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Lodged electronically: www.aemc.gov.au (EPR0052)

Dear Commissioners,

2018 – AEMC – Coordination of generation and transmission investment – Discussion Paper

EnergyAustralia is one of Australia's largest energy companies with over 2.6 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. We also own and operate a multi-billion dollar energy generation portfolio across Australia, including coal, gas, and wind assets with control of over 4,500MW of generation in the National Electricity Market (NEM). Through long-term agreements with renewable energy projects we underpin around 12.5 per cent of the large-scale wind projects in the NEM, equating to more than $1 billion of investment in new renewable generation.

We welcome the opportunity to comment on the AEMC's discussion paper on the *Coordination and generation and transmission investment* (the discussion paper). Below we provide an outline of our views on the current assessment of transmission investment frameworks in the NEM. We have also sought to use this opportunity to highlight the ways in which the regulatory framework affects the connection of storage and its ability to effectively improve the efficiency of network use.

Transmission investment framework

In the discussion paper, the AEMC have considered ways in which Renewable Energy Zones (REZs) could be implemented within the NEM. The regulatory impact of these proposals ranges from minimal to substantial changes to the existing framework. The AEMC have also highlighted alternative investment framework options that could be explored, such as access standards, optional firm access and clustering. These changes would also have substantial impacts on the regulatory framework.

In EnergyAustralia's view, justification for substantial change to the investment framework has not been provided and we therefore do not support changes at this time. Consideration of key principles of an investment framework demonstrates that the fundamentals of the current design remain valid. These key principles include:

- In considering framework design, it is important to consider what is best for the customer; customers should not underwrite investments that have high risk for capital recovery.

- Investment risk should be allocated to those best able to manage it.

- Alternative approaches to network investment, for example demand response, should be thoroughly considered.

- The framework should include a robust cost benefit analysis of proposed investment.

- Market participants that have invested in good faith and have limited flexibility in the operation of their assets should not be penalised by any future changes to the investment framework.

EnergyAustralia considers that the current combination of a Regulatory Investment Test (RIT) for regulated investment, and the option for private investment for speculative investment, remains fit for purpose in addressing the above principles. Under this framework, customers are only required to fund investment after robust analysis is conducted that identifies benefits that will be readily realised under a range of scenarios. This ensures that customers only fund efficient investment. The framework also allows a broad range of investment options to be considered and that investment risk for speculative projects can be borne by private entities that are best placed to manage this risk.

It is unclear how expected changes in the market environment and generation mix will warrant a substantial change to the existing framework. Recognising that there has been a growth in generation investment, particularly for renewable technologies, this does not necessarily render the current framework ineffective for assessing investment. The current framework considers the economic merit of a project, via a RIT, and allows for co-ordination of investment under the Scale Efficient Network Extensions (SENE) framework.[1] There is a lack of clarity on the risks and issues created by assessing future network investment within this framework. COAG recently reviewed the RIT process at determined that it remains an effective and appropriate means to assess transmission investment.[2] For a change in the framework to be considered, the issues justifying a change must be clearly articulated. A failure to do so risks embedding ill targeted, inefficient and costly regulatory arrangements.

Further, making substantial changes to the transmission investment framework in the midst of broader scale market reforms, poses a great risk to consumers and industry. Some of the major changes include the move to 5-minute wholesale market settlement and the implementation of the proposed National Energy Guarantee. Considerable investment in the NEM is anticipated[3] and stability and certainty is valued by investors operating in a market experiencing a complex transition.

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[1] https://www.aemc.gov.au/rule-changes/scale-efficient-network-extensions
[2] http://www.coagenergycouncil.gov.au/publications/review-regulatory-investment-test-transmission-rit-t
[3] *Investment in Australia's electricity generation sector to 2030*, Newgrange consulting, April 2018, available at: https://www.energycouncil.com.au/reports/

In the context of the current investment environment, Option 1[4] for implementing REZs appears the most sensible. We strongly support the provision of useful information to guide investment decisions. The focus should be on developing an Integrated System Plan (ISP) that serves as an informative document for industry to support co-ordinated investment planning. For example, modelling should consider the end costs to customers of different generation and transmission options and provide locational pricing signals.

Treatment of storage

Our response to the discussion paper reflects our current experience registering two grid storage facilities for operation in Victoria:

- Gannawarra Battery Storage, a 25MW/50MWh[5] energy storage system co-located with the Gannawarra Solar Farm and connected to Powercor distribution network,

- Ballarat Battery Storage, a 30MW/30MWh[6] stand-alone energy storage system connected to the AusNet Services transmission network.

While we acknowledge that the scope of this review is to consider transmission investment and tariffs applied to transmission-connected loads, the impact that distribution-connected storage can play in alleviating constraints in the transmission network should be recognised. We have therefore included comments on our experiences in connecting distribution connected storage in this submission.

Energy storage is considered an integral component of the future generation fleet. It allows excess generation to be stored for use during high demand periods, and can also provide ancillary services such as regulation and contingency frequency control ancillary services (FCAS). Given the critical role that storage will play in ensuring both security and reliability of the NEM, it is important that regulatory frameworks do not present unnecessary costs and difficulties for connecting projects.

The AEMC has identified two issues in the consultation paper related to storage:

- consideration of the whether Transmission Use of System (TUoS) charges should be levied on storage facilities, and

- consideration of the appropriate registration category for hybrid facilities where storage is combined with semi-scheduled generation.

EnergyAustralia provide comments on both questions in the following sections, as well as other issues we have identified that require assessment to ensure the National Electricity Rules facilitate the efficient connection of grid storage.

Treatment of network charges

A key issue for EnergyAustralia regarding the TUoS DUoS (Distribution Use of System) charges applicable to storage facilities is the tariff structure.

[4] AEMO and TNSP provide enhanced information to market to facilitate coordinated planning and investment.
[5] Discharge duration of 2 hours
[6] Discharge duration of 1 hour

EnergyAustralia recognises that network service providers (NSPs) have the prerogative to set charges as they see appropriate, subject to regulatory requirements. However, current charging structures for storage facilities do not accurately reflect the use of the network by batteries and the benefits to system operation that they provide.

A key benefit of storage is the ability to shift demand on network assets from peak periods to off-peak periods, which offsets the need for investment in network capacity expansion and supports efficient use of the electricity network.

At present, NSPs have a variety of tariff arrangements that apply to energy consumption and maximum demand. These can include Time of Use (TOU) charges and flat use charges. EnergyAustralia believes that the combination of charges applied to storage should reflect the nature of the load and its fundamental use in improving the efficiency of the network. In our experience, NSPs have not always accurately considered the value that storage can provide to the network. By applying TOU to energy consumption, rather than demand, or by applying flat charges for demand, there is a risk that the application of TUoS tariffs to storage may undermine or inhibit investment in these assets.

Our experience with Gannawarra and Ballarat energy storage systems demonstrates this issue and highlights the difference in tariffs between transmission-connected and distribution-connected storage assets and the potential impact this could have on future investment.

In the case of transmission connected assets, AEMO's current position as the network planner in Victoria, is to not levy TUoS on utility scale storage. AEMO is currently liaising with the AER to clarify the application of TUoS charges[7] and there is a risk that a tariff structure could be re-introduced that charges storage assets based on a fixed rate for maximum demand. This would dampen the incentive to utilise the facility to shift load, improving the efficiency of network use.

For distribution connected assets, the impact of inappropriately applying TOU price is more apparent. Storage facilities are charged a flat rate of $23.80/kW p.a. for maximum demand, regardless of time of use. This means that if demand reaches a level of 30MW during the invoice period, the total demand charge would be $714k. While there is a TOU charge, this is applied to energy consumption and provides limited incentive to shift peak use of the asset to periods of low network utilisation.

	Fixed Charge	**Demand charge**	**Usage Charge – Peak**	**Usage Charge – Off-peak**
Rate	$238,000 p.a.	$23.8/kW	2.55 c/kWh	0.77 c/kWh
Total annual cost for a 30 MW / 30MWh storage asset	$238,000 p.a.	$714,000 p.a.	0 c/kWh	84,315 c/kWh

Source: Powercor 2017 Pricing Proposal[8], sub transmission class tariff, assumes 1 cycle per day charging in off-peak.

[7] *FAQ Interim arrangements - Utility Scale Battery Technology*, AEMO, March 2018, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Interim-arrangements-Utility-Scale-Battery-Technology

[8] https://www.aer.gov.au/system/files/Powercor%20-%20Pricing%20proposal%202017%20-%2029%20September%202016.pdf, p41

When determining whether TUoS or DUoS charges should be applicable to storage assets, it is important to recognise that the primary use of storage is to provide generation services and facilitate the efficient use of the network. A move towards cost-reflective network pricing for storage will provide incentives for efficient use of the network and ensure that storage loads do not increase requirements for network investment.

Treatment of avoided TUOS charges

On a related note, the treatment of avoided TUoS charges for distribution connected generation should also be considered. Avoided TUoS payments are intended to incentivise behaviour that maximises the utilisation of the network but the current arrangements do not efficiently provide the required signals. Greater transparency is needed regarding avoided TUoS payments to ensure this objective can be met.

Within the current regulatory framework, distribution connected generation is eligible to receive avoided TUoS payments for offsetting requirements for network investment for transmission infrastructure capacity to service the local demand. Generators receive payments if they are generating on the 10 days of the year with the highest usage of the relevant network assets. The intent of this payment is to incentivise generators within the distribution network to generate on peak days, thereby offsetting the need to invest in expanded transformers.

However, the limited transparency of the calculation for avoided TUOS payments inhibits the ability of distribution connected storage to respond to market signals and operate in such a way as to maximise efficiency of the network. The lack of information regarding expected peak usage prevents generators from being able to identify when they should be generating to alleviate constraints on the local network. It would be beneficial if the AEMC can consider whether real time demand information, or forecasts, could be made available by NSPs.

Registration category and registration processes

As outlined above, a key benefit of storage in the future NEM is to provide firming capacity for renewable generation. However, as identified by the AEMC, the current registration categories, and subsequently separate dispatch instructions for related assets, do not facilitate the efficient use of storage to meet the intended objectives.

At present, a storage facility co-located with a non-firm generation source is registered as both a scheduled load and a scheduled generator, while the non-firm generation will be registered separately as semi-scheduled generation. Due to the individual registration of each component of the site, each asset receives separate dispatch targets. This has a material impact on the ability of storage to provide firming capacity.

To illustrate, consider a storage facility and a semi-scheduled wind generator that are co-located with a shared connection to the transmission network. Assume the storage facility has capacity of 60MW, the wind generator has capacity of 80MW and the connection asset has a capacity of 100MW. As they are registered as separate units, both generators will receive individual dispatch targets. Assume that for a particular period, dispatch instructions are issued for 60MW of wind and 40MW of storage. Should the wind generation deviate from the forecast due to a change in weather, the operator may wish to adjust the output of the storage facility to compensate, ensuring that the total generation from the site remains at a combined sum of 100MW. However, under this scenario, the operator will not be following dispatch targets and could be liable for causer pays charges.

Further consideration therefore needs to be given to address the discrepancy between registration and use of generators, caused by the requirement for individual units to be registered and dispatched separately. It is important that registration categories evolve to allow for future use of storage that recognises the unique services they provide in firming supply from semi-scheduled generation.

Regarding the registration process itself, EnergyAustralia propose that efficiency gains could be made from streamlining the application process. Currently, separate paperwork and registration payment is required to separately register the load and generation components of a storage asset. The information provided is essentially duplicated so the use of separate processes increases administration and registration costs for both AEMO and the applicant. Further, there should be regulatory clarification on how ongoing participant fees are levied on storage assets. As their primary purpose is to provide generation, it is unreasonable for full customer fees to be levied in addition to generator fees.

These additional costs are essentially a penalty on storage facilities and could not be considered to meet the technology neutrality provisions of the NEO. We recommend that the registration process for a storage facility comprise a single application and charge.

Conclusion

In summary, EnergyAustralia does not believe that problems with the existing transmission investment framework have been clearly defined. We believe that the existing framework for transmission investment remains fit for purpose. Further, making substantial changes in the midst of broader scale market reforms and investment poses a great risk to customers and industry.

We are supportive of the ISP in providing information to investors but do not consider it should serve as a replacement for the rigorous economic assessment conducted under the RIT process.

Our experience with registering grid scale storage shows that there are limitations in the structure and application of tariffs. Poorly designed TOU tariffs and TUoS payments could lead to unintentional outcomes if the price signals inhibit incentives to discharge at times and rates that relieve congestion. Registration categories also have the effect of inhibiting optimal use of storage assets and registration processes and costs impose penalties on storage assets.

Storage devices have the potential to address wholesale and network challenges and, if used appropriately, can help to minimise retail prices. Decisions and investments on grid-level storage devices are already being made, so we believe it’s critical to resolve these matters quickly.

If you would like to discuss this submission, please contact Georgina Snelling on 03 8628 1126 or Georgina.Snelling@energyaustralia.com.au.

Regards

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