Minutes

Meeting name	GC0028: Constant Terminal Voltage
Meeting number	1
Date of meeting	29 January 2014
Time	10:00 – 14:00
Location	National Grid House, Warwick, CV34 6DA

Name	**Initials**	**Company**
Graham Stein	GS	National Grid (Chair)
Robyn Jenkins	RJ	National Grid (Technical Secretary)
Antony Johnson	AJ	National Grid
Philip Jenner	PJ	RWE
John Morris	JM	EDF Energy
John Norbury	JN	RWE

Apologies

Martyn Cunningham	MC	Scottish Power
Paul Newton	PN	EON

1 Introductions/Apologies for Absence

1. Apologies were received from Paul Newton and Martyn Cunningham. GS noted that there are parties who have derogations regarding Constant Terminal Voltage, none of whom have attended the Workgroup meeting. RJ agreed to contact those parties again.

2. **ACTION: RJ** Contact those parties with derogations to invite to the Workgroup.

3. The workgroup acknowledged that if the code solution negates the need for the current derogations then they should probably be removed and the steps required to do this will require further consideration.

2 Terms of Reference and Workplan

4. The Workgroup reviewed the paper presented to the November GCRP. This paper highlighted the output of the November workshop and the draft Terms of Reference. JN noted that there is a clear deficiency in the code, and that manufacturers and generators currently have trouble interpreting its meaning. Even if the obligation does not change, the wording should.

5. JN noted that there is some confusion as some generators have been advised to change the set point during compliance testing. The Workgroup also acknowledged that there are a number of sites which are operating above their rated terminal voltage.

6. The Workgroup acknowledged that there is an increase in costs for increasing the number of taps on a transformer. PJ suggested that is linked to the MVA rating of the Transformer and whether it was a single or multiphase unit. He believed that multiphase transformers were used up to around the 500/600 MVA range .

7. It was noted that there seems to be a trend that generator transformer impedance is increasing. PJ suggested that the increase may be a natural progression as the system develops and fault levels go up. GS noted that with an increasing volume of wind generation which does not contribute the same level of fault current, fault levels are tending to stabilise and in some instances fall.

8. GS noted that point 7 (of the paper) raises the question of what the requirements are and how often you need to operate the plant at the extreme ranges (eg maximum reactive power export during high system voltage conditions or maximum reactive power import during low system voltage conditions adding that it is important to find the balance between what the system needs and what the generator can provide.

9. The Workgroup accepted that any proposals would need to be consistent with RfG. PJ asked how the interaction with RfG will work. AJ noted that this is covered in the slides.

10. For the terms of reference, the dates and membership fields need to be completed. GS noted that there are no timescales on the Terms of Reference and these were not discussed at GCRP. JN suggested that 6-12 months seems appropriate but due to the volume of other work it is agreed that this may not always be a high priority item. The timescales are also dependent on the solutions identified. The Workgroup indicated that this can be progressed irrespective of RfG as the current connection conditions will be maintained long into the future. AJ noted that where EU settings can be determined on a national basis, and are the same as the current GB values, then these can be mapped across as applicable, so this work could feed in to the RfG implementation work. AJ suggested that the TSO does have more flexibility than previously thought.

11. GS agreed to update and publish the Terms of Reference.

4 Background and Options

12. AJ provided an overview presentation, slides from which are available here[1].

13. The slides included an explanation of the RfG requirements for Constant Terminal Voltage compared to the GB requirements. PJ questioned whether the TSO wants the capability to be symmetrical.. AJ noted that the current GB requirement specifies a reactive capability range at the Generating Unit terminals and the ENTSO-E code specifies a requirement at the HV connection point. The impedance of the Generator transformer will have the effect providing a more symmetrical range at the HV connection point.

14. Slide 8 presents text intended to clarify the current Grid Code requirement (black dotted line – 0.85 Power Factor lag to 0.95 power factor lead whilst this reactive range should be fully available over and HV voltage range of ±5%) and the ENTSO-E requirement (red line – 0.9 Power Factor lead to 0.9 Power Factor lag at the HV connection point over an HV voltage range of ±5%). . JM suggested that this would mean currently derogations would stand. AJ added that with this option there would also be provision in the bilateral agreement to say that the Generator Terminal Voltage should be controlled to one per unit. He advised that a specific value had not been included in the suggested drafting as it would provide flexibility in the future, especially if larger plant struggled to achieve the requirement. JM sought clarity on whether this option states that constant terminal voltage is always constant and should be specified at one per unit. PJ asked why both the pre and post 2017 requirements reference the BCA. AJ noted that this is to negate the need for unnecessary derogations by specifying the requirement in the BCA. The Workgroup suggested that this option is not transparent and they are uncomfortable with having different requirements specified in the BCA. JN questioned why there needs to be a difference for post 2017 plant. AJ noted that it could say one per unit, but the intention was to provide a degree of flexibility. JN suggested that raising the voltage would not provide a solution for those units with a derogation. AJ suggested those generators would need to satisfy the requirement through a combination of tap changers and adjustments to the target voltage.

15. GS commented that the purpose of option 1 is to clarify the current arrangements and provide some flexibility. GS summarised the Workgroup discussion noting that there are concerns around references to the Bilateral Agreement. The wording could be changed to one per unit unless otherwise agreed. JN noted that option 1 does address one of the deficiencies as it has the potential to address the differences in interpretation.

16. Option 2 proposes a slight relaxation to the requirement, the first part is made up of the generator transformer tapping range, and the second part enables the Generator to change the set point voltage of the machine. AJ noted that, from a System Operator viewpoint, it reduces the MVAr reserves during and after a fault which in turn will affect the transmission system voltage. JM noted concerns on how that would be instructed operationally. If a generator is at its tap limit, and there is an instruction to achieve more but they cannot tap, they can instead change the terminal voltage, then later in the day when going back down, the generator firstly has to change terminal voltage back to normal, then achieve the rest with tapping. GS acknowledged that there is some complexity there. JN noted that the Workgroup would like to reach a solution that everyone can comply with the requirement whilst maintaining the integrity of the system. PJ noted that this option seems to allow both pre and post 2017 plant to comply, allowing a consistent approach.

17. JM noted that option 3 is potentially a cheaper option. AJ noted that this option is an even more relaxed requirement but the generator is controlling to one per unit. AJ added that this option has more drawbacks, in the event of a fault there are less MVars available that the previous option. NGET would need to assess the impact but potentially it is eroding the reactive margin available, despite still having full field forcing. PJ noted that a lot of the concerns seem to be about the system fault impacts but is protection likely to be impacted, or are you safely into the area where the protection will operate. GS noted that, with option 3, you lose reactive range, so potentially are not providing enough Mvars to controla step change. AJ added that if a generator runs out of taps, the actual pre fault voltage will be lower. PJ asked what the impact of missing that margin of MVars is. AJ commented that it impacts on both the voltage profile across the system during the fault since the pre fault voltage is lower which in turn can affect the post fault voltage due to the deficit of MVArs. . AJ added that short circuit ratio, fault ride through performance and constant terminal voltage are all linked and that by making a small

[1] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0028/ (Workgroup tab)

change to one of these parameters will have the effect (acknowledging this is of a secondary nature) of reducing the stability margin and overall robustness of the Transmission System. GS suggested that the implications are not the same as in option 2. PJ asked what the criteria are for assessing if there is enough reactive power available. AJ explained the system is designed at the outset to the SQSS. At the connection application stage it assumed that a Generator is fully Grid Code compliant and will be capable of providing the full reactive capability range. Where further reactive power is required, additional reactive compensation may need to be installed. In the operational timeframe the voltage profile will be established based on the outage requirements, available generation and reactive compensation. The voltage profile is set up so as to ensure the network remains within voltage and frequency limits to a secured event.

18. AJ provided an overview of the advantages and disadvantages of each option.

19. For option 1 JN suggested that it maintains the current levels of reactive reserve, which would be greater than the other two options. PJ noted that option 1 still gives the option to change terminal voltage post 2017, AJ noted that NGET would recommend that terminal voltage was kept at 1 per unit and only changed in exceptional circumstances. JN noted that, in terms of disadvantages, it is potentially more expensive than the other options and there is a potential loss of transparency due to needing to specify options in the BCA. JN added that this may not fully resolve the derogation solution.

20. For option 2 GS noted that it was missing an advantage as it still preserves the total reactive capability. PJ suggested that it could enhance total reactive capability. GS noted that it was quite appealing in that respect. GS noted that for all of these options there are also variations to apply them only in the lead or only in the lag. The Workgroup noted that one of the disadvantages of option 2 is the potential for less dynamic reserve during the fault. JN noted that a potential advantage is that these are more consistent with European practice. PJ suggested that specifying a transformer and tap changer is an iterative process, the developer has to specify what they want, but there may be investment companies building power stations who may not have the technical knowledge or an understanding of how to comply with the intended wording.

21. PJ suggested that options 2 and 3 need a line saying the margins need to be analysed before undertaking a Cost Benefit Analysis. JN noted that some of the benefits of option 2 and 3 is restoring the ability to operate at normal volts, rather than at the extremes, and for those parties with a derogation they should become compliant.

22. JN noted that, from the discussion, it seems as though option 1 is a back stop position and better for the transmission system. JN also suggested that some parties might be broadly comfortable with Option 1 for future plant (eg post 2017) and option 2 or 3 for historic plant. JN also asked whether NGET would prefer option 2 over option 3 as option 3 does not fully utilise all of the plant capability. GS noted that, for option 3, the Workgroup need to find out if there is any benefit in buying a transformer with fewer taps, balanced against any shortfall in reactive capability. JN suggested that a further option is to overlay sentence 1 of option 1 onto either option 2 or 3 so that the pre 17 plant has the option 2 or 3 and then after 2017 it becomes one per unit.

23. GS noted that the Workgroup need more information on the cost of tap changers to develop its assessment. PJ agreed to try and get more information. JM added that he might be able to get some information. GS noted that if the information provided is material, NGET would like to use it in the Workgroup report

24. ACTION: JM/PJ Seek information on cost of tap changers/transformer units.

25. JN noted that the graphs for Option 2 and Option 3 have the corners cut off (option 2 the deficit being made up by varying the Generator terminal voltage and option 3 where once the Generator Transformer runs out of taps no further voltage control is available), he asked how that result in reduction in MVars and how many less. AJ noted that in the worst case scenario the generator transformer would be unable to control voltage once the last tap had been used. AJ asked, at what point in station design do you define the minimum transformer tap range? The Workgroup also queried whether the operating limit would be needed to assess the

missing reactive power and the impact on the station auxiliaries, JM agreed to look at what EDFs internally policy is in this regard.

26. **ACTION: JM** Provide information on minimum transformer tap range.

27. PJ suggested that there may be other limitations such as flux value. The Workgroup surmised that, for option 3, the analysis should be able to say that for an x size machine there is a shortfall of x MVArs. AJ noted that to do this we would still have to determine what the voltage set point and maximum is. AJ noted that NGET need to take this away and look at, as the studies on this will drive option 2 and option 3.

28. GS noted that for the next steps NGET need transformer data, NGET will then look at a break down of options, and do some assessment of those options. JN suggested that if it only applies to existing plant, that could simplify the analysis. PJ suggested that if such a proposal goes to consultation, it may seem discriminatory that future plant does not have the same flexibility as present. GS suggested that the proposal would state that the requirements have been clarified. JN noted that if the costs are known at the outset, the excess cost would be minimal. JM queried whether, if replacing plant on a like for like basis, can the generator just specify the requirement according to the previous transformer or would they have to start specifying the new number of taps and requirements. GS noted that even if the legal text stated a completion date, that would probably still capture a modification. GS noted that the generators need to inform NGET if there are issues with this approach

29. The Workgroup agreed that the next meeting would be held on either the 10, 13 or 17 March.

5 AOB

30. JM noted that in BC2.A.2.6 it talks about the tolerance for MVAr instructions. JM added that in Scotland the Grid Code requires the MVAr output should be within a tolerance of the lesser of +/-5% or 25MVArs where as in England and Wales the tolerance is set to +/- 25 MVArs. It was noted that as GB moves towards bigger units, the tolerance may not be sufficient without changing the terminal voltage. GS agreed to look into this as it may be within scope.