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Australian Energy Market Commission

Level 15, 60 Castlereagh Street

Sydney NSW 2000

www.aemc.gov.au

Reference: 'Dispatch limits for inverter-based resources' Rule Change Request (Project ERC0453)

Clean Energy Council submission to the AEMC consultation paper

The Clean Energy Council (CEC) is the peak industry body representing around 1,000 organisations operating across Australia's clean energy sector. Its membership includes renewable energy developers and generators, energy storage providers, network businesses, retailers, original equipment manufacturers, technology companies, investors and financiers, professional services firms, installers, consultants and research organisations. Collectively, CEC members are responsible for developing, financing, building, operating and supporting the renewable energy and storage projects that underpin Australia's energy transition. We are committed to accelerating Australia's transition to a clean energy future as rapidly as possible while maintaining secure, reliable and cost-effective electricity supply for customers.

The CEC welcomes the opportunity to provide feedback to the AEMC as part of its consultation on the 'Dispatch limits for inverter-based resources' rule change request. As we outline below:

- The rule change request, submitted by the Australian Energy Market Operator (AEMO) on 18 May 2026, seeks to amend the National Electricity Rules (NER) to expressly enable dispatch instructions to include a limit on the number of inverters online at a connection point, and to require newly connecting inverter-based resources (IBR) to have the capability to receive and comply with such instructions.[1]
- The core weakness is that the underlying premise of the proposal – that the best way to manage system strength is to limit or disconnect IBR – is asserted rather than demonstrated, and does not distinguish between grid-following (GFL) and grid-forming (GFM) inverter technology. This risks an approach that is both unworkable in a power system that is expected to be predominantly IBR, and counterproductive, given a large and growing share of new IBR (particularly grid-scale batteries) is GFM and net-positive for system strength.

[1] AEMC, Dispatch limits for inverter-based resources, Consultation paper, 27 August 2026, https://www.aemc.gov.au/sites/default/files/2026-08/consultation_paper_-_rule_change.pdf

- The proposal also raises unresolved issues regarding the costs, implementation timeframe, compliance approach and lack of a clear compensation framework associated with the proposed reform, each of which we address in response to the Commission's specific consultation questions below.
- We consider there are preferable, more targeted alternatives available to the Commission that would better address AEMO's stated concerns while avoiding the risk of disconnecting the very technology that is helping to solve the system strength challenge.

Key overarching issues with the proposed rule change

- **The premise underpinning the rule change is asserted, not demonstrated.** The consultation paper and rule change request proceed from the position that a greater number of online inverters means a weaker and less secure power system, and that limiting inverter numbers is therefore the appropriate response.[2] Beyond high-level statements, neither AEMO nor the Commission has published the technical evidence base (e.g. modelling of the specific voltage oscillation or interaction mechanism at issue, or data showing the current voluntary approach is failing) that would justify moving from a voluntary, negotiated arrangement to a mandatory, civil-penalty-backed obligation. It is likewise unclear why directions are not the most appropriate means to resolve system strength challenges associated with the number of online inverters as opposed to the proposed approach.
- **The proposed approach is not workable in a power system that is expected to be predominantly IBR.** AEMO's own 2026 Integrated System Plan projects that inverter-based resources will account for approximately 90 per cent of NEM generation capacity by 2050, with synchronous resources reduced to around 10 per cent.[3] If the default operational response to a system strength shortfall is to reduce the number of online inverters, it is unclear what capacity would remain available to keep the system secure once IBR dominates the generation mix. A rule that is workable today may not be fit for purpose in the system AEMO itself is planning for.
- **The proposal does not distinguish between GFM and GFL inverters, and risks making the power system less resilient.** GFM inverters are specifically designed to provide voltage-source behaviour that supports system strength, in contrast to GFL inverters, whose control interactions with each other and the network are the more likely source of the voltage instability AEMO is concerned about. Neither the proposed Chapter 10 definitions of 'inverter' and 'online inverter', nor the proposed dispatch instruction mechanism, differentiate between the two. AEMO's Connections Scorecard shows that the substantial majority of battery energy storage capacity currently in the

[2] AEMC, Consultation paper, 27 August 2026, Summary, p. i and Section 1.1, p. 1: 'A relevant determinant for the level of system strength is the number of inverters that are electrically connected to the power system. All else being equal, a greater number of inverters online can mean a weaker and less secure power system.' https://www.aemc.gov.au/sites/default/files/2026-08/consultation_paper_-_rule_change.pdf

[3] AEMO, 2026 Integrated System Plan, Figure 1 (Step Change scenario) – inverter-based resources are projected to comprise approximately 90% of NEM capacity by 2050, with synchronous resources around 10%. https://www.aemo.com.au/-/media/files/major-publications/isp/2026/2026-integrated-system-plan-isp.pdf?rev=f2f142d0a8d740a986f186da17bb8a9d&sc_lang=en

connections queue is GFM.[4] A rule that can direct the disconnection of GFM plant on the same basis as GFL plant would risk removing from the system exactly the technology best placed to resolve the underlying system strength issue.

- **Transitional dynamics risk disconnecting the wrong assets first.** Newer, larger, and more capable plant – disproportionately GFM – is best placed to comply quickly and automatically with inverter-limit instructions, having already invested in modern control and telemetry systems. Older GFL plant is more likely to be the source of real system strength problems, but may be slower or unable to comply. This means the rule could initially affect newer GFM assets that are helping strengthen the system, while the older assets that may cause the issue remain online.
- **Potential flow-on impacts to cost, frequency control and compensation have not been addressed.** There are unresolved questions regarding interactions with frequency control ancillary services (FCAS) and mandatory primary frequency response obligations where a unit is constrained by an inverter-limit instruction, and no clear framework for compensating participants directed to curtail output or disconnect inverters for system security reasons that are outside their control. Similarly, assets being disconnected through this scheme that are being paid to provide system strength under the process envisioned in the Security Framework Enhancements rule change, or as non-network options under the existing RIT-T process, appear to be obvious points of contradiction.
- **The cost-benefit case for consumers has not been made**. Constraining lower-cost IBR out of merit order in favour of continued output from higher-cost synchronous plant, such as gas or hydro, would be expected to increase wholesale costs, with flow-on impacts for consumers. These higher prices may also lead to worse long-term outcomes for consumers by increasing project risk, weakening investment signals and making lower cost clean energy less available when it is needed. The Commission should explain how any final rule change that produces these outcomes would be consistent with the National Electricity Objective and should clearly set out those implications in its final decision for transparency.
- **No clarity has been provided on the intended use-cases for the requested capabilities**. A framework intended to act as the primary tool for operational management of system strength is clearly of far greater concern than one whose usage is subject to a limited set of specific circumstances that occur infrequently (e.g. unplanned line outages). As such, clarification is urgently sought on this topic so that further work on this topic can be contextualised accordingly.

[4] AEMO, Connections Scorecard, June 2026, Figure 5 (Stand-alone Battery GW Volume and GWh by State) – the large majority of battery energy storage system (BESS) capacity in the application, proponent implementation and enquiry stages of the connections queue is grid-forming. https://www.aemo.com.au/-/media/files/electricity/nem/network_connections/connections-scorecard/2026/june-2026.pdf?rev=64b9c711549f4890b388382450f58a9b&sc_lang=en&hash=B5EFCE5DE6D9A7415FA00BF74FBFE9BB

Responses to the AEMC's consultation questions

Our responses below draw on feedback received from CEC member companies – including generators, developers, network service providers and original equipment manufacturers – supplemented by our own analysis and publicly available material.

Question 1: Views on current arrangements for managing inverter-limits, and whether they impose costs or operational challenges

Member feedback on this question was mixed, reflecting real variation in exposure across the fleet. Several members report that they consistently and successfully comply with AEMO's manual requests to block or disconnect inverters, and are not aware of any instance where their own response has been inadequate or untimely; on this basis they query the need for a new compliance mechanism.

Other members, and a transmission network service provider consulted by the CEC, report genuine and increasing operational strain. AEMO's own data shows inverter-related constraint violations rose from 473 intervals in 2024 to 526 in 2025.[5] A member cited a fault event on the Balranald–Buronga 220kV line in January 2026 that required the manual disconnection of inverters within a three-minute window to meet AEMO's 30-minute resecuring obligation, following a 2024 event in which AEMO needed to make time-critical phone calls to more than 30 generators (some of which could not be reached, or where compliance could not be readily confirmed through available telemetry).[6][7]

On balance, we consider the costs and operational challenges of the current framework are real, but concentrated in specific network areas with limited system strength and specific outage-driven circumstances, rather than being evenly distributed across all IBR. Reform should be proportionate to this concentrated risk profile rather than imposing a blanket, mandatory obligation on all scheduled and semi-scheduled IBR.

Question 2: Extent to which AEMO's inverter dispatch initiative would address the issues identified, absent an explicit NER compliance mechanism

Members generally agree that the inverter dispatch initiative – which automates the communication of inverter-limits via EMMS, SCADA and ICCP pathways – would materially improve the timeliness and consistency of AEMO's communications regardless of whether compliance is made mandatory. Several

[5] AEMC, Consultation paper, 27 August 2026, Figure 2.1, p. 9: 473 inverter-related constraint-violation intervals recorded in 2024, rising to 526 in 2025. https://www.aemc.gov.au/sites/default/files/2026-08/consultation_paper_-_rule_change.pdf

[6] AEMO, Power system incident report: Three-phase fault on Balranald – Buronga 220 kV X3 line, 19 January 2026. https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2026/three-phase-fault-on-balranald--buronga-220-kv-x3-line.pdf?rev=1213c3a239c94901971cf3eba6544323&sc_lang=en

[7] AEMO, Power system incident report: Trip of Wagga B busbar, 2024. https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/trip-of-wagga-b-busbar.pdf?rev=303bb5c4c7e8429eae0c9708e47e5773&sc_lang=en

members indicated that their own plant would likely take up the automated pathway voluntarily once available, simply because it is operationally preferable to manual phone calls.

This suggests the voluntary initiative alone may resolve a substantial share of the operational burden AEMO has identified, without the need for new compulsory powers. We encourage the Commission to test this counterfactual explicitly – for example, by seeking data from AEMO on voluntary uptake and compliance rates once the initiative is operating (targeted for Q2 2027) – before concluding that a compulsory NER mechanism is necessary in addition.

Question 3: Whether the proposed solution would address the issue raised, and whether it would have unintended consequences

For the reasons set out under 'Key overarching issues' above, we do not consider the proposed solution, as currently drafted, would reliably solve the problem raised by the proponent. By failing to differentiate GFM from GFL inverters, the rule could require the disconnection of assets that support system strength – the opposite of the intended outcome.

We also see a material risk of unintended consequences, including: distortion of dispatch merit order and higher wholesale costs; interactions with FCAS enablement and mandatory primary frequency response obligations; potential generator performance standard compliance issues where control system changes needed to comply with inverter-limits are treated as triggering clause 5.3.9 reassessment; and reduced bankability of new and existing IBR projects given the uncertain, and currently uncompensated, curtailment risk this proposal would introduce. As noted above, we also see a high risk of unintended consequences in the case of GFM IBR being paid to provide non-network system strength services under RIT-T contracts.

Question 4: Costs and benefits of the proposed solution, whether they are one-off or ongoing, and what the Commission could do to minimise costs and increase benefits

The benefits identified by AEMO – faster resecuring, reduced manual control-room burden, and improved auditability – are real, albeit they accrue primarily to AEMO. The costs, by contrast, are also very real and fall disproportionately on participants. No clear articulation has been provided as to what the quantum of benefits and costs are let alone confidence expected benefits would confidently exceed expected costs.

One member advised that for some existing sites, the control-system retrofit needed to comply automatically may not be technically feasible at all, and that SCADA vendors are reluctant to build bespoke, per-inverter switching capability into systems not originally designed for it; these costs would be one-off in nature but potentially very substantial relative to a plant's remaining operating life.

To minimise costs and improve the balance of benefits, we recommend the Commission require AEMO to: (i) exclude GFM plant from any inverter-limit dispatch instruction unless a specific, site-evidenced case is made; (ii) clarify, in guidance developed with the AER, that clause 5.3.9 reassessment triggers arising from this rule are narrowly scoped to the specific control-system change required; and (iii) publish

the evidentiary basis underpinning any inverter-limit instruction, including modelling, incident data and information on whether the assets causing the issue are older GFL plant or newer GFM plant, so participants can understand the problem, assess compliance options efficiently and confirm the rule is targeting the right assets. This would also give greater confidence that aggregate benefits exceed aggregate costs.

Question 5: Whether any variation or alternative to the proposed solution would better contribute to the National Electricity Objective

Yes. We consider there are preferable alternatives available to the Commission, which we set out in detail under 'Preferable alternatives' below.

Question 6: Whether the proposed approach can be implemented efficiently and effectively, and any transitional arrangements, lead times or sequencing issues

Several members consider the proposed 18-month implementation period for existing plant is optimistic for the subset of plant requiring material control-system changes; some legacy assets may need considerably longer, or may not be able to comply at proportionate cost given their remaining operating life and current equipment capabilities.

As noted above, sequencing also raises a practical risk: newer, more capable (and disproportionately GFM) plant will be able to comply soonest, while older GFL plant – which members and network operators consider more likely to be implicated in genuine system strength events – will take longest.

We recommend the Commission require a differentiated implementation timeframe based on plant vintage and control-system capability, developed through direct engagement with SCADA and original equipment manufacturer (OEM) providers on retrofit feasibility and cost, rather than a single 18-month deadline applied uniformly.

Question 7: Whether the proposed compliance approach is the most appropriate, and whether relevant parties have appropriate incentives to comply

Members queried an apparent asymmetry in AEMO's current practice: AEMO treats its manual request to a participant as non-binding (participants may decline without penalty), while relying on a clause 4.8.9 instruction to the NSP to physically disconnect the facility if the participant does not comply. The rule change would, for the first time, bind participants directly through a dispatch instruction carrying civil penalty exposure under clause 4.9.8, without an equivalent change to how compensation is treated.

We consider that if participants are to be subject to a new civil-penalty compliance obligation of this kind, there should be a corresponding and explicit compensation framework – consistent with the Commission's and the AER's parallel work on compensation frameworks for directions – so participants

are not financially penalised for complying with an instruction addressing a system security risk outside their control.

We also recommend the Commission require that 'offline' be defined, for compliance purposes, by reference to the specific electrical state actually required by the underlying system strength study (for example, blocking active or reactive power output at the inverter control interface), rather than a blanket requirement to disconnect the generating unit – including, in the case of some turbine-based technology, the loss of auxiliary supply that is not necessary to address the identified system strength concern.

Question 8: Whether the proposed assessment criteria are appropriate, and whether additional criteria should be considered

The three proposed criteria – safety, security and reliability; principles of good regulatory practice; and implementation considerations – are a reasonable starting framework. However, we recommend the Commission add an explicit materiality and evidence threshold: before assessing implementation and compliance design, AEMO should be required to demonstrate the specific technical basis for treating the number of online inverters (rather than inverter technology or control mode) as the appropriate proxy for system strength risk in the circumstances where a limit is to be applied.

We also recommend the 'good regulatory practice' criterion explicitly test consistency with, and avoidance of duplication with, the Commission's parallel Security framework enhancements and Improving the NEM access standards (Packages 1 and 2) rule changes, given the substantial overlap in subject matter across these concurrent processes.

Preferable alternatives to manage system strength in a predominantly IBR system

For the reasons set out above, we consider the Commission should look beyond the solution proposed by AEMO. We recommend the following alternatives, individually or in combination, as more proportionate and durable ways to manage system strength as the NEM transitions to a predominantly IBR system.

1. **Differentiate GFM from GFL inverters.** Any inverter-limit mechanism should explicitly exclude, or apply a materially different and higher evidentiary threshold to, GFM plant, given its role in supporting rather than weakening system strength. In addition, it would make sense to pursue a framework that exempts GFM assets that are being specifically paid to provide system strength services as RIT-T non-network options.
2. **Address system strength at its source, not via fleet-wide constraint.** Continue to prioritise and accelerate procurement of system strength services (for example, synchronous condensers and GFM battery energy storage) through existing and evolving NSP system strength frameworks,

including system strength connection agreements and the System Strength Impact Assessment Guidelines, rather than managing the symptom by constraining the number of inverters online.

3. **Establish the technical evidence base before mandating compliance.** Before any mandatory obligation is introduced, AEMO should be required to publish: (i) the specific technical concern being targeted (for example, a defined voltage oscillation mechanism), with supporting data or modelling; (ii) why this is not already addressed by existing NSP stability testing requirements (for example, clause S5.3.4B, SSAT modelling, or S5.2.5.15); (iii) how GFM plant could demonstrate it does not contribute to the identified risk; and (iv) how differences in capability between inverter tiers and OEMs would be assessed (for example, per-OEM versus per-site, or factory/CHIL testing versus field testing).
4. **Retain voluntary participation in the inverter dispatch initiative until or unless a credible case can be made to transition to mandatory.** Allow the initiative to reach full implementation (targeted for Q2 2027) and assess its real-world effectiveness against AEMO's own compliance and incident data before deciding whether a mandatory NER mechanism is still required.
5. **Precisely define the compliance state required.** Any obligation to reduce the number of 'online' inverters should be defined by reference to the specific electrical outcome required by the underlying system strength study (for example, blocking of active or reactive power output), rather than a blanket disconnection requirement that may have disproportionate collateral impacts.
6. **Establish a clear compensation framework.** Any new mandatory obligation should be accompanied by an explicit mechanism to compensate participants directed to curtail output or disconnect inverters for system security reasons outside their control, consistent with work already underway on compensation frameworks for directions.
7. **Adopt a risk- and vintage-differentiated implementation timeframe.** Rather than a single 18-month deadline applied to all existing plant, implementation timing should reflect plant vintage and control-system capability, informed by direct engagement with SCADA and OEM providers on retrofit feasibility, cost and, in some cases, technical impossibility.
8. **Clearly define guard-rails on when any newly introduced capability can be used** (again, if it is demonstrated the capability is necessary and net-positive for consumers). By clearly defining the specific circumstances in which the proposed capability could be used, with appropriate checks and controls, the commercial and technical impact of any changes could be minimised and the ex-ante risks that may otherwise impact investment could be better understood.

The CEC welcomes further engagement on this matter as the AEMC progresses its review of the rule change request. Further queries can be directed to Martin Kennedy at the following email address mkennedy@cleanenergycouncil.org.au.

Kind regards,

Con Hristodoulidis

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