Question Nur	Consultation questions	CitiPower and Powercor Response
1	1. Do stakeholders have alternative suggestions for the approach to determining minimum fault level requirements?	We do not believe that using the existing fault level is sufficient to determine the minimum fault level. The same assumption was made under the previous System Strength Requirements. For the Red Cliffs 220 kV bus, the fault level was determined at 600 MVA, however subsequent studies showed the existing fault level assumption was incorrect and was subsequently increased to 1700 MVA. We request AEMO to share its exact calculation methodology for their recent minimum system strength requirement calculations (for example at Red Cliffs) AEMO may wish to consider an alternative methodology. For example, the methodology could involve the following two steps: 1. Calculate the maximum (N-1) capacity of transmission lines (and/or transformers) that connect to a node. This is the maximum export capacity of any node to the rest of the network (the lowest thermal rating (e.g. 45C rating) should be used to avoid over-investment). For example, if a node has two transmission lines rated to 250 MVA, then the maximum that could be dispatched from that node is 250 MVA (~250 MW), without overloading the lines 2. Use the maximum capacity to find the minimum fault level for this node to operate stably (3 times the capacity of generation connected (a lower figure can be used, however 3 is required by S5.2.5.15)). In the example above the minimum fault level will be 750 MVA
2	2. Do stakeholders have any alternative suggestions for the approach to assessment of projected minimum fault level requirements over the next decade? If so, please elaborate on techniques, requirements to implement, and potential benefits over simpler approaches.	We consider the modelling approach appears to be reasonable. Additional suggestions include projections of Phase Angle Shift Calculations and/or threshold at nodes for credible contingency event or protected event
3	3. In the context of clause S5.1a.9 of the Amending Rule, what are stakeholders' views on the inclusion or exclusion of existing and forecast IBR in the assumptions for determining minimum fault level requirements?	Please refer to Q1
4	4. What are stakeholders' views on how protection equipment requirements for minimum fault level can be assessed, both now and for the coming decade?	It is suggested that "AEMO and the SSSP would work together to either facilitate recalibration of the protection equipment" and "Robust joint planning will be required between AEMO and TNSPs, and between TNSPs and DNSPs" It is important to specifically require joint-planning between AEMO and DNSPs. This is because DNSPs rely on overcurrent and distance protection more often than TNSPs, as this equipment is far more sensitive than TNSP equipment. We submit that AEMO/SSSP should work with DNSPs very closely to attempt to work through any protection equipment requirements.
5	5. What are stakeholders' views on the future of protection scheme design and operation as the Australian power system transforms?	See Q4

6	6. How could AEMO enhance the proposed approach to incorporating protection scheme operation into the minimum fault level requirements?	See Q4
7	7. Are there alternatives to the allowable voltage step change limit, according to the NER S5.1a.5, proposed by AEMO for testing that the minimum fault level requirements facilitate reactive control equipment operation?	We agree with the proposal and support the use of AS61000.3.7:2001. We further note that voltage step change of capacitor/reactor sizing is normally limited to the step size of the OLTC of the nearby transformer(s). That is, if the step size of the OLTC is 1.5%, then the capacitor/reactor step size is normally sized so that it equals 1.5%.
8	8. Do stakeholders hold different views on how best to incorporate the impact of new technologies on reactive control equipment operation?	See Q7
9	9. Where should planning responsibility for synchronism of distributed DER lie – in the minimum fault level requirement of the system strength standard, the stable voltage waveform requirement of the system strength standard, or elsewhere in transmission and distribution network service providers' planning functions?	We agree with the proposal for AEMO to continue to assess the largest credible contingency size for distributed DER as part of testing appropriate credible contingencies and protected events when setting the minimum fault level requirements. Further, a system strength node in the transmission network may have a very small bearing on the fault level seen at the 240/415V level, and even the 22kV feeder level, which can be far more dependent on the impedance of the applicable transformer than the network impedance. Therefore, it is important that enough system strength nodes are chosen so that minimum fault level for all DER are adequately considered. Further investigation is required to understand the impact of DER on system strength as well as the minimum fault level/system strength required for DER to remain synchronised to the network and operate stably.
10	10. Do stakeholders have specific proposals for how to assess how distributed PV impact available fault levels considering their sparsity, uncertainty and visibility?	Type testing in lab environment or test bench to assess the limit and/or sensitivity of different DER inverters should be undertaken. Subsequently, an analytical approach can be developed to assess the aggregated impact of DER.
11	11. What other issues need to be taken in to account when considering the application of the minimum fault level requirements in an operational context?	AEMO and TNSPs should work with DNSPs to consider minimum fault levels in the distribution network for both large (and small) embedded generators within that network.
12	12. Do stakeholders consider the proposed description for stable voltage waveforms to be comprehensive? Are there any recommended additions or deletions? If so, why?	We agree with the proposal.

13	13. To what degree should the SSRM indicate assessment processes that SSSPs may apply when assessing delivery of stable voltage waveforms for IBR connections and operation over the 10-year horizon?	We consider all three approaches are suitable over differing planning periods. All three methods should be used to best inform the SSSP according to the applicable time-period. Option 1 is suitable for very short-term planning, for example now to one or two years into the future, where the models are better known, and the output is most accurate. Further for this option, the use of generic EMT models needs to be carefully investigated to ensure a clear understanding of what functions to be modelled, selection of control parameters, etc. Further, there are different versions of generic inverter models so a clear set of criteria for generic models used in this option is required to achieve a certain level of consistency. Option 2 and 3 are suitable from a one or two year to 10 year planning horizons as they can be undertaken very quickly with low computational cost for each planning year. We further note that it (and all NEM NSPs) already maintain Available Fault Level (AFL) models of the current and future networks (due to existing SSIAG (5.3.4B) requirements) and therefore these can quite easily be expanded for future planning purposes (similar to what is done for DAPR/TAPR planning) without additional burden of creating models from scratch. Therefore this method is most appropriate for long term planning as long as AEMO/TNSPs/SSSPs consult with DNSPs for the creation of their AFL models. It is imperative that AEMO provide guidance on consistency between SSSPs, especially as system strength nodes can affect other regions (eg. Red Cliffs is a border node) as inconsistent approaches may lead to inconsistent investment in different NEM regions driving different connection conditions across NEM regions.
14	14. What do stakeholders consider to be the pros and cons of the three proposed options for assessing future voltage waveform stability? Should any other options be considered? If so, what options?	See Q13
15	15. Given the multitude of possible approaches, does AEMO have a role in providing guidance through the SSRM to encourage consistency between SSSPs where appropriate?	See Q13

16	16. Under what conditions, if any, do stakeholders consider that AEMO should deviate from the ISP's 'most likely scenario' for the purposes of the system strength requirements?	We agree that a 'most likely scenario' approach with sensitivity studies applied to the input is the most appropriate forecasting approach for the ISP. New generation should be modelled down to a specific bus. Also, whilst it is easier to estimate generation as direct connected to a specific node, it is highly likely the generation will connected downstream of that node (for example in the distribution system) and therefore be subject to a material amount of impedance between the 'system strength node' and the generating system. Further to our approach suggested in Question 1, the available capacity (and therefore required system strength) of the distribution network can easily be forecast using the suggested method and can be provided up to the "system strength node". Further given that Distributed Energy Resources (DER) are by definition distribution-connected, it is essential that DNSPs provide specific input into the ISP for planning of DER and this can be by providing the system strength requirements of the DNSP's network to the SSSP.
17	17. What locational detail should AEMO provide for new generation – a REZ level or a specific network bus?	See Q16
18	18. What (if any) additional detail for new connections should be set out in the SSRM, in addition to the location and total megawatts (MW)?	AEMO should include forecasts for each generation technology separately (e.g., wind vs PV vs BESS vs hydrogen, etc)
19	19. Do stakeholders have specific suggestions for how potential new loads should be incorporated in the forecast?	Inverter-based loads and other loads that require system strength and that will be installed in low system strength areas should be treated the same as other DER with new loads assigned to a specific bus in consultation with the TNSP and DNSP. However, we suggest a detailed analysis to be done first to reasonably quantify the impact of those loads on system strength before they are included in any system strength forecast.
20	20. Do stakeholders have specific suggestions for how DNSP-connected generation plant could be incorporated, given that the ISP predominantly considers transmission-connected plant?	See Q16
21	21. Is this equation-based approach for projecting the level and type of IBR for setting the system strength requirements appropriate? If not, what alternatives should be considered, and why?	We agree with proposal, noting there has been an industry trend towards using reactive power support from inverters regardless of active power (that is Q-at-night is now being seen enabled on many recent connections).
22	22. Do stakeholders have specific alternatives to suggest in response to AEMO's proposed approach to projecting technical capability of future plant? If so, what alternatives should be considered?	We agree with the proposal
23	23. Is including only committed and anticipated network augmentation projects suitable for forecasting system strength requirements?	Similar to the Annual Planning Reports (DAPR and TAPR), the ISP should consider all forecasts without augmentation, and then provide any "committed and anticipated network augmentation projects" as part of proposed solutions with the appropriate information (as per NER 5.12.2(C)(5))

24	24. Are there any other sources of information on network augmentations which need to be considered?	See Q23
25	25. Do you consider that the proposed selection criteria will allow for an appropriate set of system strength nodes to be selected? If not, please provide specific alternatives or additions.	We consider that every transmission node should have system strength requirement. Our experience is the AFL for every node on the transmission network can be calculated as quickly as just a select few with a PSS/E model. We have scripts to run AFL on every distribution node (down to the MV bus) in our network (which are far more nodes that the transmission network), and therefore it should be relatively straightforward for this to be undertaken at the transmission level. It is also noted that MLFs are calculated for every transmission network node and therefore the SSLF (and therefore System Strength Nodes) can and should be treated the same to ensure economic investment into all parts of the NEM. Further, selecting only specific some nodes in the transmission network will most likely create uneconomic investment into that node. An example here being that system strength investment into the Red Cliffs node will not improve system strength at Kerang for loss of the Red Cliffs to Kerang line, and therefore Kerang (and others) not having system strength requirements will result in Kerang never experiencing system strength investment to allow for this credible contingency event. Finally, due to the non-linear characteristic of fault level and impedance, a limited set of system strength nodes in the network will result in a non-linear/reasonable system strength investment
26	26. AEMO has not proposed to create a system strength node at every transmission busbar, to ensure practicality of assessment and monitoring of nodes. What do you think represents an appropriate balance between accuracy and practicality? If you do not agree with AEMO's proposal, please propose specific alternative assessment processes.	See Q25

27	27. Are there specific changes that should be considered to the AEMO approach to what a ‘critical’ planned outage should be, and the potential thresholds for those outages? If so, please note alternatives.	The number of transmission lines that connect to a node should be considered. For example, in comparing Kerang to Shepparton: • Kerang has two lines connected, disconnection for maintenance of either line will result in almost halving of the system strength and therefore both lines should be considered critical • Shepparton has 4 lines connected, disconnection for maintenance of one line may result in a negligible change in system strength and therefore that line should be considered non-critical. Therefore, a % change threshold after contingency should be considered to determine whether a contingency is critical. That is, if loss of the KGTS-BETS line causes the fault level at Kerang to drop by a material percentage it should be considered critical. For SHTS if a threshold of 20% is selected, then 3 out of the 4 lines connected to SHTS can be considered critical. If 30% or something higher is chosen, then none will be considered critical.
28	28. Do you have a view on whether criteria for critical planned outages should be specified in the SSRM, versus a case-by-case assessment each year?	Criteria for critical planned outages should be specified in the SSRM

29	29. Should a material threshold be defined for the purpose of general system strength impact assessment? If so, what should those thresholds be and why (for IBL, load types, individual or cumulative, as well as generators including LIBR, connected into transmission and distribution networks)?	Yes, a material threshold be defined. This can be applied in percentage as per: AFL change (in MVA)/ (MW at POC x MCSR of Plant). However, we would like to express our concern if a new connection is required to not only remediate its adverse system strength impact but also the reduction in AFL at the connection point. The latter will mean any new connection who opts not to pay the SSS charge will need to install "a form of fault level compensation devices" if they have a min SCR for stable operation higher than zero. For example, a 100 MW new connection with a MSCR of 2 will need to compensate for a 200MVA reduction in AFL at the POC. And the solution is very limited, i.e., synchronous condensers. This may not be really neccessary, resulting in over-investment and can also lead to other consequences (e.g., increasing fault level design requirement, increasing complexity of system operation, etc.). Again we would like to note recommend that the AFL concept needs to be reviewed.
30	30. Are there any other issues relevant to the general system strength impact that AEMO ought to take into account?	No further comment
31	31. Should there be an engineering safety margin applied to the SCR withstand capability calculation considering limitations associated with SMIB based evaluation?	We note that the MSCR of 3 appears to have worked reasonably for Powercor's PIAs. Therefore we consider a minimum of 3 should be accepted by NSPs/AEMO for SSLF calculation
32	32. Are there any other issues relevant to the Preliminary Assessment methodology that AEMO ought to take into account?	Co-ordination between AEMO and NSPs could be improved. A standardised PIA model (or at least low fault level models) could be provided by AEMO as part of OPDMS. X/R ratios can have a material impact on the plant stability assessment so it should be considered in the SMIB Preliminary assessment.
33	33. What criteria should be applied to determine whether a project is classified as a committed project for Full Assessment purposes? Why?	We consider that it may be punitive that for any change in project size or OEM to cause a project to be considered uncommitted. There are events outside of the control of a developer that may require them to change size or OEM for example the bankruptcy of a supplier. We further submit that it will be more fair to apply a time limit for which a 5.3.9 package to be accepted by AEMO and the NSP. Further it is considered that if a proponent is still able to meet or exceed its existing GPS with a different OEM then it would appear punitive to de-commit such a project. If a project receives and executes a connection offer after a 5.3.4A/B is issued by AEMO, a 5.3.7g notice is provided to and acknowledged by AEMO, it is considered a committed project. Is AEMO now proposing to have another definition of "committed" status for Full Assessment purposes? How are these two "committed" statuses linked to each other? It would be very confusing if a project has different "committed" statuses if they only make a change in size (size reduction) or inverters/turbines (when an OEM discontinue one product range and offer a newer one which is slightly different). In addition, the Connecting NSP would only issue an offer to connect to a project once AEMO issues 5.3.4A/B approval. If the project is later changed from "committed" to "uncommitted" status, based on this proposal, then what would be the impact to the executed connection offer/contract?

34	34. How and when is it appropriate to include future network augmentations (new transmission upgrades, configuration changes, considered projects, system strength remediation upgrades etc.) into the Full Assessment? Why?	We do not consider it appropriate to include future network augmentations as the network should be assessed under worst case conditions. If future network augmentations are not included this ensures that generating plant are capable of operating under worst case conditions. The only condition that future network augmentations should be considered is if the generation project intends to be constrained until network upgrade is fully commissioned.
35	35. Are there any other issues relevant to the Full Assessment methodology that AEMO ought to take into account?	Greater transparency between AEMO and NSPs, and between NSPs, should be required as part of the Full Assessment Methodology. Better transparency of adjacent projects reduces the need for rework for projects, reducing connection costs. This transparency should also include system strength solution(s) that the SSSP is planning to implement, otherwise over-investment may occur as nearby NSPs will be unaware of these solutions.
36	36. Is the proposed scope of a Stability Assessment appropriate?	The proposed scope appears appropriate
37	37. Are there any studies, contingencies, and evaluations that should, or should not, be part of a Stability Assessment? Why?	See Q27
38	38. What study assumptions could be recommended to ensure there is no “free rider” situation for (system strength services) non-paying Applicants?	The system strength services required to meet the minimum system strength level considering all committed projects should be included. Any other additional system strength services above meeting the minimum should be excluded to ensure there is no "free rider" If we need to assess multiple projects at the same time (like the WMZ integration or the proposed batching process), then we may need to assess both non-paying and paying projects together and hence need to work out a solution to ensure there is no "free rider".
39	39. Are there any other issues relevant to the Stability Assessment methodology that AEMO ought to take into account?	We would like the SSRM/SSIAG to address which party should perform the stability assessment for projects. As per AEMO flow chart shown in Figure 5, it is the Connecting NSP who is also the SSSP (so that it can adjust its plants to stabilise the voltage waveform). However, if the Connecting NSP is an DNSP, the DNSP cannot tune the SSSP plants.

40	40. Are there any other issues relevant to the calculation of SSLF that AEMO ought to take into account?	We consider the proposed methodology will result in manifestly excessive SSLF for almost all distribution-connected generators. For the purposes of providing an example, we have considered a currently connected 19.8 MW generator in our network: • A 1000 MVA fault level source at the Dederang 220 kV bus will cause a 0.05 MVA fault level increase at that generator POC • A 1000 MVA fault level source at the Red Cliffs 220 kV bus will cause a 0.21 MVA fault level increase at that generator POC • To increase by 1 MVA at the POC, this will be approximately a 4762 MVA fault level source at Red Cliffs, which is 5 times larger than the minimum fault level requirement at Red Cliffs. This example links to Q25, where it is very important that every node in the transmission network is chosen as a system strength node to assist to mitigate this issue. We consider the SSLF should be calculated on a per generator connection point basis, on the amount at which they cause their AFL to fall below zero. It is not clear whether the SSLF will take into account contingencies, as previously stated a generator connected to Kerang will have much smaller SSLF without contingencies than it would with contingencies. It is also important to note that even with all transmission nodes defined as system strength nodes, there is a major flaw in the proposed approach. The transmission network is an interconnected system where most nodes will have fault currents flowing from different lines/directions. If a new generator project's POC is in between two system strength nodes A and B, it will get fault currents through both nodes A and B. Hence if we only use one of nodes A and B in the calculation of the AFL restoration, it will not accurately reflect the real system.
41	41. What is the preferred methodology and pre-fault condition assumption for calculation of short circuit currents? Why?	Our preferred methodology is that of A.2.2 of the existing SSIAG and 6.6.2 of TB 671. This methodology uses classical fault assumptions (voltage = 1.0 pu) using the ASCC method and all previous PIAs by NSPs should have been performed following these existing guidelines. AS 3851 which is commonly used over IEC60909, or the usage of IEC60909 (c=0.9) or other methods are not as reproducible over different model snapshots.
42	42. Are there any other issues relevant to the calculation of AFL that AEMO ought to take into account?	Using AFL to calculate SSLF is a flaw approach due to the non-linear characteristic of fault level and impedance. For two projects connecting to the same node, if their sizes are different, they may have different SSLF. For example, one is 100 MW and the other one is 200 MW, both with a MSCR of 3, it means one project needs 300 MVA AFL and the other needs 600 MVA AFL at the POC. However, the additional fault levels required at the nearest SSN are not proportional, which means different SSLFs.

43	43. For (high SCR) connections where SCR may change over time, what would be a sensible process to trigger the need for GPS assessment or confirmation of compliance at SCR of 3.0?	RUG and GSDS should state an approximate SCR for which current settings are appropriate to meet performance (below which settings changes may be necessary). When the SSSP/AEMO are assessing the minimum fault level requirements each year, the SCR for each generator can be checked to see whether it has fallen below this threshold (at which point a S5.2.2 or 5.3.9 should be initiated by the generator).
44	44. Are there any other issues AEMO should take into account when considering compliance of affected plant?	Generating Systems should be required as part of their on-going compliance to submit to NSP/AEMO if there are any probable "system strength" issues (after contingencies) found that could require a settings change under S5.2.5.15. Further Generating Systems should be required to regularly estimate the system strength (using a Q vs V relationship) and if this changes significantly it should be reported to NSP/AEMO for them to assess and ensure compliance. This could be in the form of a FRT performance report that is provided to the NSP/AEMO on a regular basis as an annual report (or every 3 years).
45	45. Is it necessary to include the definition of system strength in the PSSG?	A definition for system strength should be aligned from the SSRM and SSIAG as part of this body of works
46	46. Are there any other areas in the PSSG that need to be updated for system strength?	The 2.1.5 voltage stability requirements can be updated and aligned with the SSRM and SSIAG
47	47. Is there any other section of the PSSG that needs to be updated or reviewed?	No further comment