SUBMISSION

AEMC COGATI RENEWABLE ENERGY ZONES – DISCUSSION PAPER
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EUAA
Energy Users Association of Australia

AEMC
COGATI –Renewable Energy Zones Discussion Paper
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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 and materials processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and expect to see all parts of the energy supply chain making their contribution to the National Electricity Objective.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing stress due to escalating energy costs. These costs are either absorbed by the business, impacting their competitiveness and reducing their ability to maintain current levels of employment, or passed through to consumers, increasing the cost of many household items for every Australian.

We welcome the opportunity to make a submission to the Coordination of Generation and Transmission and Investment (COGATI) – Renewable Energy Zones Discussion Paper (Discussion Paper). We have also made a submission to the Proposed Access Model Discussion Paper that sits alongside. The EUAA has already made a number of submissions to the COGATI process including to the Options Paper in October 2018, to COGATI Implementation – Access and Charging Consultation Paper in April 2019 and to the COGATI Access and Charging Directions Paper in August 2019. We were also pleased to participate in the Melbourne workshop on 8th July 2019 and are regular participants as part of the Technical Working Group.

The consistent theme of these submissions has been to challenge the assumption that consumers would continue to pay the full cost for network augmentation that is required over the coming years, including these already identified in the AEMO Integrated System Plan (ISP). To be clear, we are not opposed to new network assets being built to facilitate new generation, for interconnectors to be built that allow market participants greater access to the market and to provide the market operator with improved flexibility to manage the energy system.

Our concerns have always been and continue to revolve around the assumption that a vast majority of the costs associated with these new assets will be included in the Regulated Asset Base (RAB) of the network companies involved, meaning consumers would not only pay the entire cost but carry all the volume risk. We are pleased to see that the AEMC appears to understand this and is now considering a number of alternative funding models for Renewable Energy Zones (REZ).

Superficially, developing alternative funding models for REZ appears to be a straight forward process of cost allocation and granting of guaranteed access rights. The interaction of this with the existing open access regime and the Regulated Asset Base (RAB) model of assessment and tariff setting, is somewhat more challenging. However, if a new asset class is most suitable to a revised funding model it is REZ given they either tend to be discrete assets developed specifically for new energy resources or the additional costs associated with increasing transmission due to REZ can be more readily identified.

We look forward to continuing with this important reform that, while linked to the work being undertaken by the AEMC on the COGATI Access Model, can and should be pursued independently.

CONTEXT - THE ENERGY TRANSITION EQUATION

With the transition of energy markets fully underway we are faced with the need to make significant network investment to bring new generation capacity to market and to facilitate a two-way grid as energy users are now both consuming and dispatching energy. We are also faced with a diminishing volume of dispatchable generation as legacy coal fired power stations come to the end of their economic life.

The EUAA have looked at this situation carefully and have concluded that in order to grapple with this paradigm shift we need to solve what we call the "energy transition equation". This equation being the cost of energy + the cost of system balancing + the cost of grid infrastructure. When added together this equals the total system cost of the energy transition we are in the midst of. Understanding total system cost is critical to consumers as that is the number that appears on their monthly bill. Equally, understanding what is required to drive down costs of the individual components of the energy transition equation will help guide policy, regulation and targeted government support.

The COGATI process in general and this REZ Discussion Paper specifically, seeks to provide a new cost and risk sharing platform so that this transition is managed as efficiently as possible and that those who should bear cost and risk, do so.

Following is a brief summation of our views on system balancing and grid augmentation elements of the Energy Transition Equation.

<u>System Balancing</u>

Clearly, greater effort to accelerate the deployment of technologies that "firm up" variable renewable energy and balance the energy system must be the new priority. Governments are already playing a role in this through Snowy 2.0 and the Underwriting New Generation Investment (UNGI) program. The chart below is taken from the CSIRO Total GenCost Report, released in December 2018 which provides an estimate of the total generation cost (LCOE plus firming) of renewable energy compared to a range of other generation technologies in 2040.[1]

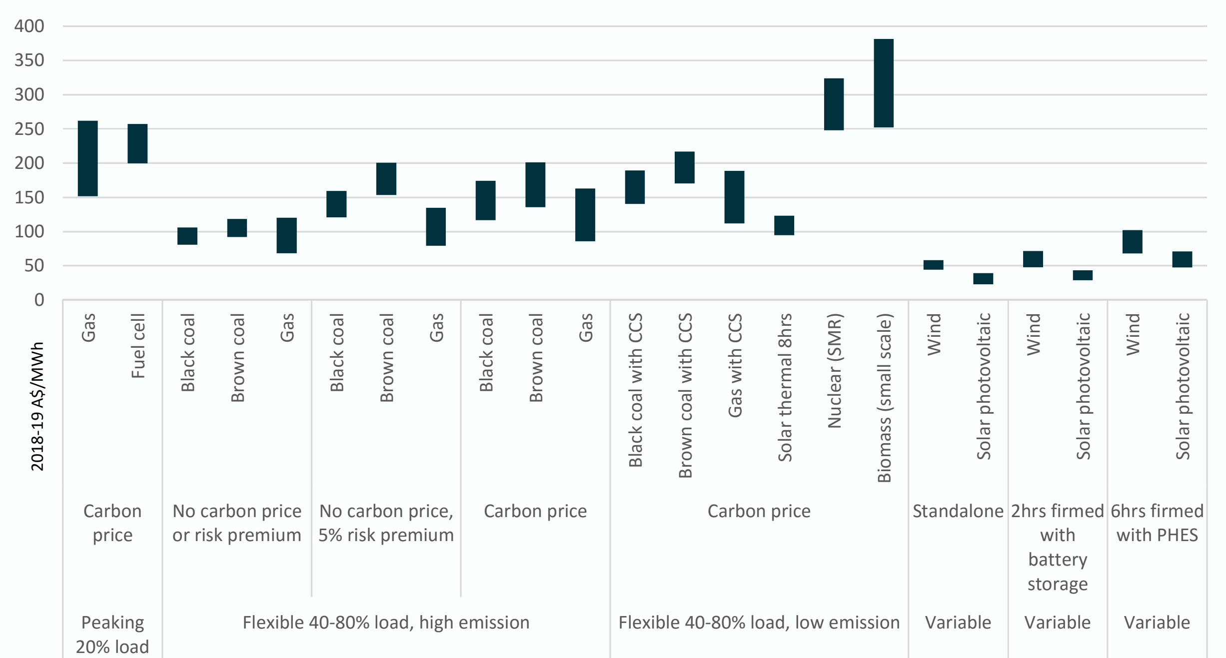

Figure 4-4: Calculated LCOE by technology and category for 2040

[1] https://publications.csiro.au/rpr/download?pid=csiro:EP189502&dsid=DS1

It is clear from this work that in 2040, renewable energy with storage delivers the lowest cost generation outcome. Therefore, we suggest that every effort should be made to accelerate the cost reduction of these energy balancing technologies with the goal of achieving the 2040 cost projections by 2030. This would also align with the closure of a significant amount of legacy coal fired capacity. We recognise a suite of measures are already being pursued (see our comments om Capacity Markets) and recommend that we fully understand the impact of these before making additional, substantial changes.

Grid Augmentation

The final element of the energy transition equation is grid costs. Historically, consumers would pay all the costs and essentially take much of the risk of upgrades to the grid. However, historically the entire energy system was state-owned where a majority of the benefits were returned to customers and taxpayers. With privatisation of the energy industry this is no longer the case, so costs and risks need to be shared between all those who receive benefit, including renewable energy companies seeking to connect to the shared energy system. Consumers are happy to help pay but are also looking for everyone else to pay their way as well.

For example, many of the assets identified in the AEMO ISP will help facilitate the introduction of new generation including variable renewable energy and access to firming capacity required to balance the system. This new generation, being privately owned and operated, is set to gain significant financial benefit from these assets while consumers cover the cost associated with this access.

It must be recognised that consumers have no control over the financial viability or operation of these assets but are currently expected to carry the cost, volume and technology risks. While consumers may receive some benefit from new transmission assets, given the fluctuating nature of the energy market and the risks involved, these benefits may be fleeting at best. In any case, the principle of only paying for that benefit that is reliably received should guide future cost and risk allocation in this area.

Therefore, we firmly believe these commercial entities should make a reasonable co-contribution to the cost and maintenance of these assets. We recognise that moving to a form of generator co-contribution could result in slightly higher contract prices (i.e. PPA's) as project proponents seek to recover these additional costs.

So yes, while the customer will always pay we should not continue to be asked to absorb aspects of project risks and costs that we have no control over or be faced with paying "full weight" for underutilised assets. Further, we contend that exposing more network costs to open markets and competition will drive better outcomes for consumers compared to a regulated environment that, despite good intentions to deliver a result that replicates a competitive market outcome, has not always proven to be so.

COGATI AND REZ

Section 3 (page 19)[2] of the discussion paper identifies two basic forms of REZ being:

Type A REZ: as a cluster of generators connected to the shared transmission network via a (large) dedicated connection asset. For a type A REZ, the transmission investment associated with the REZ are connection assets. These connection assets are paid for by the connecting party (or a party on their behalf) and so are not paid for by consumers via TUOS charges.

Type B REZ: as a cluster of generators within an approximate geographic boundary that are connected within the shared transmission network. For a type B REZ, the transmission investment associated with the REZ is shared transmission network (and connection assets for each generator). For the shared transmission network infrastructure, these will be considered prescribed transmission services and so paid for by consumers via TUOS charges (where a RIT-T has been satisfied).

The discussion paper then identifies greenfield and brownfield subsets:

Greenfield examples include:

- For a type A REZ - where there are is a brand-new cluster of generators that want to locate in the same region and so share connection assets.
- For a type B REZ - where there is no transmission infrastructure at the moment, but it is a particularly sunny location and so the transmission network is built out to that location.

Brownfield examples include:

- For a type A REZ - where there is an existing substation to connect a generator, and some new generators want to connect to that substation in order to have a more efficient connection.
- For a type B REZ - where there is existing transmission infrastructure, but the network is relatively weak, and so to connect new generators into that location the existing network needs to be upgraded and reinforced.

We generally agree these create a reasonable starting point of assessing the type and nature of expected REZ. However, recent examples have emerged of a form of hybrid REZ where a new transmission line (I.e. proposed interconnector) has been scaled up in scope to accommodate several REZ that it dissects. This type of hybrid does not strictly fall under the categories described above but may prove to be the more common REZ asset that we will see due to the overall efficiency of trying to "kill two birds with one stone". If a new transmission line (interconnector) is being proposed, it makes sense to ensure the route "picks up" new asset clusters along the way or attempts to share as much of the capacity as possible

The proposed Energy Connect (NSW to SA interconnector) and Marinus Link projects are live examples of this approach. Following is an extract of our submission to the Energy Connect (then called Riverlink) PADR in August 2018.

In the case of this project, the $1.5 billion cost would be included in the regulated asset bases of both Electratnet ($400 million) and Transgrid ($1.1 billion). Regardless of actual power flows, this capital will be recovered from consumers over the asset life. The complicating factor in the Riverlink project is that it is both an interconnector and a Renewable Energy Zone (REZ) enabler that will open up significant commercial opportunities for wind and solar proponents.

[2] https://www.aemc.gov.au/sites/default/files/2019-10/EPR0073%20-%20Renewable%20Energy%20Zones%20Discussion%20Paper.pdf

We would contend that a significant beneficiary of the Riverlink project will be the project developers in REZ 13 (Murray River) and REZ 18 (Riverland). The risk associated with the operation of these assets should rightfully reside with the project owner/operator, not consumers who have zero control over the location or operation of the projects located in REZ 13 and REZ 18.

In addition, while consumers may receive some marginal price benefit from the operation of projects located in these zones, given the fluctuating nature of the energy market that may be fleeting at best. However, the project owner/operator has access to significant financial gain from their operation and has significant contractual measures to manage revenue risk.

It is our view that the risk needs to be rebalanced such that those who have the most to gain financially and are in the best position to manage risk, need to take on an equitable portion of the costs. In the case of REZ's, this additional investment is largely driven by their need to connect their generator to the National Electricity Market, from which they will gain significant financial benefit.

In essence, we believe these REZ related assets should be considered dedicated connection assets. We do not see a justification for the consumers of NSW and South Australia to effectively subsidise renewable generators selling into the NEM.

The AEMO Integrated System Plan (ISP) identified between 3,000MW and 4,000MW of new generation assets could be developed in REZ 13 and REZ 18. The PADR also identifies REZ 13 and REZ 18 as key drivers of "value" for the project.

The PADR identifies Option C.3i (330kV line plus series compensator) as its preferred project and also identifies a smaller capacity option, C.2 (275kV line) that takes the same route. Given the route is the same, both dissecting REZ 13 and REZ 18, we assume that both options would facilitate some level of new generator connection.

Therefore, we have concluded that the additional cost of the project due to the inclusion of REZ 13 and REZ 18 is between $500 million, being the difference between option C.3i and C.2, to $750 million being the difference between these two options plus some initial capacity of the smaller option (C.2) that would be allocated to new generator connection. It is our contention that these costs should be recovered from the generator owner/operators located in REZ 13 and REZ 18.

We would encourage the AEMC to consider this type of hybrid REZ as we believe it may be the most likely to evolve over time. Being able to clearly separate the public from private asset and ensuring costs are allocated appropriately will be important.

PROPOSED MODEL FOR REZ DEVELOPMENT

When it comes to the funding of the energy transition, including transmission to facilitate new entrant generation, the EUAA are not advocating that all costs and risks of these investments are met by new entrant generators. What we are arguing for is an arrangement whereby the costs and risk are shared equitably amongst all parties.

This approach recognises that energy users will gain long-term benefits from a well-coordinated approach to the energy transition, including greater interconnection, the facilitation of new entrant generators and deployment of new resources that "firm up" the grid. This approach also recognises that the owners of these assets will also receive benefits from these investments and as such should pay their fair share of the costs. We are surprised that some see this as a controversial position when in reality it is fair and reasonable to expect that everyone covers their own costs and risk.

Similarly, we are not seeking a situation where grid augmentation is carried out in a hap hazard or piecemeal manner. It is in the long-term interests of all stakeholders that a high level of coordination is achieved which is why we are supportive of the principles driving the AEMO ISP, AEMC COGATI and ESB Post 2025 Market Design processes.

Proposed Models

The following table describing the five models considered appears on pages 32 and 33 of the Discussion Paper[3]

Table 4.1: Models mapped against REZ type and issues

MODEL	ISSUE ADDRESSING	REZ TYPE
Long-term hedges to fund transmission assets	2 - efficient generator and transmission coordination 3 - efficient transmission	B
Open season approach to connections	1 - efficient generator coordination	A
Speculative investment by TNSPs	3 - efficient transmission	B
Risk sharing model	1 - efficient generator coordination 3 - efficient transmission	A and B
Transmission bond model	1 - efficient generator coordination 3 - efficient transmission	B

All approaches described above appear to meet the primary objective (to varying degrees) of the EUAA, that the costs and risks of significant grid augmentation is more equitably shared across all participants and beneficiaries. Not surprisingly there are issues associated with all approaches.

While it is important to address these issues through further design and consultation it is also important to understand that continuing with the status quo is unlikely to result in timely network augmentation while it does little to relieve cost and risk pressures on consumers. Rather than searching for a "perfect model" that in reality does not exist, we should be searching to develop a model that achieves the goal of equitable cost and risk allocation, that is flexible enough to manage the evolving financial, regulatory and political environment and that has the lowest number of issues.

The AEMC have identified that option one, "long-term hedges to fund transmission assets", is their preferred approach. On face value the EUAA believes this to be a reasonable approach but in the absence of detailed scenario modelling including the expected cost outcomes for consumers, it is difficult to provide a full assessment.

We would also add that this model does not appear to have any AER or other regulatory oversight. We would encourage the AEMC to consider what reasonable regulatory oversight should be applied to this model that provides the owners of connecting assets with a level of comfort and protection.

We would also be wary that a model that has the auctioning of rights could be open to manipulation by participants on both sides including economic withholding by the TNSP or the acquisition and effective hoarding of rights by speculative developers for the purpose of extracting a premium at a later date. Once again, a level of regulatory oversight would be of great benefit here to ensure transparency and confidence in the auction process.

[3] https://www.aemc.gov.au/sites/default/files/2019-10/EPR0073%20-%20Renewable%20Energy%20Zones%20Discussion%20Paper.pdf

We note that this option does use the concept of transmission hedges as the primary financial instrument, as is the case in the Proposed Access Model Discussion Paper. It would be disappointing for the EUAA that the options described to help relieve the cost and risk pressures on consumers were delayed or shelved if the proposed access model not proceed or was delayed. While coordination across the two discussion papers is preferred, we believe the approach to REZ being discussed here would continue regardless.

We are also interested in more assessment of options four (risk sharing model) and five (transmission bond model) to be conducted and do not want to see them dismissed at this stage. We urge the AEMC to include options one, three and five in scenario modelling and cost impact assessments so a thorough understanding of the efficiency and costs of all relevant alternatives are understood.

Options two (open season approach) and three (speculative investment) are less appealing to the EUAA and would be unlikely to result in sufficient and timely investment in transmission while also appearing to be a relatively high-risk approach for TNSP's.