

12 November 2024

Submissions
Electricity Authority
P O Box 10041
Wellington

Via email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper— [Part 8 Common quality requirements review – Part 8 Code amendment proposal](#)

NewPower Energy Services Ltd and subsidiary Infratec NZ Ltd appreciates the opportunity to make this submission on the Electricity Authority's (Authority) consultation on addressing more frequency variation in New Zealand's power system.

NewPower is a subsidiary of WEL Networks Limited, New Zealand's sixth largest distributor. NewPower subsidiary Infratec NZ Ltd is delivering low-carbon utility-scale solar and battery solutions at a time of unprecedented growth in New Zealand. Infratec developed and commissioned NZ's first utility scale battery energy storage (BESS) facility at Huntly, connected to WEL Networks' distribution assets. By way of context for this submission, NewPower is the operator of this new 35MWh rated BESS which will operate within both Network and Grid compliance modes, and so can offer a range of network, transmission and energy market services within NZEM's wholesale market dispatch compliance rules. This BESS is already contracted to the System Operator as an ancillary service agent for instantaneous reserves.

Infratec has also constructed and commissioned approximately 66 MW of utility-scale solar farms connected to distribution networks in New Zealand for clients with an additional 60MW currently under construction. We also commissioned the 4MW Naumai solar farm in Northland in Q3 2024.

All generation except the Rotohiko BESS are exempt stations, being under 30MW net export. We have provided detailed Asset Capability Statements to the System Operator (SO) (consistent with the Code). And, despite being below the 30MW net export threshold, have incurred significant costs for each solar farm associated with detailed technical testing by both the distributor and SO both during the design stage and commissioning of these generating stations.

Key points in our submission

In summary, NewPower and Infratec:

1. FSR-001 NewPower is supportive of this proposed code change.
2. FSR-002 – NewPower believes this change requires more thought and refining to achieve fair and desired outcomes. The level of information required for smaller generation should explicitly be less onerous than the level of information provided for larger generation – commensurate with the risks. Justification for this is that smaller generation has less impact on the system and the financial impact on smaller generation is not insignificant. All information that is being specified needs to be weighed against the cost of providing it.
3. FSR-003 – NewPower is concerned about the unintended consequences of this proposed change on the behaviour of distributors and associated costs.
4. FSR-004 & FSR-005 – NewPower agrees with the intention of the proposed changes but believes that “control system setting change” should be better defined so as to not have unintended consequences.
5. FSR-006 – NewPower agrees with the intent of the proposed change but believes that “dynamic reactive power compensation device” needs better defining to avoid unintended consequences.
6. FSR-007 – NewPower is concerned about the impacts on BESS when providing the support required by AOPOs (frequency and voltage support mainly). Especially if some of the changes in the Authority’s last Part 8 consultation paper were made. Also, NewPower is concerned that the Authority has not fully assessed the impact of classifying BESS as generation in the current code.
7. FSR-008 – NewPower agrees with the intent of the proposed code change but is concerned that the definition of “generating unit” may be too broad, as most small inverters have frequency and voltage control. NewPower believes that “generating unit” should apply to a group of inverters with an overarching central control.
8. FSR-009 – NewPower is concerned and strongly disagrees with this proposed code change. NewPower asks the Authority to disclose more information on this issue, so that this can be properly considered by stakeholders.

NewPower welcomes discussion with the Authority on any points in our submission that the Authority would like further clarification or information for.

Yours Sincerely,



Darren O'Neill
Product Development Manager
NewPower Energy Services Ltd

Appendix 1: NewPower's response to the consultation questions

| Questions | Comments |
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| FSR-001: Remove the exclusion for wind-powered generation from periodic testing requirements | |
| Q1.1. Do you support the Authority's proposal to apply the periodic testing requirements in Appendix B of Technical Code A of Schedule 8.3 to wind generation? If you disagree, please give reasons and provide alternatives that address the identified problem with wind generation being excluded from the periodic testing requirements. | <p>Yes.</p> <p>We support this proposal if it makes the rules for wind generation the same as any other generation technology.</p> |
| Q1.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | <p>There is no evidence provided to support the time frames in the transitional provision of completing tests by 31 December 2028. It may be possible to complete the tests earlier or there may be insufficient capability (e.g. specialist testing companies) for all wind turbine owners to meet the deadline.</p> <p>Suggest the transition timeframes be flexible if a wind farm is in the process of being repowered.</p> <p>Is the proposed Code clear about the timeframes for testing of new wind turbines?</p> |
| Q1.3. Do you agree the proposed Code amendment is preferable to the other option identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010. | <p>Yes.</p> <p>NewPower believes that it is better to change the code than to just have a guideline. There is no issue with changing the code and having an accompanying guideline for testing.</p> |
| Q1.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | <p>Yes.</p> <p>The costs seem reasonable. But the Authority has stated they haven't quantified the benefit. We agree that there is certainly benefit from ensuring that generating units are compliant with AOPOs.</p> |
| FSR-002: Clarify that embedded generators must provide an asset capability statement in a form specified by the system operator | |
| Q2.1. Do you support the Authority's proposal to amend the Code to clarify that: | No. |

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| <p>(a) embedded generators must provide asset capability statement information to the system operator in the form from time to time published by the system operator, and</p> <p>(b) the requirement to provide an asset capability statement to the system operator applies only to generators with a generating unit with rated net maximum capacity equal to or greater than 1MW?</p> | <p>The proposal far exceeds the problem definition (the problem definition is there is a lack of clarity about whether any embedded generator has to supply ACS information in the format required by the system operator.)</p> <p>Instead of using the embedded generation threshold for AOPOs (currently 30 MW) the proposal will require all generation 1 MW and above to provide an ACS in the format required by the system operator. This proposal doesn't specify what level of information the greater than 1 MW, but less than 30 MW generation will need to provide. This point is further discussed in both of NewPower's Part 8 consultation submissions.</p> <p>We think the system operator and Transpower should bear the costs associated with translating asset information for smaller DG provided in other forms to a format suitable for modelling and assessing AOPO compliance.</p> <p>The system operator and Transpower, when faced with the costs and time required to do this, will be better placed to assess whether the effort required is worth it.</p> <p>The system operator uses ACS information for two purposes:</p> <ul style="list-style-type: none"> • Assessing compliance with AOPOs. • Modelling the power system. <p>The system operator's generation ACS format is designed for large grid connected assets. The format is onerous for smaller DG assets. We recommend that the code is explicit on the level of information the system operator can reasonably request from different size range of generation. We also recommend that the system operator develops a different ACS format for smaller DG assets that is commensurate with applicable AOPOs for the DG and not ask for information that the system operator does not need for assessing compliance with AOPOs.</p> <p>An asset owner should not be required to provide asset information in respect of a particular AOPO which does not apply to the assets of the asset owner.</p> <p>Any ACS requirements should be commensurate with the AOPO requirements on the DG and the level of detail that the system operator or Transpower will be modelling.</p> <p>Neither the system operator nor Transpower has demonstrated the benefits of discretely modelling assets down to 1 MW in size. The inaccuracies in load modelling likely dwarf any benefit of modelling 1 MW plants.</p> |
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| | <p>There are concerns around the costs of obtaining the asset capability information required by the system operator for smaller installations.</p> <p>A 1 MW solar installation might cost \$1.7M to build. Imposing a requirement to provide/update ACS information and connection studies (\$200k-\$300k ~ 12%-18%) will likely make the installation uneconomic. The ACS and Connection Study costs will be a significant barrier to entry for smaller installations if the requirement for information is the same as larger generation installations.</p> <p>NewPower is also concerned that with the proposed requirement to supply the System Operator with un-encrypted (or partially un-encrypted EMT model. This requirement is already extremely onerous for large scale IBR generation, let alone a 1 MW solar farm.</p> |
| Q2.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | <p>The requirement will create a significant barrier to entry for smaller generation installations, assuming that smaller generation plant will have to provide the same information as large generation plant. Especially with the proposed requirement for providing the System Operator with an un-encrypted (non “black-box”) EMT model.</p> <p>Also, there is an unfair advantage for residential and commercial generation aggregators for which most/all of their generation is less than 1 MW, but on aggregate can be far larger.</p> |
| Q2.3. Do you agree with the proposed Code amendment? If you disagree, please explain why and give your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010 | <p>No, not in its current form.</p> <p>The change needs to explicitly cover off the level of information required for different size ranges of generation (i.e. less onerous for smaller generation). Recognising that ACS cost impacts to smaller generation needs to be proportional to its impact on the system.</p> <p>All the option does is shift costs from the system operator to small DG owners, as smaller DG generators have been able to provide basic information for the SO to be able to translate into its models. With the proposed change the onus of the modelling falls upon the small DG owners.</p> |
| Q2.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | <p>No.</p> <p>We suggest the system operator and Transpower should bear the costs involved in translating information provided by smaller DG owners in other forms to a form suitable for modelling and assessing AOPO compliance (if the MW threshold for AOPO compliance reduces as per the Authority’s previous consultation on Part 8).</p> |

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| | The system operator and Transpower, when faced with the costs and time required, will be better placed to assess whether the effort required is worth it. |
| FSR-003: Include distributors and energy storage systems as potential causers of under-frequency events | |
| Q3.1. Do you support the Authority's proposal to amend the definition of 'causer' in clause 1.1 of the Code so that it refers to the action that results in a UFE, including an increase in electricity demand (load), and the consequential amendments to clauses 8.60 to 8.66, including proposed new clause 8.64A? | <p>No. Further assessment is required.</p> <p>The system operator is likely to define the loss of a large BESS as a contingent event while the loss of sufficient distribution capacity that could cause an UFE would be defined as another type of event. The system operator will procure instantaneous reserves for contingent events but not for other events.</p> |
| Q3.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | <p>The SO Policy Statement may need to be updated following the definition change.</p> <p>The loss of a large-scale BESS is likely a contingent event while demand related events caused by distributors is more likely to be considered an "other event".</p> <p>This may have an unintended consequence of causing distributors to either upgrade certain connections or try to pass through UFE costs to DG. Has this been factored into or considered in the Authority's assessment?</p> |
| Q3.3. Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010. | <p>No.</p> <p>A complete review of the UFE management regime should be undertaken in the near term given the shift towards inverter-based generation and use of large-scale energy storage.</p> <p>The longer such major reviews of the EIPC are deferred the greater the urgency becomes, and the greater the effort required.</p> |
| Q3.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | <p>No. An alternative option that has not been considered is to retain the status quo in respect of distributors. NewPower doesn't think that the Authority has considered the cost implications of making distributors able to be UFE causers. Also NewPower believes that the Authority hasn't considered enough alternatives to managing the risk posed from distributors and DG.</p> <p>A more detailed assessment of the probabilities of demand and energy storage causing UFE is required so that the benefits and, in particular, the net benefit of the proposal can be better assessed.</p> |
| FSR-004: Amend the requirement to have a speed governor | |

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| <p>Q4.1. Do you support the Authority's proposal to amend clause 1.1 of the Code, and clauses 3, 4 and 5 of Appendix B of Technical Code A of Schedule 8.3, to broaden them to apply to inverter-based generation technologies?</p> | <p>Partially.</p> <p>The code requirements should be as technology agnostic as possible.</p> <p>NewPower does not agree with testing the asset capability after "change to the control settings..." this is too broad. Should only be control settings that would affect the frequency control.</p> |
| <p>Q4.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.</p> | <p>Yes, the requirement to test a control system after a "change to control settings" is too broad. This needs to be limited to the frequency control, as the controller being used for this may be used for other things as well. What if the asset owner changes a minor control setting in the controller for daily operation? This would cause constant testing. Frequency response products in other countries use different settings daily, ie DS3 in Ireland had five different frequency droop settings selectable by the SO. IBR allows much more variability in the settings, which allows them to be much more flexible. This needs to be reflected as a positive which allows adaption to conditions, rather than a risk that needs continual testing.</p> |
| <p>Q4.3. Do you agree the proposed Code amendment is preferable to the other option identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.</p> | <p>Suggest the following change to the wording:</p> <p><i>"control system means equipment that adjusts outputs such as voltage, frequency, active power or reactive power (as the case may be) of an asset in response to certain aspects of common quality such as voltage, frequency, active power or reactive power"</i></p> <p>This definition should not limit control systems to voltage, frequency, active power or reactive power control systems.</p> <p>The definitions should only apply to settings that produce a noticeable effect. Control schemes are growing in capability, which more variables and control. Where it is clear that the settings change will have negligible effects, this should not require testing.</p> <p>3 (ba) and 3 (c) - Should the firmware version requirements not apply to all generating units capable of having firmware updates to frequency control systems?</p> <p>Does clause 3 have to be specifically about FREQUENCY control systems. The defined term is 'control system' which adjusts the output voltage, frequency, active power MW or reactive power. Are there other clauses that use the term 'voltage' control system?</p> <p>Note the EA proposal is to include 'active power' in the definition of control system. But the remainder of Part 8 does not refer to / rely on the definition of an 'active power control system'.</p> |

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| Q4.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | Yes. |
| FSR005- Amend the requirement to have an excitation system | |
| Q5.1. Do you support the Authority's proposal to amend the Code to replace the requirement for an excitation system with a requirement for a voltage control system, to encompass all generating technologies? Please explain your answers. | <p>Partially.</p> <p>The code requirements should be as technology agnostic as possible.</p> <p>NewPower does not agree with testing the asset capability after "change to the control settings..." this is too broad. Should only be control settings that would affect the voltage control.</p> |
| Q5.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | <p>Yes, the requirement to test a control system after a "change to control settings" is too broad. Needs to be limited to the voltage control, as the controller being used for this may be used for other things as well. What if the asset owner changes a minor control setting in the controller for daily operation? This would cause constant testing.</p> |
| Q5.3. Do you agree the proposed Code amendment is preferable to the other option identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010. | <p>Should power converters (inverters) be included as for voltage controls?</p> <p>Retesting for firmware updates should only apply were the change will have the potential to materially impact the performance of the frequency or voltage control.</p> <p>NewPower is aware of situations where firmware has been updated several times in a year and is concerned that this proposed code change in its current form could lead to over testing.</p> |
| Q5.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | Yes. |
| FSR006- Amend the Code to apply to all dynamic reactive power compensation devices | |
| Q6.1. Do you support the Authority's proposal to amend the Code to require all dynamic reactive power compensation devices to undergo periodic testing? | <p>Mostly.</p> <p>The definition of "dynamic reactive power compensation devices" needs to be better defined.</p> <p>NewPower notes that most inverter-based resources (IBR) are capable of dynamic reactive power compensation equivalent or close to that of a Static Var Compensator. If an IBR generator was contracted for voltage support services by Transpower, would this class the generator as a dynamic reactive power compensation device?</p> |

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| | NewPower argues that if Transpower contracts a IBR generator to provide dynamic reactive power support to the Grid then the testing for the dynamic reactive power compensation device should apply to this generator, but should not apply if |
| Q6.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | A potential unintended consequence could arise if “dynamic reactive power compensation device” isn’t well defined. Technically any inverter can dynamically control its reactive power and therefore this definition could apply to all inverters even down to small scale inverters. |
| Q6.3. Do you agree the proposed Code amendment is preferable to the other option identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010. | Yes, but the code amendment needs more work to avoid unintended consequences. Mainly around the definition of “dynamic reactive power compensation device” |
| Q6.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | Yes. |
| FSR007- Treat energy storage systems as only generation for the purposes of Part 8 | |
| Q7.1. Do you support the Authority’s proposal to amend the Code to treat ESSs as generation for the purposes of Part 8? | <p>No, not in its current form.</p> <p>NewPower agrees that the Authority needs to remove ambiguity around requirements on BESS in the code, but the Authority also needs to be mindful of not putting BESS at a disadvantage to other forms of generation. But this proposed code change only removes some ambiguity for BESS over 30 MW.</p> <p>The term ‘Energy Storage System’ needs to be better defined first, as does ‘generation’ and ‘intermittent generation’. There are a number of different technologies covered by energy storage, all of which have different characteristics. To gather them all together under one term will slow deployment, create unfair market conditions and lead to perverse outcomes. The code needs to look further than IBR fed BESS to mechanical storage. In the future as we decarbonise there will also be hybrid thermal and electrical storage systems which again will have different requirements. Whilst the code can’t see the future, it can be intelligently designed to enable flexibility in the future.</p> <p>The code needs to be able to incorporate hybrid solar/wind with BESS plants now. How is a DC inverter coupled solar PV and battery treated? Is this intermittent generation or BESS or both? How</p> |

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| | <p>are the rules to be applied? For example, BESS which is co-located with solar and connected to the same inverter as the solar panels (DC connected) will have to manage being both an intermittent generator and a BESS, the code will likely have competing requirements for these two types of generation.</p> <p>Treating BESS as generation may have unintended consequences and lead to unintended behaviours. For example, BESS will generally be waiting synched to the network/Grid to perform energy or reserves as dispatched 24 hours a day. For periods it will sit idle, waiting, but during this time it is still expected to provide frequency response and short circuit current at a higher relative cost than that of a thermal or hydro plant without full compensation or incentivisation.</p> <p>Synchronous plant such as this connects and synchronises when dispatched, then disconnects. It doesn't stay connected and rotating, and therefore isn't expected to provide services such as frequency response or short circuit level when they aren't dispatched. Other forms of energy storage such as compressed air use synchronous generators which would act like a hydro plant. Trying to be fair across technologies, it may be that requirements such as frequency response should only be mandatory when dispatched for energy. This would avoid the perverse outcomes where BESS and IBR would look to make the plant de synchronise whenever possible to avoid these requirements.</p> <p>A more complete approach would be to define storage, standard generation and hybrid intermittent plants in the code, and then split storage into IBR and synchronous types, with bi- and uni-directional power flows.</p> <p>Also, there is subtleties between BESS that has its own inverters (AC connected BESS) and BESS that shares inverters with solar panels (DC connected). These two types of BESS will behave differently, and the current code changes must consider this.</p> <p>The expectation and requirements for all the types of generation needs to be understood by all. The business cases for solar and storage plants are being written now, so it needs to be clear how these plants will be treated in terms of mandatory requirements and items such as forecasting, charges etc. This will create certainty for developers and investors.</p> <p>The main reason for not allowing equivalence arrangements for BESS in terms of AUFLS seems to be the system operator's inability to easily incorporate BESS functionality within its market tools.</p> |
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| | <p>NewPower is also concerned if this change means that embedded BESS generation above 30 MW is required to provide voltage support for the Grid. The issue here is that this will mean that the system operator will have the ability to control voltage on a distribution network, which creates conflict between the distributor and the system operator. Also, there will be liability issues for the system operator if the controlling of voltage was to cause issues on the distribution network.</p> |
| <p>Q7.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.</p> | <p>The proposal creates two classes of BESS:</p> <ol style="list-style-type: none"> 1. Grid connected BESS and embedded BESS above the threshold of c.8.21(1) of 30MW or more. 2. Embedded BESS below the threshold in c.8.21(1) of less than 30MW export. <p>Under the proposal, the first class will not face AUFLS obligations or costs while the second class will face AUFLS related costs.</p> <p>Embedded BESS below the threshold in c.8.21 (1) when charging will contribute to the distributor's AUFLS requirements. The distributor will likely seek back-to-back mitigation of the AUFLS obligation through the connection agreement.</p> <p>This creates an additional barrier to entry for embedded BESS below the threshold in c.8.21 (1) in terms of how AUFLS obligation is treated for the smaller BESS. The smaller embedded BESS would have to apply for exemption to AUFLS to be able to reliably supply instantaneous reserves. Also, distributors will not have clarity on how their AUFLS requirements should interact with smaller embedded BESS supplying reserves i.e. should the distributor be load shedding a feeder with many smaller BESS connected to it or not?</p> <p>Should the requirements of c.8.24 in respect of grid connected BESS be reviewed as well?</p> |
| <p>Q7.3. Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010</p> | <p>No, the code change only addresses the issue for embedded BESS above the 30MW AOPO threshold. There will be a significant number of embedded BESS connected to the system below this threshold and there will be confusion about how these are treated when it comes to providing reserves and how AUFLS interacts with these BESS.</p> <p>NewPower suggests that this option should be explored and implemented as well "Amend the AUFLS Technical Requirements (ATR) report to specify that in the case of an AUFLS event, an ESS is required to reduce demand rather than to have a system that automatically electrically disconnects</p> |

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| | demand.”. This will clarify how distributors treat BESS and allow smaller BESS to contribute to under frequency events. |
| Q7.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | <p>No. The proposed amendment does not promote competition in the electricity market.</p> <p>NewPower believes that the analysis presented by the Authority is quite high level and that further thought, and analysis is required before making a decision to avoid unintended consequences and unfair market biases.</p> |
| FSR008- Clarify the definition of generating unit | |
| Q8.1. Do you support the Authority’s proposal to amend the definition of generating unit in clause 1.1 of the Code so that it refers to a generating unit having a frequency and/or voltage control system? | <p>No, not in its current form.</p> <p>A word search of the entire Code reveals the term ‘generating unit’ is used 197 times in the code.</p> <p>This change is proposed in the context of a review of common quality rules (Part 8). The Authority’s consultation paper shows that this definition is also used in Parts 12, 13, 14 and 15.</p> <p>Also, this definition of generating unit could be seen to apply to string inverters for a solar farm (note that string inverters can individually have voltage and frequency controls). NewPower argues that ‘generating unit’ should apply to a collection of string inverters controlled by a single controller or a collection of string inverters with the same frequency and voltage control settings.</p> |
| Q8.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | <p>Given the use of generating unit in many other parts of the code it is likely that a change in definition will cause interpretation problems. The analysis in the Authority’s consultation paper does not provide confidence that the proposed change in definition will not result in unintended consequences</p> |
| Q8.3. Do you agree the proposed Code amendment is preferable to the other option identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010. | <p>No.</p> <p>Further investigation is required.</p> <p>Common quality is more to do with quality experienced by connected parties at a point of connection rather than within an asset owner’s site. It is preferable to define common quality performance and obligations at a point of connection in a way that is agnostic of the asset owner’s configuration of assets. This approach would also potentially reduce administration.</p> <p>Voltage support related AOPOs such as c.8.23 derive from a time when assets were designed and operated as part of a vertically integrated power system.</p> |

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| | <p>An alternative approach is to define 'generating unit' in terms of switches (e.g. CBs) at the point of connection.</p> <p>It may be better to move away from a 'generating unit' basis to site or station basis when it comes to assessing compliance with AOPOs – that is for the Part 8 common quality use of the defined term.</p> <p>We suggest using a specific definition of generating unit that applies for the purposes of part 8 only is another option.</p> |
| Q8.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not? | No. |
| FSR009- Clarify the Code's fault ride through requirements | |
| Q9.1. Do you support the Authority's proposal to amend the Code to allow a machine-based synchronous generating unit to be deemed compliant with the Code's FRT requirements if full compliance is not possible due to the generating unit's inherent stability characteristics and the generator has taken all reasonable measures to support grid stability taking into account the generating unit's inherent stability characteristics? | <p>No.</p> <p>This is special treatment based on technology characteristics that no other technology gets in respect of other obligations.</p> <p>This proposal is inconsistent with other code change proposals that aim for the code to be technology agnostic.</p> <p>It is strange that this problem has suddenly appeared given that the current fault ride through obligations have been in place for the better part of a decade and were under development for many years before that.</p> <p>NewPower is concerned with the number of current non-compliant synchronous generating units that might be to justify this proposed code change on a transaction cost basis. Is this a grid risk that is currently being managed or needs to be managed?</p> <p>NewPower asks the Authority to make public the total aggregate power capacity in MW for the current non-compliant synchronous generating units.</p> |
| Q9.2. Do you see any unintended consequences in making such an amendment? Please explain your answers. | <p>Will the performance shortfall of these machines increase the amount of instantaneous reserves the system operator needs to procure?</p> <p>A system fault that causes an amount of any technology type of non-compliant generation to drop off should be treated as a risk by the system operator when procuring Instantaneous Reserves.</p> <p>Note the same risk applies to area wide PV generation drop off during transmission faults.</p> |

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| <p>Q9.3. Do you agree the proposed Code amendment is preferable to the other option identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010</p> | <p>No. Information provided in the consultation paper does not indicate how many machines are affected or whether the shortfall can be more easily managed through dispensations.</p> |
| <p>Q9.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?</p> | <p>No. Insufficient detail has been provided to allow an assessment of the analysis.</p> |