SUBMISSION

NATIONAL ELECTRICITY AMENDMENT (ACCOMODATING FINANCABILITY IN THE REGULATORY FRAMEWORK) RULE (ERC0348)

03 AUGUST 2023

INTRODUCTION

The Energy Users' Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade. Our membership covers most of the major gas users in the east coast gas market who all rely on reliable and competitively priced gas for their business sustainability.

The EUAA support the pursuit of net zero targets but this must be achieved at least cost, not at any cost. Additionally, we seek an equitable allocation of the costs and risks associated with the transition as all too often energy consumers are expected to carry the heavy weight of market risk that should sit with market participants. We firmly believe that this transfer of risk is inconsistent with the NEO.

The EUAA welcomes the opportunity to make a submission to the National Electricity Amendment (Accommodating Financeability in the Regulatory Framework) Rule Consultation paper (Consultation Paper).

The EUAA did not support previous requests for a derogation to the rules that would allow transmission companies to effectively front load revenue recovery of large transmission (most notably ISP projects) and do not support this proposed rule change because:

1. It would result in a significant increase in transmission costs in the short to medium-term (cost recovery is front loaded as a result of this proposed rule change) and therefore an increase in final energy bills at a time when they are already escalating at an unprecedented rate.
2. It transfers risk that equity should be taking (as they are in the best position to manage it) to consumers (who have no ability to manage or mitigate it).
3. Increases in transmission prices are locked in (once the project is complete) while benefits are highly variable in both quantum and timeliness making net benefit analysis extremely unreliable. Front loading cost recovery would further exacerbate this situation. Specifically:
    a. While transmission prices are locked in via the regulatory process, capital costs are highly variable up to the point of project completion leaving open the very real possibility that these projects will end up costing up to 50% more than the "advertised price" (this is the experience to date). It is this final cost that consumers will pay.
    b. Net benefit modelling conducted by project proponents consistently show that large transmission projects will not begin to deliver net benefits to consumers for between 10-15 years. Front loading

revenue recovery will not only significantly increase energy bills now but push net benefits even further out into the future.

4. Because of the above, it creates significant intergenerational inequity.
5. One of the main beneficiaries of new transmission are the new assets connecting to it (i.e. VRE, batteries etc) who will see benefits flow from day-one, yet they make close to zero contribution to cost recovery.
6. In the absence of a more equitable cost recovery method (e.g. contributions to transmission cost recovery by connecting VRE and batteries) the issues should be dealt with through other means including re-structuring of debt and equity and for Government to play a significant role over the next 10-15 years via Rewiring The Nation (or other state based approaches) to help ensure a smooth transition to net zero is achieved and consumers are shielded from the risks and uncertainty that is inevitable during this time.

PREVIOUS AEMC DETERMINATION

In rejecting the original derogation request made by Transgrid and Electranet the AEMC made the following observations in its 8 April 2021 Final Determination[1]:

> *Overall, the benchmark efficient entity framework is intended to provide a long-term efficient return on capital. However, there is no expectation that a transmission network business, such as TransGrid, will adopt the benchmark efficient entity's capital structure – that is, the same distribution of debt and equity assumed by the AER to make up the finances of the benchmark efficient entity (currently assumed to be 60 per cent debt to 40 per cent equity).*
>
> *Indeed, in a period of investment and expansion, it is likely that network businesses will need to rely more heavily on finance from equity investors relative to the benchmark assumption in order to maintain the benchmark credit rating. In less capital-intensive periods, revenues may support the benchmark credit rating under a structure more reliant on debt relative to the benchmark assumption. Changes to capital structure of this nature can be considered consistent with a competitive market, in which growth is typically financed by calls on equity and recovered over time. These and other options, which are outside the regulatory framework and which can help to finance new large capital-intensive projects, would be expected to be pursued by regulated entities like TNSPs.*
>
> *The Commission considers the regulatory framework does not create a barrier to TransGrid financing its share of current ISP projects (including Project EnergyConnect). In addition, the Commission is not satisfied that the proposed rule is the best option for providing the right incentives for TransGrid and other TNSPs to invest in ISP projects now and in the future. Making the rule proposed by TransGrid would likely substantially increase costs to consumers in the near to medium term. While lower prices attributable to the low short-run marginal cost generation connecting to the grid and easing of congestion at some locations may flow through later in the life of the relevant ISP projects, the intergenerational wealth transfer caused by the proposed changes to the rules would be unlikely to be in the long-term interests of consumers, particularly given that current consumers would be paying for benefits enjoyed by future consumers.*

This determination, which we agree with, was supported by a significant piece of analysis by CEPA which is referenced by the AEMC:

[1] https://www.aemc.gov.au/sites/default/files/documents/erc0320 - final determination - transgrid - final.pdf

"In assessing the rule change request from TransGrid, the AEMC engaged CEPA to provide advice on the financeability of ISP projects. The first stage of CEPA's analysis considered whether there is a financeability issue. In the second stage, CEPA provided advice on how the AER and TNSPs could respond to an identified financeability concern. CEPA also considered the key impacts of the proposed rule on customers and investors, and the NEO more generally."

"The Commission agrees with CEPA's finding that the regulatory framework does not create a barrier to financing ISP investments including PEC"

In its rule change request, TransGrid asserts that cash flows from PEC (and many other ISP projects) will be insufficient to support 60 per cent debt funding at a BBB+ credit rating (or indeed an investment grade credit rating at all) for an extended period. It argues that as a consequence, this may result in a higher cost of debt that what is suggested by the BBB+ credit rating and a TNSP may find it difficult to obtain finance that is consistent with the regulated rate of return. This claim was based on an analysis of one credit metric, the funds from operations divided by net debt ratio (FFO/net debt), and TransGrid's opinion on how a change in this metric will affect their overall credit rating. The FFO/net debt ratio is one of the measures used by credit rating agencies to assess the level of financial risk of debt funding.

However, the analysis prepared by CEPA for the Commission does not support this claim. As noted by CEPA, the proponent has argued for a substantial rule change based on the impact of its proposed investment program of $9 to 10 billion over the next 10 years on one credit metric — the FFO/ net debt ratio. In practice, rating agency assessments are more sophisticated, reflecting other financial credit metrics and a range of qualitative factors including the quality of the entirety of the regulatory framework.

CEPA's analysis shows that ISP investments are unlikely to prompt a rating downgrade to below investment grade for a business financed at the AER's notional gearing, given that business's expected profile of ISP investments. By modelling the credit scoring framework used by rating agencies using the full range of different quantitative metrics and qualitative factors, CEPA's analysis shows that a notional TNSP would be able to maintain an investment grade rating with this assumed investment profile.

Further, while CEPA's analysis supports TransGrid's claim that performance against the FFO/net debt ratio would likely improve if the proposed rule was made, CEPA also shows that the notional entity with an investment profile consistent with TransGrid's share of ISP projects would be able to achieve a similar improvement in this ratio by using a gearing level of 55-58 per cent.

Based on this analysis, the Commission does not consider that the regulatory framework is creating a barrier to TransGrid financing its share of current ISP projects. The Commission also notes CEPA's finding that the effect of the proposed rule on the ability of the notional entity to finance these projects is not likely to be material.

There are options available to TransGrid outside of the regulatory framework to help it manage financeability

We do not believe there has been a material change in circumstances such that it would justify the AEMC coming to a different conclusion when assessing this rule change request. The projects identified by AEMO in the 2020 ISP are the same projects identified in the 2022 ISP and while timing of projects may be subject to change (although given significant social licence issues the current expected build dates seem optimistic) we do not believe that would have a material impact on financability over a period of 2-3 regulatory cycles (10-15 years). Furthermore, we are not aware of significant new evidence being made available by TNSP's or the AEMC or revised analysis by CEPA that would justify a different conclusion by the AEMC.

STAGE 2 TRANSMISSION PLANNING AND INVESTMENT REVIEW

We were surprised to find that less than 12 months after making what we believed was a well-reasoned, evidence-based decision that the AEMC changed its view on financability as part of the Stage 2 Transmission Planning and Investment Review (TPIR). As noted above the AEMC relied on significant analysis to support the original rejection of the derogation request, but it does not appear that similar analysis has been supplied to justify the change of view other than to point to the issue of project "bunching", which in our view is not as material (if at all) to the issue of financability as it is being claimed given the issues described by project proponents tend to resolve themselves over 2-3 regulatory periods.

In our 14 July 2022 submission to the Stage 2 Draft Recommendations for the Transmission Planning and Investment Review we wrote:

> *"Perhaps EUAA members should not be surprised that equity investors want to push even more risk onto consumers. We keep being told about the huge amounts of capital that are 'ready' to invest in the transition if only we had 'the right policy settings' or 'supportive Government policy' which are just code for some form of subsidy at either electricity consumers or taxpayers' expense. We are expected to subsidise equity returns because we are told 'it is in our long-term interests'. We are not convinced.*
>
> *Were the AER to be given discretion to vary the depreciation profile we support the bespoke approach proposed in the Draft to adjust the rate of depreciation on a case by case basis. We do not support introducing a financeability or commercial viability check into the revenue setting framework."*

It does not appear to us that there has been a material change in circumstances that would cause the AEMC to come to a different decision. It also does not appear to us that project proponents have sufficiently demonstrated that they have sought to pursue alternative measures to resolve their claimed issues as set out in the CEPA report.

Neither the rule change request or the Consultation Paper sufficiently make the case for change, provide evidence to support the change or clearly demonstrate consumer benefits from the proposed change. Unsubstantiated statements are not a substitute for independent analysis and impartial assessment.

INTERGENERATIONAL EQUITY. PAY TODAY BENEFIT TOMORROW?

In the absence of evidence to support the rule change or to materially substantiate the claim that it is in the interests of consumers, including the assertion that increased costs associated with transmission will be quickly negated by lower energy costs, we put forward the following to provide the AEMC with context as to why we are so concerned.

The argument is often made that while the cost of building transmission is significant, this cost will be negated by low cost renewable energy entering the system in years to come. A number of key assumptions need to be made for this to be the case being:

1. New transmission will be delivered at the promised cost as expressed in the ISP (and elsewhere).
2. The future cost of renewable energy will be significantly cheaper than it is today.
3. Wholesale costs will remain an accurate and/or relevant metric of consumer value.

There are good reasons to question the validity of these assumptions.

New Transmission Costs

The 2022 AEMO ISP identified 5 transmission projects that are on their Optimal Development Path (ODP) with a total capital cost of $12.8b. However, given this is a very early estimate and based on recent experience of significant cost increases associated with all forms of infrastructure, the potential variation in capital cost will be anywhere between 30% to 50% depending on the state of progress of each project. Project Marinus, which is probably the most advanced of these ODP projects, still faces a potential increase of 30% above the capital costs stated in the ISP.

Based on our experience with Project Energy Connect where capital costs increased from an initial estimate of $1.5b to $2.4b with the potential for more cost to be added post project completion, we would anticipate that the 5 projects identified as being on the ISP ODP will end up costing in excess of $20b, not the $12.8b stated in the 2022 AEMO ISP.

It is impossible for consumers to have any confidence in net benefits when the costs are subject to such extensive variation. Given the situation all infrastructure proponents are dealing with (supply chain constraints, skilled labour shortage, rising interest rates etc) it is difficult to envisage anything, but significant cost over runs on all transmission (and energy generation) projects. This puts both the cost and potential net benefits in doubt.

Table 6 Actionable network investments in the optimal development path

Project	Actionable ISP delivery date – to be progressed urgently[Ω]	Description	Actionable framework
HumeLink	July 2026	A 500 kV transmission upgrade connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby. Cost estimates of $330 million (stage 1) and $2,985 million (stage 2).	ISP (RIT-T is complete)
Sydney Ring [¥]	July 2027	High capacity 500 kV transmission network to reinforce supply to Sydney, Newcastle and Wollongong load centres. Cost estimates of $0.9 billion ±50% for northern option, and $2.25 billion ±50% for southern alternative option.	NSW [†]
New England REZ Transmission Link	July 2027	Transmission network augmentations as defined in the New South Wales Electricity Strategy, costing $1.9 billion ±50%.	NSW [†]
Marinus Link	Cable 1: July 2029 Cable 2: July 2031	Two new HVDC cables connecting Victoria and Tasmania, each with 750 MW of transfer capacity and associated alternating current (AC) transmission, costing $2.38 billion ±30% (cable 1) and $1.40 billion ±30% (cable 2). [‡]	ISP (RIT-T is complete)
VNI West	July 2031	A new high capacity 500 kV double-circuit transmission line to connect Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan) via Kerang, costing $491 million (stage 1) and $2.5 billion* (stage 2).	ISP (RIT-T is in progress)

It is not only the cost side of the ISP business case that is concerning but on the assumed benefits. For example, page 65 of the 2022 ISP states that:

> *"Through network investment, cost savings can therefore be delivered for consumers:*
>
> - ***in the next 15 years**, by balancing use of existing generation against even-more-rapid development of VRE and storage to achieve the decarbonisation outcomes over the ISP horizon.*
> - ***in the longer term**, by avoiding the need to rely on greater volumes of gas-fired generation and generation technologies that are currently more-costly such as off-shore wind (and associated fixed operating and maintenance [FOM] costs). This benefit is forecast to increase over time and will continue to be realised beyond the ISP's 2050 planning horizon."*

These assumptions seem to ignore the reality of what we currently see occurring in the NEM:

- **in the next 15 years**: there is a growing desire/need for governments to keep existing generation assets operating to "keep the lights on" while at the same time working to push fuel prices down (coal price cap and gas industry code of conduct). The delay in new VRE and transmission is being impacted by issues such as community social license but is also being impacted by supply chain constraints, the inflationary effect of the current infrastructure boom[2] and the significant skills shortages the energy industry is experiencing.
- **in the longer term**: we see significant government policy designed to bring forward off-shore wind such as Victoria[3] who have ambitions targets that undermine the assumption that deployment of these "more-costly" technologies will be avoided or greatly-diminished. Other states are developing similar ambitious

[2]Article in The Australian newspaper identifying the significant challenges faced by large infrastructure proponents and the inflationary impacts of the current boom. https://www.theaustralian.com.au/nation/politics/230bn-in-infrastructure-spending-by-states-fuelling-inflation/news-story/65ac12cd34dd67fec570ab5f349cec94?btr=828613e6da1f38ebd0ba50f79dab75f3

[3]Victorian off-shore wind targets are 2GW by 2032, 4GW by 2035 & 9GW by 2040. https://www.premier.vic.gov.au/next-step-developing-thriving-offshore-wind-industry

targets[4] while the commonwealth continues to clear the regulatory and approvals path through declaration of various off-shore wind energy zones.

Future Cost of Renewables

The future cost of renewable energy is often touted as a significant advantage and that lots of low cost VRE will more than off-set the increased cost associated with transmission. It is true that the cost of VRE was tracking downwards for many years. The following chart, taken from the most recent CSIRO Total GenCost report clearly shows that VRE is the cheapest energy source available on an LCOE basis.

We note that since this report was finalised the impact of external events (i.e. Russia-Ukraine war, USA Inflation Reduction Act) on global supply chains, especially the dramatic increase in global demand for materials and equipment central to building a net zero energy system and internal issues impacting domestic infrastructure such as interest rates and shortage of skilled labour appear to be pushing up the cost of new build VRE.

Anecdotally, new wind and solar (large scale) projects now require $80MWh for the project to be commercially viable. This aligns with EUAA members comments on their recent dealings in the corporate PPA market. We await the next iteration of the CSIRO report to help with our understanding.

This illustrates the fraught nature of net benefits modelling to underpin justification of this rule change with the assertion that it is in the interest of consumers.

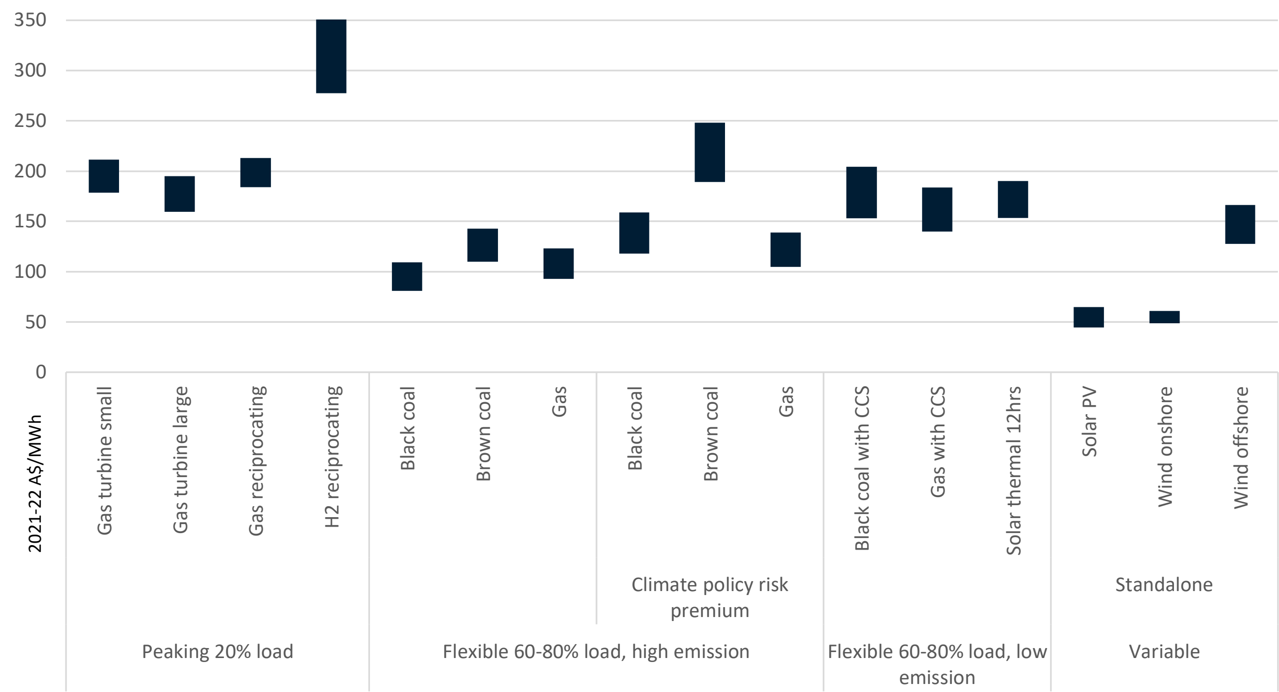

Figure 5-3 Calculated LCOE by technology and category for 2021

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4 NSW are actively considering off-shore wind targets. https://www.afr.com/companies/energy/nsw-mulls-offshore-wind-targets-for-the-state-buoyed-by-advice-20230302-p5cox9

Longer-term it is asserted that once we get to an 80%+ renewable energy system that energy will be extremely low cost. There are good reasons to question that validity of this claim.

Analysis undertaken by the EUAA finds that given the average operational life of wind and solar is between 20 to 25 years:

1. By 2035, a majority of the renewable assets on the ground (and on roof tops) today will have to be replaced.
2. By 2050, all renewable energy assets will have to be replaced; some will be approaching their 3rd investment cycle.
3. Based on the AEMO ISP step change scenario the NEM will be anywhere between 300GW to 350GW by 2050. This means that between 10GW – 12GW of renewable capacity will need to be replaced annually.

This ongoing need for repowering existing sites will ensure that wholesale energy prices need to be maintained at an investible level (i.e. $60MWh to $80MWh). Solar is easier to re-power, but wind energy requires a complete re-design and re-build from the foundations up. Therefore, we need a more realistic view of future energy costs to be considered when attempting to assess the long-term interests of consumers. Energy won't be virtually free as some people suggest because the last time we looked equity wants a return, banks want their money back and staff need to be paid.

Wholesale costs as a reliable metric of consumer value

As we transition from a highly centralised generation system dominated by dispatchable thermal resources to a highly decentralised system dominated by Variable Renewable Energy (VRE) resources a number of key challenges are becoming apparent.

Traditional dispatchable fossil fuelled generators that to date have provided energy users with a bundle of services that were folded into the provision of energy including, energy (MWh), dispatchability, system strength and inertia, is rapidly exiting the market. Some estimates indicate that all traditional dispatchable generation would have exited the NEM by 2040 or even sooner.

While the provision of zero emission energy is of great value, VRE alone is not currently required (or able) to provide a number of these services vital to the reliable and efficient operation of the energy system. From an energy system perspective, 1MWh of energy from VRE is less valuable than 1MWh of energy from traditional sources.

The unbundling of these services, including capacity/dispatchability, system strength, inertia etc, means they now need to be provided (and priced) separately. In recent years we have begun to see the costs of this unbundling become more material with the increased frequency and cost of AEMO market interventions (RERT, Market Directions etc) and increasing FCAS cost, although it must be said that some of these costs are a result of other factors such as generator bidding and escalating gas costs making gas peaking plant uncompetitive at times.

We are also observing the trend of governments taking more direct control of the transition as they seem to have lost faith in the market to deliver the outcomes they desire. We see this situation being repeated along the entire energy value chain where costs and risks that should be borne by market participants (via wholesale markets) are being pushed into regulatory and/or quasi regulatory processes. State based CFD arrangements such as VRET in

Victoria and NSW LTESA's (providing a price floor) shift cost and risk from wholesale markets into quasi regulated environments where costs are simply passed through to consumers.

So, what does this mean for the NEM? You could argue that the NEM is no longer an energy only market but a hybrid energy/capacity market where costs and risks are increasingly being transferred to consumers either via subsidy schemes or state directed initiatives.

All of this is reducing the primacy of wholesale markets and therefore the relevance of wholesale prices as a sole metric for consumer value. Consumers pay the entire energy bill not just a piece of it. Therefore, when assessing the consumer value or "net benefit" the sum of the parts needs to be considered in determining if consumers are better off, not just the bits that make the model work.

Allocation of Benefits

The EUAA agrees with the TNSP's that the risk associated with new green fields transmission networks (ISP projects) is different to the risk associated with brown fields transmission augmentations. The changed risk profile can be attributed to several factors including:

- the sheer quantum of transmission projects in Australia and globally, creating supply chain constraints, skilled labour shortages, resource shortages etc.
- social licence issues
- lack of utilisation of the transmission line in the early years until the connecting VRE are built and commissioned.

It is this last point that is the reason that the net benefits for consumers for an ISP project will not be realised for many years after energisation of the transmission line. Thus, the net benefits for consumers in the early years are negative and will be pushed further into the future if TNSP's are allowed to have higher depreciation rates in the early years (i.e. consumers would be paying for benefits they may receive in the future).

A more detailed analysis of the net benefits for the ISP projects reveals that the benefits are shared. The beneficiaries being:

- the TNSP, through an increase in its RAB,
- generators through access to customers, and
- consumers through access to electricity.

However, the above analysis does not take into account when the benefits arise. Allocating the benefits on a timescale shows that there is a public good associated with building the ISP projects ahead of confirmation and commitment of new generation and/or load (that would occur in the case of brownfields augmentations). It is these public benefits, which include the socialised benefits of continuity of electricity supply during the transition, that drive the development of the ISP projects.

It is clear that in the formative years of a new transmission line there are direct benefits for connecting generators and the TNSP, there are public and social benefits in energy continuity but negative net benefits for energy users. During a rapid transition, governments can play a positive role by "bridging the gap" by supporting the benefits associated with delivering a project that is in the public good, despite it not delivering net consumer benefits. We consider a number of ways government can do this in the next section.

ALTERNATIVE SOLUTIONS

Industry

We refer you to the suggestions made by CEPA in their analysis for the first rule change derogation that was rejected by the AEMC and repeat the statement that:

> *… in a period of investment and expansion, it is likely that network businesses will need to rely more heavily on finance from equity investors relative to the benchmark assumption in order to maintain the benchmark credit rating. In less capital-intensive periods, revenues may support the benchmark credit rating under a structure more reliant on debt relative to the benchmark assumption. Changes to capital structure of this nature can be considered consistent with a competitive market, in which growth is typically financed by calls on equity and recovered over time. These and other options, which are outside the regulatory framework and which can help to finance new large capital-intensive projects, would be expected to be pursued by regulated entities like TNSPs.*

Restructuring financial arrangements is not unusual and in the case of regulated assets where returns on equity are guaranteed, not excessively risky. We are not convinced and have not received any evidence that the proponents have undertaken all possible options to restructure their financial arrangements to manage an issue that will likely resolve itself with 2-3 regulatory cycles.

We would also argue that for transmission assets that are proving troublesome for the host TNSP to fund (which, as we are told is an issue for the TNSP and its equity holders) that the host TNSP gives up their right to build these assets and they are made contestable. This is already the case in Victoria and we have already seen that NSW Roadmap REZ are fully contestable transmission assets.

Government

We believe Rewiring The Nation (RTN) should be reconfigured to bring about a material reduction in Transmission Use Of System (TUOS) charges faced by consumers over the coming 10-15 years, reflecting the public goods associated with the ISP projects. The 2022 AEMO ISP states that 10,000Km of new transmission will be required to achieve a net zero energy system. This will place significant pressure on final energy bills. RTN funding is designed to get transmission built and reduce consumer bills. The degree to which the significant increase in TUOS will be mitigated will depend on how RTN funding is delivered.

The following analysis shows that low cost loans have negligible impact on the TUOS that consumers will pay. EUAA and ECA commissioned Boardroom Energy to undertake some indicative analysis of the consumer benefit of concessional finance as a grant compared to debt. If RTN followed an equity injection or an equity own and transfer approach (capital recycling) then consumer benefits are far greater as they reduce TUOS payments for a period of time and would reflect the public goods associated with the project. Concessional finance as debt may help the project proponent to secure finance but it has limited positive impact on consumers.

Type	Impact on government finances	Capital recycling?	Impact on TNSP	Impact on customers (no change to NER/NEL)	Impact on customers with change to NER/NEL
Grants	Expenditure - direct hit to bottom line	No	Reduce financing requirement	Reduce (TUoS) charges	Reduce charges
Equity injections	Balance sheet item - may eventually need to be written down depending on future returns	Yes	Reduce financing requirement	None	Reduce charges
Own and transfer	Temporary balance sheet item	Yes	Reduce financing requirement, but may have to share ownership with government	Reduce charges	Reduce/defer charges
Low cost loans	Balance sheet item - may eventually need to be written down depending on future returns	Yes	Cheaper finance	None	Moderately reduce charges
Deferred interest loans	Balance sheet item - may eventually need to be written down depending on future returns	Yes	Deferred cashflow	None	Moderately deferred charges

Source: Boardroom Energy analysis

Table 3: Indicative savings

Reference	Item	Value
A	new asset value ($m)	3300
B	asset life (years)	50
C = (A/B)	annual depreciation ($m)	66
Indicative rate of return		
D	RoD	4%
E	RoE	6%
F	gearing	60%
G = D*F + E*(1-F)	allowed return	4.8%
H = G*A	initial year return ($m)	
J	Component that is concessional finance	750
Scenario 1: concessional finance as grant		
K = J/B	Depreciation saved	15
L =J * G	return on capital saved	36
M =K + L	Annual savings if asset covered by grant	51
Scenario 2: concessional finance as debt finance is at 200bp below market		
N = D – 2%	concessional interest rate	2%
P = N *F + (1-F)	cost of capital	3.6%
Q =L – (J * P)	**Annual savings**	**9**

If concessional finance is the preferred method, then in order to resolve the claimed issues faced by TNSP's the Commonwealth could consider:

1. Increasing the amount of debt, they contribute to the project. i.e. Assuming a benchmark debt to equity ratio of 60-40 the split would be 40% equity, 30% Commonwealth debt, 30% non-government debt,
2. Scaling Commonwealth cash flows (in both return of debt and return on debt) to ensure the risk profile of non-government debt providers is sustainable (i.e. cash flows to non-government debt providers is given priority).
3. Debt provided at a substantial discount to commercial debt providers.

Essentially this would mean Commonwealth debt is subordinate to non-government debt while the Commonwealth seeking a lower return on capital (perhaps a zero-margin bond rate) and of capital (a shaped repayment schedule) reflects the "public good" aspects of these projects. Given the issues seem to revolve around non-government debt providers, as a quid-pro-quo, equity would need to demonstrate that they have made all attempts to re-structure their own financial arrangements to minimise the likelihood that the commonwealth is not simply taking on equity risk as well.

RESPONSES TO CONSULTATION PAPER QUESTIONS

CONSULTATION PAPER QUESTION	EUAA RESPONSE
QUESTION 1: IDENTIFYING THE PROBLEM Do stakeholders have any new information or views on the problem raised in this rule change request, having regard to what has already been consulted on and established in TPIR?	We do not believe that the situation facing TNSP's has materially changed since the AEMC determination on 8 April 2021. While Capex is likely to increase, the scale and timing of developments are of the same magnitude as contemplated in the original AEMC decision (i.e. 2020 ISP identified the same projects as the 2022 ISP). Additionally, while the 8 April final determination used significant analysis from CEPA to support its position, neither the AEMC or TNSP's have provided similar independent analysis that supports a different view. In any case we remain of the firm view that these are issues that should be dealt with by project proponents and governments as they are in the best place to manage these issues. Pushing risks (and costs) to consumers who have no means to manage these risks is not consistent with the NEO.
QUESTION 2: HOW TO ASSESS FINANCEABILITY APPLICATIONS (a) Should TNSPs have to submit an application to the AER to vary the depreciation profile of actionable ISP projects? If so, what information should this include? (b) Should the AER vary the depreciation profile of actionable ISP projects using principles or a prescriptive approach? (c) What level of AER discretion is appropriate? (d) Do you consider that the proposed principles are appropriate? Should any other assessment factors be taken into account?	Recognising that we do not support this rule change, we agree that TNSP's should submit an application to the AER to vary the depreciation profile of actionable ISP projects. Applicants should demonstrate (in detail) that their existing financial arrangements align with benchmark debt to equity rations of 60-40, have pursued all possible alternative approaches, including financial structures outlined in the CEPA analysis (including equity taking on more responsibility as per standard practice during periods of high growth) and alternative structures as part of RWTN. This should be submitted for independent verification by the AER against a detailed list of requirements (i.e. benchmark gearing levels as a minimum standard). The AER determination should be made public including evidence to support the decision. The AER should use a set of principles (as outlined in the Discussion Paper) to guide their assessment. We do not support a prescriptive approach as every situation will be unique. We also support a high level of AER discretion for the same reasons (i.e. every situation is unique). We would also argue that if an arrangement was entered into then it should only last until such time that the

	proponent has "returned to normal" (i.e. credit rating is maintained/recovered).
QUESTION 3: LEVEL OF FINANCEABILITY ASSESSMENT (a) Should the financeability assessment be at the TNSP RAB level or the ISP project level?	When assessing eligibility, financial assessment should be at the TNSP RAB (enterprise) level as TNSP's typically use a corporate facility to support development of new assets. Therefore, the position of the entity as a whole should determine eligibility. Even if a different funding structure was adopted (i.e. project financing) ultimately that asset value is included in the TNSP RAB. Application of the revised arrangements as determined by the AER should then be made at an ISP project level with a separate RAB determination for the asset in question.
QUESTION 4: FINANCEABILITY ASSESSMENT PROCESS AND TIMING Is the proposed process and timing to assess requests to vary depreciation for actionable ISP projects practical and efficient? If not, what alternative processes and timings do you suggest being specified in the NER?	The proposed process and timing seem reasonable provided there is sufficient time for interested parties to engage in the process. A minimum of 6 weeks to assess and respond to the proposed issues paper is recommended. We also suggest a minimum of 2 consultation sessions involving consumers, the applicant and the AER be held at least 2 weeks before submissions to the issues paper close.
QUESTION 5: WILL THE PROPOSAL RESOLVE THE PROBLEM? (a) Will the proposed solution to vary depreciation profiles resolve the problem raised in the rule change request? Would it reduce or eliminate the need for concessional finance from governments for ISP projects? (b) Are there any alternative solutions that would resolve the problem and be more preferable and aligned with the long-term interests of consumers?	Given we are not convinced there is a material problem to be solved all we see this rule change achieving is to transfer equity participant risk to consumers. We note that Minister Bowen has stated that if adopted, this new rule would be the primary mechanism that TNSPs use to address their financeability concerns. This raises a number of questions: 1. What is the future of RTN? 2. Will projects that have already received RTN funding (or other government assistance) be eligible for altered depreciation schedule? 3. Will they be required to return RTN funding given the financability rule change is intended to resolve their claimed issues? 4. If they are allowed to keep RTN funding (or other government assistance) should that be excluded from a proposed accelerated depreciation schedule? Received RTN funding (or other government assistance) and altered depreciation schedules would be double dipping forcing more costs on both taxpayers and energy users. This will be something that needs to be considered as part of the transitional measures. The AER should be given discretion to make judgements on a case by case basis. For example, specific circumstances for Marinus Link are likely to be different to specific circumstances for Humelink or VNI West.

	We believe that there are other options to resolve the claimed problem that we have outlined in the first part of this submission (Alternative Solutions)
QUESTION 6: AER GUIDANCE Should the AER be required to publish guidance on how it may vary the depreciation profile for assets that form part of an actionable ISP projects?	Yes. Transparency and accountability of all parties concerned is fundamental to building consumer trust and confidence that the actions being taken are in their interest.
QUESTION 7: TRANSITIONAL ARRANGEMENTS (a) If the proposed rule is made, should the AER be required to develop any guidance, or amend any AER models, before or after the commencement of the rule? If so, what level of prescription should be included in the NER? (b) If the proposed rule is made, should it provide a transitional period to enable market participants to prepare? If so, how long should such a transitional period be? (c) Is there a need for any transitional arrangements to assist with managing interactions other NER amendments or other market reforms? If so, what?	The AER should develop guidance on transitional arrangements and be able to use their discretion based on a set of agreed principles. We do not support a prescriptive approach. Principles and AER discretion must include how existing RTN funding (or other government assistance) is treated (see our response to Q5). .
QUESTION 8: BIODIVERSITY OFFSET ARRANGEMENTS ACROSS NEM JURISDICTIONS Are the costs of meeting biodiversity obligations material? Are they likely to impact financeability of actionable ISP projects?	We agree that the cost of meeting biodiversity obligations could be material as demonstrated by the additional $1b biodiversity costs for the proposed Humelink project. However, these costs should be well known and anticipated by project proponents as they are the party deciding on the transmission corridor. These costs should not be considered differently to other costs under the control of the project proponent.
QUESTION 9: RECOGNISING AND MANAGING BIODIVERSITY OFFSET COSTS (a) Does the AER already have discretion to do what the rule change request is proposing (i.e. applying depreciation as incurred for transmission assets)? (b) Should land purchased specifically for the purpose of meeting biodiversity offset obligations be depreciable? Should other costs of meeting biodiversity offset obligations be depreciable? (c) Do you agree or disagree that recovering depreciation of biodiversity offset costs as incurred (as opposed to as commissioned), would be an appropriate solution to the financeability problem? Does this re-allocate completion risk from TNSP's to consumers?	We do not support recovery of depreciation of biodiversity offsets on an as incurred basis. We note one of the reasons given by the AEMC to refuse the initial derogation (8 April 2021) as restated on page 32 of this Discussion Paper is: *"In our final determination, we considered the proposed participant derogations to apply depreciation on an as incurred basis, rather than on an as commissioned basis. We decided not to make either rule as it would transfer completion risk from Transgrid and ElectraNet to consumers, who are not best placed to manage these risks."* We agreed with that reasoning then and we agree with it now. If the AER were to use its discretion in this matter, biodiversity offsets could be dealt with as part of an early works CPA, assuming the usual independence and rigour is

(d) Is the nature of biodiversity offsets different from other assets that comprise a specific actionable ISP project, such that biodiversity offsets should be depreciated on a different basis to other assets?	able to be applied by the AER to ensure the investment is prudent and efficient.
QUESTION 10: APPLICATION OF PROPOSED SOLUTION TO INTENDING TNSPS If TNSPs are able to recover depreciation of biodiversity offsets on an as incurred basis, should this be extended to intending TNSPs?	We do not support recovery of depreciation of biodiversity offsets on an as incurred basis and therefore it should not be extended to intending TNSP's.
QUESTION 11: CLARIFYING DEPRECIATION TREATMENT OF ASSET CLASSES (a) Do you agree with the proposal to require the AER to explicitly outline how depreciation would apply to all asset classes in actionable ISP projects? Should this include biodiversity assets? (b) If you agree that the deprecation treatment of asset classes should be documented, how should it be implemented — through the NER, AER guidelines and/or other methods?	Recognising we do not support this rule change, we agree that the AER should be able to use its own judgement, based on independent assessment and free of external influence in exercising discretion on how depreciation should be applied. As above, we do not support recovery of depreciation of biodiversity offsets on an as incurred basis, but the AER should have discretion on depreciation of biodiversity offsets post commissioning.
QUESTION 12: ASSESSMENT FRAMEWORK Do you agree with the proposed assessment framework? Are there additional principles that the Commission should take into account or are there principles that are not relevant?	We agree with the assessment framework especially as it relates to: 1. Consumer costs (and the inherent uncertainty of both costs and benefits modelled by project proponents). 2. Risk allocation and who is best placed to manage it 3. Intergenerational equity

Once again, thank you for the opportunity to participate in this process. Do not hesitate to get in contact should you have any questions.

Sincerely,

Andrew Richards
Chief Executive Officer