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Dear Frank,

Infigen Energy welcomes the opportunity to make a submission in response to AEMO's Future Power System Security Program (FPSS) Progress Report published in August 2016.

Infigen Energy (ASX: IFN) is an Australian Securities Exchange listed specialist renewable energy business headquartered in Sydney. Infigen Energy is the largest owner and operator of wind energy facilities in Australia (557 MW) with six major wind farms in Australia capable of producing approximately 1,500 GWh per annum. Infigen also has a significant pipeline of Australian solar photovoltaic and wind development opportunities.

The focus of the report is South Australia (SA) due to the significant challenges in that state in the near future compared to the other jurisdictions in the NEM. Infigen is a significant stakeholder in SA with the Lake Bonney wind farms and has a strong interest in maintaining power system security in SA while contributing to a low carbon economy.

In the report, AEMO has identified four high priority areas that are the current key focus of the program:

- Frequency control;
- Management of extreme power system conditions;
- Visibility of the power system (information, data, and models);
- System strength

Infigen appreciates AEMO's timely investigation into these focus areas and provides feedback below.

Frequency Control

The report repeatedly references the change in SA's generation mix, specifically the reduction of synchronous generation (less inertia) in the system as the main cause of the emerging security challenges. To some extent system security challenges are also being linked to a higher penetration of renewables in SA combined with the retirement of the Port Augusta and Northern Power Stations (Flinders Power Stations).

The ability of the current Energy and FCAS markets to cost effectively maintain system security has not been adequately explored in this report. This is possibly due to market design obligations residing within the jurisdiction of the AEMC rather than AEMO. However it is indisputable that the outcome of AEMO's operation of the SA FCAS market within the last 12 months has resulted in the market incurring substantial FCAS costs in

the order of \$50m (just in SA) yet still not being capable of reliably delivering an adequate system security when required, most notably during the asynchronous operation of SA on 1st November 2015. This is based on the use of a new operating procedure sourcing an additional 35 MW of regulation services from within SA on a pre-contingent basis, before and not after, the occurrence of a single contingency that would effectively island the SA. In essence adopting this revised mode of system operation and not relying on the six contingency markets within SA to manage a possible separation on a post-contingent basis is perhaps the most expensive alternative.

As defined within the NER, frequency regulation is a service designed to correct in real time small frequency deviations that arise from supply and demand imbalances in the system. This is managed by the Automatic Generation Control (AGC) of the generators registered to participate in the market. Procuring regulation FCAS on a pre-contingent basis, as AEMO has been doing since October 2015 in SA is unprecedented and questionable for a few reasons.

Firstly, the purpose of regulation FCAS is not to keep a certain type of generator online.

Secondly, post-contingently and in the event of a separation of SA from the rest of the NEM, contingency services provide the necessary service to bring frequency back to normal operating standards and only after frequency is within the normal operating bands will regulation will be required.

Thirdly, AEMO claims there are insufficient synchronous generators online in SA to successfully return the SA network to a secure operating state following a separation event¹, but it has not supported this claim with facts, analysis or evidence. Furthermore, and despite the retirement of Northern Power Station back in May this year, SA has so far always operated with the supply of synchronous generators. Nonetheless, AEMO continues to apply this new operating procedure, which comes at a very high cost. The limited number of FCAS providers together with a MW target separate from the dynamic limits of the network, has meant that the predictability of the market can be exploited with prices being driven high, with no ability for negatively affected participants to respond.

The events of October and November 2015, when Electranet planned outages removed from service one circuit of the Heywood interconnector, have been extensively discussed and reported on. However, there have been more recent planned outages in Victoria which have resulted in AEMO's pre-contingent of regulation services that have cost the market over \$7 million each time (over a 3 day outage) without delivering any apparent cost effective benefit. There have been no studies or analysis provided to participants which demonstrate the need for the service. AEMO's assumption of limited or no availability of synchronous units is inconsistent with the observable operating regime of synchronous generators in the state. Despite this, AEMO continues to pre-procure regulation FCAS in SA at a very high cost to generators and customers alike.

Another area of improvement is the actual design of the frequency regulation market which allocates and recovers costs based on historical performance of a generator rather than allocating and recovering costs on a real time basis, as is the case with the energy and contingency ancillary service markets. Semi-scheduled and non-scheduled wind farms are assessed against an assumed linear trajectory to targets sent to each generator by AEMO. In relation to semi-scheduled wind farms these targets are derived from the Australian Wind Forecasting System (AWEFS) and have been erroneous for a long time resulting in a declared scheduling error. Furthermore the obligation of semi-scheduled wind farms to follow a linear trajectory to the AWEFS target at the end of each dispatch interval is in complete contradiction with the semi-scheduled generation principles within the NER. The principle of the semi-schedule generation rules are that

¹ <https://www.aemo.com.au/-/media/Files/PDF/NEM--Market-Event-Report--High-FCAS-Price-in-SA--October-and-November-2015.ashx>

generators (wind farms) are able to generate according to the variable fuel resource (wind) when there are no network constraints active. When constraints are active semi-scheduled generators must generate at the target or below the target. However, under the causer pays procedure, semi-scheduled generators are penalised by not meeting the linear trajectory to the target (at all times) they aren't obligated to follow under the Rules.

Additionally the prospective nature of allocating causer pays factors for the recovery of regulation ancillary service charges prohibits generators from responding in real time to system requirements and does not reflect the extent in real time to which a generator or load contributed to the need for the regulating FCAS service for which they are being charged. Causer pays factors are based on a historical 28-day measurement period. There is nothing a generator or load can do in this respect to mitigate or improve a frequency problem happening in real time.

Rates of Change of Frequency (RoCoF)

Infigen recognises this as an issue but believes that it has not been sufficient research to determine whether this is a current or only a potential issue.

AEMO states that '*High rates of change of frequency (RoCoF) will lead to additional tripping for the same size imbalance*'. Infigen that the RoCoF may increase for the same size imbalance with less inertia, but whether this will lead to more tripping is currently unknown as the current performance of plant is unknown, according to AEMO.

AEMO has identified nine SA separation events since the market started in 1998. To determine if RoCoF is a real issue, for those events AEMO should undertake analysis to determine the amount of synchronous generation online, interconnector flows and load at the time, the cause of the outage that caused the separation and RoCoF following the separation (and if there was any mal-operation of mis-operation of plant or load shedding systems due to high RoCoF, if it existed).

In the assessment of RoCoF in Figure 5, AEMO has assumed that with the withdrawal of Northern, this generation would have been made up by increased imports from Victoria where in practice, in many intervals, this would have actually be more accurately reflected as reduced exports to Victoria. The increase in interconnector flows as well as the removal of synchronous generation hits the RoCoF calculation twice through increasing the size of the contingency and reducing the inertia. In SA, when there is a high import from VIC, generally synchronous generation makes up a larger proportion of the generation mix as this is a time when wind generation is also low.

Many wind turbines and inverters have current capability to provide a form of synthetic inertia (high speed short duration power response) but currently, there is no requirement to do this and no market driver as there is little financial incentive to participants. In fact, in many situations, the current forecasting and calculation of causer pays could actually penalise the participant.

Fast frequency response (FFR) services are possible using new technologies such as batteries but the actual requirement and actual required performance has not yet been quantified (or how these services will fit into the existing market systems). Further detailed examination is required.

Insufficient FCAS

Current FCAS market operation prevents (or makes it very difficult) for any plant excluding the traditional thermal generators from participating. Examples of this include the way dispatch instructions are received, possible power calculations, AGC signals and 1MW step size for offers and enablement. Increased competition is always desirable and AEMO should ensure that systems enable participation by current or future technologies. Biasing incumbent technologies limits the possibility of new technologies, more suited to a future power system, being steadily transitioned into the market.

Decisions to invest in new technologies are being distorted by the pricing signals currently seen in the FCAS markets. Decisions to invest in new technologies are being distorted by the pricing signals currently seen in the FCAS markets. This includes the significantly higher value of regulation markets over contingency markets and increased costs to semi-scheduled generation for being tied to AWEFS forecasts.

Over-Frequency Generation Shedding (OFGS)

A regulatory instrument already exists in the Performance Standards in *S5.2.5.8 (a)(2) - Protection of generating systems from power system disturbances*. This requirement has existed since the Performance Standards were introduced. At this stage, AEMO has generally (to the best of our knowledge) assigned the upper bound of the extreme frequency excursion tolerance limit (52Hz) as the standard. If AEMO's intention is to implement an OFGS scheme, AEMO should merely inform generators of the limit it wishes them to reduce generation.

Visibility

What is largely ignored is that some of the future challenges identified by AEMO could be reduced if errors in the wind forecasting system were fixed.

Wind generators have been impacted with a substantial error in the forecasting system for over four years (AWEFS scheduling error), unnoticed by AEMO. The magnitude of the error is in the order of hundreds of GWh of lost energy that needed to be sourced elsewhere. The error meant that wind farms were being dispatched at a lower level than it should have otherwise been and also in AEMO requiring more regulation FCAS than otherwise necessary. This is because the targets sent to the wind farms were oscillating up and downwards every 5 minutes due to feedback in dispatch. These targets were difficult to be met by the generator and contributing to the imbalance between supply and demand and increased need for frequency control. Inaccurate forecasting leads to deficiencies in the dispatch of energy and can result in an increase in the requirement for frequency control. An improved forecasting system will improve power system security by requiring less frequency regulation and smoothing overall system dispatch.

System strength

TNSPs have a requirement to operate the power system securely. If they have allowed connections at a standard which compromises other customers they should be held to account. Any investment required to resolve any of these issues should be at their cost rather than the participants. The cost of changes that have occurred as a result of a change in the system (e.g. – participants withdrawing) should be borne across all participants. A new entrant should not be made in any circumstance to provide support



beyond that required for its own connection, rather than to make up shortfall of the system.

Infigen has experienced connection enquiry responses which have identified the requirement for syncons upfront (rather than dynamic VAR control) to manage low fault levels and inertia on the network rather than just letting the connection occur and addressing network stability separately. It is essential that planning take place and be included into connection processes.

Conclusion

A larger question exists as to whether the Frequency Operating Standards are still applicable to current technologies. Increasingly consumer and industrial equipment are now more tolerant to frequency changes – e.g. variable speed drives, DC devices. There are wider operational bands in other jurisdictions (when separated) that still allow normal and secure operation of the network. Allowing slightly larger dips in frequency could also potentially reduce cost of contingent ancillary services.

What also becomes evident is the issues presented in the report seem disjointed from the respective market structure. Most of the proposed solutions or options are technical solutions isolated from the actual market it operates in. Power system security can't necessarily be fixed by looking at the technical aspects or implementing new technologies in isolation – there needs to be a holistic approach whereby the market system is considered in conjunction with the technical solutions for a fully functional and robust energy system.

Market design should anticipate a future with periods without synchronous generation. In such an environment it is critical that the market design encourages secure operation and fairly distributes cost amongst those liable. Integrating Regulation services into the real-time market and improving wind farm dispatch are examples of first steps that can be taken. Technical solutions are readily available but need an indication from the market as to how they will be valued now and in the future.

Infigen looks forwards to further engagement in the FPSS program. Please feel free to contact me directly in relation to Infigen's submission.

Yours sincerely,

A handwritten signature in grey ink that reads "Niva Lima".

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