S&C ELECTRIC COMPANY
Excellence Through Innovation

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Sebastien Henry
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Our Ref: JC 2017-035 3 October 2017

Dear Sebastien,

S&C Electric Company response to the Consultation on an Inertia Ancillary Service Market (ERC0208)

S&C Electric Company welcomes the opportunity to provide a response to the Consultation paper on the rule change proposed by AGL Energy to create an Inertia Ancillary Service Market.

S&C Electric Company has been supporting the operation of electricity utilities in Australia for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports "wires and poles" activities but has delivered over 8 GW wind and over 1 GW of solar globally. S&C Electric Company has been actively engaged in deploying Battery Energy Storage Systems for over 10 years, supporting a full range of business models and using a range of battery technologies, at the kW and MW scale, and currently has 76 MW/189 MWh in operation. In Australia, S&C projects include the Ergon Grid Utility Support System in Queensland, which reduces peak loads and provides voltage support on rural Single Wire Earth Return lines and the 2 MW battery for PowerCor in Victoria.

S&C Electric are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low cost networks and would be very happy to provide further support to the Australian Market Energy Commission on the treatment and potential of these technologies.

Yours Sincerely

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General Comments

Lack of Clarity on what contributes to Inertia

There has been a great deal of work on System Security and Inertia in the past 12 months. The various determinations and final reports, including this current consultation, have resulted in confusion over exactly what constitutes "inertia provision" for the various proposed levels (see Figure 1 below).

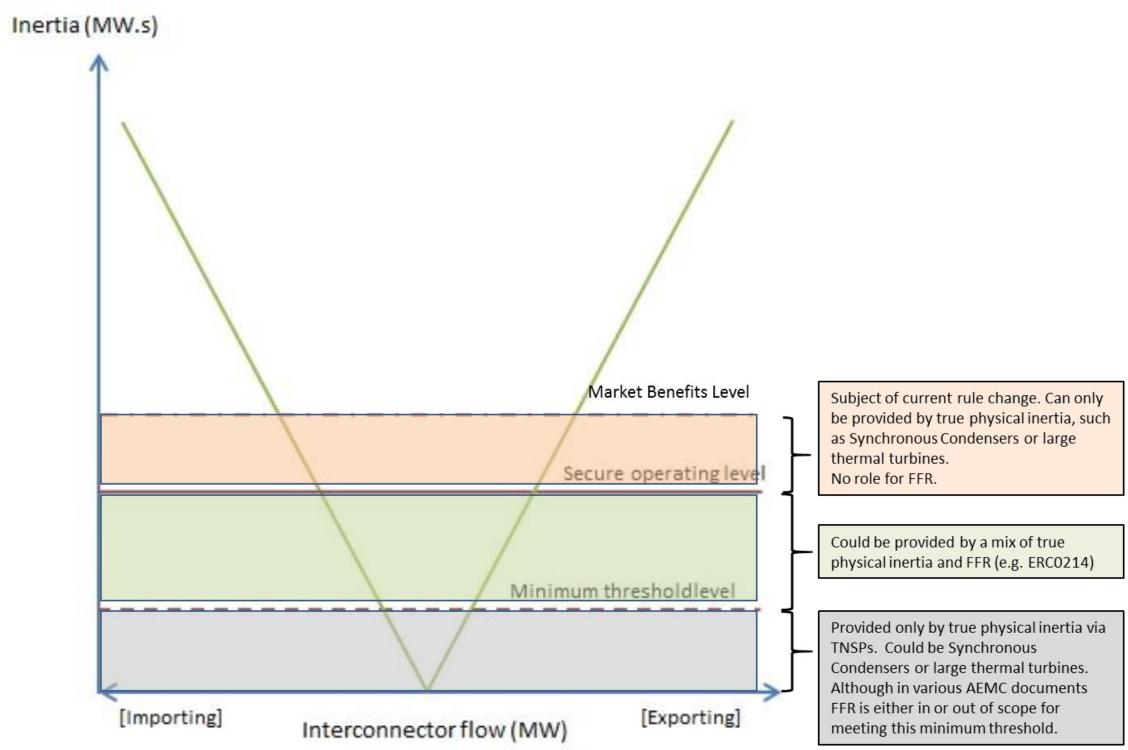

Figure 1: Proposed Inertia Levels (after AEMC, 2017)

If the Market Benefits Level is outside of both the Minimum Threshold Level and Secure Operating Level, as seems to be the case, this would suggest that is not a service the TNSPs can procure to meet either of the mandated inertia requirements.

It seems inconsistent to specify a new market service that is not technology neutral, if this new service is required at all. The new market for inertia services only favours incumbent large synchronous generators and is therefore undesirable. It also does not facilitate the development of a service that will deliver inertia via power electronics, which will be needed as synchronous generation leaves the system.

Clarity is needed as soon as possible on what level of inertia can be provided by what type of asset. We would welcome a revised diagram, similar to the figure on page 4 of the AEMC Directions Paper on System Security Market Frameworks Review, 23 March 2017, titled "Making the Electricity Market more Secure, immediate and subsequent actions", which clearly shows where FFR can and cannot contribute to inertia.

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Deadband Issue still ongoing

Frequency control in the NEM has diminished since changes in the rules post-FCAS. The issue of deadband settings and frequency control more broadly are still the subject of work by both AEMO and AEMC. One option that seems to be strongly favoured is introducing mandatory governor settings to tighten the deadband and tighten control of frequency. This will have a significant impact on the inertial response of the system.

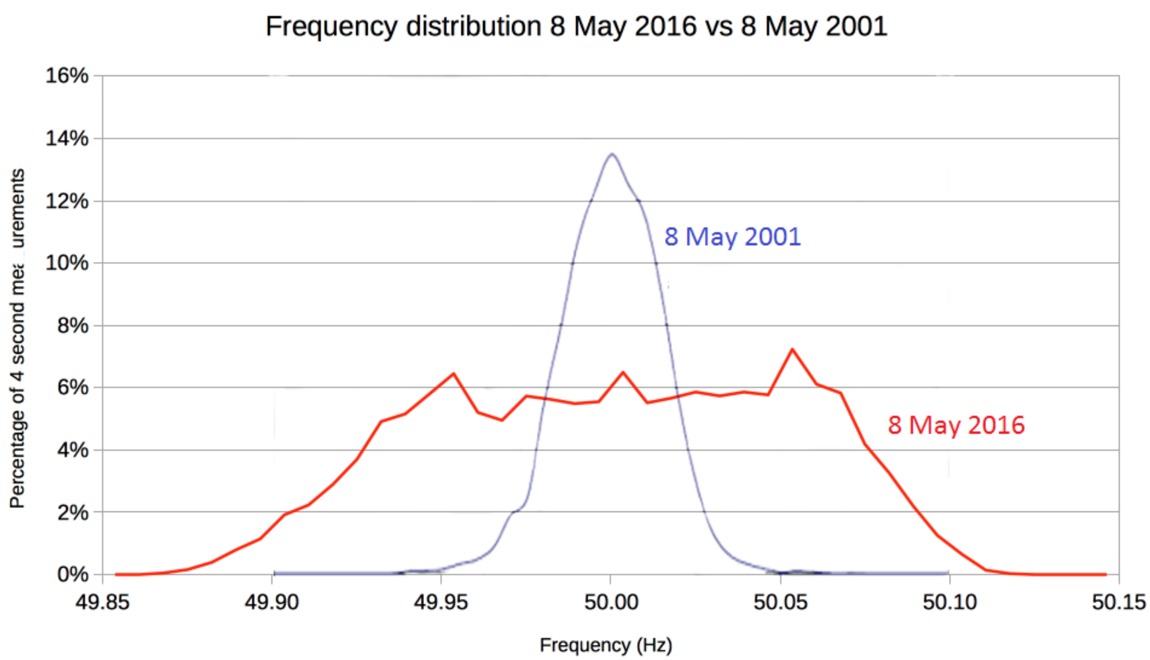

Figure 2: Taken from "Fast Frequency Control, back to the future?", Kate Summers, March 2017

It is not clear whether there will be any remuneration for a mandatory service from large-scale synchronous generators. But given that deadband settings are now wide, settings will have to be changed, inertia is perceived to be reducing and in short supply (although it could be argued that there is sufficient *potential* inertia on the system, but that it is not enabled or prioritised. See below for further comments) and current market requirements disincentivise inertia provision, then AEMO are in a position of a buyer in a sellers' market. Why should any synchronous generator now provide inertia for free? Even though it is an essential requirement for any stable electricity system and no export can sensibly or reliably occur if the system is unstable.

In other international jurisdictions inertial response is a mandatory service and as the penetration of renewable generation increases, the deadbands are tightened to ensure that frequency change is arrested more rapidly (e.g. ERCOT). This would suggest that if deadbands were set appropriately in the NEM, then there would be no requirement for the newly proposed inertia service from synchronous generators.

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Inertia is not a Selective Service

In order to provide inertia a synchronous generator must be connected and operational. Inertia is not a service that an operator can opt or chose to provide. If they are connected to the system and operating, then they will be providing inertia, whether they intend to or not. It is not possible to provide a service this week and then not next week, unless the plant is disconnected or un-operational. The time required to bring a large thermal plant, particularly coal, online is significant. Additionally, how will AEMO differentiate between plant providing the new Inertia Ancillary Service and plant not contracted to provided such a service, but delivering inertia anyway, since it is connected and operational? The former plant would be paid and the latter plant would not be paid for delivering exactly the same inertial response.

For this reason, inertia provision should be a mandatory service and the issues around deadband settings need to be resolved and a mandatory requirement to deliver inertia, within specific deadband settings, is likely to be the best route to delivering frequency control at least cost. If there is still a shortfall in “inertia” then the requirement for an inertia market should then be reviewed, but it would be preferable to create a “frequency control service”, which is technology neutral, rather than an “inertia” service, which is not.

Frequency Control not given Priority

Frequency control is not given priority over energy dispatch. The work of the AEMO AS-TAG and their consultant Digsilent has indicated that the operators of large thermal generators have the *perception* that tight governor control limits their ability to accurately meet dispatch targets. Given the recent penalties levied against owners of synchronous plant for failure to meet dispatch targets by AER, the market prioritises energy dispatch over system stability.

While there is no strong evidence from synchronous generators that there is a cost to providing an inertial response via tight deadbands, either in terms of impact on equipment or market implications, the fact is that now deadbands are wide and the vital inertial response in the electricity system is much reduced.

If the unintended market signal provided by prioritising dispatch is resolved, then synchronous generators may return to tight deadbands, reducing the need for any new market for inertia services.

A new Inertia Market sets a precedent

The perception that dispatch of energy is of more importance than frequency control must be resolved urgently. However, given the current fact that inertial response is reduced due to the widening of deadband settings and this is having impacts on system stability and is evidenced by increasing FCAS costs, it is clear that we need to value this inertial response. Whether that valuing is a simple engineering recognition that the inertial response available via governors is necessary to support a stable system or a valuing in dollar terms, the creation of a market for inertia services, will unavoidably send the signal that this is a paid for service. Having lost access to inertial response it is difficult to see how this response can be returned without now paying for it.

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In other jurisdictions it is a mandatory requirement that any large synchronous generator must provide inertia as part of gaining a connection to the system and/or participating in the energy market. In most locations the mandatory service is remunerated and in some locations not.

It would be far better to resolve the issues around governors and deadband settings to ensure delivery of inertia, than to create an entirely new market service. The discussion on remuneration for mandatory requirement for specific deadband settings is another consultation, but it is a discussion that should be had prior to any development of a new inertia service.

Obligations on Renewable Generators

Newly connecting non-synchronous generators are currently being required to provide some sort of frequency response as part of the technical requirements for connection. If AEMO and AEMC are going to require (mandate) frequency control from non-synchronous plant, then it would be consistent to require the same technical delivery from synchronous plant. There is a requirement on synchronous generators to have a “capability”, but a capability is distinct from an actual ability to deliver frequency control.

The current technical requirements for non-synchronous generators do not reward the generator for the provision of frequency control, that is, it is not remunerated, but it is an investment that the generator must make to access a connection.

However, if you are a synchronous generator, the proposed new inertia market seeks to reward the generator for a service that is mandatory and unrewarded for non-synchronous plant. All generators, regardless of type, synchronous or not, should be treated fairly and equally.

Cycle of Assessment of Inertia too short

AEMO will assess inertia requirements for the minimum and secure operating levels annually and require TNSPs to then service those levels within 12 months. Investment in assets that will support inertia (principally synchronous condensers for a TNSP or potentially a battery depending on whether FFR is permissible) are not via RIT-T, but the costs will be directly passed through to end customers.

Since inertia is only likely to diminish with time, this means that the TNSP will need to increasingly invest in assets to support inertia in the regions.

TNSPs are not allowed to anticipate or “over-size” an asset, which means that inefficient (more expensive) outcomes are highly likely, since the TNSP will have to invest in assets annually to deliver exactly inertia required (CAPEX) or may purchase a service from a third party (OPEX). If the assets count towards the asset base, then CAPEX approaches will be favoured.

It is likely to be far more cost effective to allow some degree of over-sizing to ensure that assets are ready to meet regional requirements. This may have a stranding risk, but given the adopted requirement (Finkel Review) for all generators to give at least 3 years notice of closure, this should provide a much better lead time and understanding of future changes in inertia.

TNSPs will be restricted from earning an income from any asset delivered to meet minimum and secure operation levels of inertia, even if this might mean the asset was delivered to the customer at a lower

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cost. Since the minimum and secure level of inertia are required to meet islanding requirements, when the region is not an island, the assets are idle – this is an inefficient use of system assets. Or the TNSP may fund a synchronous condenser to meet other operational requirements and may provide inertial support using the same asset. The TNSP should be able to earn additional revenue from providing inertia and we are concerned that the proposed mechanism to fund the new Inertia Ancillary Service will negatively impact on TNSP revenue, particularly that redistributed to end customers.

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Response to Questions

In as much as this is not a consultation about *whether* there should be a new Inertia Ancillary Service, since that decision already seems to have been made, this is a consultation about the mechanics of how such a service would be *delivered*.

We do not agree that a new Inertia Service is required at this particular time.

There are many other inter-related issues that should be addressed first, not least the issue of frequency control via deadband and governor settings in the current incumbent large synchronous fleet. This is particularly true if the AEMC and AEMO wish to deliver system security at the least cost to end customers.

The approach proposed will not deliver a stable system at lowest cost to the end customer.

There are other more cost-effective and efficient approaches to creating a stable system that should be actioned before the creation of *any* new frequency service, including FFR.

Question 1

Do you consider a market sourcing approach to be preferable to a TNSP incentive scheme for providing inertia? There is no need for a market sourcing approach if the issues with frequency control are resolved. There may not be a need for a TNSP incentive scheme if the issues with frequency control are resolved. Both approaches are only needed if activating the available inertia (via governors) does not provide enough inertia in a particular region/sub-region.

If so, do you consider the use of IRSR funds accruing as a result of RoCoF constraints to be an appropriate mechanism for funding inertia payments? No comment.

Question 2

Do you consider any of these alternative methods of payment for inertia to be preferable to the proposed IRSR funding approach? No comment.

Are there any alternative funding arrangements that are not discussed, which you would consider to be preferable? No comment.

Question 3

To what extent would the proposed IRSR funding approach diminish the effectiveness of SRAs as an inter-regional hedge? No comment.

Do you agree that inertia hedges could be used to assist with inter-regional hedging and would this provide increased certainty to providers of inertia? No comment.

Question 4

To what extent do you see there to be a need to address inter-regional RoCoF constraints versus intra-regional RoCoF constraints or other types of constraints? No comment.

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Question 5

What do you see as the main concerns with TNSP participation in a market sourcing approach? How can these issues be resolved? If TNSP participation delivers system stability to end customers at least cost, then TNSPs should be able to participate.

Question 6

To what extent do you see it as desirable to co-optimise inertia with energy and FCAS through the NEM dispatch process? Inertia is either there or not there, FCAS comes after inertia. If the inertial response was properly enabled, through the mandating of deadbands for large synchronous generators, then there would be no requirement for a new inertia service, no immediate requirement for a FFR service (although it will need to be developed so that it will be ready as inertial response falls) and likely less requirement for high cost FCAS services. The wider frequency control issues (e.g. deadbands) need to be resolved *before* creating any new frequency-related services.

Question 7

Do you see a need to delay implementation of the proposed IRSR funding approach? No comment.

If so, do you see value in adopting an alternative funding approach in the interim? No comment.