Increased Wind Generation in Ireland and Northern Ireland and the Impact on Rate of Change of Frequency

Karen Creighton, Michael McClure, Raymond Skillen, John O'Higgins and Tom McCartan
SONI Ltd.
Castlereagh House, Belfast, Northern Ireland

Alan Rogers
EirGrid
160 Shelbourne Road, Dublin 4, Ireland

***Abstract*— In order to meet the 40% renewable targets set in Ireland and Northern Ireland it is forecasted that a total of almost 5,100 MW of wind generation will be connected to the Ireland and Northern Ireland networks. The All-Island Transmission System Operators (TSO) Facilitation of Renewables Studies indicated that the key limit to allowing high real time penetrations of wind generation on the all-island system was the rate of change of frequency (ROCOF). Therefore in order to change the current operational rule that system non-synchronous penetration (SNSP) cannot exceed 50% of all-island demand, the issue of ROCOF needs to be understood and addressed.**

Keywords-wind power penetration, dynamic studies, frequency, rate of change of frequency

I. INTRODUCTION

SONI and EirGrid are the TSOs in Northern Ireland and Ireland respectively. The transmission system in Northern Ireland is owned by Northern Ireland Electricity (NIE) and is composed of 275 kV and 110 kV networks. The transmission system in Ireland is owned by ESB Networks and is composed of 400 kV, 220 kV and 110 kV networks. The two transmission systems are electrically connected by means of one 275 kV double circuit tie-line and two 110 kV single circuit tie-lines. The all-island transmission system is connected to Great Britain via two 500 MW HVDC links, the Moyle Interconnector between Northern Ireland and Scotland and the East-West Interconnector (EWIC) between Ireland and Wales.

Renewable energy policies have been set by the Northern Ireland and Ireland governments [1] [2], which state that 40% of energy consumption is to be met by energy generated from renewable sources by 2020. These targets have been underpinned by European Union policies [3]. Due to the vast natural wind resource in Northern Ireland and Ireland, it is assumed that the majority of this renewable energy will come from wind power plants.

There is currently an installed capacity of 2,200 MW of wind generation on the all-island system and this is estimated to rise to approximately 5,000 MW by 2020. The peak all-island demand is forecasted to be over 7,000 MW in 2020, representing an average growth of 1.35% per annum [4].

In an effort to understand the technical and operational implication associated with large amounts of wind integration, the TSOs commissioned The All-Island TSO Facilitation of Renewables Studies [5]. A range of dispatch cases distributed on the complete feasible operational range of the power system (combinations of instantaneous wind penetration and load) were studied. The operational limitations of the 2020 all-island system were defined as illustrated in Fig. 1 below.

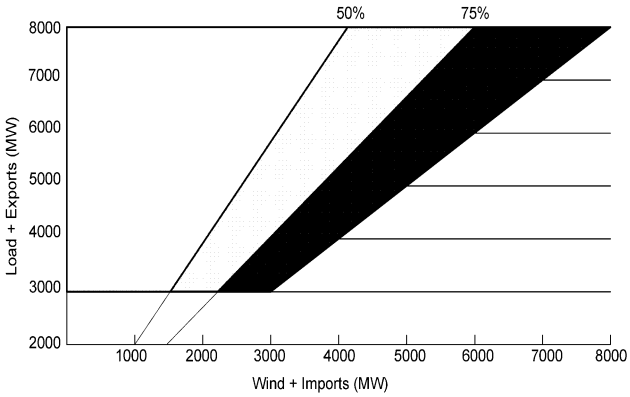


Figure 1. Schematic of region of dispatch up to 50% SNSP secure, up to 75% SNSP secure provided issues addressed, above 75% SNSP unsecure

The analysis provided evidence that two key factors limiting the level of instantaneous wind penetration in the 2020 all-island power system scenario were:

- Frequency stability after loss of generation
- Frequency as well as transient stability after severe network faults

The conclusions of the report recommended a restriction on "inertialess penetration" to about 50%, as shown in Figure 1. The TSOs currently employ an all-island operational policy that SNSP cannot exceed 50% of all-

island demand (SNSP is a combination of wind penetration and HVDC imports).

The TSOs are currently undertaking a body of work titled Delivering a Secure, Sustainable Electricity System (DS3), which invites the entire electricity industry in Ireland and Northern Ireland to help address the technical issues caused by the increased levels of renewable generation. The 11 work streams aim to equip the TSOs with the system policies, performance and tools to enable the 50% SNSP limit to be increased to 75%, as shown in Figure 1. Within DS3 there is a dedicated ROCOF workstream, which is tasked with assessing the ROCOF problem and the potential mitigation measures. As part of this workstream, a number of transient stability studies were carried out for the existing all-island network and to assess how ROCOF is affected by a changing generation portfolio, increased penetration of wind and network reinforcements.

II. Understanding the RoCoF Challenge

Starting in 2010, the TSOs have undertaken an extensive body of work in relation to understanding the ROCOF challenge. In particular, the TSOs have looked at the following areas:

- Defining ROCOF and how it is measured
- Historical Analysis of high ROCOF events on the Ireland and Northern Ireland system
- Understanding the capability of thermal generators to ride through high ROCOF events
- Understanding the requirements for anti-island / loss-of-mains protection on Distribution Systems and the use of ROCOF and Vector-shift relays

A. Defining ROCOF

Although the Ireland Grid Code [6] has a ROCOF ride-through requirement of 0.5Hz/s, it was not clear how or where this value should be calculated, and the interaction of this value with fault ride-through clauses that require a machine to remain synchronized during and after quite severe three-phase faults. Similarly, in Northern Ireland, a ROCOF value of 1.5Hz/s was specified in the Minimum Function Specification [7], but it was not specified how this value should be measured. It should be noted that ROCOF is not explicitly mentioned in the Northern Ireland Grid Code [8] at present.

The main issue is that the shorter the measuring window used to calculate the derivative of frequency, the higher the ROCOF value seen for any given event. Also, the ROCOF value will also depend on where in the network it is measured. For example should a generator disconnect from the system a frequency deviation will occur, and for a short period of time generators at different locations on the system may 'swing' against one another resulting in different ROCOF values being measured at different locations. After a substantial amount of analysis, the TSOs concluded that a measuring window of 500ms is sufficiently long to ensure that any short-term transients have died away, but sufficiently short to capture the main phenomenon of interest – the Rate of Change of Frequency caused by the loss of a large generator.

B. Historical Analysis

The TSOs carried out a historical review of high ROCOF events in Ireland and Northern Ireland, from 1988 to 2010. This review showed that ROCOF events as high as 1.4 Hz/s were recorded. No evidence of damage to any of the generators could be found, although generator owners have argued that any damage to the machines could be cumulative. In addition to this an international review of ROCOF standards was completed in 2012. This review showed that other Grid Codes do contain ROCOF standards, however no measurement time window is specified. Enforcement of such a standard could be extremely difficult in practice. Evidence was also found that other small, islanded systems had experienced ROCOF events of 1.5 Hz/s, with no generator tripping or damage reported.

C. Generator Capability

Generators raised concerns that high ROCOF events or an increase in the number of ROCOF events would increase wear and tear on their machine or even result in catastrophic failure. Therefore the TSOs committed to researching the phenomena of ROCOF. In 2013 DNV KEMA carried out independent analysis on behalf of the TSOs on the ability of generators to ride through high ROCOF events [9]. This analysis was based on mathematical models that were representative of thermal generators in Ireland and Northern Ireland. The results of this study showed that for a frequency change of 1 Hz/s over a 500 ms window, all generators modelled remained stable, though some generators were seen to pole-slip if at full-leading reactive output. Taking DNV KEMA's analysis together with the historical review, the TSOs believe that there is no theoretical reason why there should be an issue in increasing the ROCOF standard to 1 Hz/s over 500ms for generators and wind power plants [10].

D. Distribution Protection

Issues around anti-island protection schemes do exist, as protection may be activated as the result of a high ROCOF event. The activation of this protection could lead to the loss of large amounts of wind generation in Ireland and Northern Ireland. The Distribution System Operators (NIE and ESB Networks) are currently investigating the possibility of increasing the ROCOF settings currently used in anti-islanding protection. The settings need to be sufficient to identify a genuine islanding situation, but not activate for a high ROCOF event.

In 2012 the TSOs also published a summary of the studies that had been carried out to date [11]. This report studies the loss of an HVDC interconnector and system separation i.e. the loss of the AC tie-lines between Ireland and Northern Ireland.

In the next section, the results of dynamic studies show how fault-contingencies in Northern Ireland impact the all-island system, and give an indication of some of the challenges that the TSOs are facing. It should be noted that these studies are only one part of an extensive body of work in relation to ROCOF that is being carried out by the TSOs.

III. STUDY METHODOLOGY

A. Base Cases, Study Years and Modelling

The base case for the ROCOF studies is a dynamic model of the all-island transmission system and the associated HVDC interconnectors with Great Britain (GB). All conventional generators are modelled using the manufacturer specific model for that generator, and all wind power plants are modelled using detailed manufacturer specific turbine models. The studies are carried out using the PSS/E dynamics simulation function.

Base cases were created for the two study years; 2013 and 2019. All transmission network reinforcement and upgrades were included in the appropriate base case. Levels of wind generation in the 2013 studies were based on estimated connection dates; the studies assumed 500 MW of wind generation in Northern Ireland and 791 MW of wind generation in Ireland. The 2019 studies assumed 1,133 MW of wind generation in Northern Ireland and 1,700 MW of wind generation in Ireland.

In both base cases, the majority of the installed wind capacity on an all-island basis was connected to the distribution network. All transformers associated with distribution connected wind power plants are modelled explicitly e.g. 110/38 kV, 110/33 kV, 10/20 kV, 33/0.69 kV and 20/0.69 kV transformers. In Northern Ireland the distribution feeder circuit i.e. the 33 kV circuit, is modelled for each distribution connected wind power plant. In Ireland medium voltage (38 kV, 20 kV and 10 kV) circuits are not currently modelled, however this is currently under review. The internal wind power plant networks are not represented in the models.

B. Dispatches

The base case dispatch used in the 2013 studies was developed from an all-island day-ahead Reserve Constrained Unit Commitment (RCUC) schedule. RCUC calculates the unit commitment and economic dispatch schedules for dispatchable resources based on the bids and offers submitted by the Market Participants. Dispatchable resources include generators, demand side units, and interconnector units. The dispatch schedules include energy and operating reserve schedules. To ensure results from the two study years were comparable, the dispatch used in the 2019 cases is similar to that in the 2013 cases, with the main difference being the increased wind generation levels.

C. Key Contingencies

All fault-contingencies carried out as a part of this study were located in Northern Ireland. However, as the Northern Ireland and Ireland transmission systems are synchronously connected, all results and analysis was carried out on an all-island basis.

The loss of a single thermal generating unit in Northern Ireland as the result of a fault on either the HV or the LV side of its generator transformer was considered. This study was performed at two different thermal generation sites in Northern Ireland; referred to as generator A and generator B in this report.

In addition to this, the loss of the key 275 kV double circuit between Coolkeeragh and Magherafelt, following a busbar fault was also studied. The loss of this circuit was tested as it is at present the only 275 kV link between the north west of Northern Ireland (an area of high penetration of wind generation) and the main load centres in the east of Northern Ireland as shown in Figure 2 below.

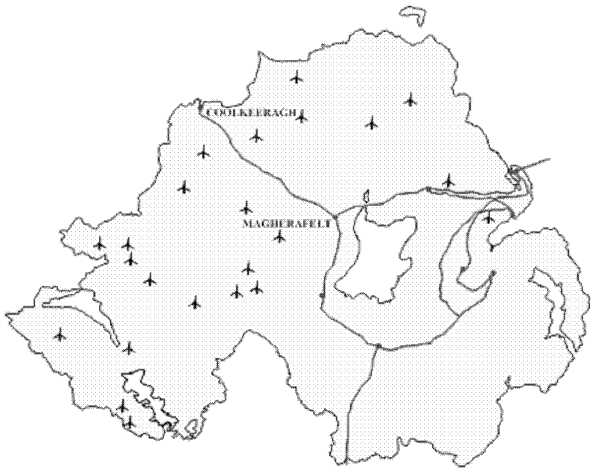


Figure 2. Northern Ireland 275 kV Network and significant Wind Power Plant Locations

All faults performed in these studies are balanced 3-phase faults, which are then cleared after 120 ms. This fault clearance time was chosen to be representative of back-up protection clearance times, and therefore representing a worst case scenario.

D. Measurement of Results

All ROCOF values presented in this report were calculated using bus frequency measurements from PSS/E at major nodes on the all-island transmission system. Raw data taken from PSS/E at 5 ms intervals was used to calculate ROCOF values over 100 ms time periods; a five point moving average was then taken of this data to determine the ROCOF value over 500 ms.

The calculation methodology used to determine the ROCOF values used a 500 ms time frame, which is consistent with proposed Grid Code modifications in Ireland and Northern Ireland. It is important to note that when the time frame is shortened, higher ROCOF values are experienced. Figure 3 below illustrates the ROCOF values calculated at the same transmission node for the same fault-contingency using 50, 100 and 500 ms time frames. The TSOs believe that 500 ms is an appropriate time frame to calculate ROCOF, as it usually takes this

length of time for the generators to return to a coherent state.

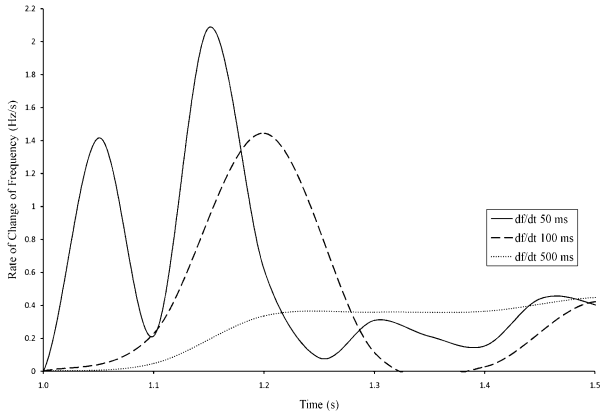


Figure 3. Illustration of how ROCOF can vary using different calculation time frames

ROCOF values were calculated at four transmission nodes on the all-island network. These four nodes are geographically dispersed; the location of these nodes is indicated in Figure 4 below. These nodes were chosen to determine how ROCOF is affected across the entirety of the all-island transmission network.



Figure 4. Location of Transmission Nodes where ROCOF was calculated

Measurements were taken at the four transmission nodes to illustrate how ROCOF can vary significantly over the network. The ROCOF value experienced at the different transmission nodes is affected by the proximity to the fault-contingency and the network topology.

Figure 5 below illustrates how for the same fault-contingency, frequency measurements can vary significantly across the transmission system during the fault and period of imbalance which follows. Following the dynamic period of system imbalance, the system frequency universally returns to 50 Hz.

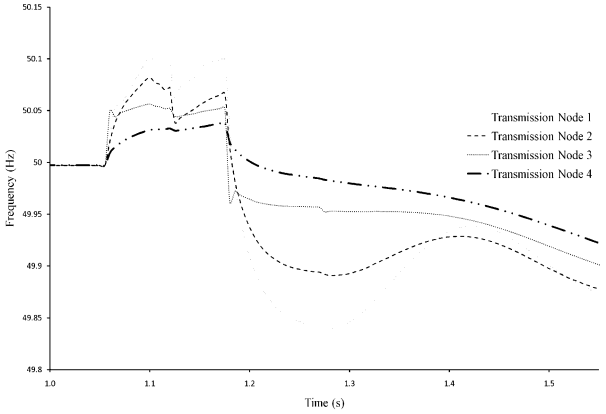


Figure 5. Illustration of how Frequency can vary during a fault-contingency on the system during the dynamic time period

IV. STUDY FINDINGS

This section will detail the key findings from both years of study; for the loss of generator A and generator B with faults at the HV and LV side of the generator transformer and the critical contingency.

A. Fault-Contingency at Generator A

A balanced 3-phase fault was placed on the HV busbar at generator A, and the fault was cleared after 120 ms by tripping generator A. This study was carried out with generator A dispatched at maximum output and repeated with generator A dispatched at minimum output, for both study years. The ROCOF values calculated at the 4 transmission nodes shown in Figure 2 can be seen in Table 1 below. All ROCOF values are expressed in Hz/s as measured over 500 ms.

TABLE I. ROCOF VALUES CALCULATED DUE TO HV FAULT AND LOSS OF GENERATOR A

Transmission Node	Generator A at maximum output		Generator A at minimum output	
	2013	2019	2013	2019
1	1.05	1.9	0.88	1.39
2	0.67	1.31	0.56	0.85
3	0.60	1.21	0.55	0.88
4	0.59	1.24	0.46	0.89

The above analysis was replicated, with the fault placed on the LV busbar at generator A. These results can be seen in Table 2 below.

TABLE II. ROCOF VALUES CALCULATED DUE TO LV FAULT AND LOSS OF GENERATOR A

Transmission Node	Generator A at maximum output		Generator A at minimum output	
	2013	2019	2013	2019
1	0.95	0.92	0.87	0.55
2	0.58	0.90	0.50	0.37
3	0.39	0.89	0.36	0.39
4	0.35	0.88	0.32	0.42

The ROCOF values experienced by the system are significantly reduced when the fault is placed on the LV side of the generator transformer, due to the generator transformer acting as impedance between the fault and the transmission system.

Higher ROCOF values were experienced when the thermal generator was dispatched at a higher operating point due to a larger generation/demand imbalance following the loss of the thermal generator. The highest ROCOF is experienced at transmission node 1, as this node is the closest electrically to generator A. The ROCOF is less severe as electrical distance from the fault-contingency is increased, as the impedance between the fault-contingency and the point of measurement is increased.

During the fault, the associated voltage dip causes local generators to reduce their active power output in proportion to the retained voltage at the connection point. The slow recovery of active power output after fault clearance, of wind power plants, results in a generation/load imbalance. Consequently, system frequency falls, a phenomenon known as voltage dip induced frequency dip (VDFD). This has a severe aggregated effect in the north west of Northern Ireland due to the high penetration of wind generation in this area.

The wind levels in 2019 are significantly higher than in 2013, and as a result the combined effect of the VDFD on local wind power plants, and the loss of generator A, results in larger ROCOF values at all four transmission nodes following a fault on the HV busbar.

B. Fault-Contingency at Generator B

A balanced 3-phase fault was placed on the HV busbar at generator B, the fault was cleared after 120 ms by tripping generator B. This study was carried out with generator B dispatched at maximum output and repeated with generator B dispatched at minimum output, for both study years. The ROCOF values calculated at the 4 transmission nodes shown in Figure 2 can be seen in Table 3 below. All ROCOF values are expressed in Hz/s as measured over 500 ms.

TABLE III. ROCOF VALUES CALCULATED DUE TO HV FAULT AND LOSS OF GENERATOR B

Transmission Node	Generator B at maximum output		Generator B at minimum output	
	2013	2019	2013	2019
1	1.09	1.49	0.54	1.26
2	0.62	1.36	0.75	0.62
3	0.44	1.07	0.34	0.65
4	0.41	0.99	0.33	0.67

The above analysis was replicated, with the fault placed on the LV busbar at generator B. These results can be seen in Table 4 below.

TABLE IV. ROCOF VALUES CALCULATED DUE TO HV FAULT AND LOSS OF GENERATOR B

Transmission Node	Generator B at maximum output		Generator B at minimum output	
	2013	2019	2013	2019
1	0.63	0.75	0.28	0.54
2	0.44	0.75	0.16	0.38
3	0.25	0.74	0.18	0.25
4	0.22	0.70	0.20	0.22

As previously shown, the ROCOF values experienced by the system are significantly reduced when the fault is placed on the LV side of the generator transformer, due to the generator transformer acting as an impedance between the fault-contingency and the transmission system.

Due to their close proximity, a fault at generator B causes a voltage dip at the Moyle Interconnector. The Moyle Interconnector uses line commutated converter (LCC) technology and therefore requires a synchronous voltage source to operate. The voltage dip caused by the fault contingency at generator B results in the Moyle Interconnector being unable to commutate during the fault, leading to the temporary loss of generation import via the HVDC interconnector.

Generator B is located in the east of Northern Ireland, away from the high concentration of wind power plants in the west. Therefore the voltage dip experienced by the wind power plants is not as severe following the fault-contingency as compared with generator A. As a result there is less impact on the output of the wind power plants, as the reduction in the connection point voltage is less severe.

C. Critical Contingency – Loss of Coolkeeragh-Magherafelt Double Circuit

A balanced 3-phase fault was placed at the 275 kV busbar at Coolkeeragh; the fault was cleared after 120 ms by tripping the Coolkeeragh – Magherafelt 275 kV double circuit. This study was carried out with generator B dispatched at maximum output and repeated with generator B dispatched at minimum output, for both study years. Generator A was not dispatched due to the high levels of wind generation in the north west of Northern Ireland. The ROCOF values calculated at the 4 transmission nodes shown in Figure 2 can be seen in Table 5 below. All ROCOF values are expressed in Hz/s as measured over 500 ms.

TABLE V. ROCOF VALUES CALCULATED DUE TO HV FAULT AT COOLKEERAGH AND THE LOSS OF THE DOUBLE CIRCUIT

Transmission Node	Generator B at maximum output		Generator B at minimum output	
	2013	2019	2013	2019
1	0.98	1.04	0.80	0.81
2	0.52	0.82	0.50	0.46
3	0.37	0.75	0.30	0.45
4	0.33	0.67	0.29	0.52

The fault at the Coolkeeragh busbar causes a significant voltage dip in the north west of Northern Ireland, the area with the largest penetration of wind power plants. The slow recovery of the active power output of these wind power plants will cause a large aggregated reduction in generation, resulting in VDFD.

When the fault is cleared and the connection point voltages of the wind power plants are restored, the generation from the wind power plants will return to pre-fault output. (With the loss of the 275 kV double circuit this generation is forced to seek alternative routes out of the

north west via the weaker 110 kV network, not shown in Figure 2.)

V. CONCLUSIONS

Rate of Change of Frequency is dependent on a number of related variables, including:

- System demand
- HVDC imports/exports
- Generation dispatch (system inertia)
- Wind power plant output
- Fault-contingency location
- Network topology

Based on these factors, ROCOF can vary greatly in different parts of the network with the highest ROCOF values being experienced closest to the fault.

As levels of wind generation increase, displacing thermal generating plant, the inertia of the all-island system will reduce. Consequently, the same disturbance in 2019, with higher penetrations of wind generation, will cause a larger ROCOF than in 2013.

In order for the SNSP limit to be increased to 75% whilst ensuring all Grid Code requirements are met, mitigation measures will be essential. There are a variety of potential mitigation measures that could be employed, all of which would require further study. They include:

- Maintaining system inertia relative to the largest infeed
- Dynamic reactive support and faster post-fault active power recovery from wind power plants to help alleviate VDFD
- Contracted load shedding schemes to interrupt customer's load when system frequency drops to a pre defined level (this would be an opt in scheme which is not linked to standard operational load shedding schemes)

SONI and EirGrid are continuing to study ROCOF and the potential mitigation measures to allow the SNSP limit to be increased.

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