Frequency Changes during large System Disturbances Workgroup Meeting 4
14th February 2013

Attendees

Name	Initials	Company
Mike Kay	MK	Chairman
Robyn Jenkins	RJ	Technical Secretary
Joe Helm	JH	Northern Powergrid
Martin Lee	ML	SSEPD
William Hung	WH	National Grid
Graham Stein	GS	National Grid
Joe Duddy	JD	RES
Jane McArdle	JM	SSE Renewables
John Knott	JK	SP Energy Networks
Adam Dysko	AD	Strathclyde University
Brendan Woods	BW	SONI
Gorman Hagan	GH	NIE
Julian Wayne	JW	Ofgem

Apologies

Paul Newton	PN	EON
Gareth Evans	GE	Ofgem
John Turnbull	JT	EDF Energy
Campbell McDonald	CM	SSE Generation
Mick Chowns	MC	RWE
Geoff Ray	GR	National Grid

Actions

The Workgroup discussed the ongoing actions; details of these discussions are captured in the action log or on the meeting agenda.

Meeting Objectives

The key objectives of this meeting are:

- Understand the work undertaken in Northern Ireland
- Discuss Safety Risk assessment proposal

Presentation from NIE

GH delivered a presentation highlighting the work undertaken by the University of Strathclyde on behalf of NIE. He added that, until this work was carried out the Northern Ireland GC did not have a RoCoF limit and the Republic of Ireland (ROI) had $0.5Hzs^{-1}$. The limits being investigated were for asynchronous generation only, synchronous are not being considered at this stage.

GH explained that there was a desire to assess with the accuracy of the LoM protection relays, and the scope of study was to determine the sensitivity and stability of LOM protection relays using RoCoF and Vector Shift (VS) algorithms, up to and including frequency changes of $2Hzs^{-1}$, definite time of 500ms and VS of 6 and 12 degrees. For clarity, this would mean that if the relay measured $\geq 2Hzs^{-1}$ and the measurement is maintained for 500ms it would trip.

AD added that the study compared 4 manufacturers, and when the test wave form applied is clean there is consistency between the relay types, but when the wave form is distorted then there are differences in trip behaviour. Adding a definite time made the relays more consistent under these conditions.

BW noted that for Northern Ireland a $2Hzs^{-1}$ setting was proposed until the second connector to the ROI was built, at which point it would reduce to $1Hzs^{-1}$ to match ROI. The biggest pushback came from synchronous generators in NI who did not want a $2Hzs^{-1}$ setting. It was reported that the KEMA desktop study indicated that $1Hzs^{-1}$ should not cause significant concern but at $2Hzs^{-1}$ further work was required to eliminate the risk of pole slipping. The settings for the studies were the same as the settings in G59.

GH noted that in the European Network Codes, anything bigger than 1MW will be required to have frequency control capability.

In Northern Ireland the settings for synchronous generators will remain at $0.4Hzs^{-1}$ and the new settings will only apply to 33kV connected generation. For generation incapable of fast frequency response a RoCoF setting of $2Hzs^{-1}$ and a definite time setting of 500ms will apply. For generation capable of responding to frequency then other LOM systems will be utilised, such as intertripping. The different settings mean generators will not all trip off at the same time. These settings will be operational by 2014.

Safety Risk Assessment Proposal

AD explained his proposed methodology. The assessment of the island non-detection zone (NDZ) would be done at two levels $0.5Hzs^{-1}$ and $1.0Hzs^{-1}$, with various options including with and without deadband, (within which frequency range protection is blocked) and 0.5s definite time.

Some workgroup members believed a longer definite time (eg 1 sec) may need to be considered. It was agreed that AD will conduct the study scenarios as proposed but include 1 sec definite time where appropriate.

For each option, AD will run a sensitivity test, and increase or decrease load until tripping occurs. This will be done for real and reactive power. AD added that the workgroup need to agree what an acceptable time for detection is, and need to decide if consideration of one type of generation technology is enough or whether the study needs to use a mix of generation. AD noted that a single generator gives worst case scenario.

MK noted that there is a need to consider the specification of the machines when the European Network Codes come in and factor in the experience in Spain where they have experienced self sustaining islands fed solely from PV generation.

Current settings do not include a definite time setting (relays are considered to be instantaneous, neglecting the measuring time). The constraint on adding a definite time setting is auto-reclose times, where there is a risk that a circuit breaker is auto-reclosed back on to an unsynchronised island. ML asked AD to consider how much longer it would take to do the tests with various definite time settings. JH noted that Northern Power Grid support proposal to do more sensitivity analysis.

GH noted that Northern Ireland was interested in the minimum time delay and looked at all possible relay settings and seeing when it became unstable. AD added that testing at a fixed setting is much easier, if looking for setting the study takes a lot of time.

ML suggested that with respect to definite time settings, some network operators are unlikely to want the settings to go above 3s as that matches their auto reclose timescales. GS suggested that 0.5s feels about right, but there was a need to know now whether there is a fundamental need to limit the delay to no more than 3s. MK suggested approaching workgroup members not present to confirm that all views had been considered.

The workgroup noted that generally, they were happy with 0.5s for timing, but want to understand what the impact is on the size of the NDZ with a longer setting.

AD noted that the voltage and frequency settings used in the assessment will be as per G59/2.

ML noted that longer periods of discrimination give longer time for other types of G59/2 protection to kick in. GH suggested being wary of how long an island can be sustained for and not present a safety risk. MK said that the risk was likely to be perfectly tolerable for minutes rather than seconds – but that the auto-reclose dead time might be a practical upper limit.

AD explained that for the risk assessment he would take a simple network model, using some measure of load profiles and NDZ. AD asked for feedback from utilities on the conditions when islands occur for the hazard risk assessment. MK noted that for a phase to phase fault on islanded network, you would expect the generator protection to trip and suggested AD use earth faults for the risk assessment.

AD explained the assumptions he will make to complete the risk assessment. AD noted that each assumption can be fixed by either a typical number representing most cases or the worst case. Otherwise they can be treated as a random variable. These include;

- Load Profile
- Network type and length of circuit
- P and Q non-detection zone duration (from NDZ repository)
- Maximum acceptable non-detection zone duration (e.g. T_{NDZmax} = 3s)
- Generator size and mode of operation (eg generator at 0.98pf – lead.)

ML noted that it is necessary to determine where we fall in the risk pyramid, to see what an acceptable level of risk is. As AD can't model every network with every type of technology, he suggested proceeding with the single generator case operating at fixed power factor adding that for most network configurations the risk is much lower than that.

MK suggested considering loss of a primary as one of the network types as this happens frequently. ML noted that following the existing proposal would be adequate in the first instance, and we should look at multiple generators as a follow on project.

AD discussed the assumed load profiles, these come from two different suburban feeders. JW asked whether the group are happy that an adequately representative spread of load profiles was being considered.

AD noted that from the feedback received there were some issues with the transparency of models, adding that this study will use a real relay, not a simulated one. He asked the workgroup what level of transparency that would be required for this work?

JW suggested the impact of the Demand Connection Code (DCC) may need consideration in the future; currently it is drafted such that thermostat-controlled load (e.g. fridges, freezers etc) may have automated frequency cut-out. He asked to consider whether we want something in the DCC so that this capability takes account of rate of change of frequency rather than, or as well as, actual frequency.

The workgroup discussed what plant should be subject to study and change, with some workgroup members suggesting that the focus is on plant greater than 5MW. GS added that there are another 4GW outside of that which should not be discounted. The workgroup concluded that they are not as concerned about the PV fitted at present but, for PV fitted from now, the requirement may need to change. The model used for risk tree in AD's proposal is typical of 11kV feeders, not those above 5MW.

AD stated that he would be much more comfortable if the DNOs provided a typical network model or diagram.

MK asked about the order with which the study needs to be done. AD noted that he needs to have assumptions first but determining the NDZ can be done separately because it is just for the generator, it does not take account of network configurations. However, for lab study, the workgroup need to be happy with the generator model and maximum time for generator to detect it. MK suggested the DNO representatives provide typical network configurations to AD.

AD asked whether the DNO's could also provide actual load profiles for a typical day from 2 to 3 different primaries, with a 1 second or faster resolution.

AD noted that he could run the risk studies (with the configurations) and then just step the NDZ (5%, 10% etc). Then with specific generator information, he can run that to determine the NDZ.

The workgroup suggested that, given the discussions the feedback received on the proposal, AD should modify the existing proposal to above 5MW for which the DNOs will provide 4 typical connection arrangements with 1 second resolution load profiles.

GS questioned whether the proposed study would make enough progress in reducing the overall volume of distributed generation at risk MK suggested that the risk assessment will inform DNOs whether they can change the protection settings for the greater than 5MW plant category.

The workgroup representatives concluded that the 1st stage study should focus on between 5 and 50MW plant connected to 33kV network as not all DNOs agree that doing the 11kV study would be representative of the 33kV.

Timescales for next steps

The DNOs agreed to provide the connection diagrams and load profiles by 1st March 2013.

GS agreed to discuss the proposal and contract details with AD directly.

AOB

The workgroup briefly discussed the letter which will be sent from a network owner to a generator. MK agreed to provide the letter from last time to help draft this one. JH noted that Northern Power Grid has concerns over the responses and feedback they are likely to get from the letter.

JD asked whether, at the next meeting, an assessment against the Workgroup Terms of Reference could be added as an agenda item.