power for good

7th May 2020

Mr John Pierce AO
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney NSW 1235

Lodged via AEMC website: **www.aemc.gov.au**

Dear Mr Pierce,

INVESTIGATION INTO SYSTEM STRENGTH FRAMEWORKS IN THE NEM (EPR0076): DISCUSSION PAPER

Established in the 1980's within the UK's Sir Robert McAlpine engineering and construction group, today, RES (Renewable Energy Systems) is the world's largest independent renewable energy company, with the expertise to develop, construct and operate projects around the globe. Headquartered in the UK, we operate globally with offices in 10 countries across the Americas, Europe and Asia Pacific. RES has delivered over 17GW of renewable generation over the last 38 years, driven by our vision of a future where everyone has access to affordable zero carbon energy.

Established in 2004, RES Australia is an industry leading renewable energy developer specialising in wind, solar and battery storage development and asset management across Australia. With a talented and experienced team, we have achieved financial close on over 600MW of new renewable generation and have 726MW of wind and solar assets under operational management. RES Australia has a development pipeline of 2.5GW across several states.

RES Australia welcomes the opportunity to provide input to the Australian Energy Market Commission's (AEMC's) investigation into system strength frameworks in the National Electricity Market (NEM). The existing do no harm and minimum fault level frameworks that were introduced in 2018 are delaying the entrance of vitally important new generation and leading to inefficient investment in system strength related infrastructure. The need for change is urgent as the frequent emergence of system strength challenges threatens investor confidence in the NEM.

Do no harm framework

Issue	Description
Time	The do no harm framework has proven to be a significant barrier to the entry of new generation projects, leading to increased fuel costs for consumers. In our experience, the delays have been caused by the complexity of system strength modelling, commitment of other generators, correction of past mistakes and a lack of clear delineation of responsibility between AEMO and the Network Service Providers (NSPs). The proposed framework should consider opportunities to accelerate the connection application process without increasing the risk of delay during the construction phase. Due to the length of time required for the NSPs and AEMO to undertake system strength modelling it is now necessary to select equipment manufacturers up to twelve months ahead of issuing notice to proceed to contractors and placing equipment orders. This delay between equipment selection and the placement of orders leads to substantial cost increases due to the lack of competition between manufacturers. This is particularly relevant for wind farms because the turbines make up a relatively large portion of the overall capital cost.
Quality	The do no harm framework does not adequately reward the development of quality projects that have optimised system strength outcomes. Projects that have been optimised for system strength are being beaten to commitment status by lower quality projects with weaker connections. The proposed framework needs to consider opportunities to incentivise projects to be optimised for system strength at an early stage. Quality outcomes can be improved by removing the first mover advantage for the allocation of system strength.
Cost	The do no harm framework is not cost effective. There are numerous examples of projects installing synchronous condensers to maintain their program without the information or network knowledge to design an optimal solution. The proposed framework needs to limit the occurrences of system strength solutions that have not been optimised in terms of their costs and benefits.
Transparency	The do no harm framework is not transparent. Developers cannot adequately forecast system strength related costs or connection application timeframes upfront. This lack of transparency introduces the need for conservatism when pricing energy, driving up costs for consumers.

	The proposed framework needs to provide developers with a transparent process to optimise system strength outcomes in line with the development approval process timelines. For example, developers will need to consider the construction of additional infrastructure as part of their development applications.

Minimum fault levels framework

Under the existing framework, Transmission Network Service Providers (TNSPs) are required to maintain minimum fault levels that have been set by AEMO. This framework has been successful insofar as it has allowed solutions to be procured to increase fault levels in South Australia, Western Victoria and North Queensland. However, the reactive approach of the existing framework is leading to significant inefficiencies that are ultimately born by consumers. Fault level gaps are not typically declared until it becomes necessary to curtail the output of wind and solar generation, leading to the dispatch of more expensive generators.

As required by the rules, the published minimum fault levels have been based on the existing fleet of synchronous machines and do not adequately consider the forecasted location and increasing penetration of asynchronous generation.

Centrally coordinated model for system strength

Of the four potential models for the management of system strength, RES supports the centrally coordinated model. The proactive planning approach of the centrally coordinated model would facilitate the removal of the do no harm requirements and the associated lengthy connection application process.

The centrally coordinated model must be carefully designed to incentivise developers to optimise projects for system strength, rather than racing each other for the allocation of low cost system strength services that do not differentiate between the design of projects. This can be achieved by ensuring that there is limited first mover advantage in system strength cost allocation.

Under the centrally coordinated model, the total cost of providing system strength would be optimised because the TNSPs possess the knowledge, skills and information required to design efficient solutions. This model can also improve transparency by ensuring that the long-term costs that a generator will incur are fixed at the time of financing.

The table below provides our high-level feedback on how system strength can be planned, procured, priced and paid for under the centrally coordinated model.

Stage	Description
Plan	Minimum system strength outcomes could be set by the Integrated System Plan (ISP). The minimum system strength levels could be based on a least regrets approach under the optimal development path. Given that the ISP is only published every two years, there should be a mechanism to increase these levels in between ISPs if necessary.

Procure	Like the existing minimum fault level framework, the TNSPs would be responsible for procuring the minimum levels of system strength as specified by the ISP. The procurement process should be competitive but timely.
Price	The price of meeting the minimum system strength levels should be regulated and determined through an evaluation of costs and benefits. The need for thorough regulation needs to be traded off against the market impacts of a slow approvals process.
Pay	To incentivise the development of quality projects, new generators should have cost exposure to system strength that is scaled depending on the technical attributes of the project. These attributes could include the maximum export capacity, connection voltage, minimum short circuit ratio and the number of transmission line exits. A transparent cost allocation process that allows for cost forecasting with a high degree of confidence will support developers in optimising long lead time projects for system strength. A real time causer-pays mechanism would damage investor confidence and reduce certainty in cost. It is our strong preference to have costs set at the time of connection. The initial financial risk on proactive investment in system strength could be taken by TNSPs and ultimately consumers through the inclusion in the regulated asset base, noting that a purely reactive approach is likely to have a more detrimental impact on consumers.

RES does not prefer the provision of system strength services via a market mechanism as it will diminish the certainty in the levels of system strength and cost of services. This lack of certainty will impact investor confidence and reduce the timing and ultimate volume of new entrants. Generators are currently exposed to the costs of frequency control ancillary services; however, these costs are expected to be an order of magnitude lower in value. Further, system strength services are specific to each location within the network, so there would be minimal competition benefits provided by incumbent generators in dispersed locations.

Technology neutral approach

The system strength framework should be technology neutral where possible. Today, synchronous condensers are the favoured solution to resolve system strength shortfalls. The equivalencing of system strength and fault current may be a convenient path forward in the near term but there is a risk that more cost-effective innovations are locked out.

The detailed identification of needs and improved analytical technology will lead to lower cost solutions. Therefore, the pursuit of a technology agnostic approach needs to be weighed up against the urgent need to resolve a system strength shortfall. We encourage the AEMC to investigate the feasibility of a staged approach to technology neutrality.

South Australian requirements

The South Australian Generator Development Approval procedure requires new projects to provide 2.74MW.s of inertia for every MW of installed capacity. This is leading to the installation of relatively large synchronous condensers within generating systems. This equipment also provides supplementary system strength but is not properly integrated within the system strength frameworks, leading to an over-investment through duplication.

We encourage the AEMC to consult with the South Australian Government, ElectraNet and AEMO to ensure that system strength and inertia are centrally coordinated in South Australia.

Interaction with existing generators

In many cases, the most cost-effective system strength solution includes the re-tuning of existing generators. This is a difficult issue because on one hand, the re-tuning of existing generators may represent the lowest cost outcome. On the other hand, the potential of forced settings changes could result in additional modelling and outages which significantly increases the risk of lost revenue.

Existing generators are reluctant to support re-tuning of their control systems due to the requirement to undertake the NER 5.3.9 approval process. Alongside the modest cost of engineering resources, this arduous process introduces the significant risk of lost production due to the requirement to re-do most of the commissioning tests. Furthermore, the risk that the NSP and AEMO will attempt to revisit the generator's compliance with rules, procedures and guidelines that have been amended since the project's connection exacerbates the resistance from existing generators.

The proposed framework should allow for the effective re-tuning of existing generators. The reluctance of existing generators to support this process could be resolved by creating a clear compensation framework where existing generators are not exposed to the costs of lost production, labour or additional equipment that might be required to facilitate the alteration.

Generator performance standards

The existing framework for the negotiation of access standards requires generators to provide a level of performance as close as possible to the automatic access standards. This approach is having an adverse impact because the automatic access standard represents the most aggressive control tuning, which is inappropriate in all but the strongest connection locations. In an attempt to meet the automatic access standards generators, are forced to tune their control systems to have an aggressive response to voltage disturbances and contingency events which often leads to underdamped oscillatory responses.

The framework could be improved by acknowledging that some performance standards should be negotiated based on the local network attributes with an explicit requirement to optimise the control system response, making it explicit that the generator is not required to meet the automatic access standard by default. Examples of such access standards include:

S5.2.5.5 (f)(1)(i) Reactive current injection in response to contingency events;
S5.2.5.5 (f)(1)(ii) Reactive current absorption in response to contingency events;
S5.2.5.5 (f)(2) Active power recovery time following contingency events;
S5.2.5.5 (g)(2) Reactive current rise and settling times in response to contingency events;
S5.2.5.13 (b)(4)(v) Rise and settling times for voltage disturbances; and
S5.2.5.13(b)(4)(vi) Reactive power rise time for changes in voltage setpoint.

Thank you for the opportunity to provide feedback into this important investigation. For further discussion on the feedback provided in our submission, please reach out to me at **martinhemphill@res-group.com**.

Yours sincerely,

X 

Martin Hemphill
Manager - Grid Connections
Signed by: martin.hemphill@res-group.com