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Dear Commissioners

Accommodating financeability in the regulatory framework — Consultation Paper — 8 June 2023

EnergyAustralia is one of Australia's largest energy companies with around 2.4 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 5,000MW of generation capacity.

We support rule changes to enable investment that is necessary to accelerate the transition. The Commission's Transmission Planning and Investment Review (TPIR) comprehensively covered regulatory matters in this regard. A key finding of this review is that gaining social licence is critical for transmission investment. Providing transmission project proponents concessional financing and other cash flow incentives seems unlikely to increase the speed at which projects can be delivered. There has been no evidence presented that Transmission Network Service Providers (TNSPs) are unable to finance projects. This includes in the current rule change proposals and in the earlier proposed participant derogations relating to Project EnergyConnect. We are concerned that the ENA and TNSPs may be overstating financing issues to gain political support for favourable treatment. The Commission is no longer pursuing contestability which would have incentivised TNSPs to genuinely pursue prudent projects. It is unclear how the Commonwealth Government will allocate support from its Rewiring the Nation fund or via the Clean Energy Finance Corporation. Given other barriers to project delivery, there is a risk that electricity consumers and taxpayers will incur costs for funding support without any effect on project timing or the realisation of modelled project benefits.

In line with the Commission's TPIR, we support minor amendments to the National Electricity Rules (NER) to clarify that assessments of depreciation have regard to the benchmark regulated entity's cash flow adequacy and price impacts for consumers. These considerations should apply generally, not only to specific transmission projects and with broad AER discretion, and would bring provisions into line with those for regulated gas networks. Our comments on the Minister's and the ENA's rule change proposals are as follows, with an extended response to the latter in the attachment given it was not covered in the Commission's consultation paper.

Additional cash flow assessments can be introduced under the current rules

Cash flows arising from regulatory determinations should be assessed in terms of financing considerations for the benchmark regulated entity, as well as price impacts for customers.

Decisions to amend depreciation profiles in this context should have explicit regard to end use bill impacts. Based on the ENA's example modelling for a single project, cash flow adjustments could see transmission prices elevated for up to 14 years, and up to 60% higher, than under the current modelling approach.[1] These impacts may be compounded where Actionable projects are completed concurrently. Many of the projects listed in the Commission's table B.1 would be commissioned from the late 2020s to early 2030s, based on the Step Change scenario of the 2022 Integrated System Plan (ISP). If transmission price impacts are material, it could be the case that they are timed to coincide with offsetting reductions to wholesale or other costs that make up customer bills. Where such cost trends are reserved, price stability could be similarly maintained.

Various cash flow and financing cross checks are standard for other regulators, including Ofgem[2] and by jurisdictional regulators in Australia.[3] The AER's Post Tax Revenue Model (PTRM) has financial analyses although these are mostly used to check the consistency of cash flows with cost of capital inputs. The PTRM also provides for a basic assessment of price paths over the relevant determination period. These features, and others, are beyond the requirements of clause 6A.5.3. Hence there do not seem to be any barriers for the PTRM to feature more sophisticated cash flow metrics or extended price path analyses to assess the effects of different depreciation profiles.

As noted in our prior submission to the TPIR[4], the NER already provide sufficient flexibility for TNSPs and the AER to adopt depreciation profiles that could accommodate particular cash flow needs.

Clause 6A.6.3(c) prescribes the use of a straight basis in cases where (1) the asset is dedicated to one or a small group of users and (2) its value exceeds $20 million. The Commission states that this would apply to Actionable projects as they cost more than $20 million[5] however is this incorrect, as these projects are not dedicated to one or a small group of users (i.e. the conditions under subclauses (1) <u>and</u> (2) must be met for a straight line basis to be mandatory). The AER's view is that there is a lack of clarity of whether it can consider financing issues in setting alternative depreciation methods.[6] Our view is that financing issues as well as intertemporal impacts for users are clearly within the scope of the National Electricity Law's (NEL) revenue and pricing principles and the National Electricity Objective (NEO) which treat investment incentives and price impacts. We are unaware that these aspects of the rules have been tested such that they indeed are indeed a barrier for TNSPs or the AER.

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[1] ENA, *Ensuring the Financeability of Actionable ISP Projects - Proposal to change the National Electricity Rules*, 9 June 2023, p. 30.
[2] See for example chapter 5 of https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_finance_annex_revised_002.pdf
[3] See for example IPART cost building block and pricing model | IPART (nsw.gov.au)
[4] https://www.energyaustralia.com.au/document/transmission-planning-and-investment-review-stage-2-draft-report
[5] AEMC, *Accommodating financeability in the regulatory framework - Consultation paper*, 8 June 2023, p. 6.
[6] ibid.

We support additional principles but not process prescription for depreciation

Although there appears to be no current problem with the existing rules, we accept they can be made more explicit regarding the ability to consider cash flow timing needs and intertemporal impacts. Thought should be given to the equivalent provisions in the National Gas Rules. Rule 89 contains a minimal references to reasonable financing needs and other tariff effects, which have provided network owners and the AER the ability to consider a variety of depreciation approaches while balancing the interests of networks and their users. Note these provisions apply generally and not just to specific projects.

The three 'principles' drafted by the Commission, and reflected in the Minister's rule change, are as follows:

> …the AER must have regard to:
>
> (1) the relative consumer benefits from the provision of network services over time;
>
> (2) the capacity of the network service provider to efficiently finance its overall regulatory asset base, including efficient capital expenditure; and
>
> (3) any other factors the AER considers relevant, having regard to subparagraphs (1) and (2) above.

Subparagraph (1) should refer more broadly to the impacts on customers in terms of 'prices', reflecting the materialisation of both costs and benefits in a way that customers actually experience, and could be made more clearer in reference to both near term and future price levels. The factor listed in subparagraph (2) is generally appropriate, in terms of explicitly referring to the regulated business's capacity to efficiently finance, although should refer to the provision of services that are within the scope of regulation rather than the 'overall regulatory asset base'. It would be sufficient for subparagraph (3) to simply refer to "other relevant factors" and it is not clear why there should be additional regard to subparagraphs (1) and (2).

We disagree that further rule amendments are needed to provide for a specific depreciation request by TNSPs and an AER determination.[7] These are already implied in existing proposal and determination provisions, including for contingent projects. New provisions for related guidelines also seem unnecessary as the AER already has the power to issue these under clause 6A.2.3(a)(2). Again it is not clear if stakeholders or the AER have attempted to exercise these rule provisions and found them to be deficient. A standing AER guideline with broad application, and based on input from all affected TNSPs and customer cohorts, would presumably provide sufficient weight and certainty for investors in line with the ENA's preference. The AER also has powers to publish issues papers under clause 6A.11.3(b) which, as part of the broader revenue determination process, can cover its expected approach to dealing with the depreciation of contingent projects. Where this is a material issue for TNSP and stakeholders, the AER should set out general guidance or address this well ahead of projects being triggered. We do not see a reason why financial data for such an assessment can only be reasonably forecast in the months ahead of lodging a contingent project application.

The AER's approach to assessing default or alternative calculations of depreciation profiles seem best placed within its existing PTRM and asset base roll-forward model,

[7] Stage 2 Proposed rule changes - Transmission planning and investment review (aemc.gov.au) – see amended clause 6A.6.3.

and their explanatory handbooks. The insertion of any new financing metrics in the PTRM would need to be explained and consulted on in any case if a depreciation-specific guideline were produced under clause 6A.2.3(a)(2).

We do not see the need to expedite any AER guidelines or model changes. Transitional rules also seem unnecessary, noting that we consider the current rules to be sufficiently flexible.

The rules should not prescribe a formulaic approach

We disagree with the ENA's proposal for the NER to set out a formula which TNSPs and the AER must satisfy in setting depreciation values. Generally, the call for greater prescription to provide TNSPs a high degree of certainty seems disproportionate to the nature of problem and the limited evidence of financing problems that has been presented to date. Prescribing a formula in the rules oversimplifies and overstates quantitative approaches used by credit ratings agencies. These approaches may also change over time and rules would be inflexible to such changes where they arise.

We also disagree that financing issues and any revenue adjustments be determined on a project basis rather than at the entity level. The reasons for this are largely aligned with the Commission's views in that other rule provisions, AER financing concepts and principles in the National Electricity Law are appropriately targeted at the entity level. Where cash flow sufficiency is a genuine issue, it should matter for all regulated entities not just for particular projects. In a practical sense, however, we appreciate that the significant cost of Actionable projects, in the face of uncertain benefits streams, means that issues will likely be limited to electricity TNSPs. In our view it would be useful for the AER's assessments to consider benchmark cash flow adequacy as a cross check across all its determinations including for gas and electricity distribution networks. This is within the scope of the AER's current discretion.

It is not clear why guidance is required on specific assets

The Minister's proposal does not provide sufficient information on the nature of biodiversity offsets, or of any other asset class, that would warrant a particular depreciation treatment. The Minister's proposal to depreciate biodiversity offset costs on an as-incurred basis is similarly not well explained.

Generally these issues should be assessed by the AER and could form part of discretionary AER guidance, should TNSPs or other stakeholders seek this level of clarity.

Our understanding is that purchases of land are not depreciable as land does not deteriorate or apportion finite benefits in the same way as other assets.

The Commission may wish to further explore how TNSPs incur costs for biodiversity, noting they may have incentives to make payments to conservation funds rather than meet obligations via land purchases.[8] This seems within the scope of the AER's assessment of prudent approaches to incurring capital versus operating expenditures.

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[8] AEMC, p. 20.

The AER has used a 'hybrid' approach in recognising capital expenditure, whereby the return on capital reflects as-incurred spending but depreciation reflects when assets are commissioned.[9] The AER's prior view was that this would most likely be consistent with NER requirements, specifically that the economic life of an asset, and so depreciation, commences once it is brought into service.[10] The AER's approach for allowing depreciation on an as-incurred basis for DNSPs is likely immaterial and irrelevant for transmission businesses given the short construction lives of distribution assets.

The choice of recognising assets as-incurred or as-commissioned will have incentive effects as well as others. Incentive issues were canvassed by the AER regarding its Statement of Regulatory Principles which was subsequently adopted into what is now known as chapter 6A.[11] These and other relevant considerations would be accommodated in the third principle of the proposed NER amendments (i.e. 'any other factors') now under consideration.

If you would like to discuss this submission, please contact me on 03 9060 0612 or Lawrence.irlam@energyaustralia.com.au.

Regards

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Regulatory Affairs Lead

[9] Appendix D - Amended electricity transmission PTRM handbook - April 2021.pdf (aer.gov.au) p. 14.
[10] Microsoft Word - 20070131 1a Post Tax Revenue Model Explanatory Statement.doc (aer.gov.au) pp. 4-5.
[11] AC00105 - Position Paper Accounting Methodologies.pdf (aer.gov.au)

Appendix - comments on the ENA rule change proposal

We consider that the ENA's proposal for the NER to prescribe a formulaic approach, and for Actionable project cash flows only, is not well justified and also impractical.

The extent of the problem

The ENA's proposal asserts the need for and benefits of transmission projects, which are then applied to (in our view) incorrect interpretations of the NEL's revenue and pricing principles and the NEO. The proposal's central claims are that:

- transmission projects will be delayed or not progress unless the proposal is adopted
- transmission projects have government support
- transmission projects are necessary for decarbonisation
- investors require very high degrees of certainty of recovering cash flows before committing to projects.

It is not clear that general government support for projects is a relevant consideration for how economic regulation should apply. The actions and policies of government are already accommodated in NER provisions, including as 'applicable regulatory obligations' in the network expenditure objectives, and power system needs under clause 5.22.3(b). We would also be highly concerned if TNSPs were to threaten the non-delivery of prudent projects and decarbonisation targets as a means to elicit political support and exert pressure on the Commission to change rules in their favour. The ENA's references to needing concessional financing from government, if it cannot obtain the desired cash flow profiles from electricity consumers, is a concerning ultimatum.

The ENA states that its proposal will address a "significant barrier" to investment in Actionable projects however it presents no evidence that financeability is an issue for the projects currently under consideration. This is important given Commission found no issues with the financial position of ElectraNet and Transgrid in their proposed participant derogations. The ENA should be able to obtain further evidence of TNSP and project specific financial data to demonstrate its case however has not done so.

Assessment against the revenue and pricing principles

The ENA's consideration of the principle in NEL section 7A(2)(a), regarding the opportunity to recover at least efficient costs, incorrectly casts this as applying to individual Actionable projects rather than the operator in providing direct control network services, as per the NEL drafting. The ENA also appears to overstate this principle in terms of "ensuring" that holders of debt and equity capital are able to earn their respective returns.[12] The NEL's "reasonable opportunity" does not equal a guarantee for investors. The application of this principle in setting revenue and building block allowances reflects inherent uncertainties in forecasting, the consequences of forecasting error, and the desirable features of incentive regulation where risk is allocated between regulated entities and consumers. Even if the AER were forced to follow the ENA's

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[12] ENA, p. 34.

prescriptive approach, investors will still face the risk of not receiving benchmark cash flows to sustain their investment.

The ENA narrowly applies the principle in NEL section 7A(6), regarding the risks of under investment, to Actionable projects only. However the drafting is clear that this applies to the network service provider with respect to direct control services. A concern with all activities of the regulated entity, and the importance of financing for all network businesses, should form part of the ENA's "central rationale for the proposed Rule Change"[13]. The ENA presents an illustrative example of why applying its approach to the project level would result in better price outcomes for customers. This is simply the result of ignoring the regulated entity's underlying cash flow situation.

The ENA states that "[r]ational firms do not make commercial investment decisions on the basis that projects that are not financeable in their own right can proceed on the basis that they can be subsidised by cash flows generated by other assets."[14] Network businesses undertake a host of spending that does not generate positive cash flow, namely works for replacement, reliability and compliance. These do not enable additional sales or revenue streams in the way that new connections and augmentations do. If anything, Actionable projects are more likely associated with positive cash flows as they are aligned with development pathways associated with high degrees of electrification and new generation and storage connections.

Assessment against the NEO

The ENA's consideration of the NEO does not attempt to address price outcomes and so does not engage with intertemporal and intergeneration issues which are central to this debate. The ENA and its members are best placed to illustrate how the cost of an expected $12.8 billion in network investment (which does not factor in recent cost increases[15] and likely more to follow) will flow through to customers via changes in transmission prices. While higher prices are acknowledged, the ENA asserts these will be more than offset by benefits, referring to AEMO's ISP valuations. The calculation of benefits in the ISP and the Regulatory Investment Test refers to the avoidance of higher cost counterfactuals, and does not reflect forecast reductions in costs or prices. We appreciate that modelling wholesale price effects involves a range of assumptions that can be challenged. However, this is no different to the quantification of market benefits in the ISP that are quoted by the ENA.

The NEO is clear in its reference to price outcomes, rather than the avoidance of higher cost counterfactuals that are presented by the ENA. The policy debate is fraught with examples where the benefits of change for customers have been poorly articulated and misinterpreted.[16] The ENA's proposal perpetuates this confusion, with statements such as consumer benefits from higher network prices are "always at least twice the annual network charge".[17] We encourage the Commission to engage on these issues in its revised approach to reporting retail price trends from next year.

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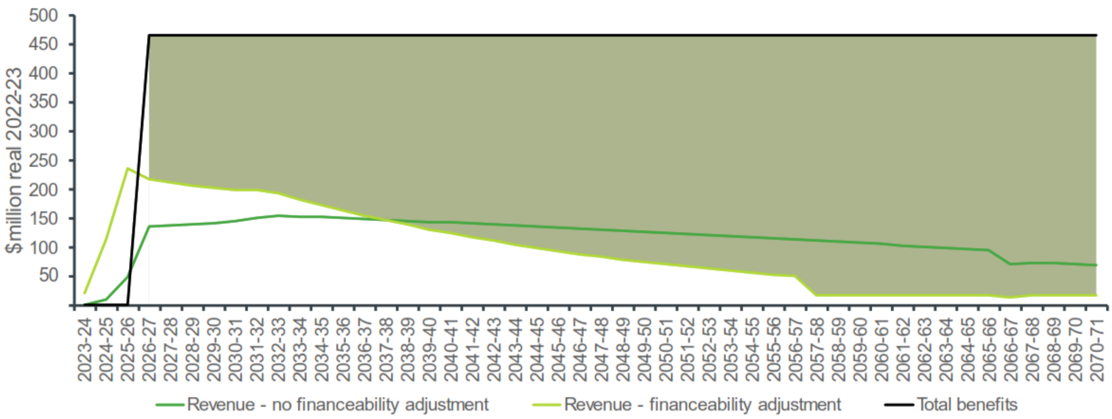
[13] ENA, p. 35.
[14] ibid., p. 21.
[15] Energy transition: Price tag for HumeLink blows out to nearly $5 billion: Transgrid CEO (afr.com)
[16] Climate and Energy Minister Chris Bowen stands by $275 power price cut pledge despite Liberal claims of a broken promise | Sky News Australia
[17] ENA, p. 32

The ENA presents an illustrative example to explore intertemporal impacts, concluding that both existing and future customers will be better off under its proposal.[18] This cannot be the case where revenues are brought forward and prices are elevated in the immediate term. The ENA's example calculation in the chart below of the "revenue – financeability adjustment" approximates transmission prices paid by users under its proposal. These are up to 60% higher[19] than normal in the earlier years but are then considerably lower over the life of the project. Even if 'benefits' are taken to be price reductions from wholesale or other non-transmission costs, this example still illustrates that current users are disproportionately affected, namely that the shaded area of 'net benefit' is smaller in the near term.

Figure 2: Consumer impact of the proposed financeability formula (real $2022)



A more fulsome consideration of long term price outcomes under the NEO brings into question how such 'front ended' pricing profiles would affect customers given there will be multiple Actionable projects constructed over the coming decade. The high capital cost of Actionable projects (which has tended to increase as they progress) combined with the ENA's mechanistic approach, would highly likely invoke front ended depreciation allowances for many of these projects. The ENA's illustrative modelling suggests addressing financeability problems for one Actionable project could require network charges to be materially increased for a 14 year period.[20] This time window coincides with commissioning dates for all current Actionable projects and others contained in the 2022 ISP.

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[18] ibid.
[19] ibid.
[20] ibid.

<u>Problems with a formulaic approach</u>

The ENA's proposed rule drafting is as follows:

> *(f) In making a determination under paragraph (d), the AER must adopt a method of depreciation that is sufficient to maintain the benchmark credit rating at the benchmark level of gearing adopted in the prevailing Rate of Return Instrument for each proposed actionable ISP project for each year of the regulatory determination.*
>
> *For the purposes of determining whether a method of depreciation is sufficient to maintain the benchmark credit rating, the AER must apply the following formula:*
>
> $$35.71\% \frac{FF0/ND_t}{9.0\%} + 28.57\% \frac{FF0\ ICR_t}{2.4} + 35.71\% \frac{Gearing_t}{Gearing_t} \geq 1,$$
>
> *where:*
>
> - *t is the regulatory year;*
> - *$FF0/ND$ is the Funds From Operations (FFO) to net debt ratio calculated using the AER's PTRM;*
> - *9.0% is a benchmark BBB+ threshold for the FFO to net debt ratio;*
> - *$FF0\ ICR$ is the FFO interest coverage ratio calculated using the AER's PTRM;*
> - *2.4x is a benchmark BBB+ threshold for the FFO interest coverage ratio; and*
> - *$Gearing$ is the benchmark level of gearing specified in the applicable Rate of Return Instrument.*

Exploring these proposed provisions illustrates their impracticality and the need to afford the AER (and TNSPs) flexibility.

The "method of depreciation" is not defined but when read in the context of surrounding provisions infers alternatives to a straight-line basis. However, accelerated depreciation under a straight-line method, by shortening the economic lives of some classes of assets, would likely be the most expeditious means to address TNSP cash flow shortfalls. Other methods could more closely sculpt depreciation profiles to provide minimal cash flow adequacy while also minimising price impacts for customers. It is not clear how TNSPs or the AER would have regard to these factors and alternative methods under a mechanistic approach, requiring further supporting rules to ensure the interests of networks and end use customers are appropriately balanced.

Other consequential rule amendments seem necessary. For example, clause 6A.6.3(b)(1) refers to the nature and economic lives of assets e.g. profiles that reflect physical asset condition or extraction of value over time, rather than to satisfy financial ratios. Methods of tax depreciation may also be affected, with the estimate of taxable income prescribed by the PTRM by clause 6A.6.4.

Where the ENA's financing formula is not satisfied, the AER and TNSPs would be required to develop depreciation profiles and parameters that depart from the AER's standard PTRM and roll forward model. The implications of making adjustments to accommodate particular projects or asset classes seem likely to require additional depreciation schedules. Complications may also arise where project cash flows are reassessed at each determination, for example with changes to cost and revenue allocation methods. These changes introduce complexity from a revenue and asset roll-forward modelling perspective. Within this complexity we anticipate opportunities for gaming, and error, which risks violating the principle of neutrality on a net present value basis. In this context, the ENA's consideration of implementation issues is lacking. It finds that financeability assessments would require "simple changes to the PTRM" with no consideration of consequential adjustments to the PTRM and roll-forward models that could be triggered by such an assessment.[21]

A mechanistic approach would force the AER to make modelling adjustments and police depreciation profiles even if there are immaterial and short term variations below the formulaic threshold e.g. one dollar short of a ratio in any single regulatory year. As per ratings agency assessments, some consideration of materiality in these situations is necessary, including consequential administrative costs.

Approaches in finance change over time and prescription in the rules has been shown to produce perverse outcomes when circumstances change. An example of this is in earlier versions of the NER that required the cost of debt (including via mandatory AER guidelines) to be calculated by reference to corporate bonds of a 10 year maturity. This benchmark applied in the wake of the 2008 Global Financial Crisis where almost no such bonds issued or observable in the market, thus undermining the validity of the benchmark and creating various estimation challenges.[22] Even where the AER has flexibility in its approach, its decisions are susceptible to changes by third party agencies at short notice.[23]

The proposed degree of prescription reflects a spurious degree of accuracy which is a common shortcoming of regulatory finance assessments. The construction of the formula by the ENA also invites various debates which are best left to the AER:

- the parameters in its suggested formula have been inferred from Moody's without regard to whether it (or any other agency) mechanistically combines ratings factors in this way
- the ENA reallocates weighting from one quantitative rating factor to others on a pro-rata basis with no justification
- the ENA similarly makes arbitrary adjustments to the remaining quantitative metrics to accommodate qualitative factors, which apparently make up the majority (60%) of Moody's rating assessments
- the codification of parameters that apply universally and without regard to TNSP circumstances is almost certainly likely to err in favour of TNSPs in order to accommodate the worst expected cash flow situations
- there is no consideration of approaches adopted by other ratings agencies, for example S&P and Fitch, whose ratings also inform regulatory determinations
- in response to the AEMC's concerns about relying on a single financial metric, the ENA's proposal relies on two, given that benchmark gearing is a constant and therefore irrelevant.

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[21] ENA, pp. 28, 33.
[22] See various Tribunal appeals, for example Application by United Energy Distribution Pty Limited [2012] ACompT 1 from paragraph 392.
[23] Update | Australian Energy Regulator (aer.gov.au)