Advice on Reactive Current Access Standards

Report

Australian Energy Market Commission

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Executive summary

Australian Energy Market Commission (AEMC) has engaged Aurecon to provide advice on reactive current injection rule change. This report summarises results obtained from vendor-specific PSCAD models of various inverter-based resources (IBR). This forms Aurecon's advice on the extent to which the current and proposed rules are achievable for the minimum access standards (MAS) on clause S5.2.5.5 of National Electricity Rules (NER). This report also provides advice on outlier conditions whereby meeting the standard will be most challenging. Alternative pathways and their merits are also investigated.

Aurecon's advice is formulated into two complementary categories as follows:

- A clear and optimal solution exists without any trade-offs.
- More than one option exists, each with some caveats and trade-offs.

Salient aspects of each category are discussed below. Noting that NER reactive current injection clauses comprise many aspects and sub-clauses, the summary below should be read in such a way that all components of category (i) shall be adopted at the same time. Options chosen for the speed and magnitude of the reactive current response following contingency events under category (ii) will then be applied in addition to those described in category (i).

i) Optimal solution could be concluded

- All requirements to remain at the connection point.
- No delineation between different types of inverter-based resources, such as wind, solar or battery energy storage systems (BESS), unless when there is a fundamental difference in their control system design philosophy, e.g., see bullet point below.
- The use of a fixed activation threshold for both the low- and high-voltage ride-through (where applicable).
  - It is also recommended to include a provision to exclude IBR technologies, whether grid-forming or grid-following, which do not use threshold triggered control systems in response to fault conditions.
- Definition of maximum continuous current as
  - The largest apparent power for the generating system as per S5.2.5.1.
  - Maximum apparent current rating of an IBR unit.
- Removing the settling time as a metric for compliance assessment.
- Assessing the response to balanced and unbalanced disturbances accounting for both the positive- and negative-sequence currents without specifying any numerical values or separate positive- and negative-sequence K-factors.
  - The new rules to highlight that the injection of current from IBR units must be at the same frequency to the terminal voltage.
- Linking at least one of the success criteria for the speed of response to the fault clearance time.
- The use of numerical values, at least as a guidance, rather than relying on descriptions such as ''as soon as possible'' for success criterion associated with the speed of response.

ii) Optimal solution could not be concluded (viable pathways are highlighted in bold)

- Speed of response
  - Rise time
    - The advantage of the rise time is that it is a known and meaningful quantity for a control system designer. Whilst a short rise time does not adversely impact system security, it does not by itself provide enough confidence that the maximum possible or required response has been delivered on

time subject to the physical limits of the generating systems and generating units. Furthermore, as discussed in this report even a rise time of 80 milliseconds (ms) cannot be met under all conditions, and unless MAS framework is revised to allow NSPs and AEMO to exempt limited outlier conditions, it cannot be used as a measure of success. As such Aurecon does not recommend the use of the rise time as the only measure of success.

- Commencement time
  - This is another metric for assessing the initial speed of response as proposed by Connection Reform Initiative (CRI) and a similar concept can be found in the UK Grid Code (noting the non-linear nature of the response, Aurecon has modified the definition to avoid ambiguities in interpreting the results as will be discussed in the body text). The commencement time shares the same drawback as the rise time that by itself it cannot ensure the overall success. As such Aurecon does not recommend the use of the commencement time as the only measure of compliance. However, it provides an advantage that it can be met in all instances, and no departure or extension of the current MAS framework is required. However, the achievable commencement time for all scenarios was determined as 80 ms which is noticeably longer than the response time of IBR control systems.
- Delivery time
  - This is proposed by Aurecon based on a similar concept that can be found in the UK Grid Code. Unlike the rise and commencement time, it is a success criterion for the final part of the response to ensure that the expected response has actually been fully delivered subject to physical limits of the generating system and generating units. It offers an advantage that it is directly linked to the fault clearance time and will not drive an unnecessarily short or unacceptably long response as pertains to the rise and settling times. It can be used as complementary aspect with either the rise time or commencement time (see below).
- **Combined rise and delivery time**
  - This is one of the two possible pathways for the speed of response with the key caveat of the need for a revision of MAS framework to allow exempting limited outlier conditions for which the settling time, even twice the current requirements, cannot be met.
- **Combined commencement and delivery time**
  - This is the second possible pathway without the need to make changes to the MAS framework. However, it will provide a less meaningful success criterion for the control system designer involving in design and tuning of individual generating units. Furthermore, in some cases the response could only be commenced, i.e., going in the positive direction, at 80 ms.

- Magnitude of response
  - **Reactive current injection**
    - A 0% reactive current injection can be achieved at the connection point in most but not all scenarios. Key scenarios of concern are those with high or maximum steady-state reactive power generation before the fault occurs. If the use of reactive current is to be pursued as a viable option, exclusion of such outlier conditions shall be accounted for.
  - **Total fault current injection**
    - The total fault current injection accounts for active and reactive currents, including both the positive- and negative-sequence currents, and as such no unintended trade-off or de-prioritisation of any capabilities is required. It can also be directly compared with the physical capability of the generating system to ensure the maximum possible response has been delivered. However, programming, testing and implementation by original equipment manufacturers (OEMs) may take more than a year, and as such this can be considered as part of a broader review of S5.2.5 also noting that it will impact the automatic and negotiated access standards.

1 Background

This section provides a summary of the proposed rule change and other industry initiatives. It then presents the fundamental principles and objectives of reactive current injection, and some of the challenges in meeting the MAS without discussing any simulation studies (simulation studies will be discussed in Chapter 2). A comparison against international requirements is also provided in this section.

1.1 Proposed Rule Change and Other Ongoing Initiatives

Table 1 presents a comparative summary of the current and proposed MAS on aspects of NER Clause S5.2.5.5 related to reactive current injection/absorption during the disturbances. Whilst a comparison against the respective automatic access standard (AAS) is also shown, the latter is not the subject of this investigation. However, it is worthwhile to note that unlike most other access standards, the MAS and AAS are currently identical in terms of the important success criteria of rise and setting times.

Key changes in the proposed rule change submission can be summarised as follows:

- Longer rise and settling times.
- Lower magnitude of injection/absorption as function of the voltage drop/rise.
- Unit terminals to be the main point of compliance assessment with the connection point as the secondary compliance point with the intent of ensuring no adverse impact on system security.
- The use of a fixed trigger compared to currently defined voltage ranges.
- The use of the positive-sequence current for assessing the magnitude of injection/absorption as opposed to both the positive- and negative-sequence components currently sought.
- Clearer definition of maximum continuous current.

Studies conducted by Aurecon will aim answering the following two questions with regard to the proposed rule change:

- Narrowing down, as far as practically possible, key conditions under which the existing MAS cannot be met.
- The extent to which the proposed access standard can be met by all IBR technologies.

Table 1: Current NER vs proposed rules on reactive current injection/absorption during the faults

	Current rules		**Proposed rules**
Access standard	**AAS**	**MAS**	**MAS**
Rise time (ms)	<u>40</u>	<u>40</u>	80
Settling time (ms)	<u>70</u>	<u>70</u>	110
Compliance point	POC (alternate points may be accepted)	POC (alternate points may be accepted)	Unit terminals
K-factor (%) (under-voltage)	4	2	2 (terminals)/ 0 (PoC)
K-factor (%) (over-voltage)	6	2	2 (terminals)/ 0 (PoC)
Commencement threshold (%) (under-voltage)	85-90	80-90	80-90
Commencement threshold (%) (over-voltage)	110-115	110-120	110-120
Commencement trigger	Range (Δ=5%)	Range (Δ=10%)	Fixed

Calculation methodology	Using phase to phase, phase to ground or sequence components of voltages. The ratio of the negative sequence to positive sequence must be agreed with AEMO and NSP.	IEC Std 61400-21-2008
Maximum continuous current	Open for interpretation	Maximum apparent current rating of an asynchronous generating unit

Another ongoing initiative to formulate a more achievable MAS for reactive current injection/absorption is that led by CRI. A comparative summary of the CRI proposal against the proposed rule change is shown in Table 2. The following key differences are noted:

- Introducing a 40 ms ''commencement time'' as a measure of the time by which IBR control systems have started to respond noting the time required for accurate calculations of the root mean square (RMS) voltage and the delays before a response can commence.
- Replacing the fixed 80 ms rise time with ''the fastest applicable primary protection clearance time''.
  - Note that the primary protection clearance time is a function of the connection point voltage level which for transmission network voltages varies between 80 and 120 ms.
- Removing the settling time as a metric for compliance assessment.
- Compliance point retained at the connection point.
- Providing an option to account for both the positive- and negative-sequence components to manage potential over-voltages during unbalanced disturbances.

Key similarity between the two proposals is the use of a fixed threshold for initiation of the response. A clearer definition of maximum continuous current is also noted by both, each proposing a new definition.

A more detailed assessment of the extent to which each of the proposed rule change and CRI proposal can be achieved in practical IBRs will be discussed in Chapter 2 based on numerous PSCAD simulation studies conducted. However, it is Aurecon's view that the CRI proposal is a more systematic way of addressing challenges associated with the magnitude and speed of response. This will be further elaborated in Chapter 2.

Table 2: Proposed rule change vs CRI proposal

	Proposed rules	CRI
Access standard	**MAS**	**MAS**
Commencement time (ms)	N/A	40
Rise time (ms)	80	Fastest applicable primary protection clearance time
Settling time (ms)	110	N/A
Compliance point	Unit terminals	PoC
K-factor (%) (under-voltage)	2 (terminals)/ 0 (PoC)	0
K-factor (%) (over-voltage)	2 (terminals)/ 0 (PoC)	0
Commencement threshold (%) (under-voltage)	80-90	80-90
Commencement threshold (%) (over-voltage)	110-120	110-120
Commencement trigger	Fixed	Fixed
Calculation methodology	IEC Standard 61400-21-2008	Using phase to phase, phase to ground or sequence components, as appropriate, of the root-mean-square amplitudes of measured voltages. The choice of voltage must be recorded in the performance standard.
Maximum continuous current	Maximum apparent current rating of an asynchronous generating unit	1) Largest apparent power for the generating system as per S5.2.5.1 2) Maximum apparent current rating of an asynchronous generating unit

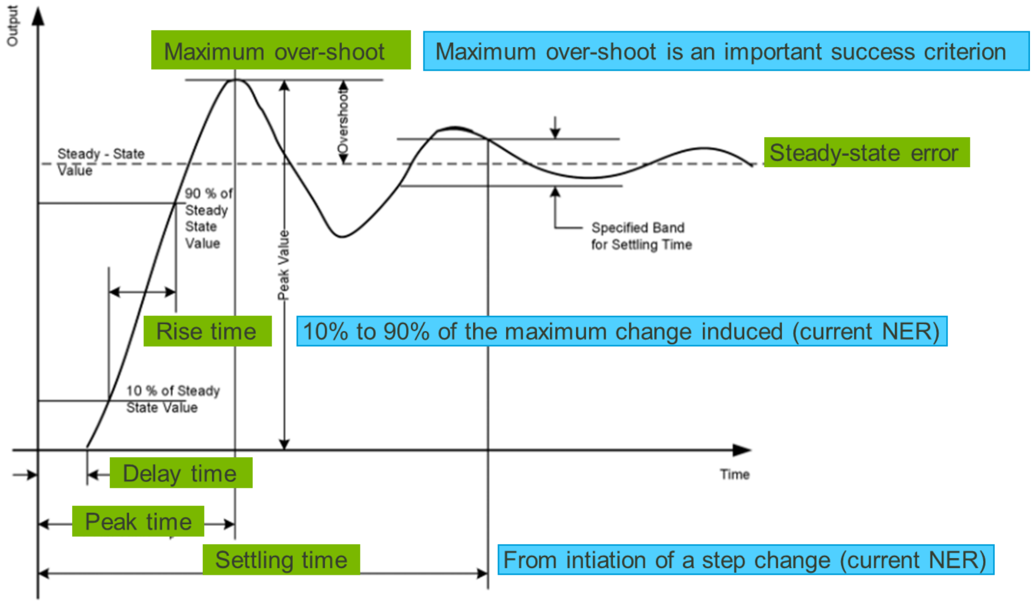
1.2 Theoretical Backgrounds

1.2.1 Rise and settling time calculations

Rise and settling times are defined success criteria for assessing the response of control systems in general, not just in the context of power systems engineering. They are defined based on an idealised step change in a given quantity, e.g., voltages. Figure 1 shows the response of a second order transfer function used in a typical control system. The following measures of success on the speed of response are generally defined:

- Delay time
- Peak time
- Rise time
- Settling time (Note that currently the permissible steady-state error for calculating the settling time as defined in the NER is 10%).

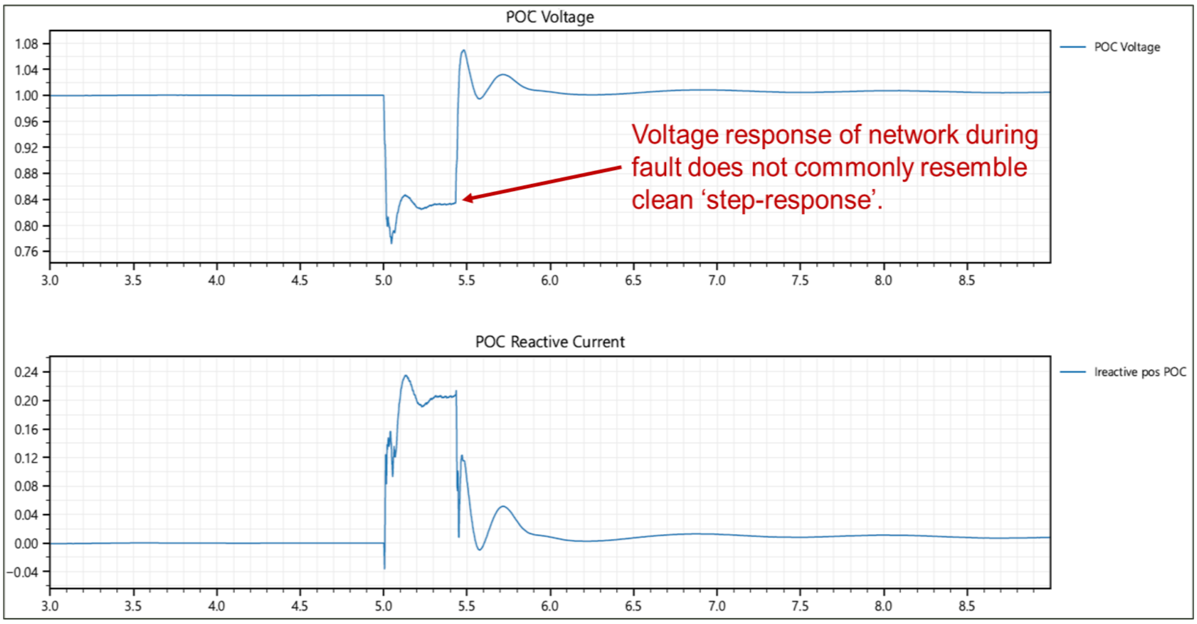
Figure 1 Key success criteria for assessing the response of a control system



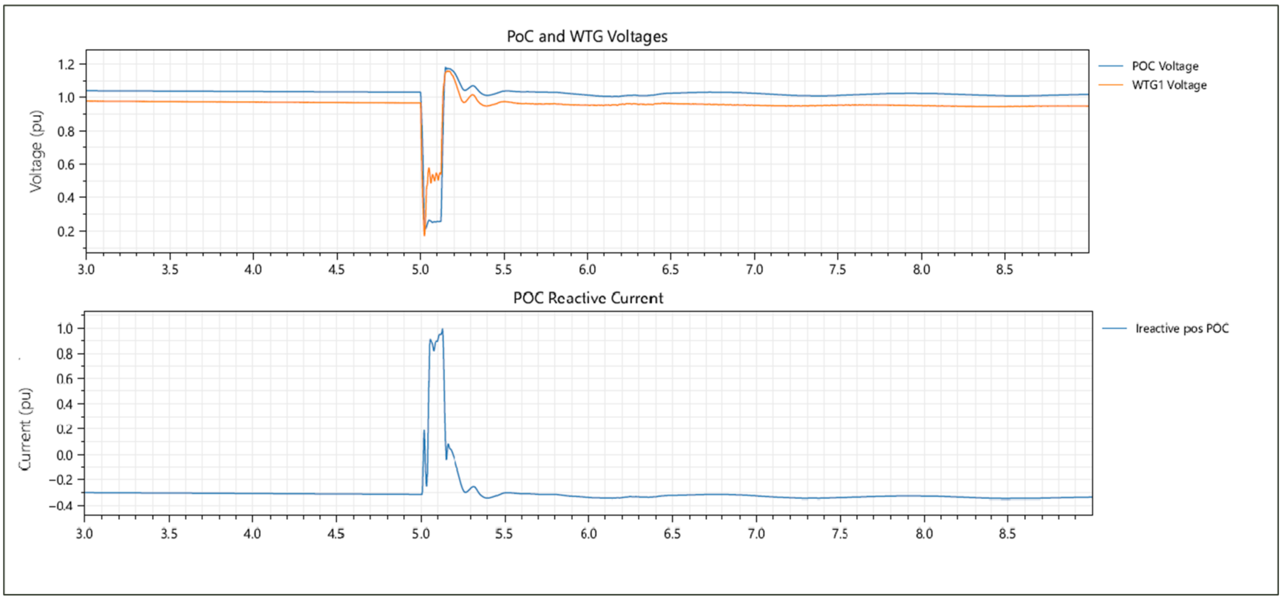
Determining the rise and settling times follows precise mathematical calculations based on an ideal step response. However, this can seldom be achieved during fault conditions as shown in Figure 2 (i) and (ii). These results are obtained from a vendor-specific PSCAD model of an IBR highlighting a voltage profile during fault conditions that is far from a step change. Besides the non-step voltage profile, the rapid voltage drop immediately after the fault, and a modest recovery a few milliseconds thereafter causes the reactive current to move backward momentarily with the penalty of increasing the rise time as shown in Figure 2 (ii). In this instance an end-to-end reactive current response of 1.3 pu was delivered, albeit not compliant with the NER rise time requirements.

Figure 2 Two examples of connection point voltages during a fault showing non-step like voltage profiles

(i)

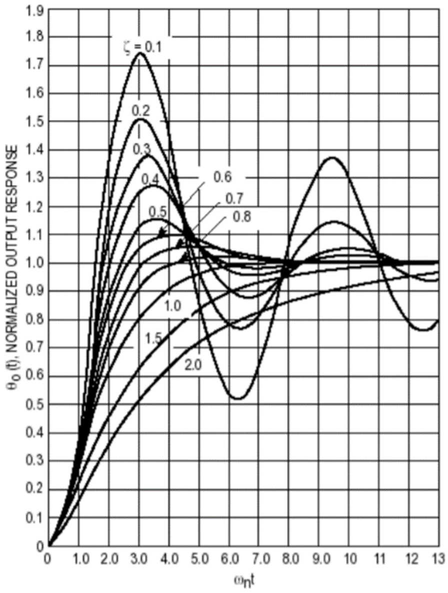


(ii)



An important consideration in determining the numerical values for the success criteria, is the conflict between some of them, and in particular that between the settling time, maximum overshoot and damping as shown in Figure 3. Whilst a fast response is generally desired, this could impact the maximum overshoot (not a directly defined success criterion in the NER) to the point that the damping requirements, e.g., adequately damped, cannot be met. Noting the practical importance of the damping for power system planning and operation, and the ability to measure and calculate it accurately in practice, an alternative to the current approach is to replace the settling time requirement with the damping requirement (albeit recognising a gap in the current definition of the damping for an inverter dominated power system and the need to potentially revise the current requirements and definitions primarily developed based on synchronous dominated power systems).

Figure 3 Trade-off between the settling time and overshoot

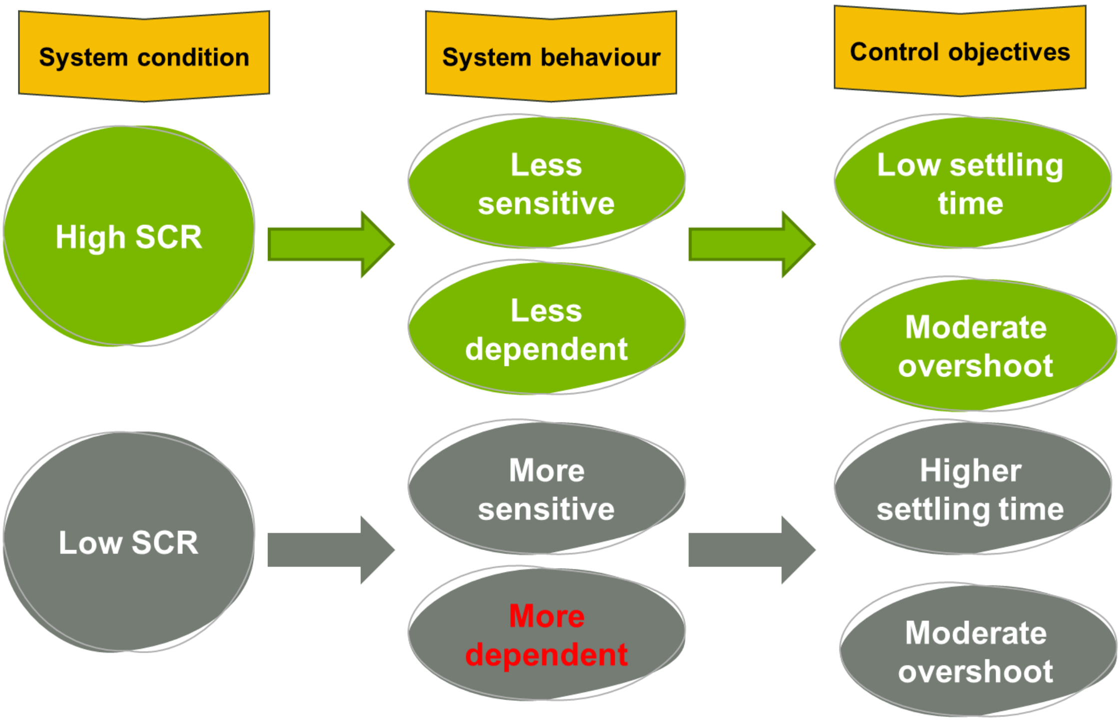


The speed of control system response also depends on the strength of the system to which an IBR is connected whereby the priority success criterion differs between a strong and weak connection point as shown in Figure 4.

- A strong power system is less sensitive and less dependent on the response of an individual generating system. A fast response can be generally tolerated well with minor overshoots and good damping. As such a fast settling time is highly desired.
- For a weak power system, there is a complexity that the system is more dependent on the response of each individual generating system to ensure system stability, however, at the same time it is more sensitive to fast and large changes in the response of any given plant. A trade-off between the maximum overshoot

and settling time is required, adding further complexities and dependencies on designing and tuning the response of individual control systems best to be done in a coordinated manner based on wide-area PSCAD models currently available to AEMO and NSPs only[1].

Figure 4 Control system objectives as function of system strength (represented by short circuit ratio (SCR))



1.2.2 Typical response of an inverter-based resource during fault conditions

To better understand the limitations and opportunities associated with reactive current injection/absorption during faults, it is important to consider this response in the context of overall IBR response. Figure 5 shows the response of a typical IBR before, during and after fault conditions. Whilst this represents a typical response, it cannot be considered as a generalised response for all IBR types and makes.

As shown in the figure, during steady-state conditions constant control of active and reactive power is typically adopted. For an intermittent resource with a maximum power point tracking (MPPT) control strategy, this often means a high active power and low or zero reactive power. Upon fault detection, the constant active and reactive power control is suspended, and a constant current control is used instead. The active current drops as function of the voltage dip and remains low until the fault is cleared. Reactive current is therefore often prioritised to assist network voltage recovery following fault clearance.

Note that all IBRs, grid-following or grid-forming, are current limited devices with a typical over-current capability of 120-150% during fault conditions (some grid-forming makes offer additional fault current capability of up to 200%, however, this comes at a cost).

The total current available can be allocated to the following components:

- Active current
- Reactive current
- Positive-sequence current
- Negative-sequence current

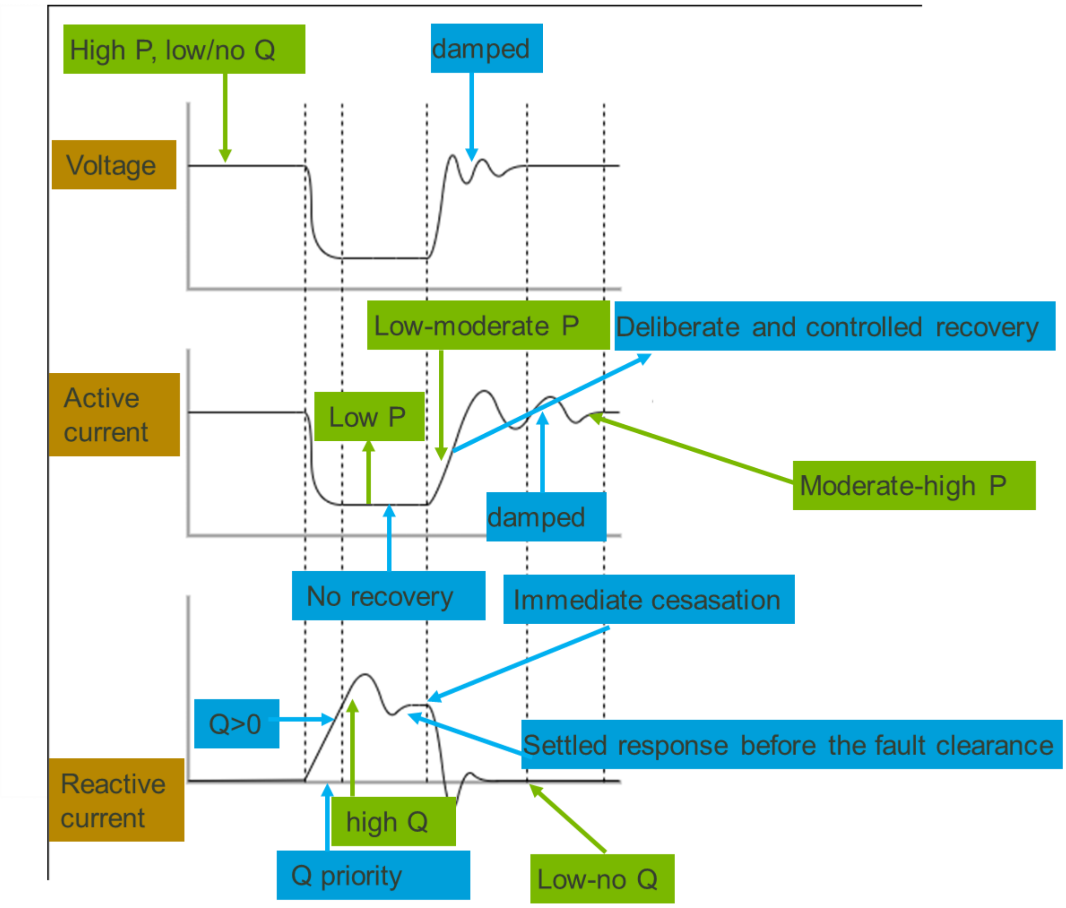
[1] It is understood that the connection simulation tool (CST) initiative currently being progressed by AEMO will permit registered participants to perform wide-area PSCAD studies without access to PSCAD models of other connections.

Aiming to achieve the full response from one or two components, could well mean that very little or no current is left to allocate to other components.

For deep faults with a low residual active power, and provided that the steady-state reactive current is low, relatively large reactive currents can be provided during the fault. This could sometimes even exceed the maximum continuous current of the generating system noting the temporary over-current capability mentioned above. On the other hand, for shallow voltage dips with relatively large residual active power, there is less opportunity to provide a high reactive current due to physical limitations of the inverters. This is further exacerbated if the inverter was operating near the maximum or minimum reactive power limit. Noting the limitation of the total current, some inverters sometimes intentionally drop the active current during the fault to zero or very low values to allow meeting the reactive current injection during the fault. Note that there is no requirement on active current/power during the fault.

Once the fault is cleared, network voltages will rapidly return to pre-event values. As such it is crucial for the inverter to cease reactive current injection immediately to avoid creating excessive temporary over-voltages. This was a recognised problem 1-2 decades ago, however, it is largely an understood and addressed issue among most (but not all) OEMs. After the fault clearance, active power will start to return to its pre-fault value, typically taking between 100 ms and 1 s. Note that unlike the voltage recovery, an as fast as possible active power recovery is not necessarily the most desirable performance. A deliberate and controlled recovery with good damping to avoid adverse impact on system security is the key success criterion.

Figure 5 Typical response of an IBR before, during and after the fault



1.3 Overarching Principles

The following principles were accounted for in Aurecon's assessment of practical options from technical and economical standpoints.

- Recovery of network voltages

- When a fault occurs, voltages across the faulted phases will drop as function of the fault impedance, proximity to the fault, and the overall strength or resilience of the power system. The weaker the power system the larger the propagation of the voltage dips across the system will be. Synchronous generators respond as function of the voltage dip experienced at their terminals even if the residual voltage is greater than that considered normal operating band, i.e., 0.9 pu, without deploying separate fault related control systems. The same approach can be found in several grid-forming control systems which aim to emulate the response of a synchronous generator to various degrees. On the other hand, most, but not all grid-following designs, are programmed such that distinct sets of actions are initiated once the voltage at the faulted phases drops to a certain threshold.
- Irrespective of the generating system size and the strength of its connection point, it is expected that the connection of a generating system does not exacerbate network voltage recovery once the fault is cleared. A very fast injection of reactive current could potentially reduce the size of the voltage dip, however, this cannot be necessarily correlated to a better stability outcome.

- Response delivery before the fault clearance
  - As discussed above the key objective of reactive current injection is to improve network voltage recovery immediately when the fault is cleared. As such it is important for the full response, subject to physical limits of the generating units and the generating system, to be delivered before the fault clearance. For this reason, a response not fully delivered before the fault clears may not provide any tangible benefit to network voltage recovery. Furthermore, continued reactive current response after the fault clearance could result in excessive over-voltages causing adverse impact on system security. How fast the response was initiated is a secondary factor, but can be considered as an interim check point rather than the ultimate success criterion. For example, a rise time of 40 ms where the response is only delivered by 50% of the total possible response before the fault clearance cannot be considered a good response.
- Ease of interpretation and compliance assessment during the lifetime of the generating system
  - The reactive current injected/absorbed at the connection point is lower than that at the terminals of the generating unit where the response actually occurs. The extent to which the reactive current dissipates as it travels from the unit terminals to the connection point, depends on the impedances of the transformers, cables and transmission lines in between. Larger sizes of the generating systems and longer distances between individual generating units, both being the typical characteristics of large wind farms, often cause larger dissipations of reactive current.
  - Furthermore, as discussed above rise and settling times are defined quantities for control systems and as such, they can be more conveniently calculated at the terminals of the individual generating units where the actual control systems are located rather than at the connection point.
  - For the above two reasons, one may conclude that the compliance with the current MAS can be more readily met at the unit terminals than the connection point for all three aspects of the reactive current response during the faults, i.e., rise time, settling time, and percent change in reactive current as function of percent change in the voltage (k-factor).
  - However, it is also important to note that compliance applies to the lifetime of the generating system rather than just during the grid connection studies process. Moving the compliance to the unit terminals will necessitate the ability to demonstrate the compliance at each and every generating unit once a real network disturbance occurs. Besides the requirement for the number of high-speed data recorders, this will also be in contradiction with good industry practices in the use of aggregate dynamic models, and in particular for PSCAD studies, also recognising that not each individual generating unit will be operating at exactly the same voltage.
- Reliance on deterministic quantities
  - Besides the challenges in calculating rise and settling times as discussed above, another challenge in their use is that they will not have the same significance and implications for all connections across all parts of the network. For example, rise and settling time of 100 and 150 ms will certainly assist in improving system security for a fault clearance of 200 ms whereas they are unacceptable and possibility detrimental if the fault is cleared in 80 ms. Using a single value for each of the rise and settling time without a reference to fault clearance time will not allow for this delineation. Likewise, quantities such as

fault impedance are unpredictable and differ from one fault to another. This also means that the same relation between the connection point and unit terminal voltage does not apply for all faults. The use of deterministic and consistent metrics between the connection point and unit terminals such as fault clearance time would address these challenges.

- Actual network faults are unbalanced
  - The occurrence of three-phase faults in bulk power systems is a rarity where almost all network faults occurring in real life are unbalanced. Whilst this is a known fact in the industry, a perception by some Engineers is that three-phase faults might be more onerous than the unbalanced faults providing a convenient and pragmatic approach for designing the generating system based on the most onerous conditions but also the most convenient conditions from the perspective of power system modelling and simulation. However, this concept falls short as several instances can be found for practical IBRs where an unbalanced disturbance is more onerous for both the IBR control system and the overall power system. Providing no response or even sometimes a detrimental response, e.g., causing over-voltages on healthy phases, is not therefore acceptable. For this reason, it is important for the compliance studies to account for unbalanced faults. This in turn means the need to consider both the positive- and negative-sequence components. Whilst a precise ratio between the positive- and negative-sequence components cannot be practically determined for all operating conditions, the overall notion that shall be accounted for is to not cause temporary over-voltages on the healthy phases.

1.4 Comparison with International Requirements

This section presents an overview of key international standards and requirements with regard to the speed and magnitude of reactive current response during the faults. The intention is to determine key similarities and differences in terms of success criteria used, the numerical values assigned to each factor, and whether they are more pessimistic, optimistic or completely different to NER requirements. Table 3 compares the requirements in German standard VDE AR-N-4120 with the current and proposed rules. Unlike the NER, Germany applies a single set of requirements rather than a range between the AAS and MAS. Closer inspection of Table 3 shows the following key similarities and differences with the current and proposed Australian requirements:

- The rise and settling times in VDE AR-N-4120 are larger than those currently in the AAS and MAS, indicating the merit to increase these values in a revised NER, assuming that these metrics are considered the most appropriate measures for assessing the speed of reactive current response (further discussions will be presented on this in Chapter 2). The overall weakness of Australian power system compared to Germany is another factor that need to be accounted for.
- Unlike the current rules but similar to the proposed rule, the compliance point defined in VDE AR-N-4120 is at the generating unit terminals. However, it is noted that the compliance regime in Germany differs to that in Australia where challenges associated with measuring the compliance at unit terminals were discussed in the previous sub-section.
- Another similarity between the VDE AR-N-4120 and the proposed rules is the use of a fixed threshold for response activation.
- The methodology to account for sequence components in VDE AR-N-4120 is different to both the current and proposed rules whereby in Germany separate k-factors are calculated for the positive- and negative-sequence current response. There are some similarities with the current rules where both the positive- and negative-sequence current, explicitly or implicitly, are accounted for.
- Similar to both the current and proposed rules, VDE AR-N-4120 is a technology neutral requirement and does not provide separate requirements for different IBR types.

Overall, the key takeaways from the VDE AR-N-4120 is that the rise and settling times in the current MAS may be too small, and that assessing the compliance based on a fixed trigger and inclusion of both the positive- and negative-sequence current components are good industry practices internationally.

Table 3: VDE AR-N-4120, Germany

	Current rules		Proposed rules	Germany
Access standard	**AAS**	**MAS**	**MAS**	
Rise time (ms)	40	40	80	60
Settling time (ms)	70	70	110	80
Compliance point	POC (alternate points may be accepted)	POC (alternate points may be accepted)	Unit terminals	Unit terminals
Commencement trigger	Variable range (5%)	Variable range (10%)	Fixed	Fixed
Calculation methodology	See Table 1		Positive-sequence	Positive and negative-sequence

Table 4 summarises salient aspects of the newly introduced IEEE Std 2800™-2022. Key difference with all requirements discussed so far is the delineation between type III wind turbine generators and other IBR types. The rational for this is the loose but important coupling between the induction machine used in type III wind turbines and the grid. This means that the overall response is not fully influenced by the converter control and depends on inherent machine dynamics as well. In simple terms, the response of a type III wind turbine will be somewhere in between a 100% control driven response such as that of a BESS and a machine-driven response as pertains to a synchronous machine.

For this reason, the response or rise time requirements are not applied to type III wind turbines, and a longer settling time is permitted for this technology compared to all other IBR types. The response and settling time requirements for all other IBR types are similar to the current rules (each being 0.5 cycles longer than the NER requirement). However, note that a six-cycles settling time will be too long for most transmission connections in the NEM with typical fault clearance times of 4-5 cycles depending on the connection voltage.

It is Aurecon's view that the approach adopted by the IEEE may not be a sustainable solution in Australian context which has been based on technology neutral requirements with only a couple of GPS clauses are different between the synchronous and the so-called asynchronous generation technologies. Furthermore, whilst type III wind turbines are often exposed to greater challenges relative to other IBR types in meeting the speed of response requirements set out in the current rules, several practical instances exist where other IBR types had similar challenges.

Other key learning from the IEEE Std 2800™-2022 is the inclusion of specific negative-sequence current injection requirement. Most notably the standard requires the injection of current from IBR units at the same frequency as that of the terminal voltage. This stems from practical experiences where IBRs injected sizeable negative-sequence (100 Hz) component during the fault causing oscillations and instabilities.

Table 4: IEEE Std 2800™-2022

	Type III WTG	All other IBR Units
Step Response Time	NA[1]	≤ 2.5 cycles
Settling Time	≤ 6 cycles	≤ 4 cycles
Settling Band	Max of (±10% of required change or ±2.5% of IBR unit maximum current)	Max of (±10% of required change or ±2.5% of IBR unit maximum current)

The last international requirement reviewed in this section is The Grid Code from National Grid UK. This is the most different requirement to all others discussed so far. A summary of key relevant requirements is shown in Figure 6. Key traits observed are as follows:

- Rise and settling times are replaced with a response trajectory indicating the required magnitude of the response as function of fault clearance time with the response trajectory accounting for a range of acceptable responses similar to the concept of MAS and AAS.

- For longer fault clearance times, inverter blocking is permitted to avoid excessive temporary over-voltages.
- Requirements can be defined at the connection point or unit terminals, both of which will see the same fault clearance time. This is an advantage compared to the use of rise and settling times which could be significantly different between the connection point and unit terminals. Note that UK also has a different compliance regime to that applied in the NER which makes it possible to have options between the connection point or unit terminals as the compliance point. However, as discussed previously, the use of unit terminals will not be practical in an Australian context.
- Regarding the magnitude of the response, the approach applied in the UK is a simplified version of the concept of k-factor applied in Australia and many other countries. The requirement in the UK is such that the full response (corresponding to the maximum continuous current) must be achieved by the time the voltage drops to 50%. This is equivalent to a k-factor of 2.5%.
- The key shortcoming of this standard is that there is no mention of how unbalanced disturbances and positive- and negative-sequence components are treated.

Overall, Aurecon supports the use of alternative success criteria for measuring the speed of response instead of commonly used rise and settling times. It is certainly a good idea to define the response requirements as function of fault clearance time recognising that faster responses are required for shorter clearance times to assist network voltage recovery. However, longer responses may still be appropriate for longer fault clearance times, especially for the MAS, without any adverse impacts on system security.

Figure 6: National Grid UK, The Grid Code

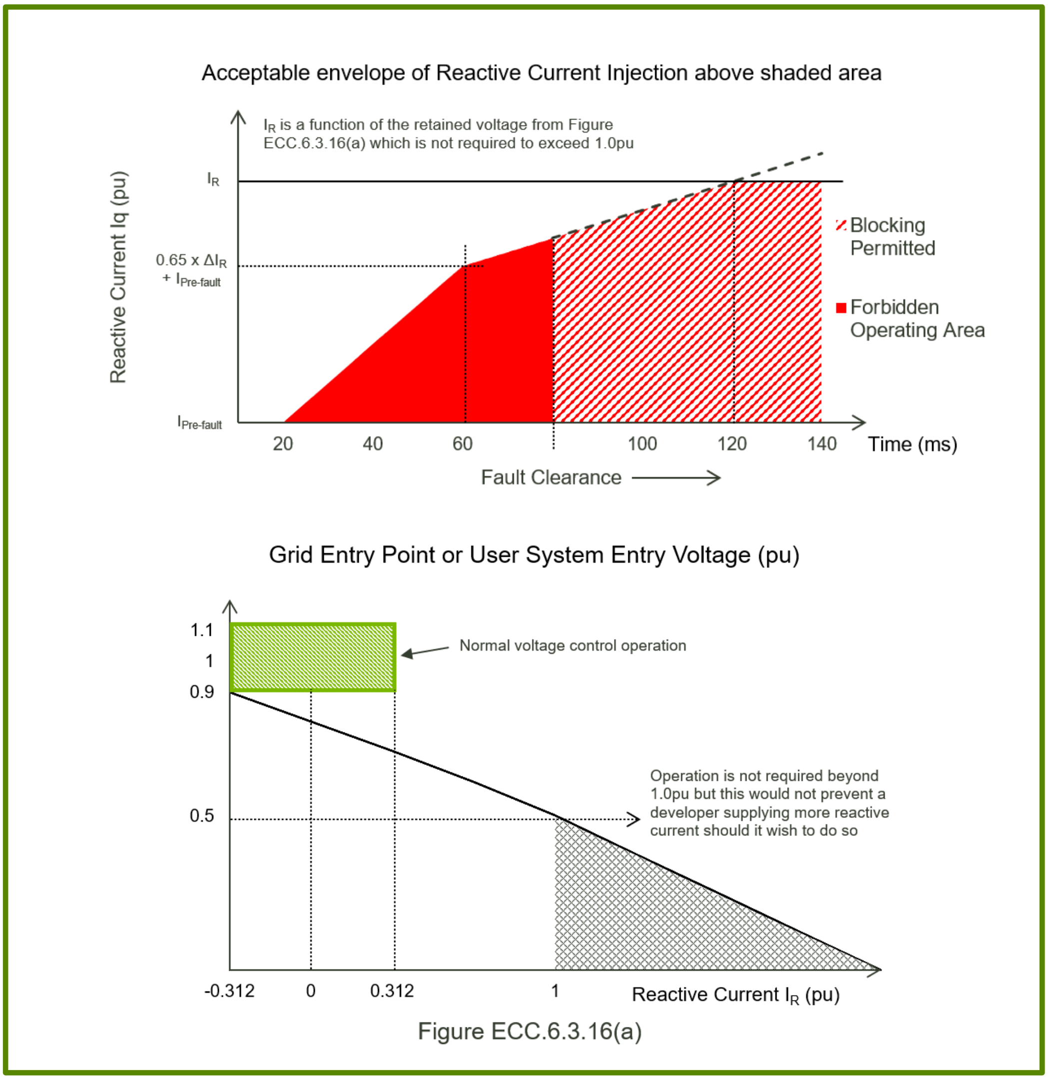


Figure ECC.6.3.16(a)

2 Modelling and Simulation Studies Conducted

2.1 Proposed Assessment Methodology

To allow an accurate assessment of the capabilities and limitations of IBR in meeting the magnitude and speed of reactive current response during fault conditions, vendor-specific PSCAD models of different IBR types including wind turbines, for which the proposed rule change has been made, were used. Several hundreds of simulation studies were then conducted initially focusing on a large practical wind farm of approximately 500 MW[2] with the following factors considered:

- Balanced and unbalanced faults including two-phase-to-ground, single-phase-to-ground and phase-to-phase
- Close-in, remote, and circuit breaker failure faults, with fault clearances ranging between 80 and 430 ms.
- Various residual fault voltages.
- Varying grid conditions: connection point SCR between 2 and 5; X/R ratios between 2 to 10.
- Generator pre-disturbance active and reactive power output, including Pmax, Pmin, Q0, Qmax and Qmin
- Impedance between the unit terminals and connection point, including transformer impedance and cable/line impedance (between 22.5% and 33% total impedance between inverter terminals and connection point)
- Installed capacity ranging between approximately 100 and 500 MW.

Aurecon's assessment has not investigated the capabilities of IBR to meet the MAS for absorbing reactive current during network over-voltage events. The focus area was solely network contingency under-voltages as these are understood to be of more concern with respect to S5.2.5.5 compliance.

The following pathways were then considered; however, this does not imply that a successful outcome could be achieved for all these pathways.

- Increased rise and settling times
- Removal of rise and settling times, and replacement with other suitable metrics for assessing the speed of response
- New definitions including new success criteria
- Compliance at unit terminals
- Delineation between positive- and negative-sequence requirements
- Identifying outlier conditions for which a response below MAS may be accepted on a case-by-case basis subject to agreement with relevant NSP and AEMO
- Combinations of some of the above

To ensure the veracity of conclusions for different IBR types and network conditions, shortlisted studies were then conducted on the following:

- Solar Farm
- Multiple nearby wind farms
- Wind and solar farm nearby

A summary of the key observations is presented in the remainder of this chapter, with more comprehensive simulation results presented in Appendix B.

[2] Larger wind farms in the order of 1000 MW or above are usually built based on such a wind farm as the constituting building block.

2.2 Challenges Observed

2.2.1 Speed of response

Rise time calculations

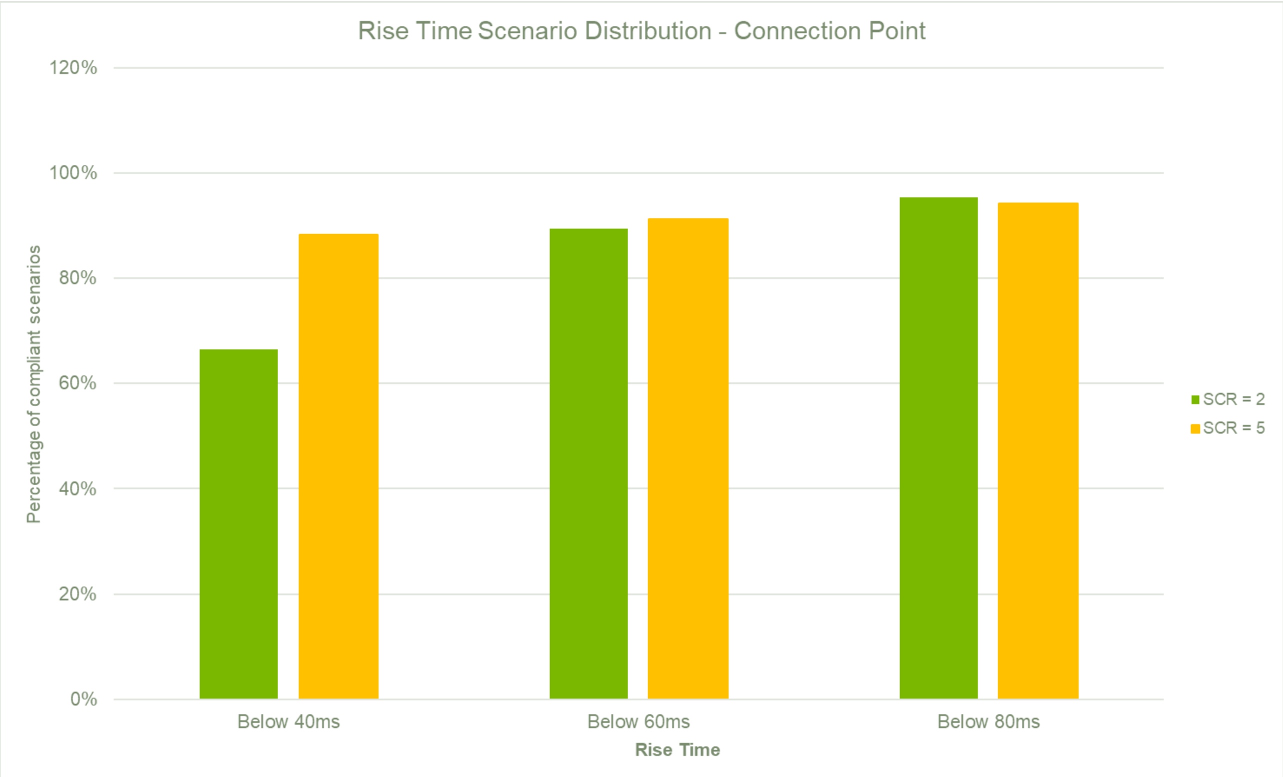
Figure 11 shows the percentage of scenarios simulated where a particular rise time can be met. The three rise time values of 40 ms (current NER), VDE AR-N-4120 (60 ms) and the proposed rule (80 ms) were used as a reference. As indicated moving from 40 to 80 ms increases the successful scenarios by approximately 30%, however, there still exists approximately 5% of the scenarios where even an 80 ms rise time cannot be met. Note that these results are obtained from the PSCAD model of a vendor-specific wind farm. Faster responses can usually be achieved with solar and BESS technologies. However, note that the proposed rule change is focused on the MAS which should be based on the lowest acceptable performance of all IBR technologies rather than the best possible response. It is also evident that network SCR variations has a minor impact, and in any case higher rise rimes cannot be necessarily attributed to lower SCR conditions.

The main cause of rise time values exceeding 80 ms was observed to be a combination of the following factors (also shown in Figure 2):

- Distortion occurring in the reactive current waveform during the initial stages of the fault caused by fault voltage profile.
- Pre-disturbance operating scenarios where the generator was absorbing reactive power before the fault, and for example even a 130% change in the magnitude of reactive current response is not sufficient to assist in meeting the rise time requirement. .

Therefore, should the rise time be still retained as a success criterion in the NER for assessing the speed of reactive current response, an extension may be warranted to allow NSPs and AEMO to exclude those known outlier conditions and base the settling time on the majority rather than 100% of the cases.

Figure 7: Summary of connection point rise time calculations across investigated scenarios

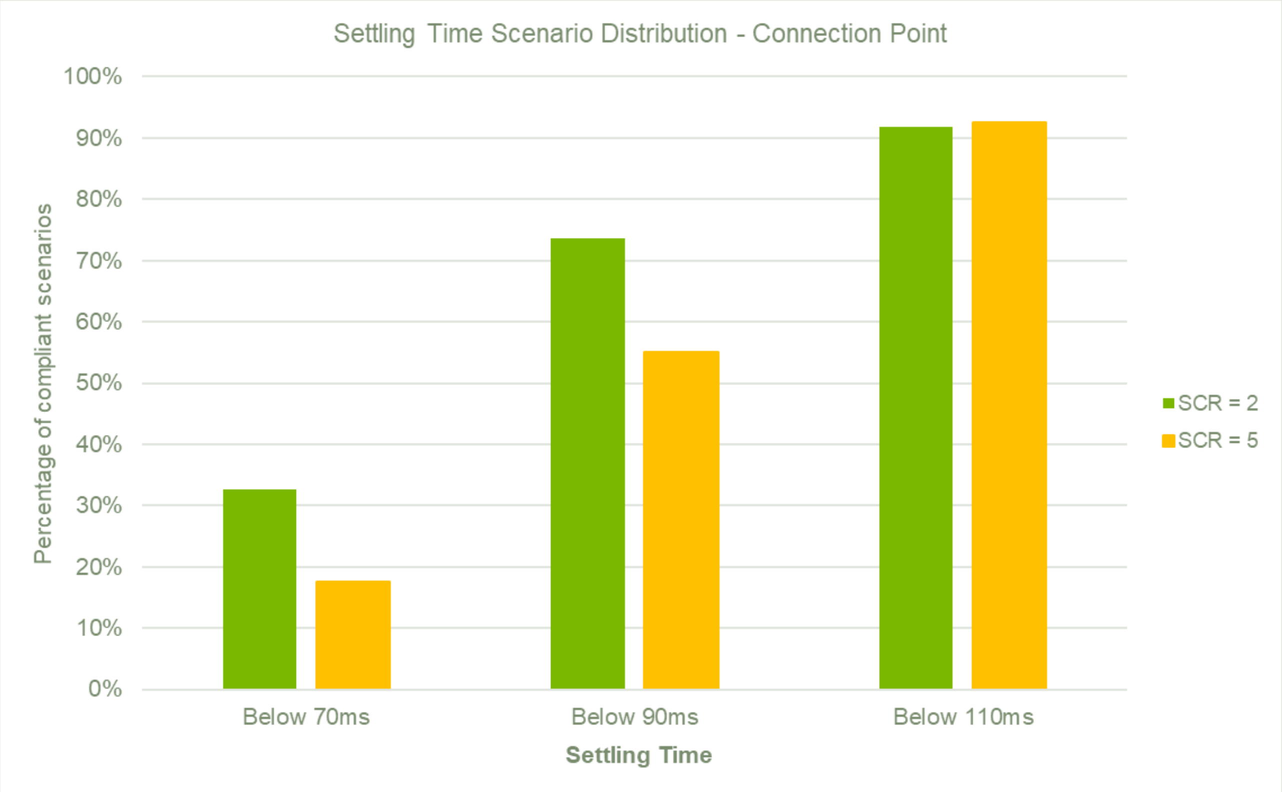


Minor discrepancies observed between the high and low SCR conditions for total percentage of scenarios below 80 ms stem from conducting fewer simulation case studies for the higher SCR conditions, hence a minor difference in percentage calculation.

Settling time calculations

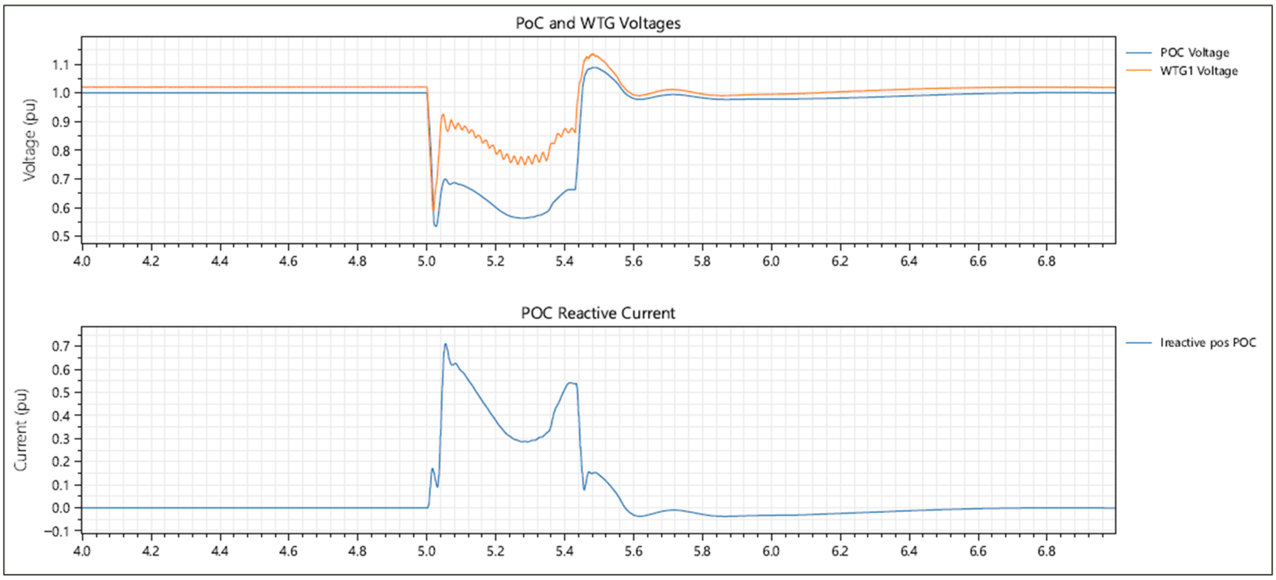
Figure 8 presents a summary of percentage of the scenarios where the current 70 ms NER settling time and the proposed 110 ms settling time can be met. For further context, the compliance percentage associated with an interim value of 90 ms is also presented. As shown, increasing the settling time requirement to 110 ms will increase the extent of compliant scenarios by approximately 60%, however, there still exists around 10% of the cases where the compliance could not be achieved. A clear delineation of these cases depending on the fault type, initial active and reactive power, and residual voltage was not possible, however, most but not all the longer settling times are associated with longer fault clearance times.

Figure 8: Summary of connection point settling time calculations across investigated scenarios



As discussed in Chapter 1, there is a direct conflict between the settling time and maximum overshoot requirements. For most connections and in particular those in weaker parts of the network, the maximum overshoot or associated damping must be respected first. Whilst the black-box PSCAD models provided did not permit changing any control system parameters, experience gained from several practical connection projects across the NEM indicates that attempts to expedite the settling time can result in inverter tripping. Often longer and relatively shallower faults, such as circuit breaker failure faults, cause the longest settling time an example of which is shown in Figure 9 where the settling time is greater than 300 ms. Despite such a long settling time, it is noted that the generating system has delivered the intended response well within the fault clearance time which in this instance was 430 ms. This therefore casts doubt on merit of retaining settling time as a meaningful success criteria noting that a shorter settling time might adversely impact on some more tangible success criterion such as system damping. This potential adverse impact on system security is a relative disadvantage of settling time compared to the rise time where the key issue is difficulties in meeting the requirement but a fast rime time does not adversely impact the power system. That said, there still exists a gap should the settling time be removed, since it is intended as a check point for ensuring the full or near-full response has been achieved. More detailed discussion on suitable metrics for assessing the speed of response will be presented in Chapter 3.

Figure 9: Example of a very long settling time



2.2.2 Magnitude of response

Reactive current injection capability

The vendor-specific PSCAD models used for the analysis showed varying capability to produce a sufficient magnitude of reactive current during balanced and unbalanced faults. Hence, the resulting assessment of generator capability to meet the existing and proposed MAS was compared for balanced and unbalanced fault separately as shown in Figure 10 and Figure 11, respectively.

Figure 10 shows that the wind farm meets an at least 2% reactive current injection for more than 90% of the instances when subject to a three-phase-to-ground fault, where the lowest injection for all cases studied is 1.96%. The magnitude of reactive current injected during the fault to determine the percentage (or k-Factor) is measured immediately before fault clearance.

However, the following concerns still exist:

- A three-phase fault rarely occurs in practical power systems. Almost all faults are unbalanced.
- NER framework is generally based on the most onerous credible contingences than the less onerous ones. Unlike what might be perceived, a three-phase fault is not necessarily the most onerous contingency (a comparison of Figure 10 and Figure 11 conveys this message).
- MAS clauses for S5.2.5.5 are excluded from an assessment against three-phase faults (only AAS clauses require such an assessment).
- Even if the three-phase faults were to be chosen as the contingencies for which MAS compliance is assessed, as Figure 10 indicates, not 100% of the instances are compliant with 2% injection. A reduction to 1.5% is required to meet the compliance for 100% of the samples.

Meeting reactive current injection will become more difficult when the wind farm is subject to unbalanced faults. As shown in Figure 11, a 2% reactive current injection could not be achieved except for low steady-state active power and when the system is subject to shallow faults. However, most studies conducted in the industry typically focus on high steady-state active power which causes more challenges on fault ride-through capability. As such for most practical operating conditions this IBR technology cannot meet the current MAS, i.e., a 2% reactive current injection. When operating at a near zero steady-state reactive power, a k-factor of greater than 1% was achievable for most scenarios studied. However, the most onerous conditions were those with the steady-state reactive power already at its maximum before a fault was applied. For approximately 5% of the cases studied, a k-factor of 0% was not even achievable.

Figure 10: Summary of wind farm connection point k-factor calculations across investigated balanced faults

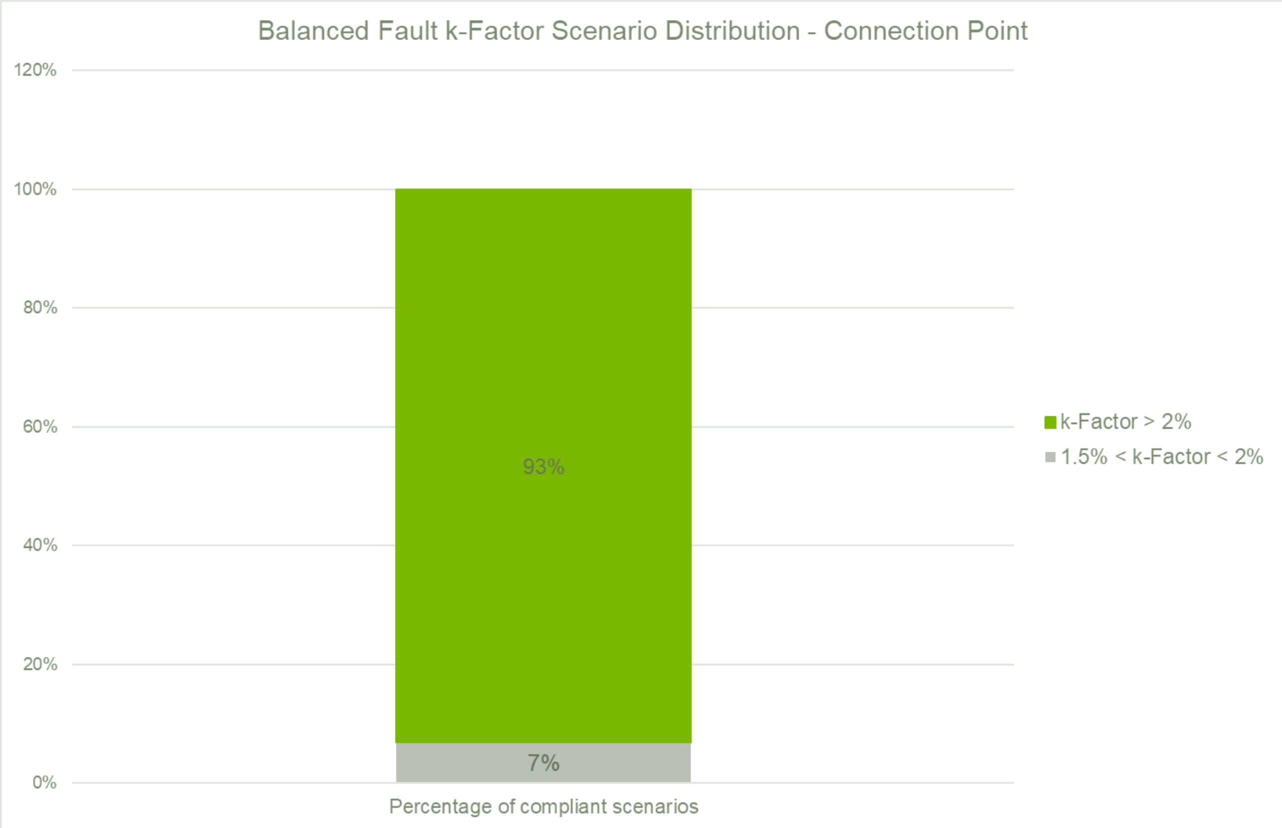
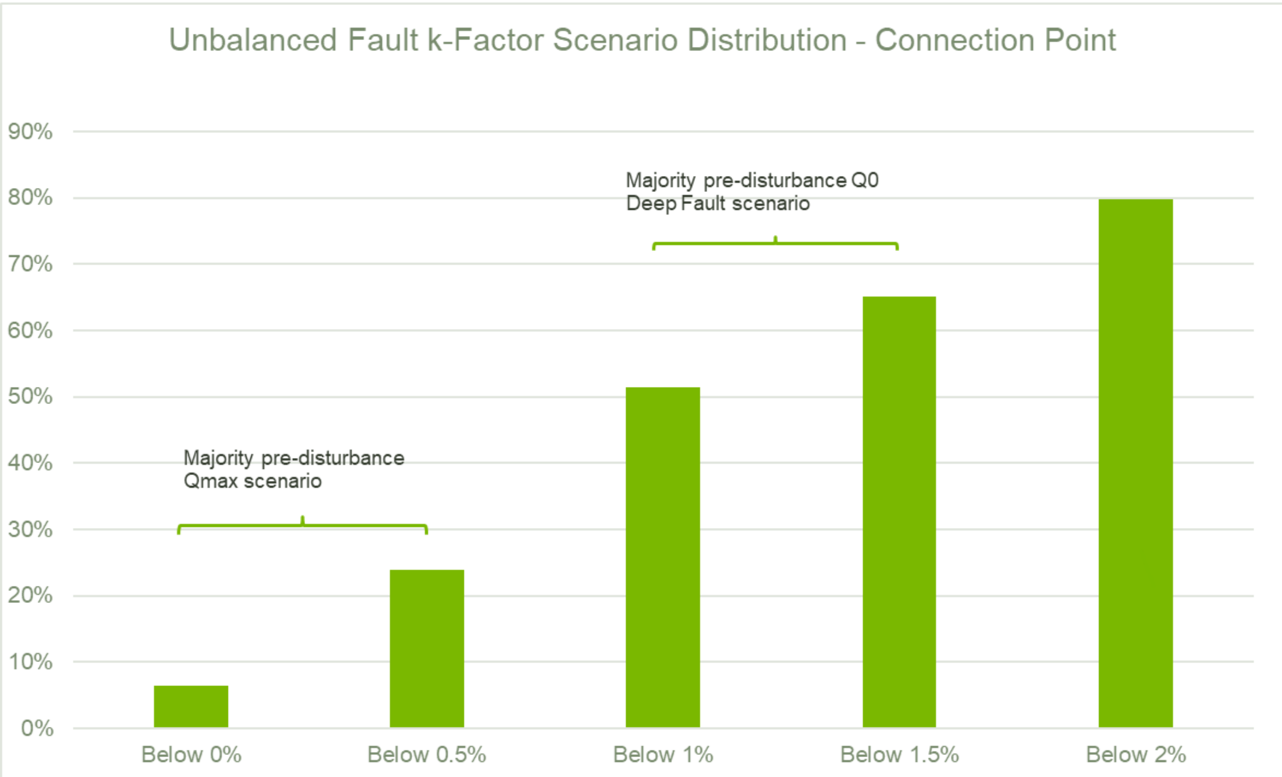


Figure 11: Summary of wind farm connection point k-factor calculations across investigated unbalanced faults

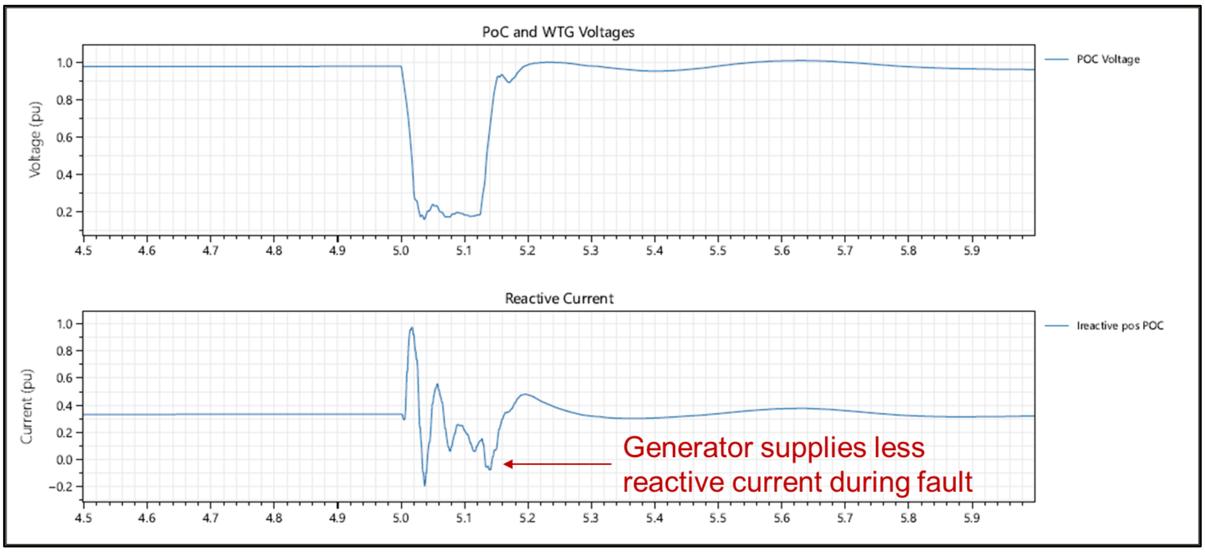


The remainder of this section discusses challenges and key contributing factors to low reactive current injections presented above.

Response variability

Figure 12 shows an example where despite a significant reactive current injection initially after the fault (within the first cycle or so), the overall response drops thereafter to the point that immediately before the fault clearance the generating system supplies less reactive current to the system, at the time the system needs it most, than during the pre-fault steady-state conditions. This corresponds to a case with a k-factor of below zero as indicated in Figure 11.

Figure 12: An Example showing a lower reactive current injection at the end of the fault than when the fault commenced



The contribution of negative-sequence current component

Figure 13 presents the contribution of the positive and negative-sequence current components during a relatively severe unbalanced fault. Common trait with Figure 12 is the response variability for both the positive- and negative-sequence components. As shown the positive-sequence current has an overall upward trajectory, i.e., injection, whereas the negative-sequence current is moving downwards, i.e., absorption. This behaviour stems from the inherent negative-sequence current absorption behaviour of type III wind turbines which is similar to that of a synchronous machine, and in both cases driven by inherent electric machine characteristics. This is usually considered a desired response in moderating the voltages across the healthy phases.

Whilst the negative-sequence current control is possible, and perhaps necessary, to some extent with type III machines, the current limited nature of the IBR would mean that attempts to maximise the positive-sequence reactive current, could result in very little or no negative-sequence current, hence the risk of exacerbating temporary over-voltages on healthy phases.

Although currently there is a provision in clause S5.2.5.5 of the NER for applicants to agree on the ratio of negative to positive-sequence current, or decide on the use of positive-sequence or total reactive current as the basis for k-factor calculations, neither will exempt applicants from meeting an at least 2% reactive current injection in circumstances where prioritising positive-sequence reactive current may not be the most desirable approach. Furthermore, as shown in Figure 14 the use of the total reactive current compared to the positive-sequence reactive current will not necessarily result in a significantly better response, in relation to response variability, or higher k-factor.

Figure 13: The impact of negative-sequence current during the faults

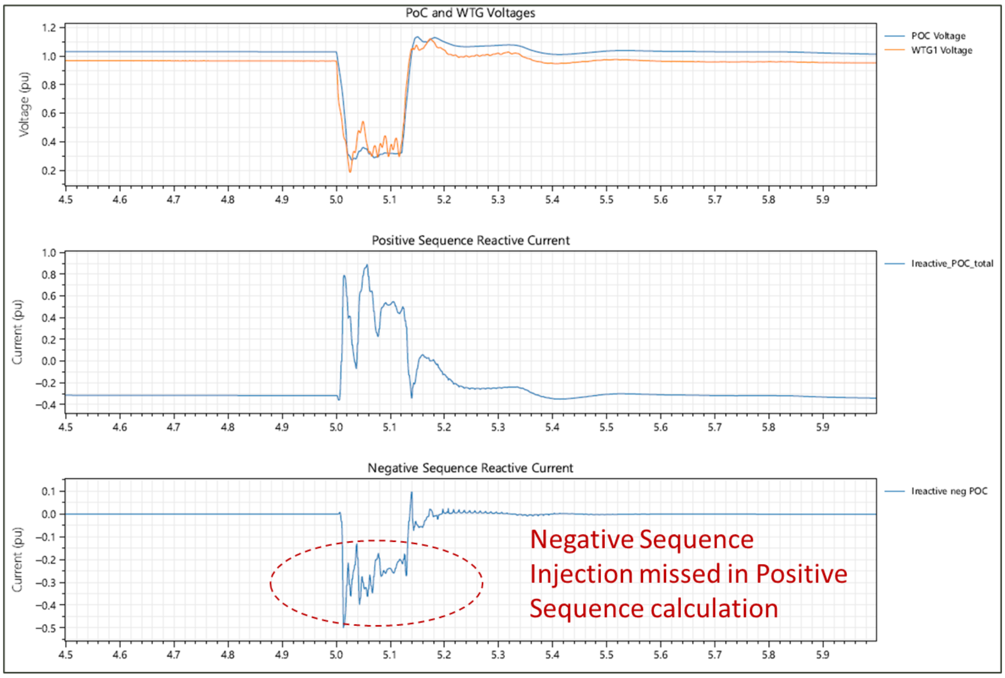
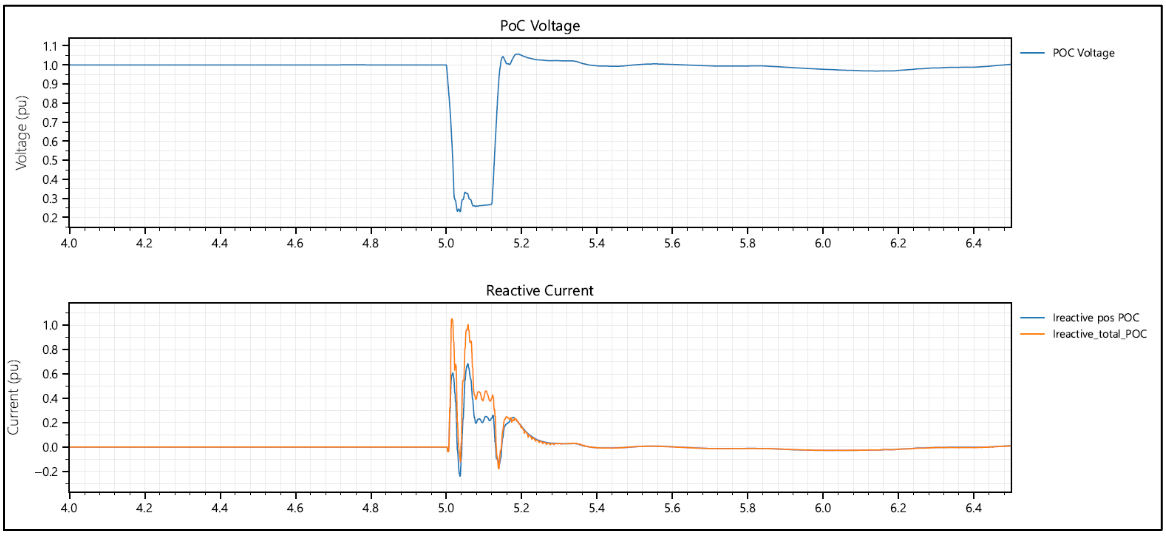


Figure 14: Comparison of Positive Sequence vs Total Reactive Current produced for an unbalanced fault

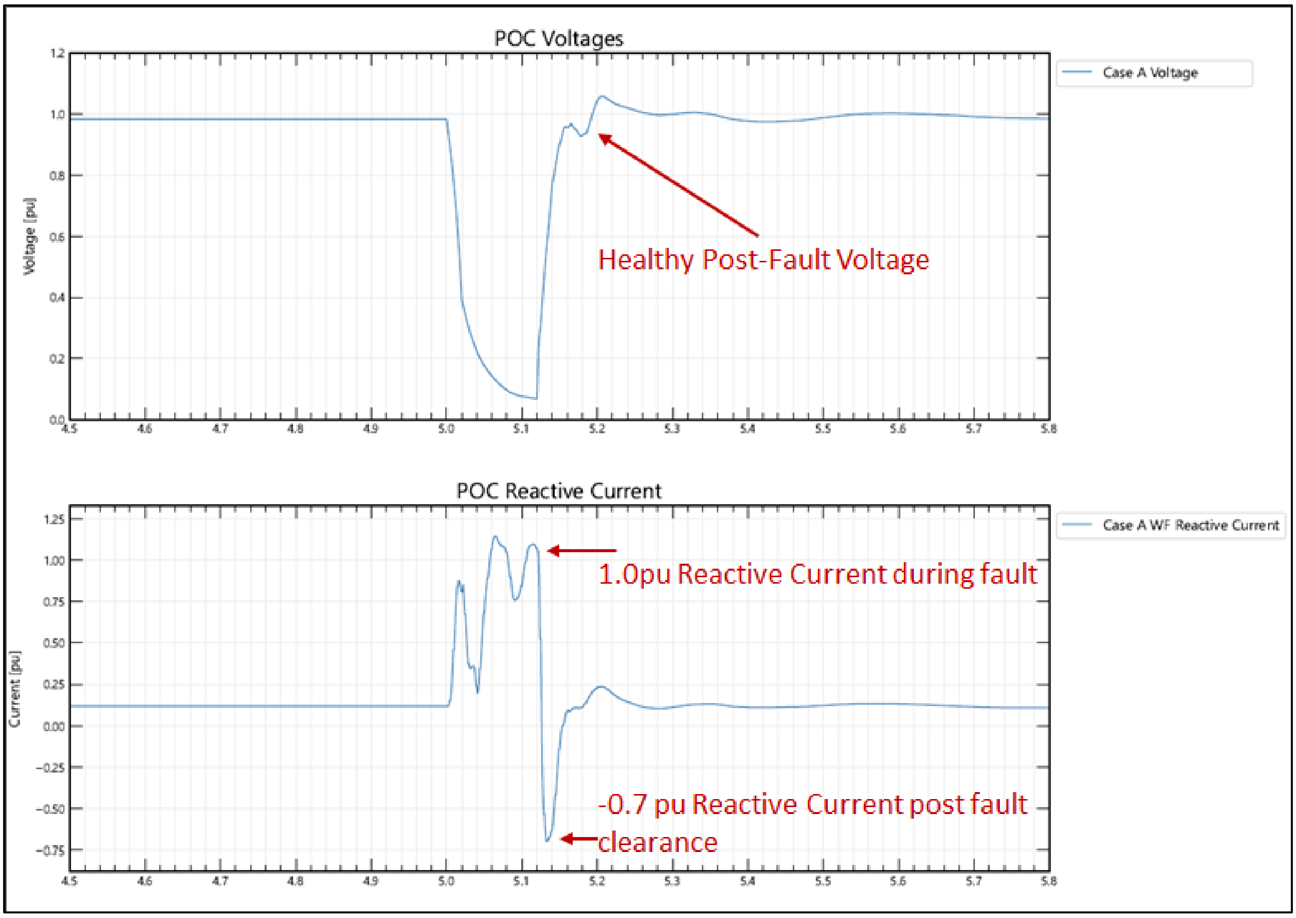


2.3 Assessing potential temporary over-voltages

One concern raised as part of the industry feedback to the AEMC with regard to the magnitude of reactive current response to network disturbances was the potential for high temporary over-voltages following fault clearance. To investigate this concern, studies were conducted on a Multiple Machine Infinite Bus (MMIB) representation of a small area of a power system containing multiple IBRs. Deep fault studies were conducted on the MMIB network model to produce 1.0 pu reactive current from multiple generators and an example is provided in Figure 15. It was found that a high reactive current injection during the fault was not the direct cause of over-voltages observed upon fault clearance. Instead, the over-voltages seen in the post-fault scenario can be influenced by the ability of the generating system to quickly react to the recovering network voltages. A fast reduction in the reactive current injected during the fault to a low magnitude (even a temporarily negative value) helped maintaining acceptable post-fault network voltages.

For technology types that incorporate separate ‘FRT mode’ logic, a slow interchange from ‘FRT’ control mode to PPC control can cause a post-fault over-voltage, rather than the high magnitude of reactive current during the fault. However, the former can be ameliorated by good control system design and coordination.

Figure 15: MMIB scenario – wind farm connection point voltage



2.4 Key findings on other IBR technologies

To assess the extent to which the existing and proposed MAS could be met by IBR technologies including solar and grid-forming BESS inverters, further fault analysis was conducted on generating systems comprising these technology types. Note that the largest installed capacity investigated for these technologies was 250 MW.

It was noted that solar and BESS generating systems exhibited less difficulty to achieve the magnitude of response requirement in comparison to wind generation. This is influenced partially by the fact that these generating systems do not typically include large reticulation networks, meaning less power losses will occur between the unit terminals and the connection point. Figure 16 illustrates the capability of a 250 MW solar farm to successfully inject an additional 2% reactive current for each 1% voltage below its LVRT threshold for the most onerous scenarios investigated including when operating under low SCR conditions and at maximum reactive power output before the fault.

Grid-forming BESS technology showed the capability to rapidly inject a large amount of reactive current in response to voltage disturbances, meaning that the rise time and commencement time requirements could be easily met by this technology type. Furthermore, the BESS technology investigated can meet the magnitude of response requirement of the current MAS.

Figure 16: Reactive current response of a solar farm – Supplying reactive power pre-disturbance

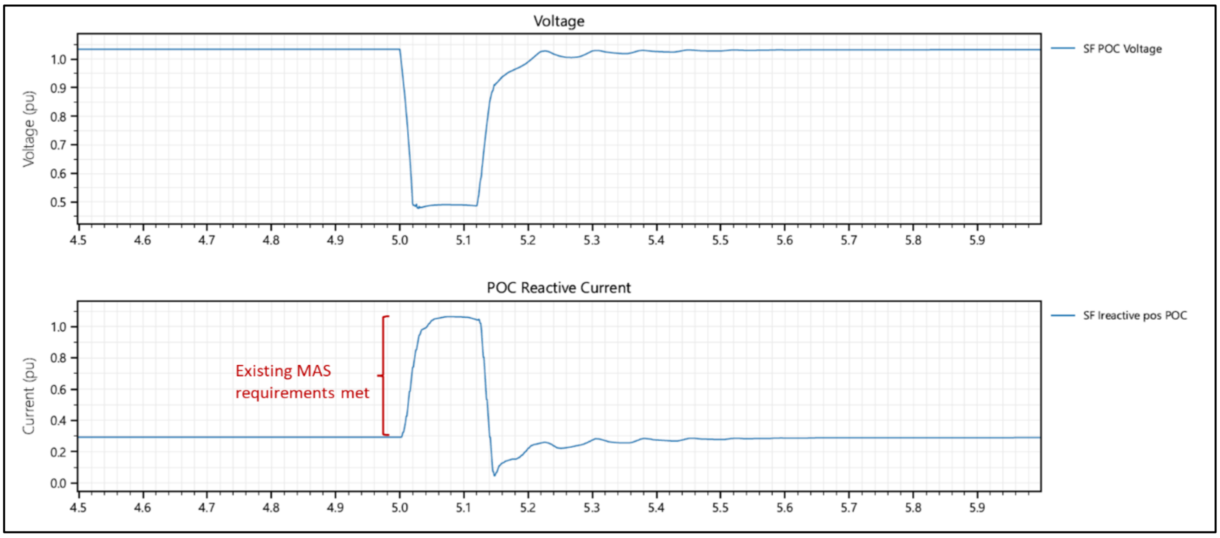
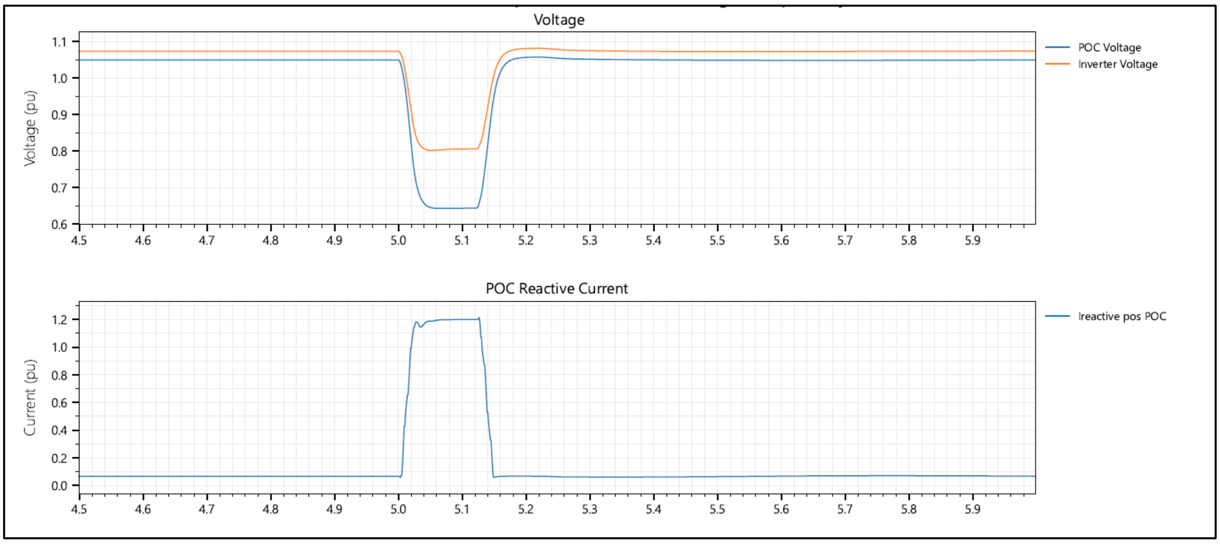


Figure 17: Reactive current injection response of a grid-forming BESS to an unbalanced fault



3 Pathways forward

3.1 Speed of response

3.1.1 Larger rise and settling time

Based on the results presented in Chapter 2, the following is recommended:

- Longer rise and settling times as per the proposed rule change, will alleviate the challenges encountered to some extent, however, will not systematically address the problem and its consequences, e.g., the potential adverse impact on other system security criteria.
- It is not recommended to combine the rise and settling time criteria together and use a single metric only. This is because these two aspects are intended for the initial and final portions of the response where the success criteria are different.
- Removing the settling time to avoid a conflict with other control system design and system security success criteria is considered a more sustainable approach. An alternate metric is however required to ensure successful delivery of the intended response.
- An increase in the rise time is, however, considered as a viable pathway provided that the outlier non-conforming scenarios can be exempt. As discussed in Chapter 2, these scenarios primarily occur when the generating system is operating at or near its maximum reactive power capability before a fault occurs.
- In any case to allow for consistent interpretation and application of the rules across different NEM regions and different entities, it is recommended to apply numerical values for the speed of response. This is because descriptions such as ‘’as soon as possible’’ could be interpreted very differently across different entities.

3.1.2 The use of commencement time

To assess the merit of the commencement time proposed by CRI, further simulation studies were conducted as shown in Figure 18 and Figure 19 which present the results for balanced and unbalanced disturbances, respectively. The ‘’voltage excursion commencement’’ and ‘’voltage traversing a voltage threshold’’ considered by AEMO as the potential benchmarks for assessing the commencement time were first investigated. However, neither could be used in all scenarios due to the response variability described before. The commencement time was therefore measured on the reactive current waveform as the next ‘zero-crossing’ beyond 20 ms of fault inception. In scenarios where the reactive current did not fall beyond its pre-disturbance value during the fault, the commencement time has been noted as 20 ms.

As shown, balanced faults exhibit a faster commencement time whereby 100% of the cases studied meet a 60 ms commencement time. Unbalanced faults generally show longer commencement time but except one scenario, all others can meet a commencement time of 80 ms.

Overall, the use of the commencement time has resulted in a lower number of non-conforming cases compared to the use of rise time when both are compared against the same benchmarks. On the other hand, the concept of the commencement time is more suitable for ideal step changes and under the conditions that once a response is commenced, it will not fall downward at any instance. Simulation studies indicate that both these conditions are more achievable under balanced rather than unbalanced faults.

Figure 18: Distribution of the commencement time for balanced faults

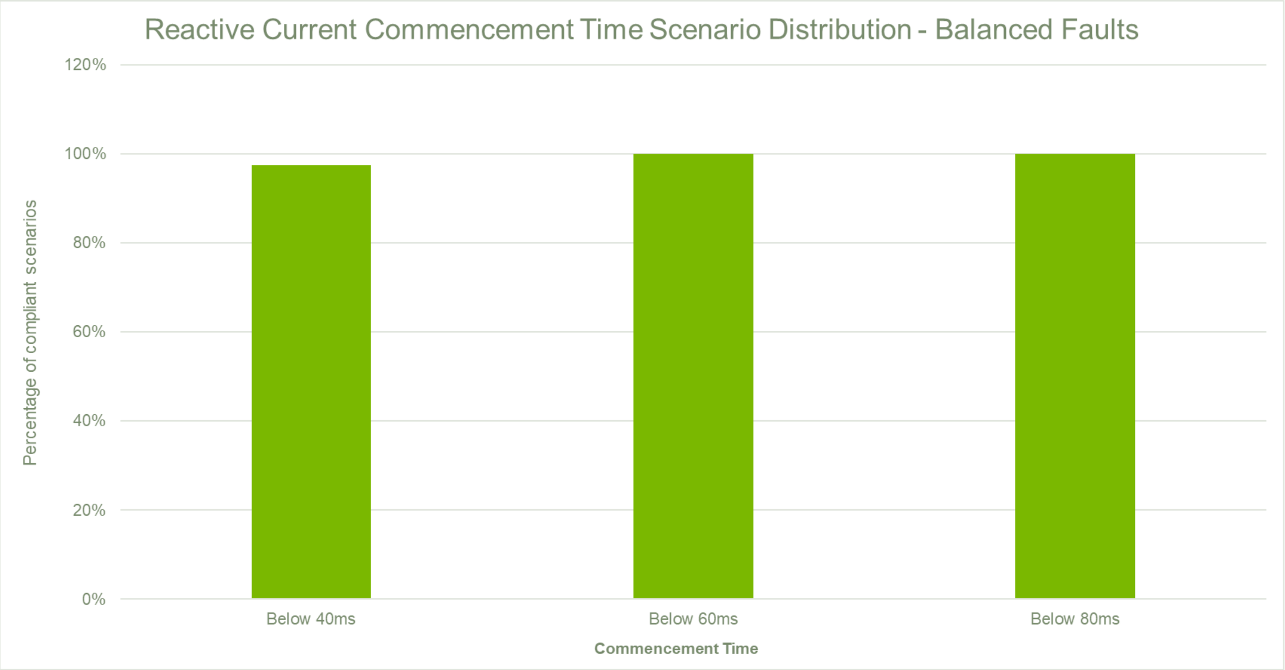
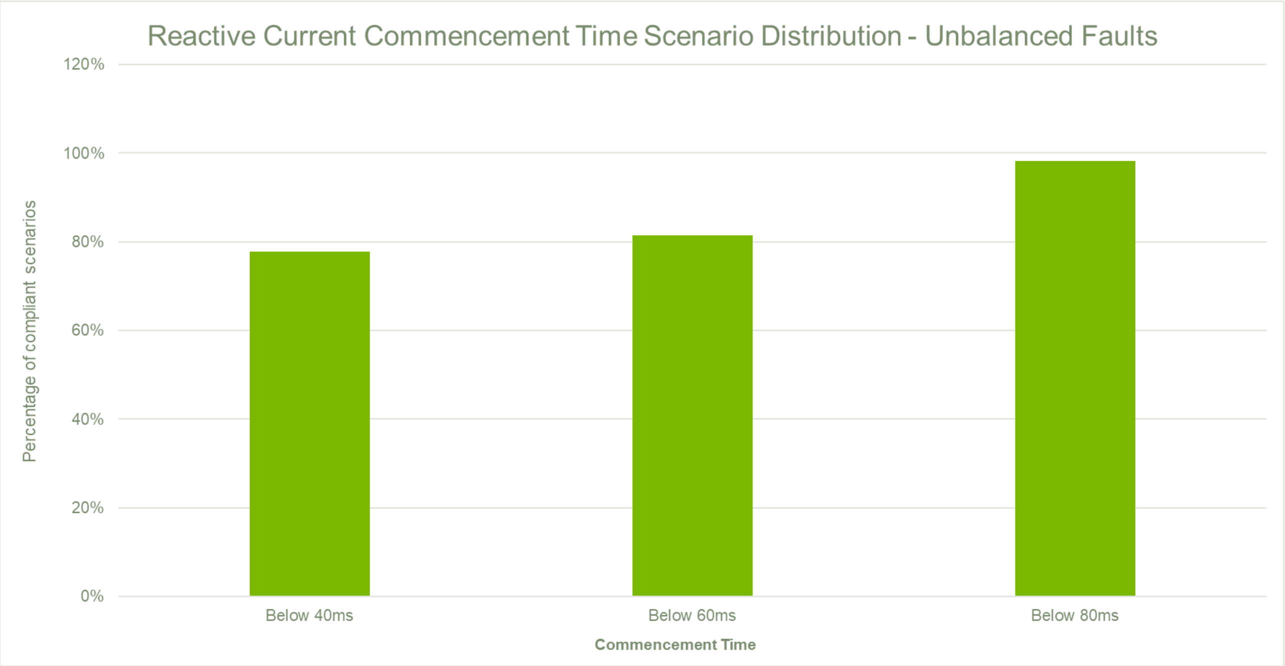


Figure 19: Distribution of the commencement time for unbalanced faults



3.1.3 The use of delivery time

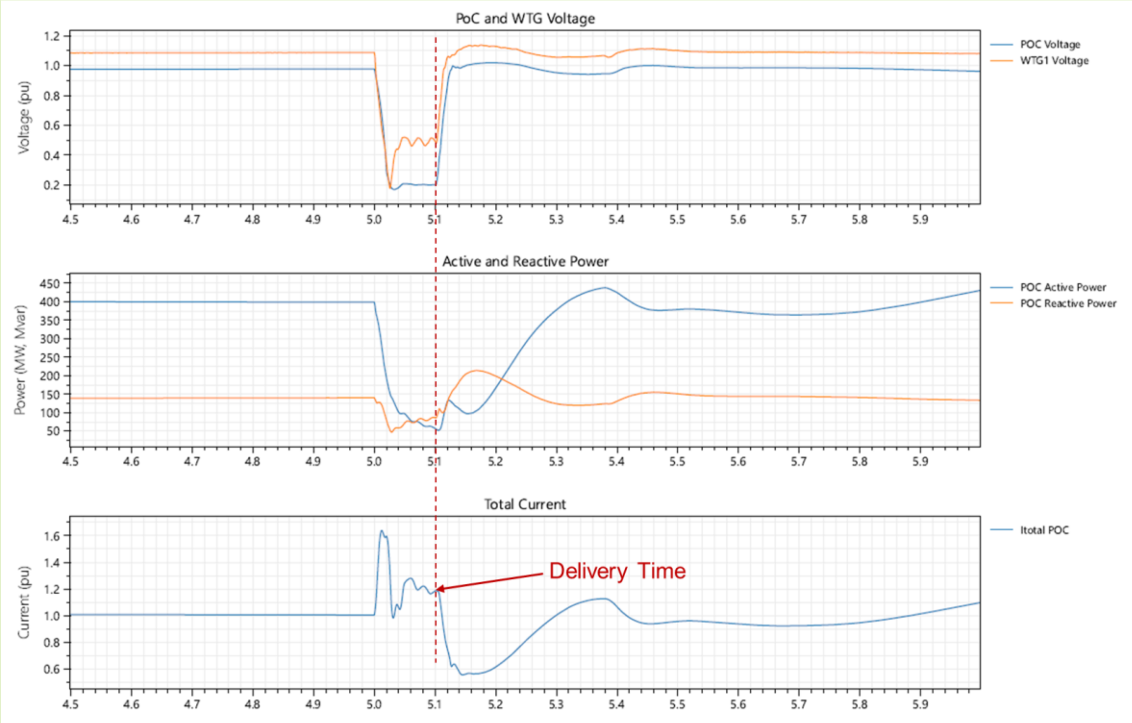
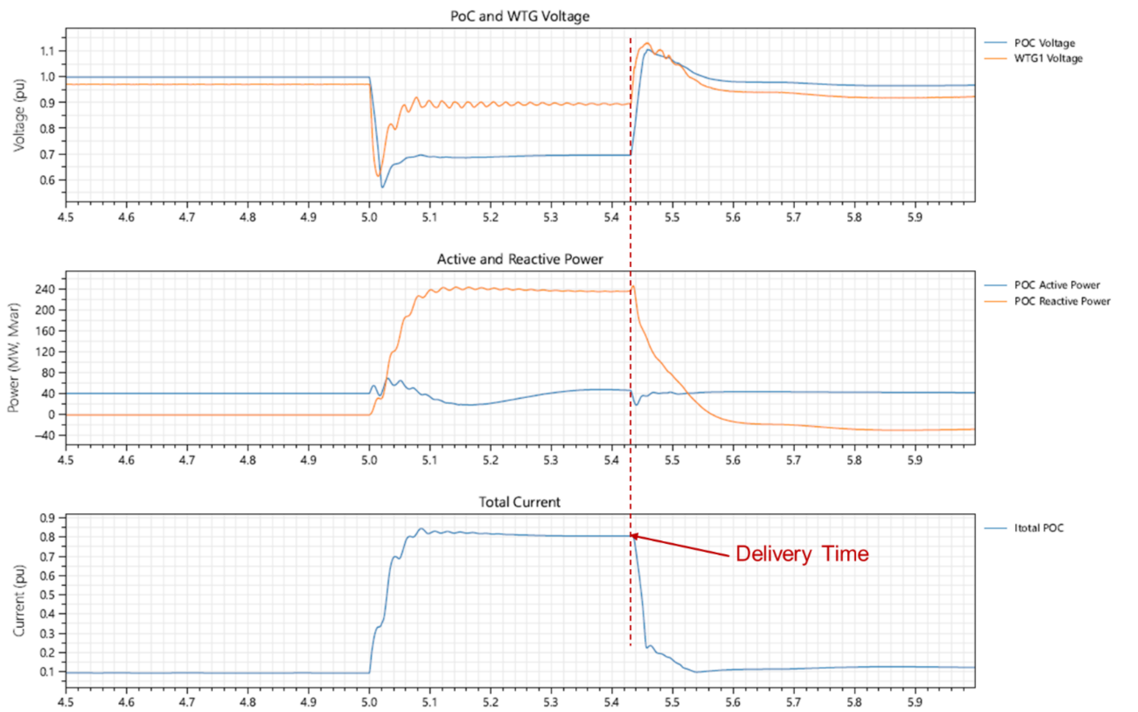
Similar to the settling time, the delivery time is intended for the final portion of the response. However, it does not follow strict mathematical calculations pertaining to the settling time and will not therefore have any potential adverse impacts on system security.

Aurecon recommends the delivery time to be defined immediately before the fault clearance. This addresses another concern with the settling time which is the use of a fixed numerical value regardless of the connection point voltage and installed capacity. Linking the delivery time to the fault clearance time means that while it is a deterministic value, it is not the same across all connection point voltages. This is because fault clearance time varies as function of normal operating voltage with the shorter clearance times associated with higher connection point voltages.

The UK Grid Code uses a similar concept based on the maximum fault clearance time for a given connection point voltage. The same can be applied in the NER or otherwise the actual fault clearance times can be used.

Figure 20 describes the concept of delivery time for 100 ms and 430 ms faults. However, instead of the reactive current the total current, comprising active and reactive and positive-negative-sequence currents, is used. This results in a significantly more constant response, especially before the fault clearance, compared to those presented earlier in the report with the use of the reactive current.

Figure 20: Demonstrating the concept of delivery time

<table>
<tr><th>Clearing Time</th><th>Delivery Time Location</th></tr>
<tr><td>100 ms</td><td>
</td></tr>
<tr><td>430 ms</td><td>
</td></tr>
</table>

3.1.4 Summary of options

Table 5 presents a tabular summary of speed of response options investigated together with their overall merit for the new rule requirement based on traffic light coding (red: not to be adopted, yellow: viable option with some drawbacks, green: viable option without any drawbacks). Noting that there were no options that were 100% issue-free, none of the options have received a 'green light' as an overall assessment. Note that the option with the combined use of the commencement time and rise time has not been considered as a viable option since it does not provide any guidance on the final response.

Table 5 Summary of Speed of Response requirement options

Initial response	Final Response	Overall assessment
Rise Time	Settling Time	
Commencement Time	Settling Time	
Rise Time	-	
Commencement Time	-	
Commencement Time + Rise Time	-	
-	Settling Time	
-	Delivery Time	
Rise Time	Delivery Time	
Commencement Time	Delivery Time	

3.2 Magnitude of response

3.2.1 Reduced reactive current injection requirements

From the results presented in Chapter 2, the following can be concluded:

- A 0% reactive current injection can be achieved at the connection point in most but not all scenarios.
- Key scenarios of concern are those with high or maximum steady-state reactive power generation before the fault occurs.
- If the use of reactive current is to be pursued as a viable option, exclusion of such outlier conditions shall be accounted for.

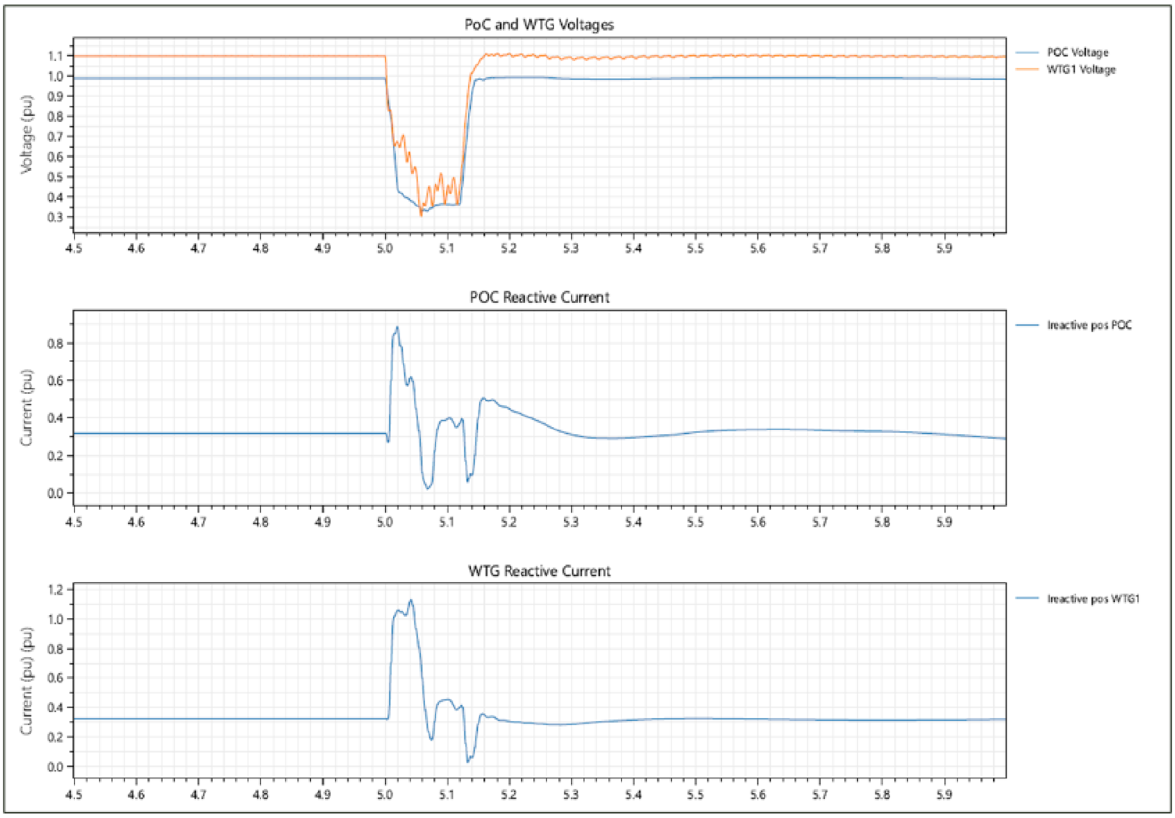
3.2.2 Compliance at unit terminals

Simulation studies conducted reveal a marginal improvement in k-factor if the compliance point were to be moved to the unit terminals. Two examples are shown in Figure 21 when the generating system is subject to unbalanced faults. In both cases, there is only a marginal improvement when the reactive current injection is measured at the unit terminals.

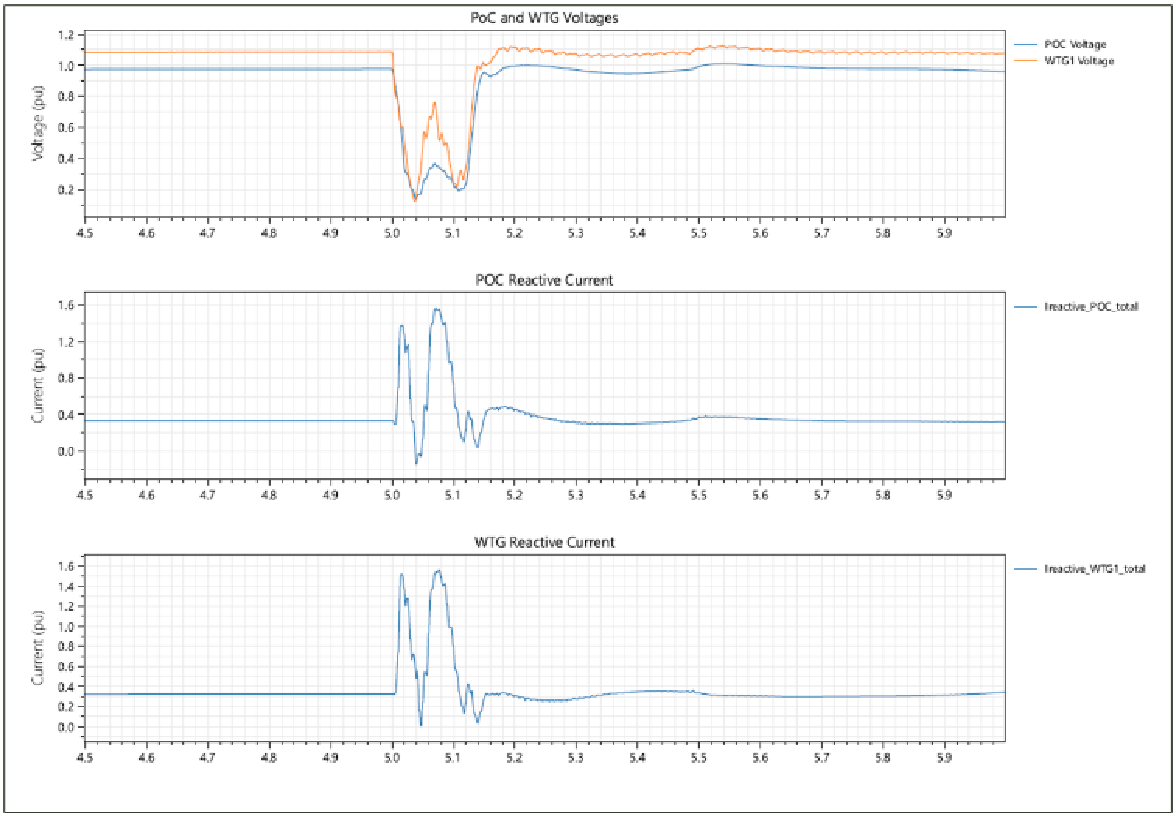
Noting several drawbacks associated with the use of unit terminals as the compliance point as discussed in Section 1.3 under item ''Ease of interpretation and compliance assessment during the lifetime of the generating system'', Aurecon recommends this option not to be considered by the AEMC.

Figure 21 Examples of reactive current injection as compared between the connection point and unit terminals

(i)



(ii)



3.2.3 The use of total current

Simulation studies presented in this report indicate the following shortcomings associated with the use of reactive current for assessing the magnitude of the response:

- Inability to achieve a positive reactive current injection, i.e., >0%, under all scenarios studied.
- Large variability of the response even within a few milliseconds, which makes it difficult to use the reactive current as a consistent success criterion.
- Inability to optimise and allocate the total current available into active and reactive, and positive- and negative-sequence currents.
- Large differences in the reactive current injection during the fault depending on the pre-fault active and reactive power and fault depth.

Figure 22 and Figure 23 present active and reactive power responses of a wind farm to severe and shallow faults. In the first scenario the ratio of active to reactive power is nearly one, whereas in the second scenario active power is more than 150% larger during the fault. Closer inspection of these two figures indicates that the total fault current is largely the same for the two scenarios despite large differences in the fault depth, and active and reactive power before and during the fault. Therefore, the concerns with reactive current response variability can be resolved if the total current were to be used as a success criterion for assessing the response magnitude during the fault.

Figure 22: Active and reactive power, reactive current and total current during a severe fault

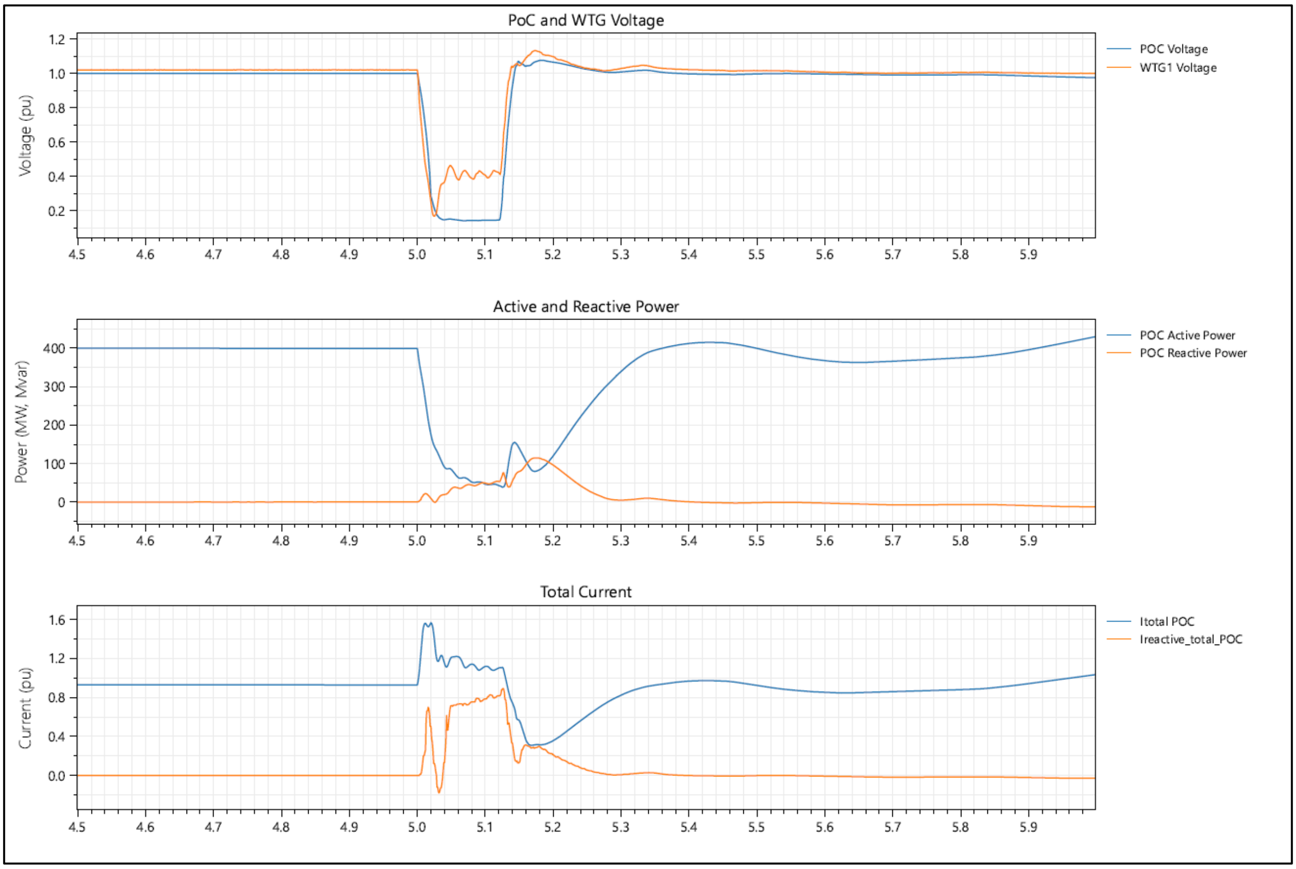
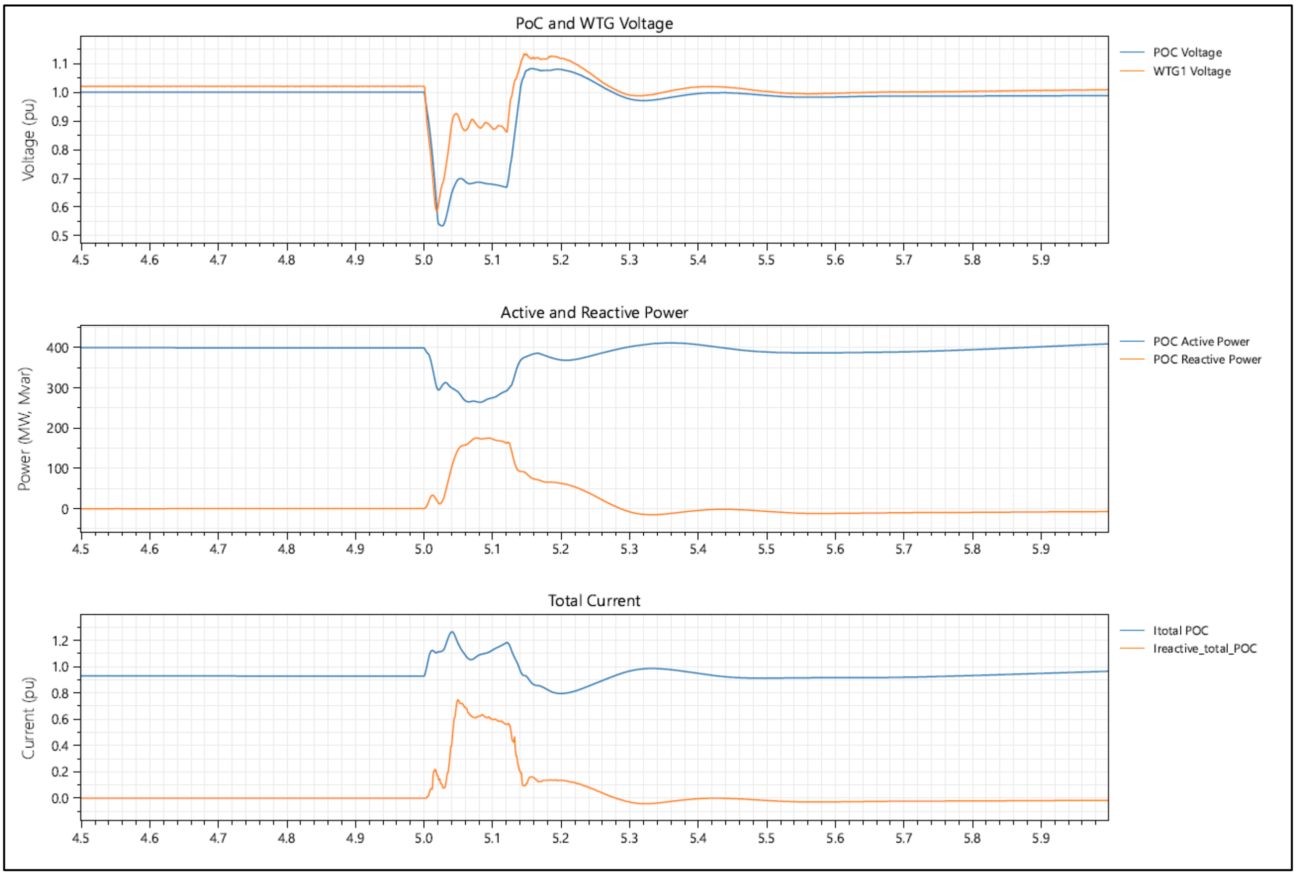
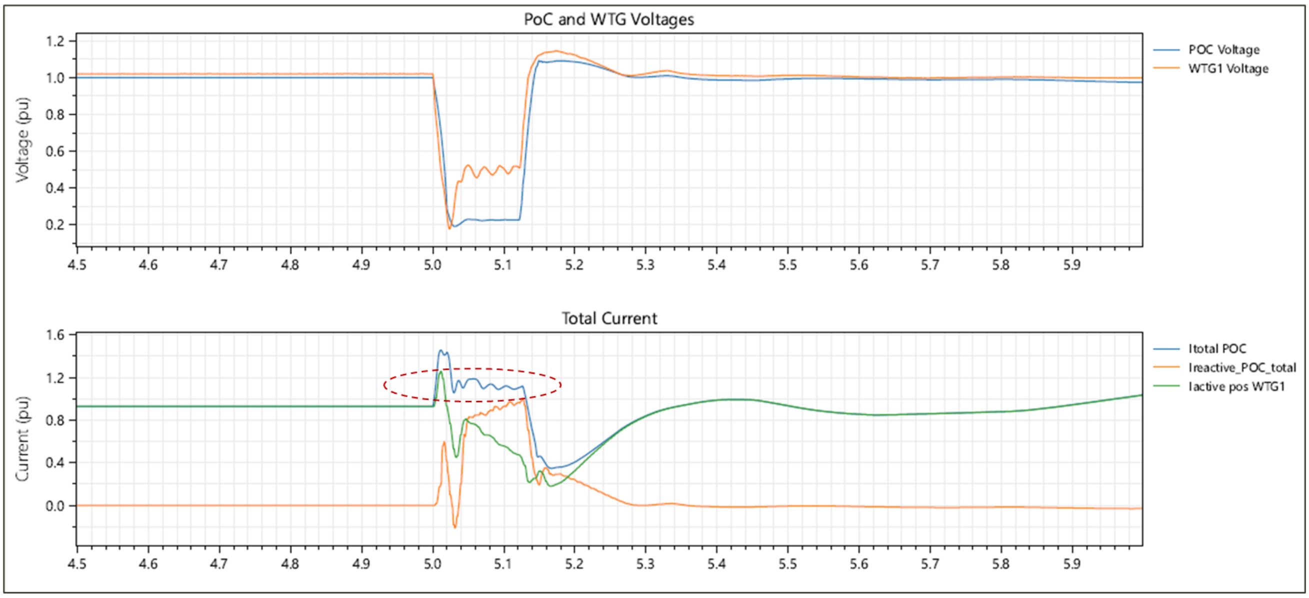


Figure 23: Active and reactive power, reactive current and total current during a shallow fault



To further elaborate on the advantages of the total current, Figure 24 provides a comparison of the total fault current, total reactive current and positive-sequence reactive current. As shown unlike both the positive-sequence and total reactive current, the total fault current remains largely the same during the fault. This provides a consistent metric for measuring the response magnitude during the fault.

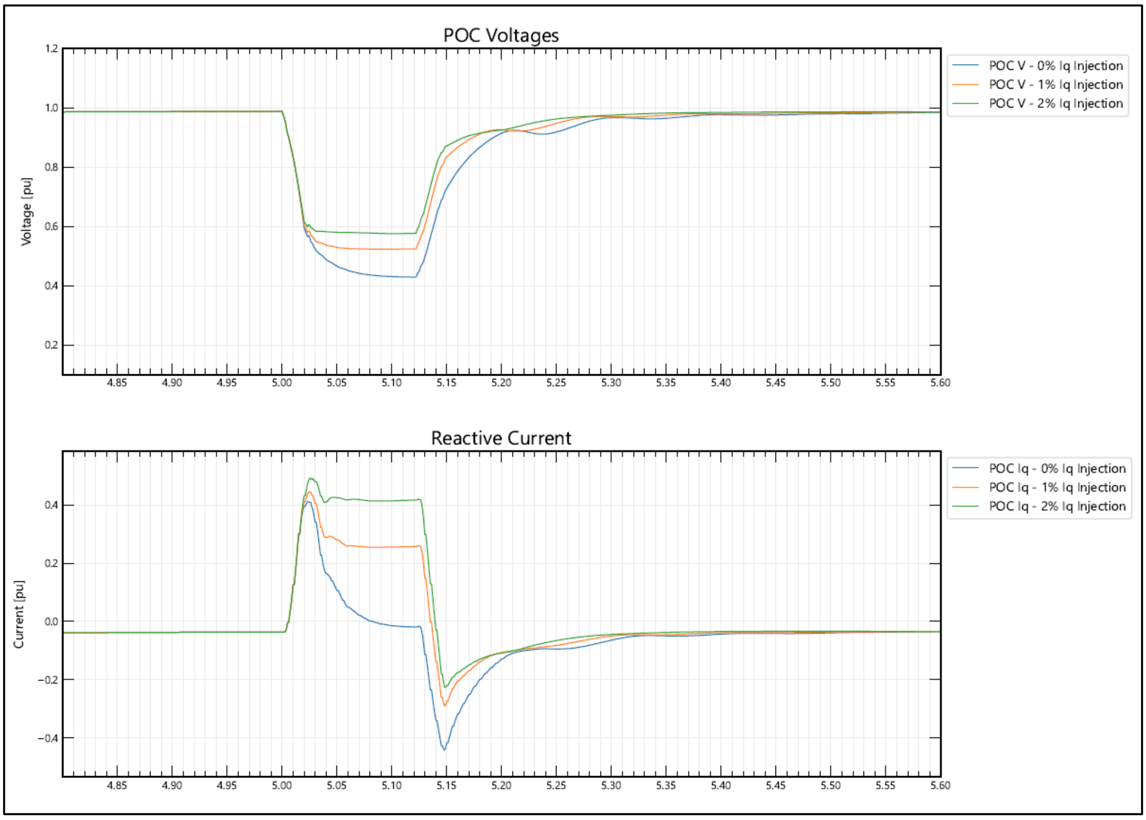
Figure 24: Comparison of total current, total reactive current, and positive-sequence reactive current

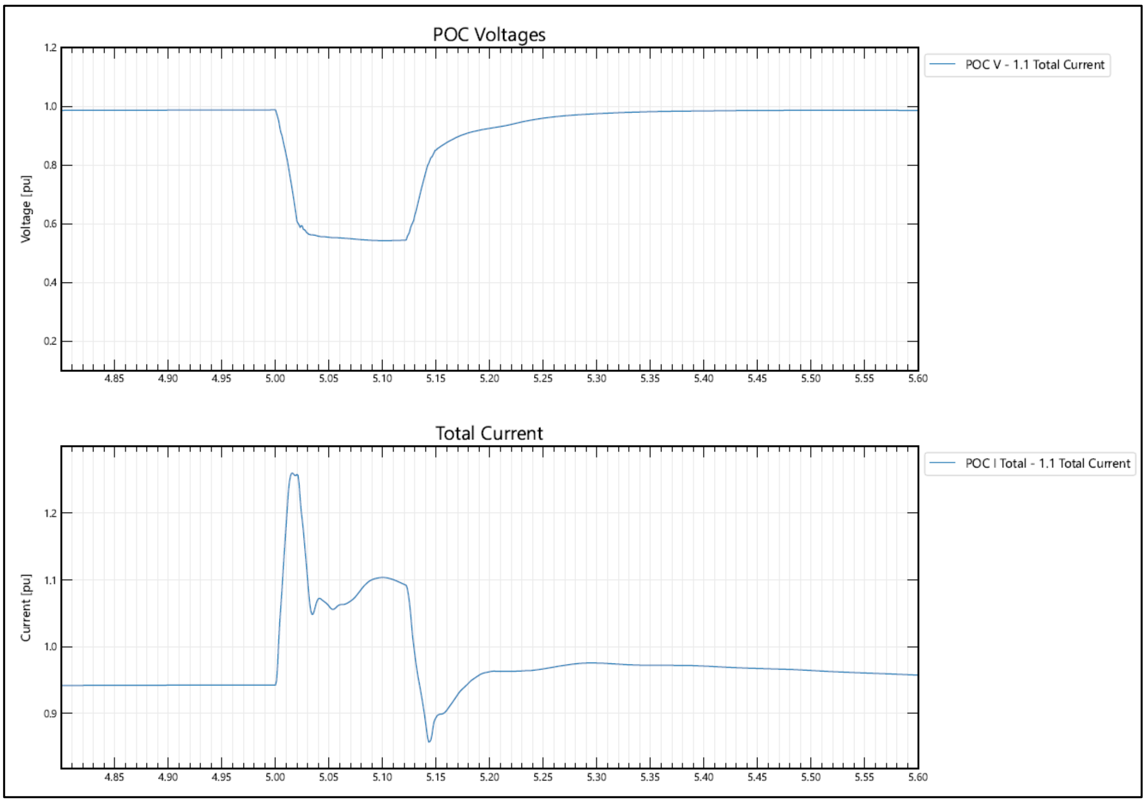


A concern with the use of total current is the potential de-prioritisation of reactive current response during the fault which is directly correlated with the recovery of network voltages. However, as discussed previously active power drops directly proportional to the voltage dip and cannot be prioritised over the reactive current due to its natural response. To the contrary, several recent experiences have shown that to achieve the required reactive current injection, active current is intentionally dropped to zero which is an overall sub-optimal outcome.

The use of the total current will provide a convenient way to account for active and reactive currents including both the positive- and negative-sequence components. This by no means results in a de-prioritisation of reactive current. To further reinstate this point, Figure 25 shows a direct comparison of the reactive current and total current response subject to an identical three-phase-to-ground fault. The reason for choosing a three-phase fault is to achieve a more consistent and reliable response compared to those discussed so far in the report in response to unbalanced faults where the response varies substantially. As illustrated in the figure, the use of total current allows for similar or slightly better voltage recovery to 1% reactive current injection.

Figure 25: Comparison of total current and reactive current for a three-phase faults





Appendix A. Simulation Cases

Hundreds of different fault scenarios were investigated as part of Aurecon's assessment which were made up of a combination of the sensitivity criteria outlined in Section 2.1. The majority of the assessments were conducted based on vendor-specific wind farm models but further assessments were also done on solar and BESS generating systems. Each scenario reflects a combination of the different values for each sensitivity criteria presented in Table 6 below:

Table 6: Summary of sensitivity criteria investigated within reactive current injection analysis

Technology Type	SCR	X/R	Pre-disturbance Active Power	Pre-disturbance Reactive Power	Fault Type	Fault Durations	Residual Fault Voltage
Wind	2 to 5	2 to 10	10% Output 100% Output	0.0 pu +0.395 pu -0.395 pu	3 Phase to Ground Single Phase to Ground Phase to Phase 2 Phase to Ground	80 ms 100 ms 120 ms 250 ms 430 ms	≈0.1 pu to ≈0.8 pu
Solar	2 to 5	2 to 10	10% Output 100% Output	0.0 pu +0.395 pu -0.395 pu	3 Phase to Ground 2 Phase to Ground	120 ms	≈0.1 pu to ≈0.8 pu
BESS	2 to 5	2 to 10	100% Output	0.0 pu +0.395 pu -0.395 pu	3 Phase to Ground 2 Phase to Ground	120 ms	≈0.1 pu to ≈0.8 pu

Additionally, fault analysis was conducted on a Multiple Machine Infinite Bus PSCAD Model that incorporated scenarios of:

- Multiple Wind Farms within proximity
- Solar and Wind Farms within proximity

Appendix B. Reactive Current vs Total Current Assessment

Table 7: Summary of assessment comparing Reactive vs Total current as the metric for fault current response.

Factors considered	Reactive current	Total current
Variability	Could vary substantially within a few milliseconds before the fault clearance, with neither the existing settling time nor the proposed delivery time can guarantee reflecting a value near the maximum possible contribution.	Relatively constant during a few milliseconds before the fault clearance. The proposed delivery time reflects a magnitude of current that does not vary greatly from the maximum possible contribution.
Ease of use for model validation	Impractical for some designs to meet model accuracy requirements during the commissioning and R2 testing for the reason above.	Much more practical to meet model accuracy requirements for the reason above.
Prioritisation of active vs reactive current	Reactive current is prioritised.	No explicit or universal prioritisation is required. The total current consists of the appropriate and case-by-case amount of active and reactive current for each particular generating system to positively contribute to system security.
Adverse impact on active current	Some OEMs intentionally drop active current to meet the reactive current injection requirement, which is not the best outcome.	Does not require dropping the active current intentionally.
Negative-sequence current treatment	The inherent negative sequence absorption behaviour in type III wind turbines is due to the machine response (similar to that of a synchronous machine) and cannot be fully compensated by the converter control. This will reduce the positive-sequence current injection, occasionally to below 0%.	Does not need distinguishing between the negative and positive sequence currents.
	Also as mentioned, negative-sequence current for type III wind turbines could be negative meaning absorption instead of injection.	
Magnitude for reactive current injection/absorption response (PoC)	A threshold of 0% is not even sometimes achievable.	Not applicable.
Magnitude for reactive current injection/absorption response (Unit terminals)	A threshold of 0% is sometimes only marginally achievable.	Not applicable.

Factors considered	Reactive current	Total current
Compliance point	The use of neither the connection point nor unit terminals helps guaranteeing consistent and positive results.	The use of the connection point provides consistent and positive results.
Benchmark for assessing best possible performance	There is no reliable and practical benchmark to assess whether the generating system has provided the best possible performance or low injection/absorption is caused by inferior control system design and tuning which could be further improved.	Contribution provided can be readily compared against the physical capability of the generating system and its constituting generating units
Implementation Time	Already the metric used for compliance, hence little/no updates required by OEMs.	Programming, testing and implementation by OEMs may take more than a year
Broader NER impact	None	Automatic and negotiated access standards will also need to change

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