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Dear Commissioners

Financeability of ISP projects (TransGrid and ElectraNet) – Draft Rule Determination – 4 February 2021

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation capacity.

We support the Commission's draft determination to not make the proposed participant derogations as separately requested by TransGrid and ElectraNet.

We consider the Commission's and CEPA's analysis raises important points around the financing issues faced by individual transmission network service providers (TNSPs), and their ability to respond to incentives to outperform or otherwise depart from benchmarks set by the AER under the rules framework.

Once the proponents' assertion of needing to strictly maintain a 60 per cent gearing ratio is set aside, CEPA's analysis suggests that required variations to notional gearing to maintain the target funds from operations (FFO) to net debt ratio would need to be less than 5 per cent.[1] Gearing levels down to 55 per cent are within the range of observed values on which the AER has set its 60 per cent benchmark. CEPA's analysis also suggests that the impact of the rule change in maintaining benchmark equity returns is negligible[2], which contrasts to the large impacts as plotted by Incenta using an assumed gearing ratio of 40 per cent.[3]

CEPA's reference to Ofgem's experience with Scottish Hydro Electric Transmission Ltd (SHETL) illustrates that regulatory benchmarks could, however, be adjusted where the scale of expansionary capex demonstrably causes financing issues for the notional

[1] CEPA, *Financeability of ISP Projects*, 27 January 2021, pp. 29-32.
[2] ibid., p. 18
[3] Incenta, *Attracting capital for ISP Projects – TransGrid*, September 2020, p. 10.

regulated entity. Note the case of SHETL, which involved a tripling of its regulatory asset base over the course of one regulatory control period, is likely to be uncommon.

We support the Commission and the AER undertaking separate work to address the broader issues raised in the examination of these rule change proposals, which would include:

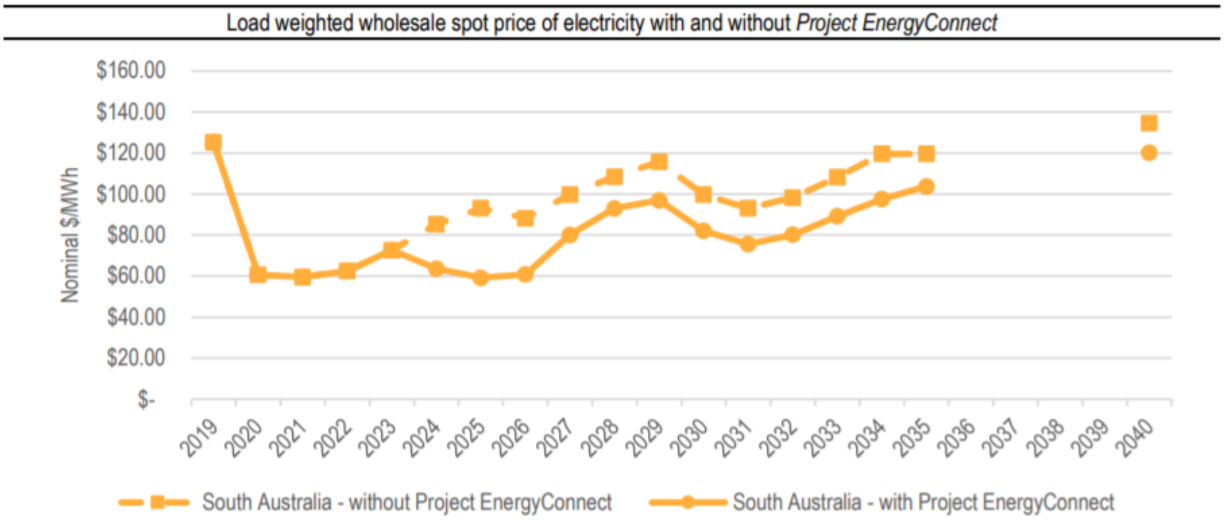
- the prospects of TNSPs not undertaking Actionable ISP projects for commercial reasons, even though they are intended to deliver wider market benefits

- how the AER should treat very large increments in capex additions for modelling purposes and in setting financing benchmarks. The Commission is of the view that separating out Actionable projects under using a nominal rate of return and as-incurred regimes would add modelling complexity. This complexity should be weighed against large potential windfall gains and losses in assuming these increments are financed at the TNSP's 'average' WACC (noting that interest rates are currently below the AER's trailing average cost of debt) or as part of blended asset classes and depreciation profiles.

- whether the AER should incorporate financeability assessments and forecasts of credit rating metrics into its determinations of regulatory allowances (including for contingent project pass throughs). Similarly, TNSP assessments of project deliverability constraints should also include access to finance as standard practice.

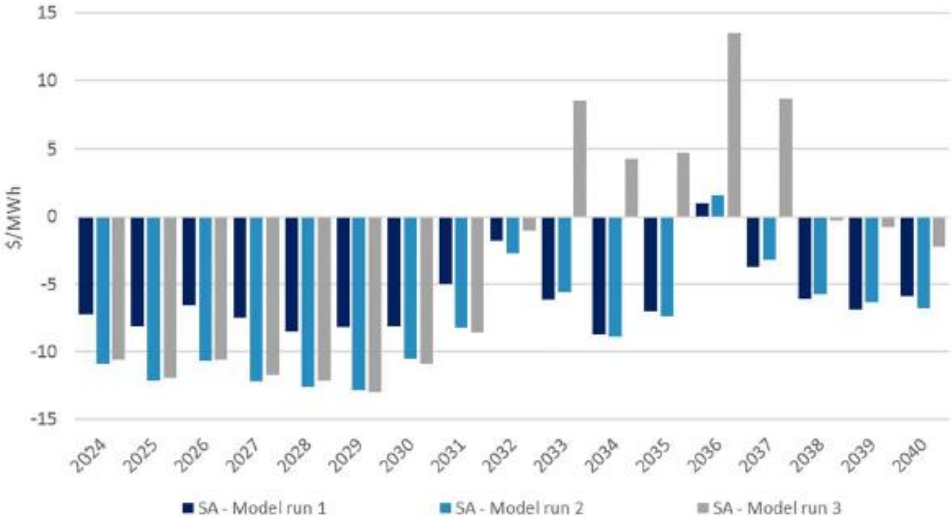
We also urge caution in the Commission's exploration of intergenerational equity issues under the National Electricity Objective, including in relation to price stability and explicit preferences expressed by some customer representatives during consultation.[4] These considerations do not appear to be critical to the Commission's overall findings, which relate to the materiality of benchmark financing impacts and empirical analysis of credit rating metrics. However, we consider the Commission should be careful in exploring the issue of alignment of price changes and the delivery of benefits, which are highly uncertain (and also likely marginal in the case of Project Energy Connect). Specifically, the Commission (likely reflecting how the proponents presented supporting data) appears to have considered the timing profile of benefits in terms of "weighted average NEM" wholesale price impacts, which suggests benefits would not be delivered until after 2030.[5] CEPA also appears to place heavy weight on a visual comparison of nominal revenues and discounted benefits[6], which we agree is potentially misleading. Yet while the profile of benefits delivered in NSW supports delayed price increases and a rejection of the rule change proposals, the Commission's determination for ElectraNet overlooks analysis by FTI and ACIL Allen which suggests wholesale price savings in South Australia would be delivered from the time of project commissioning. This might otherwise have supported front-loading regulated price increases.

[4] AEMC, *Participant derogation – financeability of ISP projects (TransGrid)*, Draft rule determination, 4 February 2021, p. 64-66.
[5] ibid., p. 47.
[6] CEPA, p. 64.



ACIL Allen, *Project Energy Connect – updated analysis of potential impact on electricity prices in South Australia*, September 2020 p. ii.

Figure 2-5: Annual weighted average SA wholesale price impact from EnergyConnect



Source: FTI Consulting, *Assessing the Benefits of Interconnectors – A report for TransGrid*, September 2020, p. 14.

We also echo comments made by ERM that much of the customer impact analysis ignores much larger impacts on commercial and industrial customers who pay a higher proportion of transmission prices in their bills, and we believe this should be a standard consideration when exploring distributional impacts of any regulatory change.

The desire to align price changes to the delivery of benefits across jurisdictions (i.e. who pays for interconnectors) is a related distributional issue and will be critical, for example, in the case of Marinus Link.

Exploration of distributional impacts (including intertemporal) should be facilitated by appropriate publication of data alongside ISP and RIT-T assessments. We consider that recent changes to the ISP framework, including new and revised AER guidelines, should ensure this information is published. However, the adequacy and timeliness of published data by AEMO and TNSPs will need to be monitored.

As raised by the Commission, changed market dynamics around Project Energy Connect following the NSW Electricity Infrastructure Roadmap are also worthy of further consideration. We also note that all the comparisons of market benefits and price impacts presented so far, including AEMO's latest guidance[7], reflect outdated (lower) cost estimates for the project, and its prudent timing has therefore likely been pushed back. That is, a higher annualised cost of the project will, all else equal, justify a later commissioning date. Again, these types of considerations are not central to the Commission's current considerations, however may be important in exploring the proponents' concerns about delays in receiving regulatory approvals and the need to expedite their requests.

If you would like to discuss this submission, please contact me on 03 8628 1655 or Lawrence.Irlam@energyaustralia.com.au.

Regards

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[7] https://aemo.com.au/-/media/files/major-publications/isp/2020/impact-of-recent-policy-announcements-on-project-energyconnects-benefits.pdf?la=en&hash=FF0D49E30FBEE3DF60B7D1795BCB2C4A