Stability Pathfinder RFI Q&A

Updated: 29/08/19 – new questions added at the end: Q102-Q104

General

1. Does this RFI act as a pre-assessment for the tender?

No, this RFI does not act as a pre-assessment for the tender process. We are seeking views that will help us shape the tender process.

2. I read about your recently published "Zero carbon operation of the electricity system by 2025". Will CO_2 reporting be considered in the assessment?

We have a license obligations to ensure safe, reliable and economic operation of the electricity system. Based on this obligation we cannot discriminate based on technology and therefore not able to directly consider CO_2 emissions in selecting solutions.

However, our CBA methodology will consider market displacement impact of any solution. Such as where a minimum level of active power export is required from a solution provider which would not otherwise be operating, the associated costs of rebalancing will be factored into the provider's assessment. This consideration indirectly notes the impact of more carbon intensive solutions operating where that may not otherwise have been the case.

3. How does my provision of stability pathfinder services impact my normal operation in the energy market?

Our minimum requirements are not specific to any one form of technology, nor do they specify any form of energy market operation. It will be for individual intended providers to take account of any impacts to broader operation that may arise from meeting the provisions of stability product.

We also note in our CBA methodology that consideration will be given to the market displacement impact of any solution. Such as where a minimum level of active power is required from a solution provider, which would not otherwise be operating, the associated costs of rebalancing will be factored into the provider's assessment.

4. Is this a one-off, or will you expect to conduct further stability pathfinders in these same areas?

We want to understand through all pathfinder projects what would be the appropriate frequency of such activity and how it may relate to other ongoing processes of both market activity and network development planning. We have stated that in addition to the long-term needs in Scotland, we intend in due course to consider long-term requirements in other areas of GB in order of priority and timing of needs.

5. Will identifying framework restrictions associated with a solution mean it cannot be considered in the pathfinder?

At this stage, we are seeking information on any code, regulatory or other framework restrictions that would impact stability solutions. It is not our intention to limit any solution on this basis at this stage; and encourage feedback at this early stage where there are concerns in this area, such that they can be explored and solutions found.

6. Do interested parties need to provide any different information for E&W solutions in comparison to the Scotland solutions?

No, we want all RFI responses via our published feedback template (Attachment 2 of the RFI pack). We welcome any additional information.

7. Slide 12 mentions TRL - who determines the TRL and on what basis?

We would expect a potential provider, using the reference to the definitions of TRL to both identify their current level and provide evidence to support that assessment. We will, based on the supplied evidence, confirm whether that TRL can be supported. Providers should note that the TRL is a minimum requirement which if not met would preclude consideration for the applicable tender process.

8. In establishing the TRL and capabilities of a proposal it may be necessary during the RFI stage to share commercially sensitive information surrounding our proposals. How do we ensure that these details are not published?

It is for the provider to conclude what level of detailed dialogue is required at this early stage, and this may necessarily need to vary across the range of technologies, if in the provider's opinion there is justification for doing so.

Note that we will only publish anonymised/ generalised Q&As and RFI feedback.

Note that slide 36 provides further descriptions of the TRL definitions, stage of development in the context of the stability pathfinder and our expectations of demonstration at each stage.

9. It may be difficult at this stage to provide indicative prices. Will my proposal not be considered if I cannot provide this information?

It is not essential at this stage to provide this information, nevertheless the information is welcomed as it will support the design of contract options and structure as we are better able to appreciate your costs.

10. Can I stack services?

To participate in the stability pathfinder, you will be required to meet the minimum requirements (including availability requirements) set out in the RFI pack, any other services you contract for should in no way compromise your ability to meet these minimum requirements. If you wish to stack services, you would need to consider whether in doing so you can meet all the requirement of the stability pathfinder whilst also meeting the requirements for other products. Note the stability pathfinder expects to include penalty clauses for failure to deliver which should be considered when ensuring that service stacking is suitable for your product.

11. You mention in slide 9 "Wider Activities impacting stability". Many of these activities are ongoing and have yet to complete- to what extent do these activities each interact with the stability pathfinder?

These other activities can inform the context within which stability pathfinder solutions may operate. A brief overview of these activities is:

<u>Grid Code VSM Expert Working Group</u>

This working group is seeking to inform subsequent decisions around the implementation of future requirements within Grid Code surrounding the operation of convertors under a Virtual Synchronous Machine (VSM) control philosophy, and other approaches more generally which are Grid Forming rather than Grid referencing in nature. Such approaches may represent one of many options for stability solutions. Additional information and data intended to support GB specific application of such approaches is captured on the workgroup website and may be useful for potential providers considering such solutions. The VSM expert working group is focused on establishing the appropriate framework for future Grid Code changes that would focus upon new users.

The stability pathfinder however separately specifies its needs which are not dependent upon the progress or direction of the VSM expert working group but are equally not incompatible with them.

Applying a “Network Options Assessment” to voltage

The voltage pathfinder has, for the Mersey area, started its initial tendering activities. The stability pathfinder is complementary and additive to the voltage pathfinder which prioritizes steady state voltage needs.

Black Start Tender

The black start tender is an example of an existing National Grid ESO process, which considers aspects of inertia and short circuit support, and requires a feasibility stage to demonstrate technical capability. Providers are invited to review the feasibility stage documentation available there for further information. The Black start tender is entirely separate to the stability pathfinder, procurement in one in no way effects procurement in the other, as the services being delivered are for very different reasons and times.

EU Code Implementation

As EU codes are implemented into GB, several areas of additional clarification are provided to how future metrics of stability apply to the transmission and distribution networks. An example of this is updated now in the code which relates to fault ride through. These set the context to the requirements we define but neither influence our minimum specification nor process. It should be noted that more broadly new users will be expected to meet the salient areas of the Grid code as applying to their programme of connection, which may include areas of EU code as adopted into the GB code over that time, where applicable.

EFCC NIC project

The findings of the completed EFCC project are summarised on our website. This project provides further information on how local frequency varies from national frequency across current and future network disturbances. The findings of the EFCC project also inform our specification of inertial support identifying the speed at which interactions between inertia and fast response may occur. The stability pathfinder is separate to the completed EFCC project and does not seek to shape broader frequency needs.

Phoenix Project

Scottish Power Transmission and National Grid ESO are partners in an NIC project considering options for using synchronous compensation and hybrid synchronous compensation-Statcom solutions to enhance network stability and operation. This includes the installation of a 140MVA total capacity hybrid device at Neilston within the Scottish Power Transmission system. As with the VSM export working group, this project has the potential to provide additional information on certain types of solutions which a provider may consider but in no way interact with the process of the stability pathfinder.

Requirements

12. Will you be buying all 6000 MVA in Scotland you mentioned in the RFI pack?

6000MVA is our initial indicative requirement, but it represents neither a threshold nor limit to our tendering. We will review the offers and where it is more economic to procure less or more of this requirement we will determine this in response to that data, which would be compared against other market intervention and/or network development options available as part of our CBA process. The CBA outcome should tell us if there are sufficient competitive offers to meet the requirement and it is efficient to do so. However, we reserve the right to buy less (or even nothing) if the prices are not competitive. We may also repeat the tender process in subsequent years as our requirements and the clarity for meeting them evolve.

13. Slide 24 quotes requirement as "requirement (MVA at 1.5p.u.)" what is meant by this?

The levels of requirement quoted in the table each assume that the service provider is meeting the minimum requirement of the service of a 1.5p.u. (150%) inclusive of overload capability. In other words, the scale of the requirement would be 9000MVA in absolute terms if no overload capability was provided. The specifics surrounding how this overload capability is required is contained within the more detailed technical specification document.

14. Page 2 of Attachment 1 - "What is meant by Inertia (MVA.s)> 1.5p.u. MVA available in steady state operation? Can you define it as the additional active power? Why is inertia defined in MVA.s and not in MW.s?

Our definition of the inertia contribution relates to the level of MVA reserved for normal operation, and as such is a user defined term. Inertia can be defined on a p.u. MW.s or a p.u. MVA.s basis. MVA available in steady state operation is a term that we have defined to allow generation or devices which may have limited overload capability beyond their rating to find options for providing stability solution.

We have chosen to use the MVA.s definition to be flexible to the range of inertia provisions that may result not just from a synchronous generator (full or part of machine rating), but also from a range of technologies which may or may not operate with active power in the steady state. Device such as a synchronous compensator or a Statcom with VSM can provide inertia response while no active power capability is provided in the steady state. It is a definition consistent with that used for our black start tender.

For example, consider a generator with a 500 MW at a rated capacity of 525 MVA. This generator would have a rated MVAr range based on a 0.95 power factor of 167 MVar (lead/lag) at 300 MW output. It would still be expected to provide 167 MVar in the steady state (343 MVA in steady state operation). This 343 MVA represents a capability to achieve 1.5 p.u. overload of 515 MVA which is within the rating of the generator.

15. What is the system need for your requirement?

The requirement is mainly driven by the declining system strength. This is leading to several operability constraints that collectively we are calling stability. If you want more details of the issues behind our requirement refer to our previous System Operability Framework (SOF) publications.

16. Why are the locations specified in Scotland?

Stability needs are locational specific. i.e. to solve an operability constraint the solution need to be at or near to the constraint. The location published in the RFI are where solutions will be most effective. Other locations are acceptable but the effectiveness of the solution will potentially decline as you move further electrically and is highly dependent on the nature of the dynamic performance of a given proposed solution whose response will depend upon its specific parameters. This will be further explored during feasibility stage of the tender process.

17. Can I connect at lower voltages?

We are not limiting where solutions are proposed. However, as with the above response solution become less effective as they get electrically further from the need. Our studies show that connecting behind the impedance of a transformer drastically reduces the effectiveness of solutions.

Our analysis tells us that solutions become significantly more effective as their connection voltage increases (Refer to SOF report on Whole system short circuit levels). This is consistent with our expectation that effectiveness increases as network impedance reduces and means that we are very much focussed on transmission connected solutions in this exercise. We welcome engagement from all providers, including those who see an opportunity to connect at distribution voltages, but would ask interested parties to note that we believe it is unlikely that solutions based on a connection below transmission voltages will deliver best value for consumers.

18. Can I provide the solution using more than one device?

Our minimum technical criteria being functional in nature are open to being met by one device, or indeed from a combination of devices – this is very much for the provider to outline.

19. Are synchronous compensators the only available solution?

Our approach to solutions is technology neutral. Any solution will need to meet our minimum technical criteria per MVA as specified in attachment 1 of the pack. Whilst a synchronous compensator represents one technology that could meet this, we do not believe it is the only one, and encourage all providers who believe they can meet the minimum technical criteria to contact us during the RFI stage to discuss their proposed solution. It should be noted that our criteria being functional in nature are open to being met by one device, or indeed from a combination of devices – this is very much for the provider to outline.

20. I have a new technology, can I participate?

Provided the technology meets our minimum technical criteria and represents a level of technical readiness that allows the technology to be delivered in time to meet the proposed contract period, there is no reason why that technology cannot participate. Where a new technology is proposed, we would welcome as much information as can be supplied as early as possible to inform the modelling and operation of that technology. This can inform an efficient programme of subsequent feasibility stage work, should that solution ultimately prove successful in going forward.

21. Can you tell me how effective I will be now?

This will be calculated at the feasibility stage of the process as it will depend on the fundamental performance of your technology in response to frequency and voltage disturbances then simulated with the presence of your device and the location of your device relative to those disturbances.

22. What is the rationale behind procuring support from less effective locations?

A solution may be less effective but may present lower overall cost, thus better value for consumers.

23. My product cannot meet one part of the specification can I participate?

We will require all parts of the technical specification to be met for you to participate in any tender. However, please let us know in the RFI which areas you find difficult to meet and what you could do as this may inform later stages of the pathfinder process, or our approach to requirements in other areas of GB where our balance of core requirements may be different.

24. Do I need a connection agreement to participate?

No, we do not intend for a connection agreement to be a pre-requisite to participate in this RFI process.

We may require connection agreements for a tender, but that will be confirmed later.

For short term GB tenders for 2020, we will publish our next steps after the RFI feedback but would expect the providers to be already connected or be in the process of connection for 2020 delivery.

25. Who pays for energy?

We include our draft CBA process within the RFI pack and welcome feedback on this. Within this, we make no explicit allowance for the energy costs associated with operation of the provided solution. We expect the solution provider to support any ongoing operational costs including where appropriate for energy exchange as associated with their solution and reflect this in their bid. This includes any losses directly associated with that energy exchange.

26. Who pays for connection assets?

This will be as normal connection offer process.

27. What is the expected utilisation?

We are current expecting all solutions to be made available at all settlement periods, notified to run in the normal manner, which allows where possible any solution with active power consequences to self-dispatch within the BM (except for agreed maintenance periods). The service utilisation cannot be reasonably predicted as the requirement is for an inherent and near immediate response from a solution when a voltage and/or frequency disturbance occurs and sizeable responses would relate to fault conditions whose location and frequency is variable and indeterminant. Equally small disturbances such as switching and load change could still see some natural response from such a solution. The VSM expert working group has published some indicative data on frequency and voltage variations which may assist a potential provider considering such matters.

28. On slide 27, additional scoring is indicated for additional technical consideration between otherwise equivalent commercial solutions. What is meant by “otherwise equivalent”?

If solutions, as a result of cost benefit analysis, are equivalent in value across contract periods we will consider them equivalent in evaluation. Any differentiation then relevant will be derived from the additional 3 consideration areas outlined which are non-essential, yet desirable factors in a solution.

Contracts

29. How long will contracts last?

No decision has been made on this. We welcome your views. We have equally not decided whether one or more potential contract forms could be made available for a provider to select across based on the nature of their proposed solution. We welcome your views on this.

30. Will there be availability and utilisation payments?

No decision has been made on this. We welcome your views. Note however that given the nature of utilisation as described in stability product description, it would be problematic for any party to anticipate. Given the core need is to be available and then to respond appropriately to any disturbance that occurs, it is more likely that contract forms would be more geared towards availability at this stage, together with some consideration of how that availability is combined with in service performance against expectation.

31. Will there be penalty clauses?

We currently expect there to be some form of penalty clause for non-delivery of service. The exact nature of this arrangement will be dependent on broader questions of contract form, structure and supporting demonstration of capability in simulation at the feasibility and later compliance and other testing stages of any solutions delivery.

Process and Timescales

32. When can we participate in the tender?

We will publish timescales for short term GB tenders and long term Scotland tenders after the RFI feedback.

33. How do I respond to the RFI?

There is a feedback template included in the RFI pack. Please send your completed feedback template to box.networkdevelopment.roadmap@nationalgrideso.com

34. What do I need to demonstrate at the feasibility stage?

We expect you to demonstrate that you meet the requirement set out in the specification and in doing so provide information on the nature and timing of your proposed solution. We welcome your views on how this is done, and are flexible to what evidence/ information is provided at this stage. Please note that the more information that can be provided at this early stage, the better informed we will be in ensuring subsequent stages can be structured to encourage the maximum participation and the most efficient assessment and feasibility stages that would follow. For example, where possible we would welcome a mixture of equipment specifications, models and technical reports evidencing solutions being provided/ referenced at this stage.

Questions from 6th August Webinar

35. Can we get a copy of the 6th August Webinar slides?

The slides are available on our website.

36. Have NG ESO economically justified the optimum timing for stability improvements for the committed offshore wind farm connection nodes in Scotland?

While defining our requirements, we consider Future Energy Scenarios for the next 10 years. The economic justification will be considered in the Cost Benefit Analysis process while comparing different solutions.

37. Is the 6GVA in slide 7 of the august 6th webinar including the 1.5p.u. or excluding?

6GVA in slide 7 refers to the requirement including the 1.5p.u. overload contribution from providers. i.e. the total requirement at 1p.u. is 9GVA. If provider offer solutions with an overload contribution greater than 1.5p.u. the amount required may drop lower than 6GVA.

38. How long is the overload rating required (in minutes following an event)?

In the technical specification, we state that we require a minimum of 1.5p.u. of MVA available in steady state operation for both SCL and inertia. This is required during a fault and for 0.5s after the fault clears. After 0.5s response following a fault, response is required to decay with a time constant of at least 12s (this is equivalent to a time-period of 20s as defined in NETS SQSS).

39. Is the 1.5p.u. level required the full day 24hrs or can it be offered for parts of the day?

We have specified 1.5p.u. capability as a minimum technical specification. We expect this to be made available 24 hours a day for long periods of time. A network disturbance could happen anytime during a day and it is challenging for us to provide a view of within day needs for next 10 years. We also specify minimum availability of 90% in a year for a solution. We would welcome feedback during the RFI on how best this level of availability could be achieved.

40. Who is going to ensure the overall small signal stability issues (electromechanical, AVR/exciter modes) are addressed following stability enforcements?

Each of the regulated parties who own and operate the assets have license obligations to ensure that the network is safe and secure. The Electricity System Operator and Transmission Network Owners work together to ensure all aspects of stability are understood across all time scales.

41. I would like more information on how the CBA works - what parameters, what durations, marginal cost basis etc. Is your modelling based on PLEXOS software?

Cost Benefit Analysis is described in the technical performance and assessment criteria document (Attachment 1 to the RFI pack). The CBA will consider the effectiveness of a solution against the system requirements and the cost of providing the service.

The effectiveness for each solution will be calculated at the feasibility stage and will be dependent upon the technology/ specification of a solution, the location of the solution and any associated active power exports of the solution that make it less effective.

Our market modelling is based on BID3 tool. More information on BID3 can be found at:

https://www.nationalgrideso.com/document/90866/download

https://www.nationalgrideso.com/document/90871/download

https://www.poyry.com/BID3

42. Slide 9 of the August 6th webinar: please clarify "without impacting the energy market"?

This refers to the fact that in the CBA we will take account of active power exchange from any solution. If a solution needs to import or export active power to provide stability service this will have an associated cost due to the required interaction in the energy market this is for the provider to manage and should be reflected in the provider's cost. There will also be a cost associated with rebalancing actions associated with this energy market action this will be considered in the CBA.

43. Is the service to include both availability and utilisation payments? What would be the likely contract payment structure. Fixed availability payment?

We currently expect the contract to be predominantly based on availability payments, due to the nature of the service required. At this RFI stage we would welcome any view on the form of contracts.

44. The FAQ mentions contracts, however does not offer any visibility of likely contract length for this support service, which will be a key criterion for providers. Is there any information that can be shared i.e. is this <5 or >5 years?

At this RFI stage we would welcome any views on the length of contracts.

45. What is the timing for England and Wales short term, Scotland long term and E&W long term?

After RFI feedback, we will publish our next steps- this will be in part informed by your feedback to us.

46. Slide 10 of the August 6th webinar states contract award of Jan 2020? However, service are not called upon until 2023, is that right?

We are hoping that offering a period between contract award and the start of the service will open up this opportunity to providers who may need time to construct their solution. We would appreciate your feedback on what length of time would be required to make this possible.

The timescales for contract award will be finalised for Scotland long-term tender (2023 onwards) after RFI feedback. As these are long term solutions, we expect solutions to appear between 2023 and 2030 subject to our CBA assessment. E.g. a solution if successful in CBA could still be awarded a contract in 2020 for delivery in 2025.

47. Do you have any indications of the volumes of services to be procured in the short-term and long-term tenders?

Not at present. After RFI feedback, we will publish our next steps.

48. Are all synchronous generators TRL 9?

If a synchronous generator is already connected to the transmission network and is compliance tested, then it would be considered TRL 9. Same applies to any generator connected to the transmission system as the technology is proven, compliance tested and can be instructed by the Electricity Network Control Centre.

If a provider is proposing to decouple its active power from its stability support (through a clutch, a lower Stable Export Limit or another method), the new running arrangement would need to be demonstrated for it to be considered TRL9.

49. How will the solutions be sourced? i.e. will it be a TO-owned asset?

Both market and Transmission Owner solutions will be considered as part of the overall assessment. CBA outcome will determine which solutions will be contracted/taken forward.

If you consider your solutions require areas of framework/ regulatory clarification, please let us know and we will seek to explore these areas further with you and other appropriate parties.

50. Will RFI submissions be released publicly?

Only generalised feedback will be published. Any specific responses will not be shared.

51. It is important someone takes an overall system wide impact following these stability reinforcements?

Stability Pathfinder is part of our Network Development Roadmap. The aim is to apply Network Options Assessment (NOA) type process to consider operability issues. Stability Pathfinder is a trial for us to learn how we incorporate short term and long term stability issues into more enduring processes. Stability solutions procured will have an impact on rest of the network such flows from one area to another. This will be considered in determining our future system needs.

52. Could you elaborate some more on the points in slide #9 of the 6th August webinar: regarding 'connection diversity' and enhance capability for stability support?

Under the NETS SQSS, the ESO is required to ensure that system stability is maintained for the loss of the largest source of reactive power support. Where the stability support provider has designed proposals such that no single failure would fully remove the capability of the solution offered, we will allocate value to the diversity afforded by that design. Attachment 1 of RFI reflects 6 levels of connection diversity we would value.

It should be note this will only be considered where two solution are otherwise equivalent value commercially in the CBA.

53. Should the solution model be in DigSilent or other packages (e.g. Matlab or PSCAD) are also possible?

We will specify what format we expect any models to be submitted in, to allow us to incorporate solution into an existing GB model. This is expected to be DigSilent Power Factory for RMS models and PSCAD for EMT models, and should include any initialisation scripts and enabling software where applicable that enables that model to be run.

54. You mentioned transient voltage dip, short circuit level, inertia support and fault current injection; do you expect all these four services from the same unit/technology/provider or can a provider provide any one of these?

We expect any solution to meet all the technical specification to participate and do this for all forms of frequency and or voltage distortion discussed within the specification. However, this must be met at a given Point Of Common Coupling upon the onshore transmission system so this can be either one device delivering all areas of the specification, or multiple devices acting together.

55. Are NG ESO looking for 100% commercial solutions to these requirements or are these solutions competing against traditional TO build solutions? If they are competing can you provide details about the traditional solutions being considered. Cost benefit details would be great to benchmark.

Transmission Owner solutions will be considered against commercial solution as part of the CBA process. Either can propose solutions which meet our technical specification, these could be traditional technology or other. We are technology neutral in our approach to solutions.

56. You are already procuring reactive power services. How would this affect that, does it make existing tenders redundant?

Our stability need is new and different to what is being considered by our existing reactive services and does not replace this service.

To participate in the stability pathfinder, potential providers will be required to meet the minimum requirements (including availability requirements) set out in the RFI pack, any other services contracted for should in no way compromise the proposed solution's ability to meet these minimum requirements. If you wish to stack services, you would need to consider whether in doing so you can meet all the requirement of the stability pathfinder whilst also meeting the requirements for other products. Note the stability pathfinder expects to include penalty clauses for failure to deliver which should be considered when ensuring that service stacking is suitable for your product.

57. If the principal part of a plant is related to a turbo generator & HV equipment and if these are standard, do we need to demonstrate compliance with the technical specification?

We expect all participants to demonstrate that they can meet the technical specification. However, if you have an existing plant we would expect this would be easier for you to demonstrate.

58. Does TRL relate to the plant or the equipment providing the service?

TRL relates to your installation. If this has not been built and commissioned yet it cannot be TRL 9 but it may be TRL 7-8.

59. Is a synthetic inertial response allowed, i.e. via DC-AC converter with a ms delay?

We expect all convertor based technology to respond instantly to a fault (within 5ms). This has been demonstrated for convertor based technology via Virtual Synchronous Machine (also known as grid forming convertors). Typical PLL based technologies have not been shown to be able to meet the minimum technical criteria but it is for any provider to show their solution meets the minimum specification. We are open to further discussion on any of technology option. However, solution providers will be expected to meet the required TRL to enter any tender process.

60. Why don't the TOs use the same engagement processes as everyone else?

Transmission Owners are regulated parties and maintain their own license obligations. ESO and TOs, as licensed parties, worked together within the framework of System Operator Transmission Owner Code (STC). The current Network Options Assessment (NOA) process of system boundary analysis recommends which TO investments should be taken forward compared to system operator constraint costs. Through the Network Development Roadmap and the Stability Pathfinder we are aiming to open the NOA process to market participants and more operability issues. However, this need must be done within the constraints of the ESO's and the TO's licenses.

We believe our approach is the best in achieving this aim and we welcome feedback from TOs and market participant as part of this RFI.

61. Will the TOs be limited to 7 year contracts?

TOs will not be given a contract in the same way as other participant but given a signal (as under the NOA process) that investment is in the best interest of consumer. They will get a return on their investment in line with their regulatory deal. It should be noted that in the proposed CBA methodology for assessing TO solution in the CBA will assume the benefit of any TO solution needs to be recovered over the equivalent contract length. This aims to demonstrate whether a TO solution or a market solution present greatest value for consumers.

Question from 14th August Webinar

62. Can we get a copy of the 14th August technical webinar slides?

The slides and a recording are available on our website.

63. Is the impedance (voltage source behind impedance) only for 50Hz? Is the 10% impedance sub-transient or transient or synchronous? (slide 6 of technical webinar)

During a disturbance, frequencies may be present that are different to 50Hz both in steady state and transient conditions. In our technical specification, we are referring to impedances at steady state conditions of 50Hz. It is for the provider to ensure, irrespective of the frequencies that the response is consistent with our specification. This needs to be an intrinsic response to the 50Hz system, rather than measurement of other frequencies in the first instance.

Potential solution providers may find considerations of bandwidth limitation of secondary control systems within the draft VSM outline functional specification, and CC.A.6.2.5.5 of the Grid Code to be of benefit to them in further consideration of their design.

64. What is driving minimum 10% impedance requirement?

Slide 5 of our technical webinar discusses the fundamental nature of control required within our minimum technical requirements. In the technical webinar recording, we explain the importance of a minimum impedance which is sufficiently large that it can generate the required response to a range of disturbances. We would welcome your feedback if you believe there are other methods of achieving the same effect via a different measurement-less approach.

65. Slide 5 of technical webinar - I agree with this diagram and the need to hold the phase angle to deliver real inertia power. If there is a continuous RoCoF, the grid frequency and hence its phase angle will fall and the new unit must track this change. Is this agreed?

It is expected that the solution will respond to change in angle within 5ms. To achieve this, the solution is expected to be measurement-less and should be able to provide inertial support during the fault and up to 0.5s after the fault clearance. A further period of damping ahead of transition to a frequency response provision being delivered by relevant providers is then required.

We note that you may choose to potentially provide both stability support and frequency response- this would be your choice and it is separate to the focus of the stability pathfinder. We do not preclude you providing both stability support and frequency response, provided you meet the requirements of both, and stack successful services for both without compromising either provision.

However, if this is not the case and only stability support is being provided; this would then be limited to the period of the service. Beyond that period, subject to whether there is a steady state active power operation or not before the disturbance, the solution would operate according to the principles of Limited Frequency responsive operation, as defined within the Grid code and as applicable to the solution's classification. Where the solution is not providing active power before the event, following the end of the period of the event there would not be a further requirement for continued active power provision. However based on the minimum technical criteria, reactive power support may continue if the voltage remains disturbed at that point.

66. I have heard your preference for transmission connected assets - what about a 30MW battery connecting into a Scottish GSP at 33kV? Seems the intermediate impedances to the transmission system would then be minimal and easy to assess. Would such a facility potentially work for your needs?

If a solution can demonstrate meeting all minimum technical specifications at the nearest transmission node, we would consider it to be meeting our needs. You would need to ensure this is the case for the range of intervening network conditions that could occur. It is for you to demonstrate you can meet the minimum technical specification.

67. Slide 8 of technical webinar - at rated output what is the required power factor and also what is the required power factor at the 1.5p.u. value?

We explain this through examples in slides 8-9 of technical webinar. We don't specify a power factor or how a solution should meet minimum specifications (e.g. through inherent capability or steady state conditions driven capability).

68. Does the solution need to be able to provide the fault current for a zero retained voltage at terminals? or is it down at a % of nominal.

The technical criteria are expected to be demonstrated at the nearest transmission node. The solution is expected to have minimum 10% impedance between itself and the nearest transmission node. This means even if there is zero retained voltage at the nearest transmission node, there will still be impedance that the solution will see hence a level of voltage. The solution is expected to inject reactive current to support voltage for the duration of the event when voltage is depressed.

69. What generator impedance would you use to assess the fault contribution of the generator during and after a fault? e.g. x''d or x'd or xd?

The solution is expected to respond dynamically to network conditions. The solution will need to demonstrate its performance against all periods of a disturbance. We will need to know fault contribution across all time periods as specified in our technical specification. E.g the solution will need to start responding within 5ms of a disturbance and will need to provide relevant response (active power or reactive power or both) up to fault clearance and up to 0.5s beyond that.

70. Is response (inertia) evaluated equally at any of 400kV or 275 kV or 132 kV voltage levels?

The response will be considered at the nearest transmission node (which could be 400kV or 275kV or 132kV). Compliance with the minimum technical specification will be based on this response.

71. RFI Attachment 1, 1.12 Inertia criteria: Could you please explain if this is about "true inertia" response from a voltage angle step? Or is it about ramp rate limited/filtered inertia response from solution?

The inertia response expected is to be similar to the behaviour of voltage source behind a minimum 10% impedance. Slide 11 of technical webinar explains this further. The response is expected for a voltage angle change at the nearest transmission node.

72. Will the incremental increase from added inertia to the Largest Infeed Loss/reduced frequency response holding be valued?

This requirement is regional and different to our existing frequency response services. It may be that largest loss response holding for national frequency may be impacted, but it is not the intention of the stability pathfinder to replace frequency response services. Providers can consider participating in more than one service. For stability evaluation, we will only consider performance against our defined criteria.

73. Slide 14 of technical webinar - what if the device only provides reactive power?

The solution is expected to meet all minimum technical specifications to be considered eligible to patriciate.

74. Slide 14 of technical webinar - Is there any estimation of how often are these power oscillation events? What is the value of the oscillation frequencies?

It is difficult to estimate how often these oscillations will occur on the network as these will be dependent on variety of network conditions and their combinations. The inter area oscillations ranging between 0.1-1Hz occur between various areas of the transmission network. Notably oscillations on Anglo-Scottish boundary around 0.5Hz.

75. If a new unit does not have a continuous power deliverability but does have an energy store that meets the 150 % MVA fault current rating and the H = 1.5 rating then it would only deliver real inertia power when there is a df/dt. For a RoCoF of 1 Hz / s the real inertia power will typically be less than 6% of the MVA fault rating. Is this acceptable provided that it is then maintained with the 12 second time constant. This then implies that a unit of this type will need to provide a power / frequency response in addition to its RoCoF response.

This is the correct understanding regarding the damping criteria. Our stability need is separate from our frequency response services.

76. Please clarify the compatibility of the 12s decay time constant with the requirement to support oscillation damping (as discussed in the following slide)

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) defines system instability based on this same 12s time constant which relates to the duration across which rotor angle oscillation is attenuated. It is important that, regardless of the technologies used to support stability, that they complement and support one-another over the overall period of both response to an event and subsequent support in damping the system voltage, frequency and angle following the disturbance.

In practice, the control responding should continue to support with reactive and active power to at least a magnitude of support as defined by the maximum magnitude response then declining in magnitude over 12s to half its original magnitude.

77. Is there a possibility of the usage of grid-forming inverters?

Yes. We are aware of this technology theoretically being able to meet the minimum technical specification. It is for each provider to demonstrate that their design is compliant and sufficiently mature to satisfy the demonstration of TRL for the timeframe of service delivery.

Other technologies that meet the minimum technical specification would also be possible.

78. Do you expect windfarms which have an enhanced (i.e. above the grid code minimum and at any MW output) reactive capability to be able to provide useful fault current contribution and therefore participate in this service despite not providing an inertial response?

We would expect all solutions providers to meet all the minimum technical criteria. This could be achieved in various ways, e.g. changing steady state dispatch or ensuring enhanced capability above the grid code.

79. Slide 22 -Droop: is better than 4%, e.g. 5% or 3%?

By better than a 4% droop, we mean a 3% droop.

80. Is the 5ms commencement of response or part of the rise/settling time?

5ms is the commencement of response.

81. Is this real inertia or virtual inertia you are looking for?

The inertia response is expected to be initiated within 5ms, this could be achieved through real inertia or virtual inertia.

82. Is Inertia expected to be provided at low production at low wind?

Yes.

83. Are you planning to publish some detailed criteria for how compliance will be assessed? Such that it is possible to assess whether a solution based on e.g. a combined system based on an inverter based generator and an inverter based storage system will satisfy the performance requirements.

Yes. We expect to publish guidelines around this as part of the tender process.

84. I understand that the use of a conventional synchronous compensator would not be acceptable due to the inability to meet the 12s inertia decay. Is that correct?

We discuss some examples in our technical webinar on how different solutions can potentially consider meeting the technical specification. For example, through additional capability or steady state operating conditions.

85. Slide 24 of technical webinar: How does a real synchronous machine react to a 90deg or 200deg phase jump? The red line look like something that could be deemed instability in conventional stability study. Would a synchronous machine if this were the solution conventionally stay stable for such an angle behaviour.

There are limited international standards in this area. A synchronous machine would follow equal area criteria for its stability. In a system with high system strength a synchronous machine would be expected to recover quickly following a large transient angle disturbance.

86. There are differences in synchronous solutions, have you modelled cases where synchronous response is dominated by synch comps and scenarios where there are sync generators, what is the impact on system stability and phase angle movement

We acknowledge that there will be difference between synchronous solutions. We have not modelled different scenarios to compare responses under different solutions. We want to understand what solutions can meet our requirement and how they can be modelled. Our minimum performance criteria is defined to address potential network stability issues.

87. What levels of damping is NG considering appropriate for the inertial characteristics? And is it acceptable that this is damping is delivered by the controller and does not involve any active power exchange with the power system

The damping is required with such that it follows a time

88. why do you need models for synchronous generators where you already have the Data Registration Code (DRC) data?

If we have the right level of information already available to us for already connected users, we will take that into account.

89. Is it possible to get a test benchmark from national Grid to verify the performance of the developed method?

We expect to publish guidance on what we expect to be demonstrated in performance at the initial tender stages.

90. Availability will be linked to the costs of running the device; if it is mainly being run during high wind and wind is being constrained then the MW losses will actually count as a benefit. How will you evaluate the value / cost of MW import / export of a provider?

We are seeking feedback on the practical limitations of availability for range of solutions. We will better understand the application of availability in our CBA and contract structure after the RFI feedback.

91. When you refer to the benefit on the 'transmission' voltage - do you mean within this the 132kV network (i.e. transmission in Scotland)?

132kV in Scotland is considered as transmission level.

92. What demonstration of performance would be required within the RFI?

In the RFI, there is no requirement to demonstrate any performance. However, more accurate responses will mean that we may be able to consider these within our tender specifications.

Where performance capability is cited in the response, we would expect where possible for relevant information being provided.

Additional Technical Questions

93. Section 1.1.1. of the technical specification: What is the timeframe for "during the fault and 0.5s after the fault clearance"- please clarify?

Grid Code GC.6.3.15 and ECC.6.3.15 refer to the variable timeframes for the faults at 400kV or 275kV which are being considered against this requirement.

The type A fault is a solid balanced or unbalanced fault at that voltage. This fault will last no longer than 140ms but could potentially be cleared earlier locally, remotely or completely dependent on fault's location.

The type B fault is a remote fault condition, a potential solution must equally support these conditions relating to a family of voltage dips across a fault period which could be longer or shorter depending upon its severity. For example, at the longest duration of 3mins the dip in voltage is less severe, corresponding to no less than 0.85p.u. voltage. The voltage being measured at the point of common coupling of the provider's connection in relation of the onshore transmission system.

Regardless of the duration of the fault, the capability of the solution to respond for 0.5s after fault clearance is also required. if the voltage disturbance is smaller, the response will be expected to be reduced accordingly. This should be considered in the design principles of the solution.

94. Section 1.1.3. of the technical specification: steady state voltage requirement- what is meant by solution is expected to "withstand voltage changes following disturbance/ fault"?

Post fault steady state voltage requirement is defined by NETS SQSS. The network may be expected to continue to operate following a disturbance across a wider range of voltages than were present in the pre-fault steady state. For example, the voltage may only recover to 0.9p.u. for 15mins and post fault steady state to 0.95p.u. following a voltage depression. A solution will be expected to withstand such operational changes and continue to provide stability support.

95. Section 1.1.4. of the technical specification: the frequency range 47-52Hz is a wide range. What do you mean by "operate across this range"?

Operation across this range is a base Grid Code requirement for all existing transmission generation connections. The solution is expected to withstand the stated frequency range and continue providing response.

96. Section 1.1.20. of the technical specification: How would National Grid ESO calculate this availability level- why can you not identify the times you would need these solutions?

The 90% level relates to making the solution available across all settlement periods across of the year, with no more than a 10% unavailability. Providers can expect to be asked to be called upon across the year to demonstrate this capability practically and to provide support to the disturbances upon the system that arise under the normal course of operation. Any period the solution is not made available, is not available when called upon, or does not deliver the tendered capability under a disturbance will be discounted against this availability requirement in practice.

At the RFI stage, we welcome feedback from all providers to understand the considerations around availability and how this may be influenced by technologies and costs that may arise from this minimum requirement. The requirement for stability support is year-round. The year-round flexibility is necessary that ahead of real time when these factors are clearer, the operator has the confidence that the right solutions in the right locations are available.

97. Section 1.1 of the technical specification: what is your definition of Short Circuit power (MVA); what do you require? How does this relate to what would be expected from distribution connected providers?

Our definition is consistent with international definitions of this term, for example IEC 60909-0, section 3.6. Short circuit power is defined by the short circuit power multiplied by the rated voltage multiplied by the square route of 3. The rated voltage is defined by the rated line voltage of the point of common coupling to the transmission system.

For example, for a 250MVA provider with a 0.95pf lag-0.95pf lead range (78mvars) is connected at 400kV to the transmission network. Let us assume this convertor operates at 148MW pre-fault including the full 78Mvar range, it would be operating at a maximum of 167MVA. This would provide a 1.5p.u. overload capability of 250MVA equivalent to the convertors maximum rating. During a fault this provider would have the capability to provide a 250MVA short circuit contribution. The associated current relating to this would be 0.36kA, representing 250MVA, divided by 400kV, divided further by the square route of 3. In this example, if the voltage at the connection point during the fault was 0kV, the minimum level of SCL current that must be supplied is 0.36kA, corresponding to the short circuit MVA of 250MVA

A distributed connected source (let us say 33kV connected, but again a 250MVA provider embedded within a distribution network connected to the same 400kV transmission point) would need to satisfy the same appearance of a 250MVA additional contribution to fault current at the same 400kV connection point. Not only would this mean separating this contribution from others which may be present within the distribution system at the time, but the intervening voltage levels and network impedance (both of which would need to be understood across the times services would be provided) would mean, as we discuss in the ***whole system fault levels SOF report***, that the total fault current contribution of the distribution system provider would be much lower in practice than that of the transmission connected resource connected at the same point. It is for these reasons that we do not expect that distribution based services will be economic and efficient in the assessment of stability services and our interest is therefore focussed on transmission providers.

On an additional point of clarity, we are interested in the SCL contributions to transmission system fault levels at the points of common coupling with the wider system. We do not consider the areas of support that could be provided to distribution systems during distribution faults- this is a separate area outside of the ESOs role and remit.

98. We are concerned that decaying the maximum power supplied via a 12s time constant will result in an unreasonable requirement which may preclude certain technologies- this would seem to contradict with the 0.5s specified, can we confirm that this what is meant by the specification?

The two areas of specification are separate but complementary. The time period in the specification is 12s which equates to a degradation over 20s. The 20s degradation is intended to relate to the response of the provider over the residual 0.5s-20s period should the inertial response not exhaust the providers' delivery at 0.5s. The absolute values relating to this 0.5s-20s period would relate to prior period of RoCoF and the inertia provided by the solution. Any residual power capable of delivery should be capable of being degraded based on a 12s time constant or slower for that event.

This allows compatibility of the inertia providers in today's low RoCoF situations of being able to transition to conventional response provision, whilst recognising that for higher RoCoF levels up to 1Hz/s a faster or indeed immediate transition will be needed with faster response providers. The 20s degradation is not intended to increase the scale of energy made available over time by the provider, rather inform the nature of that energy's subsequent deployment where it is not exhausted over that initial 0.5s timeframe for a maximum RoCoF event.

99. Across high transient voltage change, a convertor base approach may go into current limit. If I cannot trip, can I take other control action to protect the convertor?

Our specification is intended to be a functional across the broadest range of technologies capable to meet it and would not seek to define a specific control or technology approach which would preclude other options.

In a situation where the solution has reached a current limit, across the first 0.5s of the disturbance, for the period that limit is in place we would not expect the device to trip or, via network measurement, modulate its output and/or phase angle. This is as outlined in our minimum technical specification.

Other solutions such as clipping the voltage waveform being delivered at that phase are however acceptable to the specification. There may be other approaches which are also able to meet this specification.

100. In respect of transient voltage angle withstand and performance, for a synchronous generator/ compensator does this represent any higher requirement than the current Grid Code?

The current Grid Code contains no specific criteria for transient voltage angle change. However, across the range of simulation and network disturbance conditions considered within the Grid Code and NETS SQSS, the range of voltage angle changes considered may be inferred. For conventional synchronous technologies, the performance specified would expect to be inherent. Given the significance of response to voltage angle change identified, we have explicitly drawn out our needs. For certain technologies meeting these criteria may represent a significant area of control consideration. These criteria apply regardless of the technologies being considered.

101. In section 2.2, you refer to resilience of support in terms of short circuit ratio of no higher than 0.96- this presumably is a score only available to Synchronous generators for which the term Short Circuit Ratio is relevant?

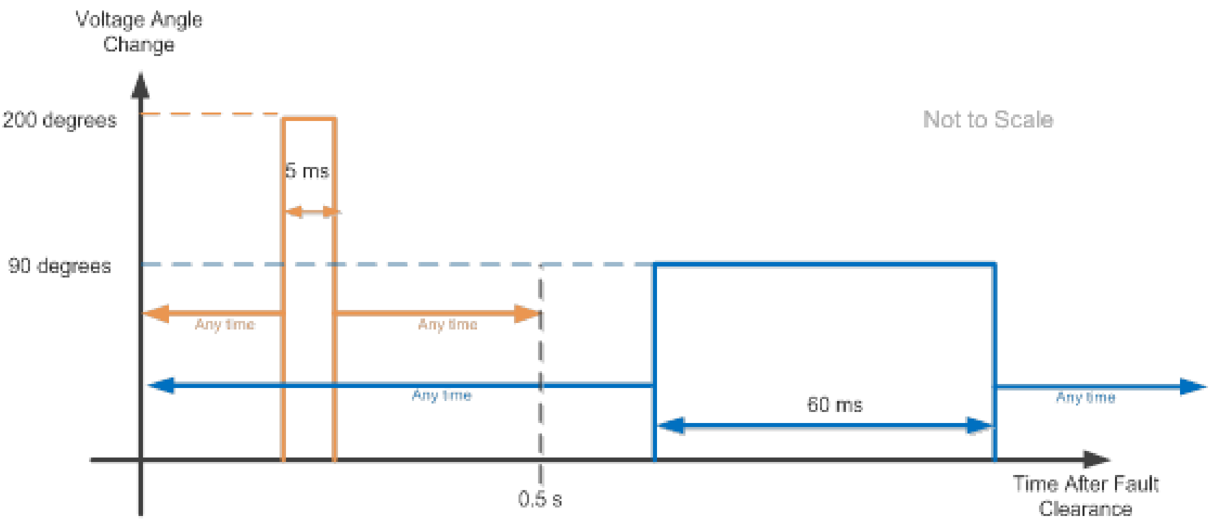
Apologies for the misunderstanding. In terms of network analysis, the term Short Circuit Ratio is also defined as the ratio between the MVA rating of the user and the Short Circuit Level expressed in MVA. For example, 0.96p.u. would mean that the Short Circuit Level (without taking into account the connecting provider's contribution) represented 96% of the MVA rating of the provider.

Section 2.2 seeks to explore, above and beyond the levels defined in 1.1.14, an ability to further operate and perform at or beyond the minimum criteria at lower short circuit ratios than 0.96- i.e. conditions of lower fault levels as may arise during conditions of further network depletion. We will update this section 2.2 of attachment 1 to clarify this point within the document.

102. You are looking for 9000 MVA short circuit power, however in the assessment criteria (point 2.3) you state increased scores for additional inertia as well as short circuit level current. From my understanding 5 p.u. short circuit level current would mean a total short circuit power of 30 GVA. It this correct? I just wanted to confirm it as this appears to be an immense amount.

For clarity, we do not expect to procure for over 9000MVA. Solution will be assessed based on what they can deliver, e.g. a solution with 3p.u. short circuit overload capability can deliver twice that of a 1.5pu device so will be twice as effective in a CBA. We are suggesting to consider additional scoring only for the solutions that are equivalent in financial value in the cost benefit analysis.

103. In point 1.1.8. of the Technical Performance and Assessment Criteria you mention ride-through post fault voltage angle deviations. Do you have a plot explaining the mentioned effect?



104. Point 1.1.2 of the Technical performance and Assessment Criteria: From the technical webinar on the 14th I understood that the decay of inertia criteria was related to synthetic inertia as created by semiconductor based solutions rather than physical inertia, as this inertia does not degrade. Is this correct and if a solution has sufficient physical inertia, there would be no need to add an additional source of active power to provide a fast frequency response?

The inertial response is required for during the fault and 0.5s after fault clearance and needs to follow damping criteria of 12s time constant, an appropriately specified physical inertia should be able to achieve this without additional active sources. Our identified stability need is separate to any current/future fast frequency response needs. Damping criteria is applicable to both synchronous and non-synchronous solutions (e.g PSS or a POD control).