic objects.

5.1 *Small-signal frequency-domain stability study with windfarm dynamics included*

The influence of windfarm A on system stability is illustrated in Fig. 7, and can be summarised as follows:

a) 1.05 Hz mode decay time increases significantly (T = 1.1 s → 5.3 s) when the farm dynamic model is included. The mode was identified as 1.09 Hz in measured data.
b) 0.4 Hz mode decay time increases significantly (T = 4.5 s → 9.9 s). The mode was identified as 0.4 Hz in measured data.
c) 0.6 Hz mode decay time increases significantly (T = 1.7 s → 3.8 s). The mode was identified as 0.65 Hz mode in measured data.
d) 0.3 Hz mode decay time increases slightly (T = 3.5 s → 3.8 s). The mode was identified as 0.32 Hz mode in measured data.
e) 0.1 Hz mode decay time increases very significantly (T = 0.4 s → 8.2 s). The mode was observed in measurements.
f) Small increase in the decay time of local modes.
g) Introduction of a new 0.66 Hz wind turbine mode.

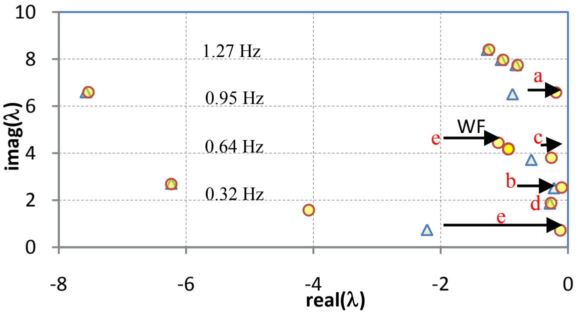


Fig. 7 Influence of Windfarm A dynamics on system stability. Circles denote modes obtained when the dynamic model of windfarm A was included in the system model while triangles denote modes obtained when the windfarm was modelled as a constant current source. Arrows show the movement of modes due to introducing dynamic windfarm models.

5.2 *Non-linear time-domain simulation study*

Frequency-domain small-signal models could not model 1P and 3P excitation coming from turbines. Hence a non-linear time-domain simulation study was carried out to investigate the propagation of 1P and 3P oscillations through the system. The system model included the detailed dynamic model of the windfarm. It was of interest to know if these effects are purely local, or if they can be observed at other plants in the system.

The 1P and 3P effects were modelled as periodic forces on the turbines. The simulation was run for an extended period, and the influence of the oscillations on the system was observed through analysis of signals (including output of generating units) in different points in the network.

Of the four frequencies caused by the 1P and 3P effects of the dual-speed turbines, three were seen to excite system modes, as outlined in Table 4. While the decay time of the modes in the linear model was not excessive, it was noted that oscillations at the 1P and 3P frequencies could be seen around the system.

Table 4 Excitation of system modes by windfarm A 1P and 3P frequencies

System mode	**1P/3P effect**	**Main points of observability of the mode**
1 Hz	0.96 Hz	Observed at one major generator
0.69 Hz	0.66 Hz	Observed at all units
0.3 Hz	0.32 Hz	Republic of Ireland system equivalent

The 0.96 Hz mode, corresponding to the 3P oscillations at the high gear ratio, is the strongest of the 1P and 3P effects observed at windfarm A. The oscillation amplitude is related to the windfarm output, and is largest when the farm is operating at its rated capacity. This frequency coincides with a local mode frequency, and power swings at 0.96 Hz are observed at the unit.

The 0.66 Hz 3P effect at the lower gear ratio coincides with a system-wide mode that can be observed at all units, including the NIE generators and Republic of Ireland (ERIN) equivalent. Undamped oscillations were observed at around 0.66 Hz, as described in Section 3 (see Table 2 and Fig. 2). These events occurred at periods of low output from windfarm A, when the low gear would have been selected.

The 0.32 Hz 1P effect at the higher gear ratio is clearly seen in the equivalent generator representing the Republic of Ireland (ERIN) system. In fact, it is more clearly observed in the equivalent generator than at the output of the windfarm A generators that are driving the oscillation.

5.3 Comparison between the frequency-domain and time domain modelling.

Table 5 shows comparison of frequency and time constants of different modes observed using frequency-domain and time-domain simulation models. The second column of Table 5 corresponds to the same model as that shown in Table 3, i.e. the linear model without WF. There are some differences, e.g. 0.3 and 0.1 Hz modes in Table 5 are better damped while modes 1.05, 0.6 and 0.4 are less damped. Those differences are due to different operating points of the system considered.

Main comments to Table 5 are the following:

1. 0.32 Hz mode found in the nonlinear model fits well the measured 0.32 Hz mode shown in Fig. 5a. The mode corresponds to 1P oscillations for high gear ratio of wind turbines. Clearly the mode deteriorates system stability as demonstrated by long time constants reaching 32 s. The mode exhibits different damping at different units. The mode does show up in the linear model too but is well damped.
2. 0.96 Hz mode found in the nonlinear model fits well the 0.95 Hz measured mode shown in Fig. 5a. The mode corresponds to 3P oscillations for high gear ratio of wind turbines. It also deteriorates system stability as demonstrated by time constants reaching 16 s.
3. 0.6-0.69 Hz modes found in both linear and nonlinear models can be treated as the same mode. They correspond to the measured mode of 0.65 Hz in Fig 5a and are well damped.
4. Time constants for the frequency-domain linear model with WF are similar to those for the time-domain nonlinear model without 1P/3P effects which is to be expected as the linear model did not include 1P/3P effects. For 0.4 Hz and 1.05 Hz modes one can see slightly higher values of the time constants for the linear model. This is quite typical as often eigenvalues indicate unstable modes while the nonlinear model is stable.

Table 5 Comparison of the simulated modes using linear (frequency domain) and non-linear (time-domain) models

Linear model			Non-linear model with WF		
f [Hz]	T [s]		f [Hz]	T [s]	
	no WF	with WF		no 1P/3P	with 1P/3P
1.05	1.1	5.3	1.0^*/ 0.96^{**}	1.5-3.0	**12-16**
0.6	1.7	3.8			
0.66	-	1.1	0.69	2.7-3.7	3.5
0.4	4.5	9.9	0.4	3.0-6.0	5.8-8.1
0.3	3.5	3.8	0.30^* /0.32^{**}	2.5	**6.5-32**
0.1	0.4	8.2			

* mode frequency with 1P/3P effects not included, ** mode frequency with 1P/3P effects included

5.4 Conclusions from simulation studies

Windfarm A was seen to degrade system stability for several modes. 1P and 3P effects were found to interact with system modes for at least three of the 1P/3P frequencies at windfarm A. If a 1P or 3P effect excites a system mode that is already poorly damped, it is possible for the system oscillation to grow significantly larger and appear less well damped than it would be through normal excitation of the mode with random perturbation by loads.

It should be noted that the model-based expectation of damping was better than the observations. In particular, the observed damping of the interarea mode was poorer than in the simulations. Various explanations of the discrepancy were investigated. The most likely candidate is thought to be a discrepancy between the modelled and actual gain of the AVRs at a generator in the system. There is potential to improve the dynamic behaviour of the system significantly by adapting conventional controllers. A plant was identified where retuning AVRs and deploying PSSs would be effective.

It was not possible to recreate the 0.55 Hz mode that was observed at the interconnector and at windfarm A. This is a significant mode, and was responsible for the longest duration and largest amplitude of continuous oscillations observed in the system from the data available. It would be useful to characterise this mode more effectively using simultaneous GPS-time stamped measurements at key points in the network, both in Northern Ireland and the Republic but this was unfortunately not possible.

6 CONCLUSIONS

The study reported in this paper was prompted by a discovery that oscillations at the output of a FSIG farm in Northern Ireland Electricity (NIE) power system can reach about 6-10% of the farm output. This paper showed that the main reason for the oscillations seems to be an interaction between the FSIG windfarms and the system dynamics . This was proven using modelling that was validated against dynamics measurements over a long period. A comparison was made between modelling the FSIG windfarms as constant power sources and as dynamic machines. This showed that system modes become significantly more resonant and approach the instability boundary when the FSIG are modelled as dynamic machines. A definitive measurement-based proof using simultaneous data was not possible due to limitations of the measurement system.

It is noted that the observations refer to the particular system studied, and it is not a general conclusion that these effects will necessarily be seen in other systems. However, the observation of these effects in the Northern Ireland network shows that the effects are real and can occur in practice.

At this point in the development of wind power in Northern Ireland, it is considered that the small-signal stability of the power system can be managed with the design and commissioning of new and existing Power System Stabilisers at the main conventional generators, as well as the possible re-tuning of certain AVRs. Since there is an operational rule that a certain amount of conventional generation must run for security, even in low load/ high wind scenarios, stabilisation provided by conventional generation would improve dynamic performance if existing PSSs were optimally designed and activated.

In the future, as wind power penetration increases, it may no longer be feasible to apply the operational rule that conventional generation must run within the NIE network. As wind power penetration increases, it could become a more significant constraint.

Finally, it is noted that the phasor measurements at key points in the network, coupled with extraction of the mode frequency and damping, were instrumental in providing a unique insight on the dynamic performance of the system. The dynamics monitoring facilities could be greatly improved with WAN communication to the substations and a commercial-grade WAMS platform. This would provide both an operational view of system stability and good information for longer-term analysis and identification of emerging trends.

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