Mr John Pierce
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000
Lodged via www.aemc.gov.au

Friday, 6 October 2017

Dear Mr Pierce,

RE: Inertia Ancillary Service Market Consultation Paper (ERC0208)

ENGIE appreciates the opportunity to comment on the Australian Energy Market Commission (AEMC) inertia ancillary service market consultation paper (consultation paper).

Concerns with minimum level of inertia

This consultation paper builds on the AEMC's previous Final Determination to introduce new arrangements to define a minimum necessary level of power system inertia, and to require transmission network service providers (TNSPs) to procure this minimum amount. The calculation of the minimum amount of inertia for each sub-network will be the responsibility of the Australian Energy Market Operator (AEMO), based on guidelines established in the rules.

ENGIE accepts that it is conceivable to have a portion of inertia procured through a regulatory / contractual process by TNSPs, and the remainder procured through a competitive arrangements by AEMO, although ENGIE remains of the view that splitting responsibility between AEMO and TNSPs is unlikely to be the most effective or efficient way forward. In any case, it should be recognised that the attempt to draw a line to establish a minimum level of inertia based on power system security principles seems to ENGIE to be based on unsound logic.

Since inertia is only required when there is a disturbance to the power system frequency due to a contingency event, a number of different approaches could potentially be adopted to establishing a so called 'minimum required level' of inertia, as follows:

- One (extreme) approach would be so set the minimum level of inertia at zero, meaning that any contingency event, even relatively small load or generation change events, would cause a large rate of change of frequency (RoCoF).

Australia
Level 33, Rialto South Tower,
525 Collins Street Melbourne, Victoria 3000, Australia
Tel. +61 (0)3 9617 8400 Fax +61 (0)3 9617 8401 engie.com.au

INTERNATIONAL POWER (ENERGY) PTY LTD ABN 53 062 798 510
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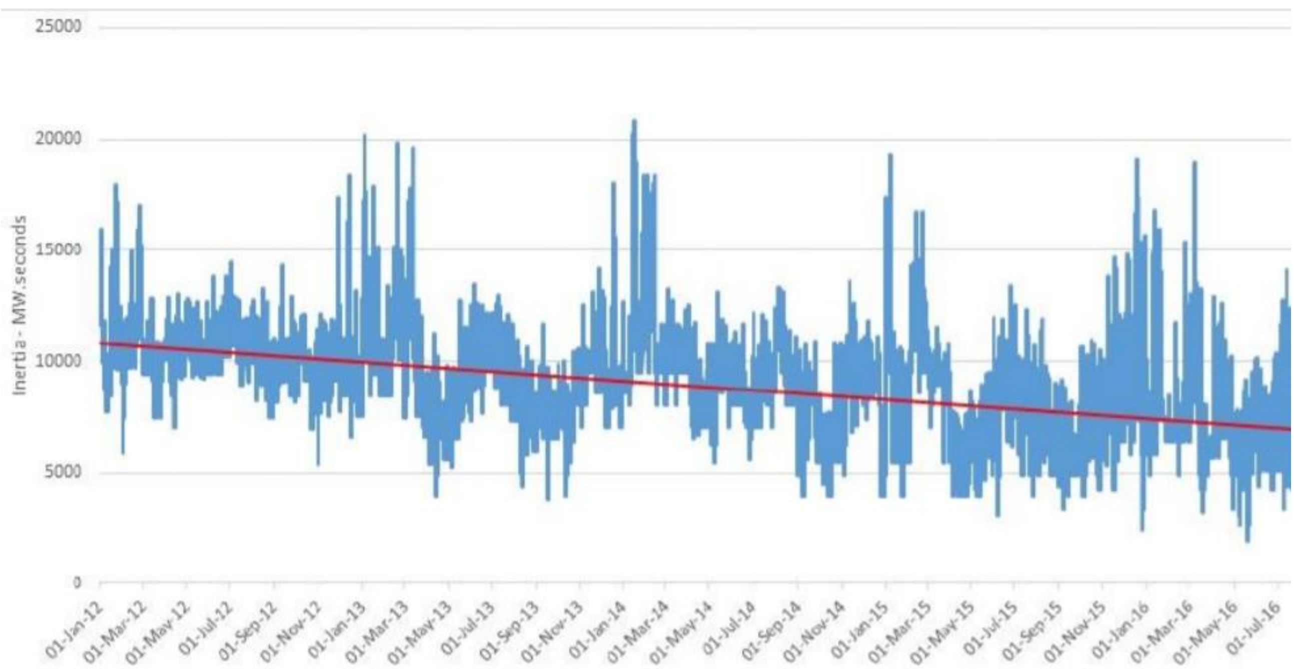
- Another approach would be to ensure that a region, when islanded, has sufficient inertia to cater for the loss of the largest generator in that region operating at its minimum output level.
- Another alternative would be to ensure sufficient inertia to cater for the loss of the largest generator in the region when it is operating at full output.

Any of these options, or a wide range of alternative options, could be utilised as the basis to establish a minimum level of inertia. It should be recognised however that although any such decision is arbitrary, it will nevertheless have important implications for procurement costs and operational arrangements.

If the AEMC is minded to continue to pursue the concept of a minimum level of inertia, ENGIE suggests that the attempt to establish a deterministic approach to calculating a minimum level is abandoned, and a more pragmatic probabilistic approach is adopted. For example, in consideration of the trend in power system inertia available in South Australia in recent years as shown in the following diagram, it could be decided that the minimum inertia should be maintained at a level that was exceeded for say, 90% of the time in the sample period. An approach along these lines would avoid the problem of trying to establish a minimum level of inertia through a deterministic approach, which inevitably would be subject to a number of assumptions, all of which would be arguable.



Another good reason for using a probabilistic approach (rather than a deterministic approach) to determining the minimum level of inertia is that it would be more easily customised over time on the strength of more knowledge and experience with the new inertia arrangements. For example, it may be that in time, the competitive arrangements for inertia that are the subject of this consultation paper, are found to be sufficiently effective so that the longer term contractual procurement via the TNSPs becomes unnecessary. Allowing room for this kind of improvement over time is consistent with the key principle of the AEMC's approach noted in the consultation paper that competition and market signals generally lead to better outcomes than centralised planning.

Market mechanism for inertia

The AEMC have proposed a straw man approach for the design of a market mechanism which would feature an inertia price paid to inertia providers based on the value they provide in relieving RoCoF constraints between regions.

ENGIE does not support this straw man design for the following reasons.

The proposal would rely on a binding RoCoF constraint acting as an incentive for the provision of additional inertia. The nature of constraints in the 5-minute dispatch process of the national electricity market (NEM) is that they can be quite volatile, difficult to predict and are subject to changes in each 5-minute dispatch period. It is therefore highly unlikely that the presence of a binding constraint in one particular 5-minute dispatch interval will be a sufficient incentive for a participant to decide to commit a synchronous generating unit in order to provide inertia.

Furthermore, if a participant did decide to start a synchronous generating unit in response to a binding RoCoF constraint, as soon as the generator comes on-line, it will have the effect of reducing the need for the constraint to bind, and the price separation between the regions will reduce. In other words, the price signal that encouraged the generator to start could disappear as soon as the generator comes on-line.

This fleeting nature of binding constraints and inter-regional price separation is unlikely to provide a sufficiently large or reliable signal for synchronous generators to commit. It is even less likely to provide an incentive for new potential inertia providers to invest.

Another reason that ENGIE does not support the straw man proposal is that it would interfere with the effectiveness of the existing settlement residue auction (SRA) mechanism. As noted in the consultation paper, funding inertia payments from inter-regional settlement residues has the potential to reduce the effectiveness of SRAs which are currently used as a tool for hedging inter-regional price risk.

The AEMC have suggested that one possible response to this detrimental impact on SRAs could be for purchasers of SRAs to also enter into contracts for recipients of inertia payments – an "inertia hedge". ENGIE believes that such a mechanism is likely to be complex and subject to various implementation issues. It is therefore unlikely to succeed and the more likely outcome will be that SRAs, which are already seen as an imperfect hedge against inter regional price risk, will see their potential use further limited.

Finally, ENGIE does not support introducing an inertia mechanism that is entirely focused on inertia requirements arising out of inter-regional flows. Although it is true that at present, inertia requirements are highest when there are large flows on interconnectors which are either a credible contingency or a protected event, there can and will be additional circumstances that will drive inertia requirements that are not related to inter-regional flow. This point is acknowledged by the AEMC in the consultation paper.

ENGIE therefore favours an approach to competitive inertia procurement that will have utility for all kinds of inertia requirements, and not just those that are due to inter-regional flows.

Alternative

ENGIE supports initiatives that promote competitive arrangements both for efficient investment and operation of inertia services. The ideal arrangement would be one that co-optimises the dispatch of inertia services along with energy on the NEM dispatch processes. For the reasons outlined above however, ENGIE is of the view that the binary nature of inertia provision (it is provided when a synchronous machine is on-line, and is not related to the units power output) makes co-optimisation with energy in the 5 minute NEM impracticable.

Since the provision of inertia services from synchronous generators requires decisions to bring units on-line, they require consideration across a longer time frame than 5-minutes. For many generating units, a decision to start a unit would involve consideration of a number of factors including start-up costs, minimum run times (to avoid maintenance penalties), fuel supply arrangements and staffing, to name just a few.

A fleeting 5 minute signal is unlikely to be sufficient to justify the provision of inertia services from anything other than units that can be started and stopped quickly with little cost implication. Although it is likely that inverter based technology will be able to respond to fleeting inertia signals, AEMO are of the view that the synthetic inertia provided by such technologies is not a substitute for synchronous inertia.

A better way to manage inertia requirements and provision would be to consider the likely need for inertia in the upcoming forecast period, and to then ensure that sufficient inertia service providers are enabled. To allow sufficient time to cater for generator start-up times and minimum run times, the inertia forecast period would need to be sufficiently long. As a minimum, ENGIE suggests that the inertia forecast period would need to be 8 hours.

In consideration of this alternative approach, and noting recent discussion about the possible inclusion of a day ahead market into the NEM[1], ENGIE proposes that a day ahead market could be considered, not for energy, but for firming services including inertia.

A day ahead market for firming services could be designed to allow AEMO to consider the forecast requirement for inertia and other firming services such as system strength and flexible ramping, for the upcoming day. Where particular generating units are required to be online to provide firming services, the firming services day ahead market would be used to allow potential service providers to indicate to AEMO in advance, their willingness and price to provide these services. AEMO would then select the cheapest combination of firming services to meet the forecast requirements, and produce a day ahead schedule to indicate which services are required, and when they need to be enabled.

This day ahead schedule of firming service provision would then become binding upon the selected service providers, which would be required to be online and able to provide the nominated services as scheduled.

[1] ENGIE is opposed to introducing a day ahead market for energy into the NEM as this would seriously undermine the existing financial hedging positions that generators currently use for risk management in the NEM. It should be noted that a day ahead energy market was considered and rejected in the mid 1990's as part of the NEM design. The decision then was based on the view that financial markets provide a more efficient means to generator planning and investment.

The day ahead firming service schedule would inevitably lead to a displacement of the 5-minute energy market since it is likely to result in some generators being online (to provide firming services) which would not have otherwise been on. This in turn is likely to lead to a reduction in the energy only market price, but this would be balanced by the need to pay for the firming services day ahead market. If this idea were to be taken further, consideration would need to be given to ensuring that the distortionary impacts on the energy market are minimised, and that energy hedge contracts are not undermined in a manner that cannot be managed.

ENGIE believes that a day ahead firming services market has a number of advantages over attempts to force inertia (and other services) into a compromised co-optimisation of these services with energy in the 5-minute dispatch process. One advantage is that a day ahead schedule is more reflective of the inter-temporal nature of unit commitment decisions that span many hours. A second advantage is that the firming services day ahead market can be utilised to accommodate inertia, system strength and other firming services such as flexible ramping capability. These services can all be considered in combination by AEMO to achieve the most cost effective combination to meet the forecast requirements.

ENGIE trusts that the comments provided in this response are of assistance to the AEMC in its deliberations. Should you wish to discuss any aspects of this submission, please do not hesitate to contact me on, telephone, 03 9617 8331.

Yours sincerely,

Chris Deague
Wholesale Regulations Manager