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Common quality requirements in Part 8

Transpower appreciates the opportunity to respond to the Authority's issues paper *Common quality requirements in Part 8* published 4 April 2023. We support the review of the common quality requirements to ensure they accommodate and facilitate the opportunities offered by inverter-connected resources[1] while managing their effects for real-time system operation, and grid connections.

We agree with the technical issues and that it is necessary to address all of them. We consider inverter-based systems are very flexible, using multiple configurations, topologies, levels of redundancy (with different trade-offs) to achieve the desired performance outcome. For consumer confidence in the electrification paradigm, all performance requirements should seek to maintain quality electricity supply with lower cost outcomes for end consumers and the system.

The summary below answers questions on priority and whether any issues are missing, using the system operator's phase 1 report[2] and input from Transpower (system operator and grid owner) subject matter experts.

The review assumption is that the existing common quality settings (derived in a different context) are retained, however as more inverter-based resources (IBR) comes on the system the common quality requirements may need revisiting. As expected, the urgency of the issues relies on forecasts of the penetration of IBRs, their own technological advances, and

[1] Refer The Authority's covering paper for phase 3, section 4.5
[2] Future Security and Resilience final phase 1 report

their location; notable is that the North Island and South Island may experience different issues at different times.[3]

Transpower view of the issues, their priority, and other issues

The table below identifies our view of prioritisation of the issues and any components. A key timing check is alignment where possible with the outcomes' dates in the Phase 2 Future Security and Resilience roadmap.[4]

Description	Priority (by when issue needs to be remedied)
Issue 1 Frequency	
Low Inertia making events worse (NI) (off peak)	4 - 6 years
Low Inertia making events worse (SI) (low water, DC flow South)	4 - 6 years
Variability making normal band (+/- 0.2 Hz) control more difficult	4 - 6 years
Issue 2 Voltage - system strength	3 - 4 years
Issue 3 Voltage – network performance	
Lower fault levels – larger voltage effects for all system events	4 - 6 years
Lower system strength – increased flicker / other distortion	4 - 6 years
Issue 4 Voltage - fault ride through (inc. frequency effects)	
Multiple IBR trips – voltage impact on distribution level	Now - 2 years
IBR impact on Grid Voltage regulation/control	3 - 4 years
Multiple IBR trips – impact on Grid Voltage Stability (VSAT)	4 - 6 years
Multiple IBR trips for a Grid event – potential frequency event, reserves implication if the risk MW is high	3 - 4 years
Issue 5 Harmonics[5]	Now - 2 years
Issue 6 Access to information	ASAP - Highest priority
Issue 7 Code terms	ASAP - Highest priority
Issue 8 Others	
Connection Code interdependency	In parallel with Part 8 Code changes
System operator dispensation - whether the rule is fit for purpose	Now - 2 years
Protection settings auto-reclose on distribution networks	3 - 4 years

[3] For example, a pending issue of 45 Hz tolerance for IBR on the South Island.

[4] Covering-Paper-FSR-Final-Roadmap-and-Phase-Three.pdf (ea.govt.nz)

[5] Transpower (grid owner) will present its research on harmonics at the EEA conference June 2023.

Part 8 with Part 12 (the Connection Code under the Benchmark Agreement)

In the face of anticipated increased IBRs we support urgency in addressing the common quality requirements in the Part 8 of Code but consider the scope for changes must necessarily include the grid owner's Connection Code as Schedule 8 of the Benchmark Agreement.

The Code at 12.21 outlines the principles for developing the Connection Code and includes "(b) *the desirability of the Connection Code and Part 8 operating in an integrated and consistent manner, if possible*" and "(c) *the need to ensure that the grid owner can meet all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8.*"

For the grid owner, a connection principle would be to avoid having existing and future generators impose costs onto the grid and consumers by ensuring they remain connected during faults, and continue to generate and provide reactive power and fault current.

System operator dispensation process

The expectations of the availability of the dispensation process and the system operator granting dispensations underpins several conclusions about asset operations in the future state. We consider the dispensation process should be reviewed to ensure that it is fit for purpose in that future state. This could include ensuring it is future-proofed for possible advances in inverter technology that support higher quality system operation. If continued, the current process may impose unnecessary costs on the grid owner and consumers.

Finally, we support the decision for an FSR technical working group. The system operator and grid owner are key stakeholders and both parties should be in the group to support technical understanding - underpinning policy settings - amongst all stakeholders.

Yours faithfully,

Joel Cook

Head of Regulation

Appendix - Response to Questions

For an issue's priority, please refer to the cover letter.

Question	Transpower Response
1. Do you agree with the description of the first common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons. *[2.30(a) inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia]*	Although frequency management may not impact Transpower in the immediate future, key clauses under Part 8 could be amended now to avoid increased operational cost with potentially non-compliant (with the asset owner performance obligations) equipment in the system. A priority is how to maintain common quality in the trading periods during mid-summer with high solar/wind and low synchronous-based generation. As thermal plant is decommissioned, the frequency range in which the grid can be operated may even increase, as hydro and IBR can operate at quite wide frequencies. The grid owner (GO) is responsible for AUFLS in the South Island and is a key stakeholder for the frequency issue. The GO also offers frequency keeping control (FKC) modulation on its HVDC asset, to support frequency keeping. For the South Island, the impact on frequency control is much more significant if IBR displaces the part loaded hydro. Currently 6s fast instantaneous reserve (FIR) can be provided by tail water depressed (TWD) hydro but that will not be fast enough for high HVDC south flow. When economic instantaneous reserve scheduling results in TWD in the South Island with HVDC transferring south, this can result in oscillations in the scheduled results leading to difficulties in system security assessment. Frequency management for a contingent event (CE) event is also an issue, if a lot of IBR is tripped for a simple fault the size of the contingent event might be large. IBR performance may lead to reconsideration of the definitions used for contingent and extended contingent events and hence the reserve procurement.

	We note the action to zero the time error once a day is not needed for the power system to function i.e., no consequence on frequency or voltage management if it isn't done.
2. Do you agree with the description of the second common quality issue (i.e., first voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons *[2.30 (b) inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows]*	As the phase 1 report recognises, grid forming inverters can, in principle, provide 'synthetic' inertia when connected to the wider network.[6] A 'grid forming' inverter is more robust to network disturbances than a 'grid following' inverter because the former has an extra degree of freedom. Synchronous condensers can also produce reactive power and provide rotational inertia. Synchronous condensers are installed at the Haywards substation to support HVDC transfers.
3. Do you agree with the description of the third common quality issue (i.e., second voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons. *2.30 (c) inverter-based variable and intermittent resources can increase the likelihood of network performance issues*	From FSR phase 1 system operator report "*Most locations in New Zealand are at a level of system strength that it is just acceptable. This is not currently a concern however as the penetration of IBR is still low and synchronous generation is considered to be a positive contributor to short-circuit levels."…" the power system will likely experience lower system strength in the transmission network and higher system strength in the distribution network, as distributed IBR displaces grid connected synchronous generation."…" Advancement of inverter technology has led to the development of grid-forming inverters and advanced site-specific grid-following inverters which can operate in low system strength and provide a positive contribution to system strength."* The issue is that IBR that displaces synchronous generators in the dispatch mix will reduce the size of generation delivering the "effective system voltage source" – i.e., creating a sinusoidal voltage waveform. Flicker is normally caused by short duration loads like welders or arc furnaces and voltage magnitude step changes. Step changes are created by switching events (most noticeably

[6] System operator's phase 1 Future Security and Resilience final phase 1 report Page 43

	for capacitor banks but also for lines, transformers, and loads.) Voltage distortion can be mitigated at a cost - e.g., active filtering, use of grid-forming inverter technology. Lower system strength is not usually a direct causal factor for poor harmonics – system resonances (determined by system impedances and the mix of inductive and capacitive components) are usually more relevant. Fault current level is a proxy for system strength – lower fault levels tend to mean there is less synchronous generation running. An example of a mitigation for lower system strength is to limit the size of the filter banks at Haywards to prevent the voltage step down when they are switched out from causing commutation failures on the HVDC link. Inverters need to fail "gracefully," and their control systems recover in a stable manner (like the HVDC most of the time). The grid has 2 x 700 MW grid following inverters at Haywards. However, for small modular inverters it is not usually economic to build in control systems with complex recovery capabilities. Large solar arrays using multiples of these small modules and each with no control capability can cumulatively create grid issues. We agree with the issue of the potential for protection maloperation under low system strength. There are also potential performance issues with transmission protection maloperations due to IBR control response during a power system fault when there is a high proportion of inverter-based generation. International experience indicates generator fault response behaviour is not as modelled. To provide more adequate and discriminative protection with high penetration of IBR, protection manufacturers are amending protection algorithms and utilities are adjusting settings and protection elements they apply. However, responsibility should also fall on the IBRs to improve control settings. System strength is an important parameter to assess the type of Inverter that can be connected stably to a particular location in our power system. IBRs can also operate under zero short circuit

	which is useful for the black start grid service e.g., as demonstrated by PowerCo's Battery Energy Storage System at Whangamata CBD. The GO should have access to unencrypted equipment & control system models to understand how plant will interact with the grid and perform during grid events. Provision of static and dynamic models would ideally be provided to Transpower in both its roles (system operator and grid owner). Since models are proprietary to equipment manufacturers, contractual controls would need to be in place to ensure commercial confidentiality.
4. Do you agree with the description of the fourth common quality issue (i.e., third voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons. *2.30 (d) over time increasingly less generation capacity is expected to be subject to fault ride through obligations in the Code, as more generating stations export less than 30 MW to a network*	Fault ride through (FRT) requirements provide certainty that grid connected assets can ride through a fault, to determine the size of the risk and procure enough reserve to mitigate the risk. Cumulative IBR embedded on distribution that is unable to ride through faults potentially can disconnect together causing frequency disturbance to the power system. Lack of FRT tolerance is a local issue for voltage steps and for staying within the required voltage band. But IBR tripping may be limited to a certain radius around a fault location which might be more manageable. FRT performance may be poor for severe but local faults, and whether the effects stay local or become island-wide needs to be better understood.
5. Do you agree with the description of the fifth common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons. *2.30 (e) there is some ambiguity around the applicability of harmonics standards*	Harmonics are not a PPO issue for the system operator but are governed via the connection Code under the Benchmark Agreement. Harmonics events are a high impact – usually because they often cause equipment damage or force equipment to disconnect – and resolving the problems caused usually takes time. NZECP36 is from 1993 when synchronous generation was dominant source of generation. The standard implicitly assumes that sources of generation are pure voltage sine waves which do not introduce any harmonic distortion onto the Grid. With IBR connecting at grid level it is timely to

	review this standard. The most urgent matter is to have an appropriate harmonic standard, and updated allocation methodology, for the technology available now and fit for purpose. Other standards referenced in the connection code (e.g., IEC) do not have a harmonic allocation methodology. The grid owner assesses new connections against the harmonics of existing users. When there is a new inverter connection, we look at the current state to determine the headroom to the limit in the standard. We allocate 1/3 of the remaining headroom. We are currently reviewing how other jurisdictions allocate harmonics. All GXPs have harmonic, voltage & current measurements for the commonly seen harmonics (3,5,7,11,13,17,19,23,25), with data going back several years. The grid owner is progressively enhancing all its revenue meters to measure harmonics up to 32nd, as well as installing at least one dedicated power quality meter on each Network Supply Point to measures to the 50th harmonic. We note the regulation references flicker standards. The connection code in the Benchmark Agreement (BA) also references to voltage flicker, but a different (and possibly superseded) standard is used. The standard in the BA should be addressed and amended as part of this review. Whether IBR will cause a noticeable change in background harmonics needs more evidence. IBR appears to be more susceptible to control system resonances –interaction between control systems at different sites - and the grid is just the medium passing the effect from one to the other (i.e., modification of the grid is usually not a solution).
6. If you are a distributor, what is your experience of asset owners sharing information with you for network operation purposes?	N/a
7. Do you agree with the description of the sixth common quality issue	Transpower in both its roles requires ACS (asset capability statement) information. Part 8 and the Benchmark Agreement obliges this information is provided to the SO and the GO respectively. For

and that addressing it should be a high priority? If you disagree, please provide your reasons *2.30 (f) network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner*	efficiency, the Code could support that provision of ACS information to the SO can be shared with the GO to avoid duplication of effort by the Customer and remove the risk of information differences. Under higher penetration of IBR on distribution networks the GO will need more visibility of those asset capabilities. The level of penetration of embedded generation (and type) at each GXP and GIP should be available to Transpower both for real-time system operation needs and for grid planning and system analysis. As raised under issue 3, the GO preferably needs access to unencrypted equipment & control system models to understand how plant will interact with the grid and perform during grid events. Provision of static and dynamic models would ideally be provided to Transpower in both its roles. Since models are proprietary to equipment manufacturers, contractual controls would need to be in place to ensure commercial confidentiality. Network configurations such as backfeeds and parallels will all need more thought if embedded IBR generation is significant. The SO and Distributors are likely to need to share more information. As large loads become more electrified for example in transport and industry, then more information from those loads is also required for optimal operation. Loads may also be highly intermittent or suddenly turn on/off and affect the system the same way as embedded generation. Generator (fault response) models are shared and incorporated in Transpower's power system analysis software and fault response is monitored after commissioning to check behaviours are as expected (international experience indicates behaviour is often not as expected).
8. Do you agree with the description of the seventh common quality issue and that addressing it should	We consider Code definitions for existing known issues should be amended as soon as possible to set the IBR future on course.

be a high priority? If you disagree, please provide your reasons. *2.30 (g) the Code is missing some terms that would help enable technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies*	
9. Do you consider there to be other high priority common quality issues not identified in this paper that are occurring or that you expect to occur because of: a. the uptake of inverter-based resources, and/or b. how the Code enables different technologies?	**Connection Code dependency with Part 8** – Part 8 of the Code ties to the Connection Code under Part 12 and common quality considerations include harmonics (as identified), power factor (a lot of leading power factor (capacitive) equipment is coming into the grid), flicker due to electrification of load (transport and industry). **System operator dispensation process -** should be reviewed as to whether its current form is fit for purpose for all new assets connecting to the grid and operating in the system. **Protection setting and auto reclose**. Lack of information in Part 8 of the Code on roles and responsibilities for provision and co-ordination of systems such as anti-islanding is contributing to auto-reclose being disabled in the presence of embedded generation. Without auto-reclose there is a prolonged loss of supply.