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Submitted electronically via AEMC web-site

10 February 2017

System Security Market Frameworks Review: Interim Report

Delta Electricity welcomes the opportunity to contribute to the AEMC's consideration of market frameworks for incentivising the provision of system security services. Delta operates the Vales Point Power Station situated on Lake Macquarie in NSW and has 18 years' experience in operating and developing generation in the NEM. As a wholesale market generator, Delta values a secure and reliable power system in which to operate and acknowledges that with the changing mix of generation technologies there is a need for an enhanced system security market framework that enables cost effective provision of voltage and frequency rate of change suppression services.

Delta has observed a trend of increasing frequency events over the last three years, as covered in Attachment 1, which points to a material change in the way the power system is operating. This raises concerns about the ongoing security of the NEM and adverse operational effects on highly responsive generators like Vales Points. Delta is hopeful that the AEMC review will lead to an improved competitive system security framework reflecting the COAG Energy Council's view that security and reliability of electricity supply is paramount[1].

In relation to potential procurement options, Delta strongly supports the AEMC pursuing a separate market design that recognises the full value of system security services provided by conventional synchronous plant. Option 4 (b) best meets the guiding principles and has the advantage of full supply/demand and price transparency that enables risk mitigation through hedging as well as efficient co-optimisation between fast frequency response and inertia markets.

Delta also supports the inclusion of voltage change system strength considerations within the market framework review. However, Delta does not support the inclusion of system strength in the consideration of the design of a market mechanism for inertia services. The technical characteristics of inertia and voltage control differ significantly and it is more appropriate that separate mechanisms be employed for each service.

Preferred Procurement Option 4 (b)

The proposal that best meets each of the objectives of the assessment framework is Option 4(b), which is a dispatched market with prices set by participant bids through a separate dispatch process. The key feature of this approach that sets it apart from the other proposed options is the transparent discovery of supply, demand and prices through dynamic supply side bidding. This market feature maximises competition and innovation to ensure that the lowest cost services are provided.

[1] Independent Review into the Future security of the National Electricity Market – Preliminary Report, December 2016.

Importantly, a dispatched market also enables real time co-optimisation between fast frequency response services and inertia services. Efficient co-optimisation between the two services, which to an extent are interchangeable, will provide demand and price signals that will drive investment. From an equity standpoint, costs should be borne by the market participants that contribute to the demand for the service. This is analogous to the causer-pays approach currently operational in the FCAS markets. Such an arrangement would require the causer-pay calculation to be undertaken in real time to allow exposed market participants to respond quickly to price excursions. A half-hourly spot price with a liquid secondary contract market will allow market participants to hedge their risk.

Other Mechanisms

Both Options 1(a) and 1(b) are less transparent and less competitive forms of option 4(b) which could create substantial inefficiencies for the system and risks for project proponents. A lack of transparency will reduce competition and, depending on the generator obligations, could lead to over investment in services. Both of these options will necessitate the specification of minimum inertia capability at the plant level. It is possible that as the proportion of non-synchronous plant increases across the NEM, minimum standards may need to increase. This will place an increasing financial burden on new plant that will stifle investment.

As synchronous generators retire it will be necessary to reassess the level of service provision from each generator to ensure that system security is maintained. This would create the risk that generators would need to construct additional physical plant to supply the service or contract for additional services. This creates substantial uncertainty for a generator that would be impossible to manage and plan for, and would likely lead to unnecessary costs to consumers through either over-building inertia capacity or inflexibly contracting capacity at a time of tight supply. Options 1(a) and 1(b) also raise the question of which type of service, synchronous inertia or fast frequency response, is required and to what level. A centralised regulatory process would need to be established for these services that would be difficult to apply equitably over time as technologies evolve.

Options 2 and 3 require direct procurement by AEMO and/or a TNSP. Whilst an open tender provides a competitive procurement process, the task of efficiently determining the requirement and specification is problematic. A centralised procurement process, relying on modelled market projections, will tend to deliver an oversupply of services to cover the maximum possible future requirement. It is unlikely such an approach would satisfy the NEM objective and only result in higher than necessary costs. Without clear price signals, a direct procurement for fixed period service provision will favour less risky and proven technologies at the expense of more innovative solutions.

Options 2 and 3 also present much higher investment risk, unless contracts are long term. However, with changing market requirements long term investments are unlikely to be efficient. Accordingly, these options do not lend themselves to innovation or lowest-cost procurement as market dynamics and technologies are expected to continue to evolve. As regulated monopolies, TNSPs will have limited incentives to drive least cost outcomes and consumers will rely heavily on the AER to determine the appropriate level of expenditure for the services procured. Whilst AEMO is obligated to adhere to the National Energy Objective, the interpretation of this goal creates unnecessarily wide limits to what might be the most efficient service to procure. Furthermore, it will be difficult for these organisations to balance the cost of these services with the cost of energy provision in a reliable manner over the long term. This can only be done through market pricing incorporating supplier bids to enable price discovery.

Option 4(a), the inclusion of system security payments in the energy price via constraints, is not favoured because it emphasises the contingency constraints rather than the value of the services.

While a value is placed on inertia under this option, it results entirely from constraint equations. Calculating a value this way leaves the inertia providers as passive participants and does not promote competition or innovation through price discovery from the service suppliers. It similarly, does not enable risk to be allocated or mitigated at the provider level as there is no risk distribution or sharing process that can be applied when all participants are price takers.

Option 4(a) potentially incentivises the mitigation of contingency constraints through network solutions. This incentive arises because the pricing information from inertia providers that would be supplied through bids in Option 4(b) is removed. What remains is a direct link from the constraint to the price outcome. Particularly, when a transmission contingency event is the cause of the constraint, the inertia value would be more readily ascribed to the relief of the constraint than to the provision of additional inertia service.

Setting System Security Requirements

Delta understands that fast frequency response services are currently unproven at a large scale and will therefore provide limited support to synchronous inertia. Over time it may become appropriate to allow fast frequency response services to take over more of the role of providing system security services. This transition should be contingent on a thorough assessment of the performance of each type of fast frequency response technology in supporting system security. To facilitate this transition Delta supports the creation of separate markets for synchronous inertia and fast frequency response with oversight by a separate independent body charged with ensuring a smooth transition to a low carbon economy without compromising system security.

A conservative approach to setting the requirement for inertia and fast frequency response, which takes into account the N-1 principle and credible contingencies, should be considered if system security is paramount. For example, if an inertia market dispatched a 660MW synchronous unit to provide inertia, there would need to be sufficient supplemental inertia available to cover any unexpected trip of that unit.

Delta looks forward to engaging further with the AEMC on system security issues. If the AEMC wishes to discuss this submission, please contact Peter Wormald on (02) 4352 6425 or peter.wormald@de.com.au.

Yours faithfully,

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Attachment 1: Technical Observations of the Current System

Delta Electricity has observed an increase in the number of system frequency events, outside the normal operating frequency band, since 2014 (see Table 1). In these observations, the large increase in the number of detected events where frequency is outside the normal band does not appear to be associated with contingency events.

Table 1: Frequency Event Statistics as Observed at Vales Point Power Station

	Number of events (>0.15Hz deviations as detected by Vales Point recorders)	Number of Events (>0.2Hz) required by the FCAS Spec. to be assessed	Percentage of time outside normal band
11/12	71	19	0.033 %
12/13	91	34	0.032 %
13/14	84	18	0.020 %
14/15	309	34	0.078 %
15/16	872	61	0.237 %
16/17 Total (as at 1 Feb 2017)	1533	60	0.806%

Delta has observed that in controlling frequency using conventional regulation FCAS controls, AEMO's AGC system often determines that a load increase (above dispatched energy) is required when local frequency is already high or that a load decrease (below dispatched energy) is required when local frequency is already low. These experiences, which have been typically observed to occur 10-20minutes per hour in the observed periods, are concerning and suggest the overall dispatch and regulation FCAS control is becoming less stable.

As the number of events continues to increase, it is possible that the underlying cause could become a threat to system security. Some possible causes for the increase in deviations include:

- increasing unscheduled demand reductions;
- increasing intermittent generation;
- reduced automatic FCAS provision by large generators;
- a mismatch in frequency measurements between AEMO's AGC and generators;
- increasing non-scheduled generation; or
- a combination of factors including those listed above.

It is likely that further withdrawal of conventional synchronous plant from the market will increase frequency deviations which could pose a threat to system security.