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Merryn York
Acting Chair
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

20 August 2020

Dear Ms York,

System services rule changes consultation paper

AGL Energy (AGL) welcomes the opportunity to comment on the Australian Energy Market Commission (AEMC) System services rule changes consultation paper.

AGL is one of Australia's leading integrated energy companies and the largest ASX listed owner, operator and developer of renewable generation. Our diverse power generation portfolio includes base, peaking and intermediate generation plants, spread across traditional thermal generation as well as renewable sources. AGL is also a significant retailer of energy and provides energy solutions to over 3.6 million customers in New South Wales, Victoria, Queensland, Western Australia and South Australia.

The energy transition has increased the supply of electricity from asynchronous variable renewable energy (VRE) generators which have only limited ability to provide system services. While the supply of system services has reduced as some aging synchronous thermal generators have exited the market, and others are now more frequently offline due to competition from VRE generators. VRE generators have also increased the variability of supply and demand in the NEM which has increased demand for system services and led to a market operating closer to the reliability standard. As a result, there has been an increased need for market interventions from AEMO to ensure the adequate provision of system strength and operating reserves in the NEM, including system strength directions and the RERT, both of which were intended be last resort interventions rather than the regularly used mechanisms they have become.

The seven rule change requests included in this consultation paper are designed to ensure that there is adequate provision of system services and operating reserves in the NEM, and that the providers of these services are appropriately compensated. AGL supports that objective, since it is crucial for ensuring an efficient energy transition and an orderly exit of thermal generation plant. We also support the AEMC considering these rule changes in one consultation paper since it ensures the interaction between the various rules is fully considered.

We also note the highly technical nature of these topics. While AGL is supportive of implementing the appropriate services as soon as possible, it will also be important to understand the impacts through detailed design and market modelling of the impacts, before making a draft decision.

The first section of the attached submission discusses system strength and inertia and the TransGrid *Efficient management of system strength* and Hydro Tasmania *Synchronous services markets* rule change proposals. We discuss the extent to which system strength and inertia are compensated through the spot market, through system strength directions, and when provided by synchronous condensers. It then outlines why decentralised markets for system strength and inertia, and the ESB unit commitment for security mechanism, which use the forces of demand and supply to determine prices may not lead to efficient outcomes. Finally, competitive tender provision of system strength and inertia, which is consistent with the approach proposed in the 2016 AGL *Inertia ancillary service market* rule change request, is discussed.

The second section discusses operating reserves and the Infigen Energy *Operating reserve market*, Delta Electricity *Capacity commitment mechanism* and Delta Electricity *Introduction of ramping services* rule change proposals. We believe an operating reserves market is worth considering further, as it has the potential to incentivise investment in dispatchable or flexible capacity to complement the increasing uptake of variable generation. The specific design is likely to influence the costs of such a mechanism, and we make some comments below for the AEMC to consider further.

The third section discusses frequency control and the AEMO *Primary frequency response incentive arrangements* and Infigen *Fast frequency response market* rule change proposals. We indicate our support for new incentives for primary frequency response since mandatory primary frequency response is an imprecise mechanism which weakens investment signals for frequency response. We discuss the benefits of a fast frequency response market and suggest the AEMC explore opportunities to expedite this rule change request.

We look forward to the opportunity to discuss these proposed rules in more detail. If you have any queries about this submission, please contact Anton King on (03) 8633 6102 or aking6@agl.com.au.
Yours sincerely,

Chris Streets

Senior Manager Wholesale Markets Regulation

AEMC System services rule changes submission

System strength and inertia

Traditionally almost all generation units in the NEM provided system strength and inertia and therefore there was an abundance of these system services. With the growth of asynchronous generation, concerns have arisen regarding the provision and compensation of these services. We support the objective of modifying the NER to ensure system strength and inertia are appropriately compensated, since existing compensation mechanisms are inadequate which reduces investment signals for units capable of providing these services.

Spot market compensation

System strength and inertia when provided by synchronous generators are by-products of energy production and are therefore compensated jointly with energy in ordinary spot market dispatch (i.e. when directions are not required). As by-products they do not increase the cost of output and therefore they do not change the short-run marginal cost (SRMC) for a given level of output.

Typically, there is adequate supply of system strength and inertia in the NEM and they do not affect dispatch or compensation. When an undersupply of these services is expected, synchronous generators which supply these services are dispatched in priority to non-synchronous generators, either through the curtailment of wind or system strength directions. The effectiveness of the market signal provided is limited however as curtailment will only sometimes resolve the undersupply, and more commonly additional generation units are required to come online through directions, for which compensation is often inadequate. Nevertheless, by being dispatched in higher volumes due to the system strength and inertia they provide, synchronous generators do receive some additional compensation for providing these services. Asynchronous generators, which do not provide these services, will be dispatched less when these system services are required which provides a market signal that the demand for this capacity is limited. The greater the undersupply of system strength and/or inertia, the more it will impact dispatch, and the greater the market signal for synchronous generators to enter or remain in the market.

Directions compensation

When system strength directions apply, system strength and inertia are compensated as by-products of the provision of energy. Directions compensation however does not always equal the price a generator would receive if it offered its output to the market at a price which reflects its SRMC curve as it does not account for all aspects of SRMC and, since it does not account for the price impact of scarcity, it does not account for the long-run marginal cost (LRMC). As a result, directions compensation is often below the efficient market price and does not adequately incentivise plant which provides system strength and inertia to remain or enter the market.

System strength directions were designed as a last resort mechanism to ensure the necessary units for system security were available at dispatch. As a last resort mechanism, they were designed to be used infrequently and they therefore provide compensation based on the simple formula of the 90th percentile spot price over the preceding year, with the opportunity to seek additional compensation based on review of actual costs.

The appropriate cost should be based on the SRMC cost, which includes all opportunity costs, however past AEMO determinations on costs have excluded the opportunity cost of fuel. Ignoring opportunity costs weakens the allocative efficiency of the forces of demand and supply. For example, it is only by accounting for the opportunity cost of fuel that a generator will ensure it keeps fuel in reserve in order to operate in high demand periods.

A further deficiency with directions compensation is that it does not account for scarcity, even though the need for a unit to be directed online indicates that the supply and demand are tight for the services provided by that unit. In a competitive market a tight supply demand balance can lead to prices above the SRMC curve. These price spikes provide a scarcity price signal for new investment and are the efficient market price which should apply in these undersupply conditions. By excluding scarcity pricing, directions compensation does not ensure compensation reflects the LRMC and therefore it can lead to compensation below the necessary level to appropriately incentivise investment. This deficiency may not be able to be remedied however because the appropriate scarcity price would be very difficult to determine. Given the combinations of units which meet system security requirements for directions can be very limited (see below), the determination of compensation would need to be able to distinguish between price spikes due to ineffective competition and prices spikes due to scarcity, which would be very challenging.

Compensation for synchronous condensers

System strength and inertia as provided by synchronous condensers are compensated when they are installed and operated to support asynchronous generators and support the dispatch of those generators e.g. a wind farm with a synchronous condenser will be curtailed less and will receive more revenue by virtue of its provision of system strength. The compensation is imprecise however as other local competing generators may benefit from the system services provided, which is one of the reasons why AGL supports the proposed abolition of the 'do no harm' obligation. If a synchronous condenser is installed by a network, it will be compensated through the normal compensation frameworks for network infrastructure.

Decentralised market provision of system strength and inertia

One option for providing sufficient system strength and inertia investment and dispatch is a decentralised market-based approach which uses the forces of demand and supply to determine efficient prices. For example, a decentralised system strength and inertia market may incentivise a synchronous generator to stay online during the middle of a sunny day when high solar output is causing low spot prices but high demand for system strength. While over the longer term it may for example incentivise the conversion of retiring generation assets to synchronous condenser mode. However, while a decentralised market would drive system strength and inertia provision, the forces of demand and supply in a decentralised market for system strength and inertia are unlikely to lead to efficient market prices for the reasons outlined below.

A decentralised market for system strength on its own is unlikely to lead to efficient prices. Unlike energy, frequency, and inertia which can be supplied from other regions, system strength is a local requirement. A provider of system strength a few hundred kilometres up the network will not typically be a substitute or competitor to a local provider. As a result, multiple separate markets would be required for each region and each market may only have a few or even just one participant. In South Australia, there are only four owners of synchronous generator units and one owner of network synchronous condensers, and they do not all provide system services to the same area. Currently system strength provision in ordinary spot market dispatch is subject to competitive constraint since it is provided and compensated jointly with the provision of electricity. However, if specific system strength markets are created, these markets may have few participants and therefore may not have effective competition or efficient price discovery.

The geographic scope of an inertia only market would only be limited by the transmission network and would therefore not be restricted to a local region as applies to system strength markets. However, remediation of system strength shortfalls leads to increased inertia in the system, therefore an inertia market is likely to be undermined by any system strength remediation mechanism. Since systems strength must be supplied locally, system strength shortfalls will tend to emerge earlier than inertia shortfalls which can be overcome with contributions from remote synchronous units. The proposed fast frequency response market discussed further below in this paper and the emerging ability of batteries to provide inertia, may also lessen the need for inertia remediation.

It is not clear whether network synchronous condensers should be participants in a decentralised system strength and/or inertia market. Regardless network investment is a centrally planned decision rather than investment as a result of market forces, and therefore the risk of network synchronous condensers would create significant investment uncertainty for participants in a decentralised system strength and inertia market. For example, if decentralised system strength and inertia markets currently existed in South Australia the current installation of four network synchronous condensers by ElectraNet would potentially remove opportunities for compensation in these markets. In addition, synchronous condensers have a very low operating cost which means they would bid into a decentralised system strength or inertia market at very low prices, which may lead to inefficient price discovery if they become the main source of supply in these markets. It should also be noted that there are only a few synchronous condensers currently operating in the NEM.

In energy markets, the reliability standard is determined on the basis of modelling but the combination of generation units which can meet that standard is determined by market forces. This contrasts with system strength and inertia standards where AEMO determines the standard and the minimum acceptable unit commitment combinations are based on their own modelling of the power system. In three years there have been 27 versions of the *AEMO Transfer limit advice* publication which lists the acceptable combinations. There are only eight generators with four different owners included in the combinations for South Australia and only ten generators with five different owners in Victoria. While it may be argued that AEMO's assessment of the minimum acceptable combinations is conservative, it is understandable that system strength and inertia requirements must be determined down to the unit combination level given the local nature of system strength markets, and the blocky nature of system strength and inertia requirements (i.e. the fact that system strength and inertia are not improved through incremental increases in output, but through the commitment of additional synchronous generator or condenser units). As a result, the forces of demand and supply in a decentralised system strength and/or inertia market may not function as they would in most markets. Since incremental investment is not possible, a market for these services is likely to be characterised by an undersupply or oversupply at any point in time. In addition, the blocky nature of system strength provision would make it challenging to price these services marginally.

On the basis of these reasons, AGL considers the nature of system strength and inertia may make them unsuitable for provision through a decentralised market which relies on the forces of demand and supply to determine prices.

Unit commitment for security

The *ESB System Services and Ahead Markets* April 2020 paper identifies a unit commitment for security (UCS) option for the provision of system services. AGL has not made a full assessment of the merits of this mechanism however we encourage the AEMC to include consideration of this mechanism in this consultation process. We would support greater consultation on the proposed UCS and how it might specifically address system strength and inertia.

The UCS process requires participants to provide bids for each defined system service and also economic cost and operating information. We note that the bidding process may not be effective at determining efficient market prices due to the local few-participant nature of these markets and because the markets may be prone to investment uncertainty due to network investment, consistent with the decentralised market provision of system strength outlined above. Under the UCS mechanism the economic cost and operating information is designed to be used by AEMO to determine the least-cost out-of-market commitment should a security or reliability gap be identified. We consider that determining appropriate compensation in this instance will share the same challenges as system strength directions, i.e. accounting for opportunity costs which can be highly variable and accounting for scarcity which is very difficult to determine for markets with few competitors.

Competitive tender provision of system strength and inertia

AGL considers a centrally co-ordinated model for the provision of system strength and inertia services in the NEM with a competitive tender process for remediation (when a shortfall is identified) may be worthy of further consideration by the AEMC.

In our 14 May 2020 submission in response to the *AEMC Investigation into system strength frameworks in the NEM* discussion paper we outlined how this might operate when system strength remediation is achieved through network infrastructure and similar principles could apply for the provision of system strength and inertia through generation assets. The mechanism could operate in a similar manner to the provision of system restart ancillary services (SRAS) with the advantage that system strength and inertia requirements can be more accurately specified.

We proposed a similar approach for inertia only in our 2016 AGL *Inertia ancillary service market* rule change request, which suggested that inertia services could be procured on a competitive basis by AEMO, similar to SRAS. The rule change request specified that AEMO would:

- administer the market and determine the quantity of capacity to be contracted;
- determine the timeframe for the capacity to be procured (currently a three year timeframe for SRAS;
- be the responsible entity to conduct the tender/auction process;
- set any relevant terms and conditions and or any other relevant requirements associated with procurement; and
- complete any other relevant functions as necessary to ensure that the service contracted is reliable, contracted efficiently and competitively.

In the final determination the AEMC decided not to introduce the rule since it was in the midst of its *Frequency control frameworks review* and also because it considered the application of constraints by AEMO to manage low system strength issues in South Australia limited the market benefits that could be obtained through the provision of additional inertia.

We suggest that AEMO could assess system strength and inertia levels in the NEM through an ongoing transparent process which includes timely notification of forecast shortfalls and opportunities for market participants to access AEMO's whole of system PSCA models. Following the assessment, AEMO would conduct a competitive procurement process to obtain tenders from market participants with proposed remediation solutions to address the identified system strength and/or inertia shortfall. Ideally the procurement process would be technologically neutral, and therefore it would define the system strength shortfall without mandating the technology required to remedy it.

Proposed solutions could include:

- a commitment by an existing synchronous generator to operate at minimum generation or above as directed for a defined period (e.g. three years) and duration and frequency parameters
- synchronous condensers
- network augmentation
- batteries
- modification of a hydro unit to allow it to run in synchronous condenser mode
- conversion of a decommissioned thermal plant into a synchronous condenser
- any other technology that could address the shortfall

ERC0300 Efficient management of system strength (TransGrid)

AGL supports the abolition of the ‘do no harm’ obligation and a greater role for TNSPs in the competitive provision of system strength as proposed by TransGrid.

This position is consistent with the above analysis which suggests a centrally co-ordinated model for the provision of system strength and inertia services in the NEM with a competitive tender process for remediation may be a suitable model to ensure sufficient investment in system strength and inertia in the NEM, and also our 14 May 2020 submission in response to the *AEMC Investigation into system strength frameworks in the NEM* discussion paper.

We support the abolition of the “do no harm” framework as we believe it has been an inefficient framework for ensuring sufficient investment in system strength in the NEM. The uncertainty of cost and duration of connection, and challenges in coordinating approaches to address system strength, caused by the framework have been of particular concern as they have raised barriers to entry and stalled investment in new generation.

ERC0290 Synchronous services markets (Hydro Tasmania)

AGL does not support the introduction of a synchronous services market as proposed by Hydro Tasmania. The proposed rule is not technological neutral since it provides for the provision of system services by synchronous generators only, even though other technologies are able to provide these services including batteries and synchronous condensers. Further, decentralised market-based price discovery for system strength is not likely to lead to efficient prices since the markets will be local and have few participants and will therefore be unlikely to have effective competition, as outlined above. Finally, the proposed rule ignores the existing mechanisms for system services compensation which exist in the NEM.

Operating reserves

As noted by Infigen in its rule change request, operating reserves are capacity in an energy system that can be called on within a (short) timeframe to balance supply and demand in case there is a material change in market conditions which was otherwise unforeseen. Operating reserves ensure reliability when there is a disruption to supply (e.g. a sudden plant outage). While frequency control provides a reserve function, the term operating reserves typically refers to disruptions of a greater magnitude. Operating reserves are currently provided by increasing the output of generators which are already connected to the power system and by bringing new fast-start generation online.

The market price cap

The ability of the forces of demand and supply to ensure reliability and therefore operating reserves in the NEM is limited by the market price cap intervention. Nevertheless, a high market price cap has traditionally ensured the availability of adequate operating reserves in the NEM. The growth of VRE has however increased the variability of demand and supply, and there has not been complementary investment in flexible supply which can fill the gaps. The low marginal cost bidding of VRE generators has reduced prices across many price periods and the impact of this reduction in revenue has not been offset by an adjustment to the market price cap. Increasing fuel costs have also weakened the investment case for new capacity capable of filling these gaps in supply. Finally, the RERT, UNGI and other government interventions intended to remedy the shortfall have further contributed to the dampening of investment signals.

The ability of the NEM to adapt to increased variability has been limited because the market price cap intervention reduces revenue and investment signals for different generation types in different proportions. Flexible capacity generators which have a low capacity factor and receive most of their compensation from high priced periods above $300 (which only occur in less than 5% of trading intervals in the NEM) receive a high proportion of their revenue from extreme price spikes and therefore forgo the highest proportion of revenue due to the market price cap. This contrasts with other generators which receive a much smaller proportion of their revenue from extreme price spikes since they are designed to operate at much higher capacity factors and are more likely to be offline during extreme price spike (due to weather variations for VRE or due to plant outages for inflexible dispatchable generators). These generators also have a much lower SRMC and therefore recoup long run costs at much lower prices than flexible capacity generators.

Increasing the market price cap may improve reliability and increase operating reserves in the NEM, however it would increase the cost of electricity and increase risk for unhedged spot market participants, especially during plant and network outages and extreme weather events. In addition, rising the market price cap would increase revenue for all generators that may be online during extreme price spikes, including those that are ill-suited to providing operating reserves. Therefore, a remedy such as an operating reserves market which can be more targeted may be preferable.

Provision of system services through an operating reserves market

Operating reserves markets are designed to improve reliability and therefore may lead to the increased availability of synchronous generator units which will contribute to system security. However, as a targeted mechanism for the provision of system services they have several key limitations. First, operating reserves markets do not provide for unit commitment of specific generator units which may be required to meet minimum generator combinations for system strength and inertia. Second, since operating reserves markets involve market-based price discovery they are unlikely to lead to efficient market prices for local system strength markets which have few competitors. Fourth, operating reserves markets have slower response times than those necessary to provide for frequency control.

ERC0295 Operating reserve market (Infigen Energy)

AGL shares Infigen's concerns that there may be insufficient investment incentives in the NEM to deliver the operating reserves needed to respond to the increasing variety of contingency events that can occur in the NEM. We agree a new incentive to increase the provision of operating reserves in the NEM should be further investigated by the AEMC. Such a mechanism may increase system costs, as it would help to drive greater levels of investment. However, this could be offset by the lower RERT costs, and may be a more targeted mechanism than raising the market price cap.

Infigen has suggested that the operating reserves market procure reserves 30 minutes ahead of time with a 15 minute call time and that any plant capable of raising supply in that 30 minute timeframe could participate in the market, similar to contingency raise FCAS markets. In investigating this option further, AGL suggests that the AEMC consider the most appropriate definition for the service, with reference to the issue to be addressed. We suggest that the AEMC explore the merits of different designs of the service. For example, the impacts of different durations of the reserve and the call time.

Infigen has not proposed an ahead market aspect to its operating reserves design and AGL supports that choice. Ahead markets can weaken the accuracy and efficiency of dispatch because they are more prone to errors in forecasting since they must forecast conditions with longer lead times. This leads to less accurate forecasting of weather (which impacts VRE supply, demand, thermal constraints etc), plant availability, and demand. While ahead markets may alert the market operator of a unit commitment issue earlier than otherwise, an ahead market does not itself resolve unit commitment issues.

For the above reasons, AGL supports the AEMC's continued consideration of a real-time operating reserves market in the NEM and is keen to engage further on this option.

ERC0306 Capacity commitment mechanism (Delta Electricity)

AGL does not support the introduction of a day ahead capacity commitment market as outlined in this rule change request, however we are open to further consideration of the ESB's UCS model which has some similar aspects to this rule change.

The proposed rule provides additional incentives for non-peaking dispatchable generators to provide operating reserves and system services. The rule targets non-peaking dispatchable generators due to the growing frequency of these generators going offline in response to high VRE supply and low prices, and their inability to come online quickly in response to high prices. However, if these resources cannot economically respond to gaps in supply, then it is counterintuitive to design a mechanism to provide for supply in these gaps which targets investment in these generators. We suggest that any mechanism designed to incentivise investment in operating reserves and system services should include flexible capacity generators, which includes peaking generators, batteries and hydro.

ERC0307 Introduction of ramping services (Delta Electricity)

AGL does not support the introduction of a new 30 minute ramping service as proposed in this rule change request since NEMDE is already able to adjust dispatch in increments of 5 minutes. While the increased uptake of wind and solar in the NEM is leading to increased demand and supply variability, and this will increase wear and tear and therefore costs for inflexible thermal generators, AGL does not support the creation of a rule just for this purpose. The rule may increase the availability (and compensation) of operating reserves from the narrow category of dispatchable in-service generators, however it does not support the provision of operating reserves from other plant which may be able to respond to the 30 minute signal. AGL therefore does not consider this rule change to be technologically neutral as Delta has claimed. In regard to the objective of reducing price volatility in the NEM, AGL considers this is an inherent aspect of the NEM design which can be managed through the contract market. Delta suggests the proposed rule may facilitate the provision of system services, however since it is designed to support supply from in-service generators it is unlikely to lead to increased synchronous generator unit commitment and is therefore unlikely lead to increased provision of system services.

In regard to Delta's view that a causer pays principle may be appropriate for this rule, we note that the problem here exists due to the inflexibility of some thermal generation plant in responding to demand signals, therefore if the causer pays principle is followed it would follow that those receiving compensation under the service should be the ones paying for it.

Frequency control

ERC0263 Primary frequency response incentive arrangements (AEMO)

AGL strongly supports the creation of new incentives for primary frequency response (PFR) to replace the mandatory PFR requirements prior to the June 2023 sunset.

Mandatory PFR provides no incentive for generators, loads, and storage to invest in new PFR supply and it weakens the price signals and incentives provided by FCAS markets. Mandatory PFR is an imprecise mechanism for PFR provision since it does not require the provision of a known level of PFR or require the PFR be supported by stored energy. Mandatory PFR is also a discriminatory approach as it places the burden on generators capable of providing PFR without providing compensation. It can also be costly to implement since existing generators do not always meet the requirements. For these reasons, AGL does not consider the mandatory PFR mechanism to be fit for purpose as the power system transforms.

AGL suggests that the AEMC focus its consideration of a replacement PFR mechanism on a market-based approach and also the double-sided causer pays approach as advocated for by the AEC, which compensates providers that improve the frequency and penalises those that weaken it.

A market-based approach could have a defined standard and level of PFR provision that balances security and economic objectives. It would also provide compensation and therefore investment incentives for PFR provision and would also preserve existing FCAS markets. We would welcome the opportunity to provide further comment on a proposed PFR market if the AEMC outlines how it contemplates such a market would operate.

ERC0296 Fast frequency response market (Infigen Energy)

AGL strongly supports the introduction of new raise and lower fast frequency response (FFR) markets with a faster response time than the existing 6 second, 60 second, and 5 minute FCAS markets. We agree with Infigen's contention that it is critical to establish an appropriate FFR market sooner rather than later and we encourage the AEMC to consider ways to accelerate the introduction of these new markets. While other new rules contemplated in this consultation are more suitably dealt with over a longer timeframe and in conjunction with the ESB NEM 2025 processes, we believe this rule is more of a standalone rule which should be enacted more quickly.

The proposed rule is designed to facilitate quicker responses to frequency changes, since the rate of change of frequency following contingency events in the NEM has increased due to decreased inertia in the power system, the increased frequency of extreme weather events, and the growth of VRE which has increased the variability of demand and supply and therefore the likelihood of contingency events. AGL agrees new FFR markets will be an effective mechanism to respond to these challenges. The proposed rule will also increase investment incentives for providers of fast frequency response, which are currently not appropriately compensated for their unique capabilities.

While new FFR markets will introduce new costs into the NEM, they should improve system resilience and the efficiency of dispatch for frequency response services, which should lead to savings in reduced demand for other FCAS categories and potential savings in inertia remediation, which should offset the new costs.