Government of South Australia
Department of State Development

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Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

System Security Market Frameworks Review – Interim Report

Dear Mr Pierce

The Energy Markets and Programs Division of the Department of State Development, South Australia (Division) considers the Interim Report (Report) on the System Security Market Frameworks Review (Review) as a positive step in the progress towards reaching the most suitable regulatory framework to meet current power system challenges in the wake of increasing levels of non-synchronous generation in the National Electricity Market.

The Division appreciates the comprehensive analysis taken by the Australian Energy Market Commission (AEMC) to deal with the complex-inter-related issues raised by the rule change requests. However, the Division sees a pressing need for the AEMC to finalise this work as a matter of urgency to provide the necessary flexibility in regulatory and market frameworks to manage the current system security challenges.

Referring to the package of rule change requests submitted by the South Australian Government on 12 July 2016, the Division wishes to emphasise the importance of the component of establishing a system standard for the Rate of Change of Frequency (RoCoF) to determine the optimum capacity to return the system to a secure state after a contingency event. Establishing a RoCoF standard is thus considered critical for the interrelated work conducted by the AEMC in processing the two South Australian rule change requests for the design of new or modified Emergency Frequency Control Schemes, currently in the Draft Determination stage, which fall within the AEMC's system security work program.

Please find attached a submission on the Report where the Division is providing feedback to assist with achieving the aim of the Review. Should you wish to discuss any of the content of the submission, please feel free to call Ms Rebecca Knights, Director - Energy Markets and Programs Division, on (08) 8226 5500.

Yours sincerely

Vince Duffy
EXECUTIVE DIRECTOR
11 February 2017

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SOUTH AUSTRALIA

System Security Market Frameworks Review

Submission to Interim Report

Energy Markets and Programs Division, Department of State Development

South Australia

February 2017

EPR0053 – SYSTEM SECURITY MARKET FRAMEWORKS REVIEW

The Energy Markets and Programs Division of the Department of State Development, South Australia (Division) generally supports the direction the System Security Market Frameworks Review (Review) is taking, as demonstrated by the Interim Report (Report) in addressing the range of challenging issues, technical solutions, costs and procurement options.

Acknowledging the fact that the Australian Energy Market Commission (AEMC) aims to deliver policy changes that are strategic in nature, the Division wishes to see delivery of solutions for the current system security challenges as a matter of urgency. While the unique situation in South Australia is considered only a first in the overall National Electricity Market's (NEM's) energy transition to a low emissions future, it may be a matter of time before the rule change requests submitted by the South Australian Government and covered by the Review become more relevant in other jurisdictions, albeit at different points in time as the need arises in each jurisdiction.

System Challenges

The Division agrees that the two main challenges associated with the transition to greater levels of non-synchronous generation, high rates of changes of system frequency in a low inertia system and localised reductions in system strength are key starting points to identify and develop solutions.

For the management of frequency in a low inertia system, it should be acknowledged that this only is an issue under two conditions:

(a) A sudden disturbance as a result of a non-credible contingency event that would result in a high Rate of Change of Frequency (RoCoF), usually when a region is abruptly separated from the NEM, as a strongly connected NEM would almost always have adequate inertia to dampen the sudden effect of such disturbances; or
(b) Deficiency in resources in controlling frequency when a region is operating as an electrical island with low inertia, usually after separation from the NEM, as the NEM would always have sufficient Frequency Control Ancillary Services (FCAS) to arrest, stabilise and recover frequency after a contingency event as well as provide frequency regulation in response to small changes in demand and supply as required by the central dispatch system.

For the above conditions, it is essential to define the non-credible contingency events to be covered by any policy changes so that risk-cost trade-off can be assessed. Current work by the AEMC to define such events as 'protected' events, where several measures are designed to be in place to protect against the consequences of such events, should put this system challenge in perspective when designing and implementing solutions. This step will pave the way to establish market and regulatory mechanisms to enable the provision of inertia or Fast Frequency Response (FFR) services.

For the management of system strength, both the reduction in synchronous generation and the increase in inverter-connected generating units (more recent wind turbines, solar PV, battery storage and HVDC) at certain points in the grid are main sources of having 'weak' spots with low contribution to fault currents. As this issue is anticipated to appear anywhere in the NEM fairly quickly with the jurisdictional low emissions policy changes and rapid rise in inverter-connected generation technology, it is important to have the most appropriate regulatory mechanisms to deal with it.

In addressing this challenge, system strength should not just be addressed only at new generation connection time but needs to be maintained as the conditions of the power system change with some types of generators retiring and other types taking their place.

Technical Solutions

The Division agrees that the technical solutions proposed by the AEMC to address system security following a contingency event are based on the following three factors:

(a) Minimising the initial RoCoF by either the introduction of constraints in the automatic dispatch process of the power system to reduce the size of the contingency or the provision of extra inertia by utilising synchronous generators/condensers to increase system inertia;
(b) Increasing the capacity to return the system to stability by obtaining Fast Frequency Response (FFR) services that exhibit a time delay but operate within a shorter timeframe than the current fastest FCAS specification of six seconds, including schemes that shed load or generation; and
(c) Enhancing the tolerance of the system by imposing additional obligations on generators to withstand higher RoCoF.

With regards to the provision of extra inertia, the costs of different measures need to include all market implications. For example, similar to the costs associated with introducing constraints in the dispatch process, the inefficient outcome of generators running to increase inertia (to minimise initial RoCoF) displacing other generators with lower marginal cost out of merit order, as dictated by operational restrictions such as minimum load and ramp rates. This may also have a nil effect on inertia if one generator providing inertia replacing another generator placed high in the merit order that is also providing inertia.

It is important to add, relevant to this discussion, the possibility of running generators in synchronous condenser mode as another solution besides stated solutions of running synchronous generators or condensers. This solution is usually achievable by decoupling the turbine (prime mover) from the generator using an automatic 'clutch' mechanism. If the retrofitting of plant to achieve this mode of operation is feasible and given the appropriate regulatory framework, this could be an attractive market-based ancillary service for 'peaking' generators, as no power output is injected into the network.

Following attempts to reduce initial RoCoF by having a base level of inertia, FFR services can be a valuable resource in the first few seconds to give more time for fast FCAS services (6 second response) to be effective.

As mentioned in the Interim Report, some inverter-connected generators or HVDC are capable of providing FFR. However, a holistic approach needs to be followed to achieve the desired outcome. For example, the ability of a wind turbine to inject power immediately after an under-frequency event for a short time as a form of FFR has been discussed in recent literature[1] and applied within few overseas jurisdictions. Although there is merit in maintaining the level of active power supply

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[1] DGA Consulting, 14/10/2016, International Review of Frequency Control Adaptation (a report prepared for AEMO)

(synthetic inertia) immediately after an event, studies have shown that such response from individual generators is also followed by a short period of active power recovery, depending on the wind speed at the time. If the proportion of wind generation at the time is high, collective slower recovery of active power could have a detrimental impact on system frequency unless some other form of synchronous generation or power injection takes place and fills the void. Hence, the custom design of a coordinated scheme for active power recovery post disturbance should be dependent on the specific nature of the power system and how all assets connected to the grid respond to disturbances at different response times after the disturbance.

In relevance to this discussion, following the principle of technology neutrality in not discarding any technology from providing solutions, the modification of active power control systems of synchronous generators should be considered to provide FFR. This faster response is possible by adding a 'boost' function that is triggered by a frequency level or RoCoF signal to force the speed governor to provide a rapid boost in MW output by accelerated opening a control gate in a hydro turbine or a valve in a steam turbine (for example), usually to full load. This methodology is adopted in some jurisdictions to provide frequency control within the first two seconds of a contingency event occurring and it is up to the provider of the service to leave some headroom in generation to provide an ancillary service as compared to generating at full load.

With respect to utilising interruptible load (also known as demand response) to provide FFR services, some jurisdictions (such as New Zealand) are benefiting from load as a source of fast instantaneous reserve to help arrest frequency within the first second of an event using under-frequency relays. Load may also be valuable resource if the detection of protected events (rather than detecting system frequency) can trigger reduction or shedding of load in a matter of hundreds of milliseconds. This methodology is currently adopted in Tasmania under Special Protection Schemes to reduce constraints and maximise power transfers.

It is also a matter of high priority to consider tightening the normal operating frequency band, thereby improving the ability of the system to return the system to a secure operating state following a contingency. Following completion of the emergency frequency control rule change, it is expected that the AEMC will include in the terms of reference issued to the Reliability Panel for reviewing the Frequency Operating Standards (FOS) the reintroduction of the original tighter normal frequency band of 49.9 Hz to 50.1 Hz.

With regards to system tolerance, imposing additional obligations on generators will largely depend on accurate modelling of the system post-disturbance, which should determine the optimum settings for generators to remain connected after a disturbance resulting in high RoCoF. It is then important for the industry to agree on settings that would not adversely affect plant protection systems for generators. However, it is acknowledged that the timing of the introduction of arrangements will need to be carefully considered depending on the degree of penetration of inverter-connected generators in each jurisdiction so that the market is not impacted unnecessarily. In South Australia, this is a pressing issue and currently the Essential Services Commission of South Australia (ESCOSA) has started an inquiry (initiated in July 2016) into the licensing arrangements for inverter-connected generators to address the problem on a local basis in the interim.

Costs

In finding solutions to address system challenges, it is vital to consider the inter-relationship between services. The outcome of AEMO's system studies will likely determine the optimum mix of solutions to be deployed. This may have direct implications on the costs of procuring each type of service. For example, the setting of initial RoCoF at a high level (hence lower cost as compared to targeting a low level) may mean higher cost in increasing the capacity to return the system to stability by using FFR or enhancing the tolerance of the system to withstand higher RoCoF, and vice versa. This is related to setting a RoCoF standard discussed later in this paper.

Options

The Division considers that the range of procurement options for additional services stated in the Report covers in concept all possible mechanisms.

It may be beneficial for the AEMC to investigate market-based solutions considered by other jurisdictions for the procurement of ancillary services, such as inertia and FFR.

For example, the ongoing development attempts by the Electric Reliability Council of Texas (ERCOT) for Synchronous Inertia Response Service (SIR) is based on SIR supply and demand curves to determine a clearing price for an inertia service and other manual processes if a market-based solution is not met. The SIR is part of ERCOT's work on revising the ancillary service market (as a result of operational challenges from running the highest penetration of wind generation in USA) and includes other products such as FFR.[2]

With regards to the FFR service mentioned in the Report under the five-minute dispatch option, it may be useful to assess the option to integrate the FFR service as a new product in the existing FCAS arrangements with a 1 to 2 second response time for both raise and lower markets.

ERC0214 – Managing Power System Frequency

The rule change requested by the South Australian Government questions the suitability of current rules for AEMO to procure a broader range of ancillary services. In particular, amending Chapter 3 of the NER to allow AEMO to manage emerging security challenges, such as high RoCoF or low fault levels, and enable AEMO to develop guidelines for the acquisition of these services. These provisions have been largely explained in the Report.

However, the requirement to have a RoCoF standard needs to be clear. Hence, the Division emphasises the importance of establishing a RoCoF standard including a maximum limit that all generating assets connected to the grid can sustain and beyond which loss of all total generation could occur. Whether the Reliability panel or AEMO sets the RoCoF standard, clear criteria of setting the RoCoF standard will assist in the management of power system security and will help clarify the responsibilities of AEMO, Network Service Providers and market participants. A set limit or operating range for RoCoF will inform how the capacity of the system to return to a secure operating state is managed, whether for developing options for the procurement of the required additional

[2] https://www.ferc.gov/CalendarFiles/20140421084800-ERCOT-ConceptPaper.pdf

system security services or designing the emergency frequency control schemes as the last line of defence to control frequency.

ERC0211 – Managing Power System Fault Levels

In the Report, the issue of system strength seems to be considered as a consequence of a solution to provide inertia. As system strength is a localised issue that is not necessarily associated with the discussion of high RoCoF, which is most likely to occur following a non-credible or a 'protected' event, some options geared more for providing inertia or FFR may be constrained by the requirements of system strength, and vice versa, and result in a less than feasible, or no, solution. Hence, looking at system strength as a separate issue (similar to voltage levels) may be more prudent as it will dictate the option of procurement in certain cases. For example, this may be the case if an ideal solution for inertia may not resolve the issues with system strength in certain network locations. Alternatively, the choice of a generator on the upstream path of an interconnector for system strength purposes is not ideal for inertia if the transmission loss through the interconnector occurs downstream from where the source providing inertia is located and the generator is cut off from providing inertia to the islanded region.

As per AEMO's preliminary advice to ESCOSA[3], the problem with reduction in system strength in particular parts of South Australia may be exasperated by the connection of a new inverter-connected generator due to the low contribution to fault levels at certain 'weak' points in the network.

In this regard, the introduction of allocated responsibility for fault level contribution should not be regarded as to impede the connection of non-synchronous generation because of its performance characteristics being different from conventional generation. However, a standard for a minimum fault level contribution should be based on the premise that any new connection should not rely on the 'strong' characteristic of a point in the network to meet performance standards. Otherwise, the next generator connection at that point may have to compensate for past issues.

Hence, the contribution to system strength following a fault should be based on the concept that every new connection is responsible for sharing in the operability and security of the network (similar to maintaining acceptable levels of voltage, power factor or reactive power) rather than being allowed to degrade network performance during and after a contingency event.

A real example of a post-contingency direction by AEMO for synchronous generation to run because of low system strength was evident following an incident on 13 November 2016 where the South Australian power system might not have been operating in a secure operating state with only one synchronous generating unit in service. A market notice[4] following that incident published by AEMO stated an interim solution for improving system strength requiring AEMO to put a contingency plan in place to ensure sufficient fault level available for wind generation and dynamic reactive support

[3] AEMO's preliminary response to ESCOSA on 9 September 2016 can be found at http://www.escosa.sa.gov.au/ArticleDocuments/1046/20161202-Inquiry-InitialAdvice_WindFarmAndInverterGeneration-AEMOLetter.pdf.aspx?Embed=Y

[4] Notice was published on 2 December 2016 at http://www.aemo.com.au/Market-Notices?currentFilter=&sortOrder=&searchString=56089. According AEMO's website, a review and report of the incident is targeted to be published on 28 February 2017.

plant to run. This example highlights the consequence of such measures as a constraint on the system that could be avoided if generator obligations are put in place to enhance the tolerance of the system irrespective of the presence of risk of a high RoCoF event.

In conclusion, a solution of imposing tighter localised generator obligations is based on the principle of allocating the risk to the parties best placed to manage them rather than a centralised solution where an intervention or constraint in the market would most likely bear a higher cost, as demonstrated in the above discussion.