19 August 2022

DIgSILENT Pacific
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St Kilda, VIC, 3004

To whom it may concern,

Re: System Strength Requirements Methodology and System Strength Impact Assessment Guidelines amendments consultation

DIgSILENT Pacific welcomes the opportunity to provide a response to AEMO's second stage of consultation on the System Strength Requirements Methodology as well as the proposed changes to the Power System Stability Guidelines.

We commend AEMO on their endeavours to develop a set of practical guidelines to manage system strength on the power system and we are passionate about making a positive contribution to this effort. Please find attached a technical note detailing our feedback on the consultation.

Should you require any clarification or further information, please do not hesitate in contacting us.

Yours faithfully,

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TECHNICAL NOTE

For	AEMO	**Date**	19 August 2022
From	DIgSILENT Pacific	**Subject**	SSRM and SSIAG amendments consultation

1 Introduction

DIgSILENT Pacific welcomes the opportunity to provide feedback to AEMO's consultation on amendments to the System Strength Requirements Methodology (SSRM), System Strength Impact Assessment Guidelines (SSIAG) and Power System Stability Guidelines (PSSG) in accordance with clauses 5.20.6, 4.6.6, 4.3.4 and the Rules consultation procedures in rule 8.9 of the National Electricity Rules (NER).

We understand that the overall approach proposed in the Issues Paper published in April and the Draft SSRM published in July is as follows:

- System strength requirements are calculated at System Strength Nodes (SSN) using a combination of EMT analysis (preferred) or simplified approaches, which could include Available Fault Level (AFL), Short-Circuit Ratio (SCR) methods, the calculation of voltage sensitivities (referred to as simplified switching studies) or future not yet defined methods. This requirement is expressed as an MVA equivalent fault level for each SSN.
- For the plant of an Applicant which is proposed to connect or be altered, a Preliminary Assessment will be carried out at the proposed minimum SCR (no less than 3.0 in accordance with the newly created S5.2.5.15) to confirm the stability applicant's plant, the amount of charge for fee paying clients and whether investment may be required by the Applicant to meet the minimum SCR standard. This assessment is carried out using a Single Machine Infinite Bus (SMIB) detailed EMT model of the Applicant's plant.
- The Applicant can then elect to do either of the following:
    - Option A – Pay a charge which is calculated from the result of the Preliminary Assessment. A Stability Assessment will also be carried out by the Connecting NSP to verify the plant's stability.
    - Option B – The Connecting NSP carries out a Full Assessment to determine the System Strength Remediation Scheme (SSRS) and the System Strength Connection Works (SSCW) required to remediate the plant's "general system strength impact."

This technical note seeks to comment on the following aspects of the AEMO consultation documents:

1. General aspects of the Draft SSRM such as:
    a. The lack of clarity around the process for selecting SSNs given their criticality in the overall process.
    b. Maintenance of adequate protection system operation through the lowest cost means (rather than only through the provision of system strength).
    c. Concerns around the following aspects of the "stable voltage waveform" definition:
        i. The necessity of a phase angle change criterion (criterion 2).
        ii. The possibility for voltage waveform distortion to not directly relate to system strength (criterion 3).
        iii. Adequate justification for the selected peak to peak sustained voltage oscillation thresholds (criterion 4).
2. Inaccuracies in the Preliminary Assessment process can lead to incorrect charges calculated in Option A:
    a. Insufficient analytical basis to support the accuracy of these methods (and their assumptions) as no case studies have been undertaken.

b. Insufficient information on the setup of the EMT study for the minimum SCR particularly the result can be significantly influenced by these factors (which are outside the control of the Applicant).

c. The AFL calculation method does not correctly aggregate the effect of multiple Grid Following (GFL) Inverter Based Resources (IBRs) unlike the Equivalent SCR (ESCR) method defined in CIGRE Technical Brochure 671.

d. Inadequacies of the proposed modelling of Grid Forming (GFM) IBRs in the AFL calculation method.

These issues are discussed and explained with examples within the sections below.

2 Draft SSRM general aspects

2.1 Location of SSNs

The location of the SSN will have a material impact on the cost of system strength services provided by the System Strength Service Provider (SSSP) for a plant as the locational factor is a function of the impedance between the plant and the SSN. Our understanding of the methodology for determining the location of the nodes is that:

1. Collectively the SSNs should allow reasonable representation of the overall system strength requirements of the power system
2. The SSNs should be within a transmission system
3. There should be a practicable number of SSNs having regard to the assessment effort required
4. There should be regard to where SSNs locations are expected to be most efficient
5. The SSNs can be in future network locations

However aside from an overview, a clear process for how the location of the SSNs would be defined is not provided particularly when some of the requirements above conflict. Since the SSNs will affect the location of system strength services, this is a critical aspect of the proposal. Hence the SSNs must include the location that optimises the services, otherwise generators will be paying too much and the NEO will be not served.

A particular issue is the statement within the Draft SSRM that "total number of SSNs declared per region must be limited to a level which is practicable having regard to the effort required to device system strength requirements for each node." However, DIgSILENT understands the process for determining system strength requirements for SSNs to consist of the following:

1. Determining a set of worst case realistic power system scenarios (for power system demand and dispatch) for minimum system strength. This would include all the criteria detailed within the draft SSRM – projecting future IBR, changes in synchronous machine operation, changes to HVDC equipment etc. These worst case scenarios would need to be robust to ensure that the system strength adequacy is tested across the power system. For example, it is expected that new worst-case realistic power system scenarios and contingencies would need be incorporated into the assessment for the publicly announced renewable energy zones (REZs) which will accommodate GWs of new IBRs. Failure to adequately capture the full range of scenarios and contingencies will result in an incomplete assessment.
2. Assessing the minimum fault level requirement then would involve the following:
   a. Assess protection system operation needs: The fault level calculation must be performed for all nodes against the worst case operating scenarios and contingencies. This assessment is expected to be carried out using phasor based short circuit programs. Hence reporting the results considering a large number of (i.e. nearly all) transmission nodes to be SSNs will not introduce significant effort.
   b. Assess voltage control system operation needs: This assessment must be carried out at all nodes to which voltage control systems connect against the worst case scenarios and contingencies. This assessment is

also proposed to be carried out using phasor based short circuit programs. As before, reporting the results considering a large number of transmission nodes to be SSNs will not introduce significant effort.

c. Assess power system stability needs: This assessment must be carried out by performing detailed wide area EMT simulations using the worst case contingencies and operating scenarios. The number of SSNs is not relevant to this aspect of the assessment as the inputs to it are the operating scenarios and contingencies. The results of the EMT simulations will identify the worst case scenario and contingency pairs (worst case dispatch and events) with respect to stability. These conditions can then be configured within a phasor baed short circuit program to determine the equivalent fault level requirements at the SSNs. Again, expanding the set of SSNs will not introduce significant effort in the latter phase of this process (calculating and reporting fault levels). The time intensive aspect of this assessment concerns the breadth of operating scenarios and contingencies considered which are not related to the SSNs.

With the above process outlined, the SSSPs could publish the minimum system strength requirements (expressed as fault level in MVA) at each node from which it will be possible to identify the optimal amount and location of system strength services to serve all the connecting generators that are subscribing to the service. To ensure that the solutions are optimum, particularly when the limiting aspect is power system stability, sensitivity studies using a detailed wide area EMT model can be carried out by applying varying levels of system strength services at the locations in question to determine their influence.

2.2 Provision of system strength to alleviate protection performance issues

Regarding using adequate protection operation as a criterion for minimum fault level, the relative low cost of modifying or replacing protection systems to the cost of additional system strength services (in the form of additional grid forming inverters or synchronous condensers) must be borne in mind. For instance, if the fault level is so low that a protection scheme is no longer working, the inclusion or exclusion of it as a criterion should be based on whether there is an alternative protection scheme that would work in the circumstances and the cost of changing the protection scheme, relative to cost of system strength mitigation to increase the fault level to the next most limiting criterion that would set the minimum fault level. The time and cost associated with reviewing the protection should not be a reason for excluding the criterion because the NSPs will need to ensure that their protection still works for every location in the transmission system at any time in the future whatever minimum fault level is selected.

2.3 Definitions of stable voltage waveform

SSSPs are required to plan, design, maintain and operate their networks, or make system strength services available to AEMO, such that the descriptions of “stable voltage waveforms” in the SSRM are achieved. Several comments are raised around different aspects of these definitions below.

2.3.1 Criterion 2 – phase angle change

AEMO’s proposed criterion 2 for a stable voltage waveform states that the change in voltage phase angle at a connection point must not exceed 45 degrees following any credible contingency event or protected event. AEMO have stated that this is a reasonable threshold as most sync check relays are set between 30 and 60 degree phase angle though a caveat is provided that this is not a “hard requirement”. However we consider this requirement and the proposed threshold to not be justified in AEMO’s documents.

Firstly, by this definition a post-contingency system response where the voltage phase angle change at a connection point is greater than 45 degrees but which is in reality stable (the system response settles to a new steady state not violating any limits) would be declared as not exhibiting a “stable voltage waveform”. This could then trigger the need for the procurement additional system strength services when there is no real stability issue to be resolved. Of course, this is separate from instances where (any level of) phase angle jump results in unstable responses within the power system, which may need to be mitigated with additional system strength services.

Secondly, AEMO’s claim in the SSRM that the 45 degree threshold value is justified by the fact that sync check relays have settings between 30 and 60 degrees is not appropriate in our opinion. Sync check relays are used to close a circuit breaker to synchronise (i.e. tie together) two parts of the power system which may not be in synchronism and which may have a large steady state voltage angle difference between them. This is a controlled operation and limiting the phase difference angle at which synchronisation occurs is reasonable as it will reduce the magnitude of torques on synchronous machine shafts and transient power flows within the power system. However, this is entirely different from a scenario in which after a contingency caused by the tripping of one or several network elements, an immediate large change in voltage phase angle occurs which could eventually reach a new steady state value. If the system is stable after such an event, there does not seem to be a need to be concerned with the size of the phase angle jump.

Lastly, AEMO's earlier justification within the April Issues Paper concerned the fact that the average change in frequency over a time window of 500 ms is equal to 0.25 Hz. This is also not an appropriate justification as a phase angle jump is an instantaneous phenomenon (with no change in frequency apart from the instant when it occurs when the rate of change of phase angle is undefined), which is wholly different to phenomenon where system frequency ramps over some time (for instance when a large power imbalance occurs on the power grid). The use of the 500 ms measurement window in this instance is also entirely arbitrary.

2.3.2 Criterion 3 – voltage waveform distortion

AEMO's proposed criterion 3 concerns the level of voltage waveform distortion which is defined as deviations from a 50 Hz sinusoidal waveform. DIgSILENT interprets this criterion to primarily refer to issues of excessive harmonics and harmonic instability resulting from IBRs. However, the definition of stable voltage waveform in the context of the SSRM is concerned with issues which may arise as a result of inadequate system strength, which is primarily to do with the 50 Hz voltage being too sensitive to 50 Hz current injections. Whilst it may be possible to resolve cases of excessive harmonics and harmonic instability in parts of the power system with the provision of additional system strength (for instance by installing a synchronous condenser), these harmonic responses are also significantly influenced by the characteristic of the power system elements (including other IBRs) at the harmonic frequency of concern. In this regard, it is possible that measures which do not involve additional system strength provision such as the installation or modification of a harmonic filter or the retuning of harmonic control loops may be just as or more effective at resolving the issue (neither of which have an effect on system strength as traditionally conceived). In this instance, considering voltage waveform distortion for the requirements concerning system strength would be inappropriate as the fundamental issue is not directly related to system strength in the first place. The fact that some waveform distortion issues may not directly relate to system strength should be captured within the SSRM.

2.3.3 Criterion 4 – RMS voltage oscillations

AEMO's proposal for criterion 4 is that undamped RMS voltage oscillations should not exceed a threshold which could be between 0.1% and 0.5% and is active under discussion within the Power System Stability Working Group and Power System Modelling Reference Group.

We are concerned that the lower end of this threshold range may produce limitations particularly when measuring such responses on the bulk power system. For instance, a precise voltage transformer for revenue metering (class 0.2) may have a ratio error of 0.2%. The second issue is whether noise in the measurement (whether due to interference or harmonics within the voltage waveform which pass through the RMS processing) could cause oscillations to be indistinguishable from noise.

It is important for AEMO to collect evidence to justify the practicality of the threshold which is selected.

3 Preliminary Assessment method

3.1 Lack of case studies verifying simplified methods

The existing process utilises the Preliminary Impact Assessment (PIA) as a screening method for the Full Impact Assessments (FIA). However, from DIgSILENT's experience on connection projects, the results from PIAs have been deemed to be unreliable as a screening method such that nearly all connection projects have undergone an FIA regardless of the result of the PIA.

For the new process, a Preliminary Assessment will precede a Stability Assessment if the Applicant elects to pay the system strength charge. However, given past poor experience with simplified preliminary methods, it is incumbent on AEMO to carry out verification of this proposed approach prior to implementing it. Though the new process involves a detailed assessment to be undertaken in any case to ensure that the system is stable after the connection of the plant, the accuracy of the estimated charge (based upon the SSLF and System Strength Quantity required from the plant) will not have been validated by this assessment.

Given recent industry experience and the fact that several low system strength areas are known to exist within the NEM, we propose that AEMO undertake sufficient case studies benchmarking the results of Preliminary Assessment with Stability Study (Option A) to that of a Full Assessment (Option B). Good candidates for this are the connection of additional plant within the West Murray Zone, Northern Queensland and South Australia. The study methodology which leads to consistent results should be published as an item for consultation.

3.2 Different minimum SCR result using different EMT simulation setups

In a SMIB EMT model, a plant model (including its internal network) is connected to a simplified (Thevenin equivalent) representation of the grid. The minimum SCR for which the plant operates in a stable fashion that is calculated from this model is influenced by the following variables:

1. Aspects that relate to the design and operation of the plant such as:
    - the plant's internal network,
    - the architecture of its controls and technology, and
    - its control parameters
    - its initial dispatch
2. The nature of the disturbances to be applied to the plant
3. Aspects which relate to the static/peripheral setup of the SMIB case such as:
    - the presence of any loads at the connection point (representing loads in the vicinity of the plant which avoid the unrealistic condition where all its active power output is transferred via the source impedance)
    - the presence of any shunts at the connection point (representing shunts in the vicinity of the plant which avoid the unrealistic condition where all its reactive power output is transferred via the source impedance)
    - the magnitude of the voltage source (which may reflect voltage levels at the source and be used to achieve the desired voltage magnitude at the POC).

Whilst an Applicant has control over the items within #1, items within #2 and #3 relate to the nature of the network and its representation within the SMIB model. Key aspects are discussed further below.

In all whilst it is possible to specify the most onerous conditions with respect to the items discussed, this carries the risk of producing results that are not fit for purpose in that the minimum SCR values calculated and hence the system strength charges are out of alignment with the mitigation which would be required in reality. Hence the rules for undertaking the minimum SCR assessment should take into consideration the unique aspects for each plant concerning these items.

3.2.1 Simulated disturbances

A factor which can have a significant influence on the calculated results is the nature of the disturbances applied to the SMIB system to determine the minimum SCR. Critical aspects of disturbances which are likely to influence the result are:

- Changes in the source impedance of the grid because of the disturbance.
- The profile, duration and location of faults noting that on a radial line a fault closer to the source is more likely to introduce stability.
- The magnitude of phase jumps which may occur at fault clearing (or during staged fault clearing).

The concern here is to arrive at a set of disturbances which are representative of the conditions likely to be encountered by the plant to give an accurate calculation of minimum SCR.

3.2.2 Representation of loads within the SMIB model

Another factor that also has a significant effect on the calculated minimum SCR is the presence of load at the plant's POC within the SMIB model. This represents the effect of loads within the vicinity of the plant consuming some of the active power that the plant produces. In some instances, particularly where the plant is located within a load centre, the size of this load may be greater than the plant rating. Not including this load entails that all the power generated by the plant is transferred to the source through the source impedance. This introduces a limit on the feasibility of the steady state operating point as the steady state voltage angle difference across the SMIB network (ignoring the effect of transformer phase shifts) must be less than 90 degrees for a viable solution for **any** technology. This steady state limit equally applies for synchronous machines, GFM IBRs or GFL IBRs and hence cannot be used as a system strength indicator.

To illustrate the effect of this load on the calculated minimum SCR result, the following EMT simulation has been carried out (with plots provided in Appendix A Figure 1):

- A EMT SMIB model has been configured (using the OEM detailed EMT model for a GFL IBR) with a voltage source to achieve a POC voltage of 1.0 pu with an SCR of 5 and an X/R ratio of 10.
- The plant is dispatched to 1.0 pu active power output and 0.0 pu reactive power output.
- A resistive active power load is place at the POC.
- The model is initialised with an SCR of 5 and the SCR is slowly ramped down over time (by varying the source impedance) until plant instability is observed.

The table below shows the SCR values attained prior to the onset of instability for varying load sizes (as a proportion of the initial plant active power dispatch). It is observed different load factors lead to different minimum SCR results.

Table 3.1: Influence of representative loads on the calculated minimum SCR

Load factor [%]	Minimum SCR
0	1.35
25	1.25
50	0.97
75	0.80
100	< 0.2

3.2.3 Representation of static shunts within the SMIB model

Lastly, the representation of static shunts at the POC of the plant can also influence the calculated minimum SCR result. To provide an indication of the effect of on the calculated minimum SCR result, a similar simulation to the load representation case is carried out (with plots provided in Appendix A Figure 2):

- A EMT SMIB model has been configured (using the OEM detailed EMT model for a GFL IBR) with an SCR of 2 and an X/R ratio of 10.
- The plant is dispatched to 1.0 pu active power output and 0.0 pu reactive power output and no load is placed at the POC.
- The initial POC voltage of 1.0 pu is achieved using two different methods: in one case voltage source magnitude is modified (V source) and a shunt is introduced at the POC with the voltage source magnitude fixed at 1.0 pu (Q shunt).
- The model is initialised with an SCR of 2 and the SCR is slowly ramped down over time (by varying the source impedance) until plant instability is observed.

The table below shows the SCR values attained prior to the onset of instability for different static shunt model representation.

Table 3.2: Influence of representative shunts on the calculated minimum SCR

Case	Minimum SCR
V source	1.42
Q shunt	1.57

3.3 AFL calculation and aggregation

The existing AFL calculation method does not correctly aggregate multiple GFL IBRs when compared to the Equivalent SCR (ESCR) method as defined in CIGRE Technical Brochure 671. This is demonstrated through the following three examples which show the conditions where the inaccuracies do and do not arise. For simplicity the examples are configured such that the ESCR method produces a result indicating the system strength requirements of the plant are just met by the system strength contribution of the grid (which is the only source of system strength contribution in the examples). If the AFL method is accurate, it is expected that the calculated AFL is zero which is equivalent to the calculated SCR being equal to the Minimum SCR (MSCR) using the SCR methods.

The detailed calculations for this comparison are provided in Appendix B and a summary of the results is provided below. The conclusion is that the AFL method underestimates the required level of system strength for the condition where it must consider the effect of multiple GFL IBRs within a network.

Table 3.3: Comparison of AFL method and ESCR method for various study cases

Case	ESCR result	AFL result	Comment
1 – SMIB with single POC bus	POC bus SCR = 3 = MSCR	POC bus AFL = 0 MVA	Results align at POC bus
2 – SMIB with grid and POC buses	POC bus SCR = 3 = MSCR Grid bus SCR = 5 = MSCR	POC bus AFL = 0 MVA Grid bus AFL = +286 MVA	Results align at POC bus, but AFL provides optimistic result at the Grid bus
3 – DMIB with grid and POC buses	POC1 bus SCR = 3 = MSCR	POC1 bus AFL = +109 MVA	AFL provides optimistic result for all buses

The cause of this inaccuracy is due to the AFL method's representation of Asynchronous Generators (AG) in determining the required system strength. The AFL method represents AGs as an equivalent inductive source impedance (the magnitude of which is related to their size and stated MSCR). It then uses the fault contribution from these AG models to determine their system strength requirement. However, use of an inductive source impedance means that an AG's fault current contribution reduces as more reactive impedance is placed between it and the faulted bus. This indicates less system strength is required to stabilise the plant if the system strength is provided at electrically distant buses.

For instance, consider an AG connected to the system via a radial connection. According to the AFL method, the AG's fault contribution indicates that the system strength required by the AG at buses further away is less than that required for buses closer to it. However, this is the inverse of what is required in reality: more system strength will need to be provided at a bus that is further away from the AG as the impedance between these two will reduce the system strength contribution (i.e. synchronous fault level) at the AG's POC. This shows how inaccuracies arise within the AFL method when calculating the system strength requirements of several AGs within an area.

Some ways to get around this issue would be:

- Revise the AFL method to account for the fact that greater system strength contribution is require at a bus which has a larger impedance to an AG. Some preliminary work that DIgSILENT has carried out shows that a revised AFL calculation method as follows would address this issue:
  - Treat Synchronous Generators (SG) the same as before.
  - Model AGs as voltage source behind a capacitive source impedance but with magnitude equal to what the AFL currently specifies.
  - Include both SGs and AGs in the same network model. It is suggested that all shunts and loads be removed at this point in line with the IEC method.
  - Determine the fault level at all AG POCs. The results indicate the adequacy of system strength as follows:
    - There is adequate system strength for an AG if the fault current at its POC is inductive (i.e. the Thevenin equivalent source impedance is inductive)
    - There is inadequate system strength for an AG if the fault current at its POC is capacitive (i.e. the Thevenin equivalent source impedance is capacitive)
- Utilizing the ESCR method, which may be difficult as it requires equivalent transfer impedances between AG buses to be calculated. These impedances are normally not directly reported by short circuit programs and may therefore require the user to manipulate the network model to derive them.

3.4 Modelling of GFM IBRs within the AFL

In the Issues Paper AEMO proposed using the following equation to determine the AFL with GFM inverters:

AEMO proposes the following methodology to redefine AFL:

$$\mathrm{AFL(MVA)} = \mathrm{S_{SG}} - \mathrm{k} * \alpha * \mathrm{ES_{rated}} * \mathrm{SCR_{\_withstand}}$$

k: Technology coefficient, where:

k = 0 when grid forming IBR (not used for SSS)

k = -1 when grid forming IBR is used for SSS

k = 1 for grid following IBR and HVDC links (for grid forming HVDC, the k factor shall be decided on a case-by-case basis in consultations with OEM and AEMO).

However, GFM IBRs fundamentally involve fast control loops which regulate the inverter's terminal voltage. In this regard, unless the GFM IBR is operating at a limit, the behaviour of a GFM IBR is like that of a SG: both act as voltage sources behind an impedance. Hence GFM IBRs (which are used for System Strength Services) should be modelled as voltage sources behind a source impedance and be treated the same as SGs in the AFL calculation. In this way, the AFL would involve two categories of device:

- System strength contributing devices which include SGs and GFM IBRs which are modelled as a voltage source behind an impedance in a short circuit program. The fault level calculated with only these devices in service is inversely proportional to the sensitivity of the voltage to current injections.
- System strength consuming devices which include all manner of GFL IBRs modelled as proposed.

To determine the system strength contribution at the GFM IBR device's terminals, one would have to determine the ratio of the injected current for a small step disturbance in voltage within a very short timeframe (i.e. a cycle). This value will depend on the specific control implementation of the GFM IBR but will be influenced by the impedances (either real or virtual) between the inverter terminal bus and the point where voltage regulation occurs. As with an SG where slower dynamics involving time varying reactance, automatic voltage regulation and mechanical dynamics are ignored for these types of calculation, slower dynamics involved in active and reactive power control of a GFM IBR should also be ignored.

In circumstances where it is expected that post contingency a device could reach its current limits, the system strength contribution can be reduced by increasing the impedance by a factor to account for this in the AFL calculation. This would need to be carried out on a case by case basis as the transient operation at a limit post-contingency may not occur for all cases and may not be critical in any case.

Given the flexibility to implement all sorts of controls within IBRs, it would be prudent to devise a set of technical standards that GFM IBRs must meet prior to incorporating them into the AFL calculation. As an example, this could include specifications on the response of such devices to voltage disturbances (i.e. the timeframe for a response which acts to oppose the disturbance in a similar fashion to a voltage source).

4 Conclusions and recommendations

This technical note has raised questions on the Draft SSRM and the proposed aspects of the Preliminary Assessment process and associated methods. DIgSILENT recommends the proposed Guidelines be revised with following additional tasks to be undertaken:

- Concerning the Draft SSRM:
    - Cleary define the process for selecting SSNs and, as has been argued, consider expanding these to nearly all nodes within a SSSP network with the process outlined in this technical note.
    - Emphasize that where lower cost solutions not involving additional system strength exist to meet the requirements of the SSRM (e.g. protection system modification) these should be adopted to resolve the power system issue of concern (e.g. inadequate protection system operation due to insufficient fault level).
    - For the "stable voltage waveform" definition:
        - Reconsider the need for a phase angle change criterion when stability is already covered by other criteria.
        - Emphasise the need to determine whether a voltage waveform distortion issue is primarily influenced by system strength rather than other factors.
        - Undertaken adequate assessment to ensure that use of the sustained voltage oscillation threshold is practical in a real power system.
- Concerning the Preliminary Assessment processes and methodology:
    - Perform sufficient case studies and benchmarking activities to validate the Preliminary Assessment methodology.

- Specify the full details of the EMT SMIB assessment such that it is fit for purpose.
- Amend the AFL method to address its deficiencies or use the ESCR method.
- Amend the modelling approach for GFM IBRs within the AFL or similar method as proposed by DIgSILENT.

Appendix A EMT simulation results

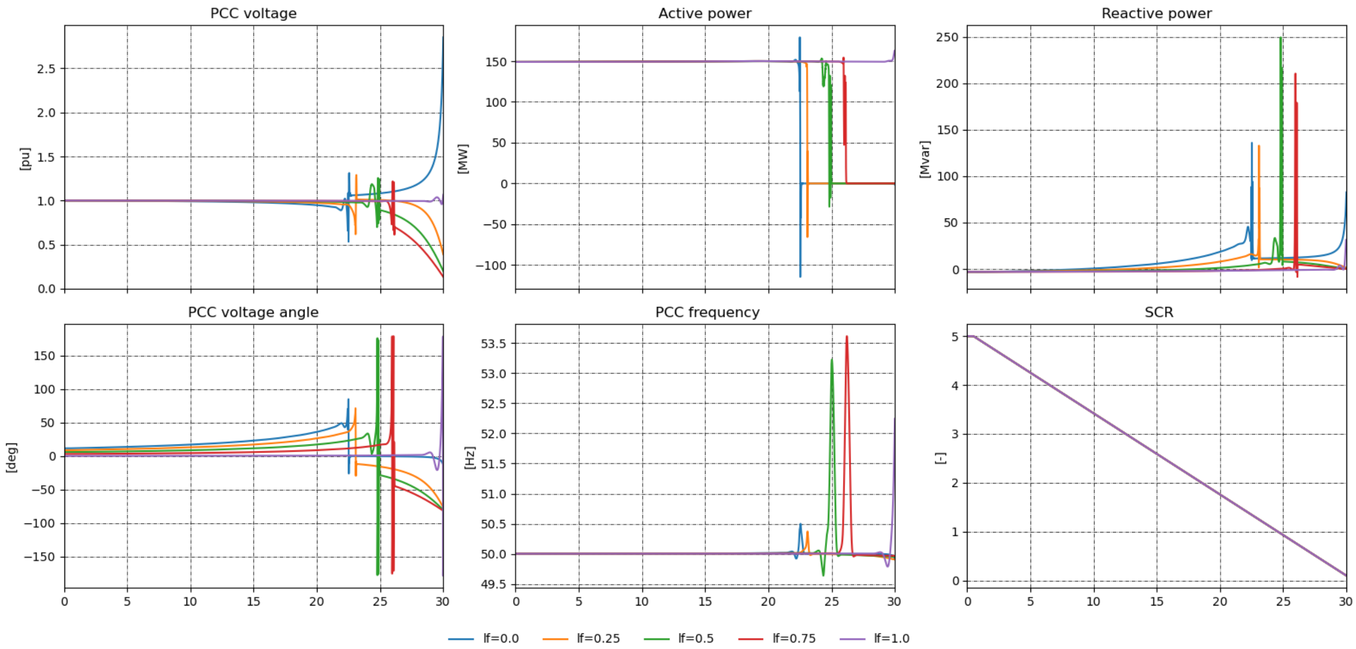


Figure 1: SCR ramp down results with various load factors (lf). The load factor is size of the load at the POC.

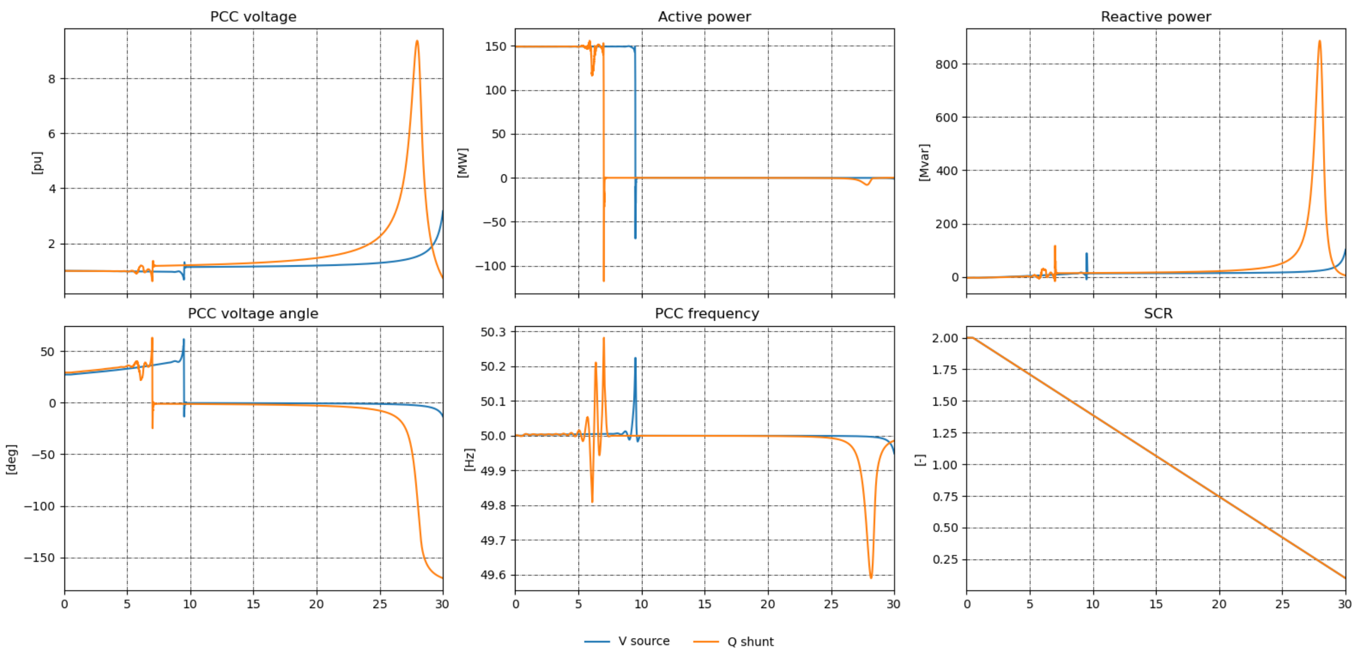


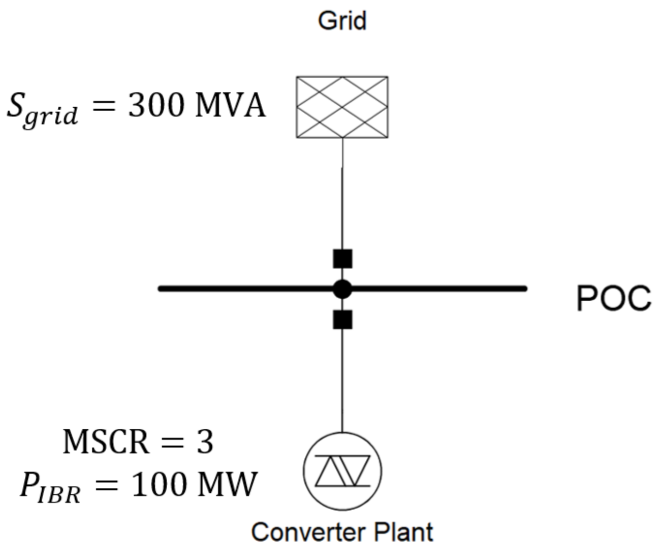
Figure 2: SCR ramp down results with various ways to achieve an initial 1.0 pu voltage at the POC. The "V source" method varies the source voltage magnitude whereas the "Q shunt" method varies a capacitive shunt at the POC to achieve this.

Appendix B AFL and SCR calculations

These example calculations compare the result of the AFL method with the ESCR method. All impedances are expressed in pu on 100 MVA base (Sbase).

B.1 Case study 1

In this case study the result of the AFL and SCR methods align.



SCR method

At the POC bus the SCR is calculated to be 3 as per below:

$$SCR = \frac{S_{SG}}{P_{IBR}} = \frac{300}{100} = 3$$

The plant minimum SCR is 3 hence the SCR at the POC is equal to the minimum SCR. By this method the above condition.

AFL method

At the POC bus the fault level with only SG connected is 300 MVA and the source impedance is j0.333 pu:

$$Z_{SG} = j\frac{S_{base}}{S_{SG}} = j\frac{100}{300} = j0.333 \text{ pu}$$

The asynchronous plant (AG) equivalent impedance is j0.333 pu:

$$Z_{AG} = j\frac{S_{base}}{P_{IBR}}\frac{1}{MSCR} = j\frac{100}{100}\frac{1}{3} = j0.333 \text{ pu}$$

Hence the fault level with both SG and AG connected is calculated to be 600 MVA:

$$S_{total} = \frac{S_{base}}{|Z_{SG} \parallel Z_{AG}|} = \frac{100}{0.167} = 600 \text{ MVA}$$

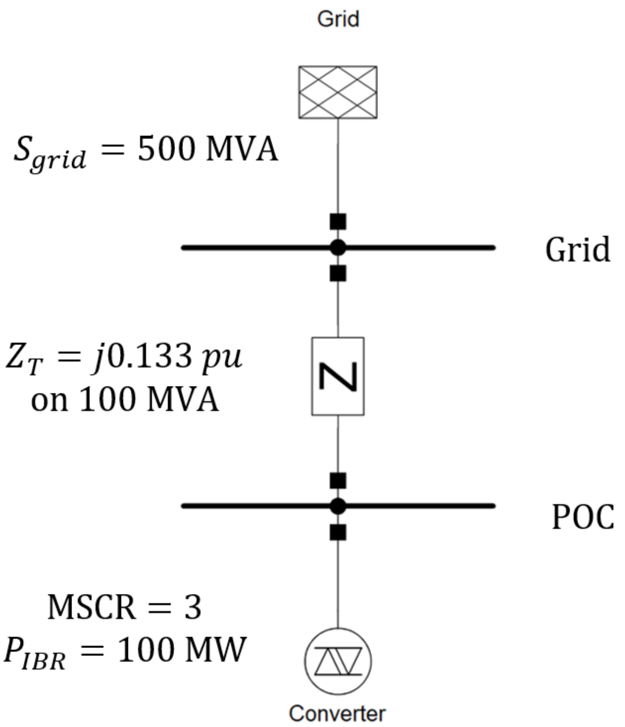
The AFL is then calculated as follows

$$\Delta = S_{total} - S_{SG} = 600 - 300 = 300 \text{ MVA}$$

$$AFL = S_{SG} - \Delta = 300 - 300 = 0 \text{ MVA}$$

B.2 Case study 2

In this case study the fault levels and IBR connected to the POC bus are identical to case study 1. Whilst the result of the AFL and SCR methods align at the POC, they do not align at the grid bus indicting an inaccuracy in the AFL method for remote buses.



SCR method

At the grid bus the SCR is calculated to be 5 as per below:

$$SCR = \frac{S_{SG}}{P_{IBR}} = \frac{500}{100} = 5$$

The plant minimum SCR is 3 at the POC bus which corresponds to a source impedance of j0.333 pu at this bus. Considering the additional impedance of j0.133 pu between the POC bus and the grid bus, the source impedance at the grid must be at least 0.2 pu to meet the minimum SCR condition at the POC bus. Hence the minimum SCR at the grid bus is 5.

Hence the grid bus meets the marginal system strength condition

AFL method

At the grid bus the fault level with only SG connected is 500 MVA and the source impedance is j0.2 pu:

$$Z_{SG} = j\frac{S_{base}}{S_{SG}} = j\frac{100}{500} = j0.2 \text{ pu}$$

The asynchronous plant (AG) equivalent impedance is j0.333 pu as before.

Hence the fault level with both SG and AG connected is calculated to be 600 MVA:

$$S_{total} = \frac{S_{base}}{|(Z_{AG} + Z_T) \parallel Z_G|} = \frac{100}{|(j0.333 + j0.133) \parallel j0.2|} = \frac{100}{0.14} = 714\ MVA$$

The AFL is then calculated as follows:

$$\Delta = S_{total} - S_{SG} = 714 - 500 = 214\ \text{MVA}$$

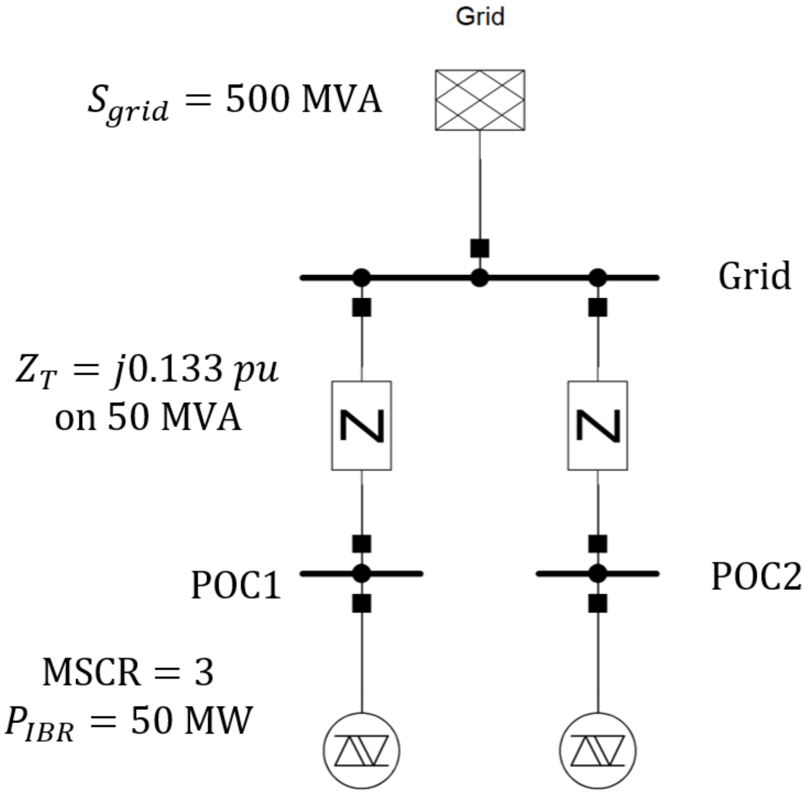
$$AFL = S_{SG} - \Delta = 500 - 214 = +286\ \text{MVA}$$

The AFL method incorrectly calculates sufficient system strength at the grid bus. This is indicative of its inaccuracy for calculating system strength requirements at remote buses.

B.3 Case study 3

This case study involves the same conditions as case 2 but with the single GFL IBR split into two separate but equal IBRs. Since the IBR capacity and fault level conditions are identical to case 2, the ESCR method estimates that the system is operating at the margin of system strength.

For this case however, the AFL calculation produces incorrect results even for the POC buses instead predicting sufficient system strength exists.



SCR method

Since the aggregate IBR capacity and impedances have not changed, the SCR method produces the exact same results as the Case study 2.

AFL method

The SG fault level at the grid bus is 500 MVA and the source impedance is j0.2 pu. Hence at the POC1 bus the fault level with only SG connected is 300 MVA and the source impedance is j0.333 pu as before:

$$S_{SG} = \frac{S_{base}}{|Z_G + Z_T|} = \frac{100}{0.333} = 300 \text{ MVA}$$

The asynchronous plant (AG) equivalent impedance is now j0.666 pu for each IBR:

$$Z_{AG} = j\frac{S_{base}}{P_{IBR}}\frac{1}{MSCR} = j\frac{100}{50}\frac{1}{3} = j0.666 \text{ pu}$$

With both SG and AG connected at the POC1 bus, using network reduction the total source impedance is j0.204 pu and the total fault level is 491 MVA:

$$Z_{total} = [(Z_{AG} + Z_T) \parallel Z_G + Z_T] \parallel Z_{AG} = j0.204 \text{ pu}$$

$$S_{total} = \frac{S_{base}}{|Z_{total}|} = \frac{100}{0.204} = 491 \text{ MVA}$$

The AFL at the POC1 bus is then calculated as follows:

$$\Delta = S_{total} - S_{SG} = 491 - 300 = 191 \text{ MVA}$$

$$AFL = S_{SG} - \Delta = 300 - 191 = +109 \text{ MVA}$$

Hence the AFL is calculated to be positive this (and all other buses) incorrectly indicting sufficient system strength.