SUBMISSION

SA ENERGY TRANSFORMATION: RIVERLINK RIT-T
AUGUST 2018

EUAA
Energy Users Association of Australia

South Australian Energy Transformation
PADR Feedback
31 August 2018

Via email: consultation@electranet.com.au

Introduction

The Energy Users Association of Australia (EUAA) is the peak body representing Australian energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing and materials processing industries. Combined they employ over 1 million Australians, pay billions in energy bills every year and are desperate 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 increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items. Many of our members have operations in both NSW and SA and therefore have a keen interest in the proposed Riverlink project.

We acknowledge there are reasons to support greater interconnection between jurisdictions as it allows market participants to move energy when and to where it is needed, potentially obviating the need for investment in certain types of generation in one region where there is an overcapacity in another region.

We also acknowledge that interconnection between states can provide greater flexibility for market participants and the system operator and could foster more competitive markets. We trust that a robust RIT-T process will ensure that only those assets that are in the long-term benefit for consumers are built.

However, we are concerned that the rapid rate of change in technology, fundamental changes in end user behaviour and significant political and regulatory uncertainty make the benefits from future investments such as Riverlink difficult to assess from a consumer perspective.

Individually each of the issues described above creates their own set of risks for investors in long-lived investments, particularly “volume” risk whereby long-lived assets like these could be underutilised. When taken together, as we are witnessing now, the risks are multiplied resulting in an unlikely but not out of the question, stranded asset.

Unfortunately, under the current regulatory framework, including the RIT-T framework, the consumer takes 100% of the volume risk if this $1.5 billion project is included in the regulated asset bases of Electratnet ($400 million) and Transgrid ($1.1 billion). Regardless of actual power flows, under the current framework this capital will be recovered from consumers.

While this submission raises a number of risks and therefore reasons to be cautious, we also offer solutions that seek to share these risks more equitably across multiple participants as a means of progressing this project and others in the future.

Rapidly Changing Energy Markets

Energy markets have been in transition for the last decade and it is clear to the EUAA that this transition will continue, at pace, for some time to come. This transition has been driven, in part, by the social, environmental and economic need to manage climate change risk. The inevitable retirement of legacy fossil fuel assets and the rapid deployment of low-cost renewable energy at both residential and industrial scale are central to this transition.

All of this means we will continue to see significant changes in the structure of energy markets and the nature of its participants. To date this transition of our energy system has not been well managed, for a variety of reasons, which has resulted in a chaotic period for the energy industry, increased risk for investors and higher prices for consumers.

Despite the best efforts and general agreement by a vast majority of energy industry stakeholders, this chaos is set to continue with the rejection of the National Energy Guarantee (NEG). We had hoped the NEG would have delivered some level of stability to the transition already underway. In particular, we believe the Reliability Guarantee could have played an important role in maintaining system reliability by supporting both the continuation of dispatchable resources in the NEM and providing a market environment for new resources to be deployed as we transition to a lower carbon, but more variable and dispersed energy supply.

The alternative, being an ad-hoc, disconnected approach will surely lead to unintended consequences that will only hurt all energy users. For example, the 2017/2018 summer RERT activation by AEMO cost energy users well in excess of $50 million and is a salutary lesson that without a more structured approach to the transformation of energy markets we should expect not only more direct intervention but more costly intervention as well.

In the absence of the NEG, the task of maintaining system reliability is likely to increase the reliance on RERT be solely managed by AEMO via RERT. While the AEMC's current RERT review may result in improvements in its' operation that reduce costs, there is a risk that this increased reliance will increase costs over time as a larger volume needs to be procured to meet the NEM reliability standard. Ultimately State Governments, especially those that have sought to accelerate deployment of renewable energy without due consideration to its effect on system stability, may be forced into costly intervention as has been the case in South Australia.

It is this highly uncertain but continually evolving environment that the current SA Energy Transformation RIT-T is being assessed.

The Project Assessment Draft Report

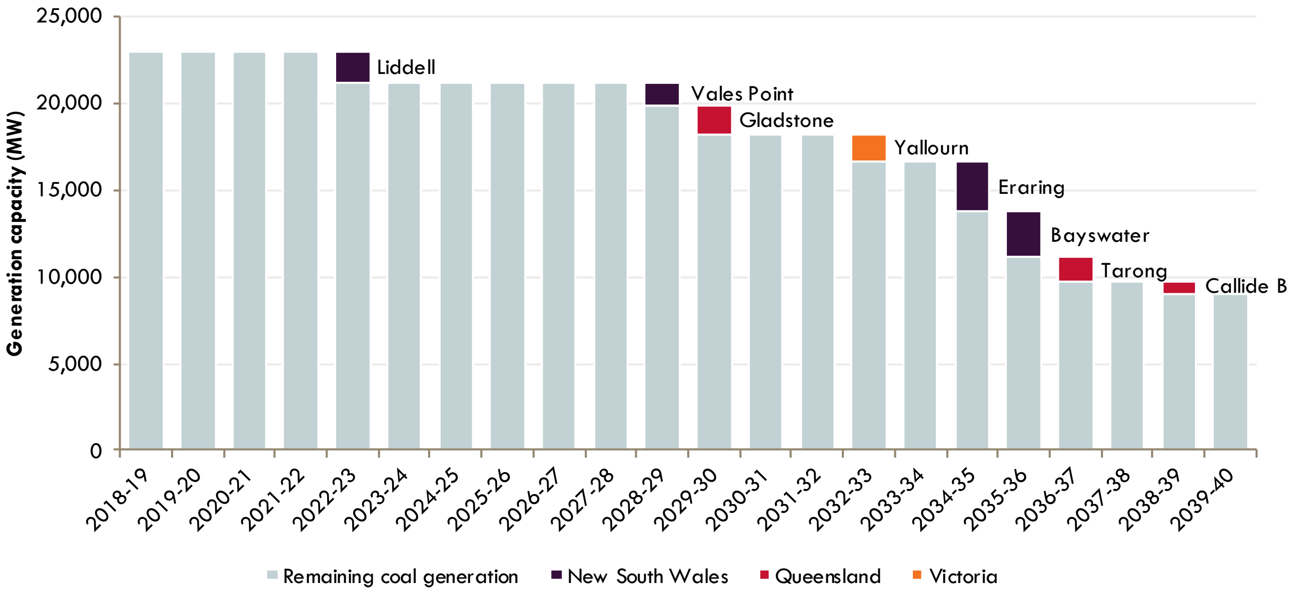
We have reviewed the Project Assessment Draft Report (PADR) and have consulted with other end user advocates who have been most useful in the preparation of this submission. We have also spoken to a number of our South Australian and New South Wales members, many of whom have not been consulted directly by either Electranet or Transgrid despite all of them being significant energy consumers in each jurisdiction.

We suggest this is an area of improvement for the next round of consultation and the EUAA would welcome the opportunity to be involved as facilitator.

A fundamental assumption of the PADR seems to rely on the NSW region being in a state of "oversupply", especially with the type of asset required to provide "firming" of variable generation in both South Australia and those assumed to be developed in the Renewable Energy Zones (REZ's) the project dissects.   Yet according to the AEMO ISP, two NSW based coal fired assets in Liddell (in 2022) and Vales Point (2028) are assumed to retire removing some 3,320 MW of the type of dispatchable generation that is required in both NSW and SA.

While you can also assume that other "resources" enter the market, the current trend is for a majority of these to come from distributed generation sources that also have a level of variability. With the National Energy Guarantee now put into suspended animation and with it the Reliability Guarantee that could have played an important role of integrating variable generation and deployment more dispatchable resources, the unpredictability of the system is only set to get worse.

Figure 2 NEM coal-fired generation fleet operating life to 2040, by 50th year from full operation or announced retirement

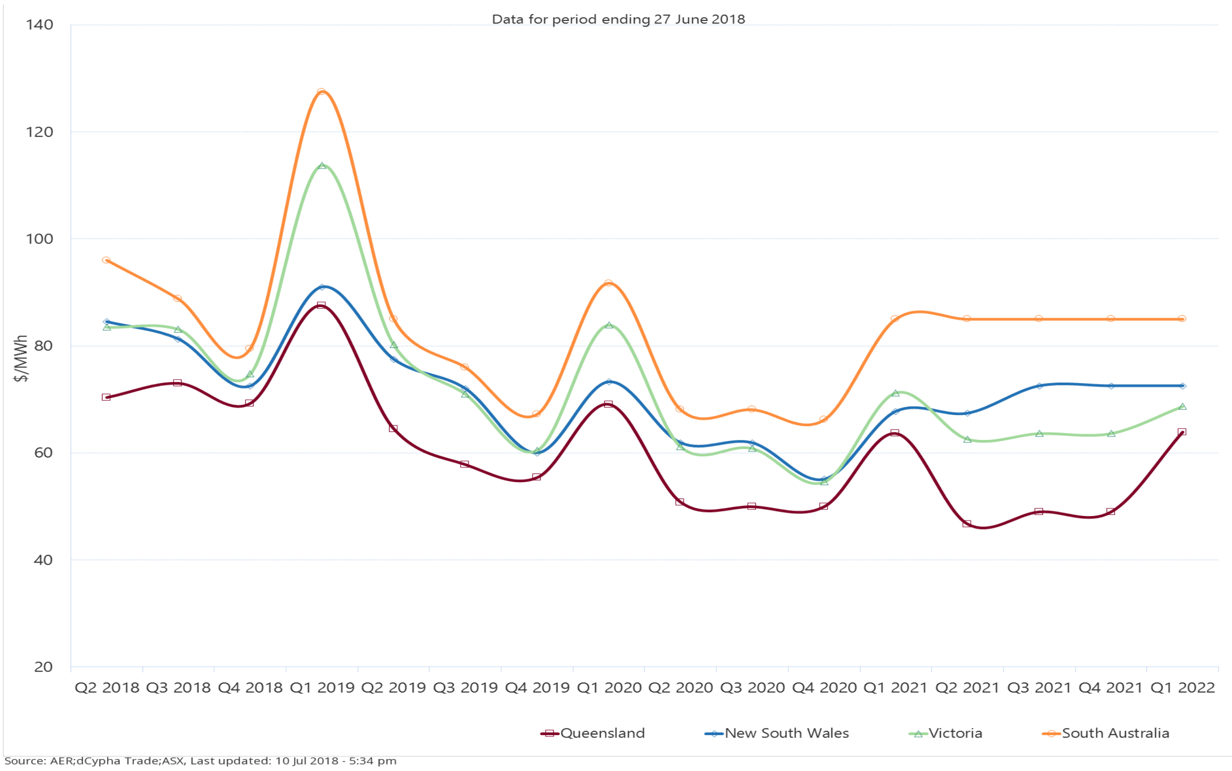


Source: AEMO ISP Page 17

The PADR also assumes that 800 MW of gas fired generation retires in SA (2024) and a further 63 MW of generation fired by liquid fuels retires in 2027.   The capacity of which largely mirrors the capacity of the project itself raising concerns that rather than the project increasing liquidity in the SA market, it merely replaces it with capacity from NSW, a market which in itself will become much "tighter" in the coming decade.

This is important to understand as the key driver of consumer benefits of the project is lower fuel costs by the removal of expensive gas and liquid fuels, to be replaced by "cheaper" black coal generation from NSW. Given retirements of dispatchable generation in both regions, the long-term MWh price spread, relied upon so deeply by the proponents, may not be as wide as anticipated and therefore the consumer price benefit may not materialise.

We note that the latest AER Quarterly 2022 base futures price for NSW is in the order of $75 MWh while in SA it is in the order of $82 MWh.



We raise these issues not necessarily as a criticism of the modelling undertaken for this PADR but that, given the highly uncertain state of energy markets, it is virtually impossible for <u>any</u> modelling to be reliable given base assumptions can change so dramatically.

A number of EUAA members have expressed a view that a more balanced approach that includes lower cost, more localised grid strengthening investment combined with strategic non-network solutions such as described in the PADR (Option A – Least cost non-interconnector option in SA) and greater incentives for demand response provide a lower risk pathway that does not lock consumers into paying for long-term investments that may not deliver promised benefits.

We acknowledge the pragmatic approach by Transgrid in their Powering Sydney's Future proposal where, after consumer feedback, they altered the scale of the project while also building in flexibility for a future upgrade. This resulted in a lower cost, and therefore a lower risk investment that gained broad consumer support.

We believe there is great merit in this approach and would like to see further work undertaken by the project proponents to "dive deeper" into these non-network opportunities if not to remove the need for the project but to reduce its scale so as to minimise costs for consumers.

However, we also recognise that if we are to achieve a true National Electricity Market (NEM) as opposed to a collection of lightly connected state jurisdictions pursuing separate and at times contradictory agendas, then greater interconnection is a must.

So, how do we move forward?

Risk Allocation Needs Re-Setting

As stated previously, under the current regulatory framework, including the RIT-T framework where the capital cost of new infrastructure is incorporated into the Regulated Asset Base (RAB) of the owner/operator, the consumer takes 100% of the volume risk.

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.

In their April 2018 Discussion Paper, Coordination of Generation and Transmission Investment, the AEMC have stated that one of the key aspects of transmission framework within the NEM is efficient risk allocation:

"*A key consideration that should be taken into account when determining arrangements for REZ's is who is best placed to manage risk…..The Commission does not necessarily think it is appropriate for consumers to bear the costs associated with centralised resources (e.g. large-scale generation and transmission). This risk is likely to be better placed with the generation and transmission businesses themselves.*"[1]

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.

This view is supported by the AEMC who state in their April 2018 Discussion Paper:

"*Under the transmission framework, as amended by the TCAPA Rule from 1 July 2018, the assets associated with REZ's would most likely be considered dedicated connection assets and identified assets that are required to connect a group of generators to the shared transmission network. In other words, these assets would be considered*

[1] AEMC Discussion Paper, Coordination of Generation and Transmission Investment: Page 64

connection assets, providing connection services, and so would be paid for by the connecting party/is (i.e. generators)."[2]

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 recognise that moving to 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.

The key difference between a fully regulated Riverlink and generator co-contribution is that unlike a regulated asset regime where the rules seek to drive efficiency gains with a portion of savings passed through to customers at some point, costs that are exposed to market forces are more likely to be reduced through genuine innovation and competition and therefore more likely to deliver an economically efficient and cost-effective outcome for consumers.

Recovery of these costs from generators could be managed in a number of ways including:

- Capital cost recovery from generators as they connect based on the total installed capacity of the asset (expressed either in MW or % of line capacity). The assessed capital contribution would then be deducted from the RAB of the participating TNSP's in a form of "reverse contingent project" process. There already exists a contingent project process for adding capital to a RAB in the middle of a regulatory period so a precedent exists for mid period adjustments.
- Several options for providing generators with firm access in exchange for co-contribution to deep augmentation costs are:
    - Optional firm access: This would allow generators to purchase a partially firm financial access right to the regional reference node, at a regulated price in order to manage the financial impacts of network congestion. Generators would be entitled to compensation if constrained below their level of firm access. This would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some

[2] AEMC Discussion Paper, Coordination of Generation and Transmission Investment: Page 56

transmission investment. In effect this would introduce firm transmission rights, while providing locational (nodal) pricing signals to generators.
  - Locational marginal pricing, with deep connection charges: This would establish sub-regional pricing, and generators would have access to their locational marginal price, but would also be able to purchase optional fully firm financial access to defined trading hubs. In order for generators to be able to acquire access rights beyond those available through the existing system, they would have the option of paying deep connection charges, for which they would also receive optional fully firm access. In essence, this option would provide generators with fixed financial access, compared to optional firm access where only firm financial access would be provided (i.e. there would be times under an optional firm access model where there would be operating conditions under which the capacity of the transmission network would be reduced and so access for firm generators might also correspondingly be reduced. The deep connection charge would not reflect locational differences in costs.
- Government equity participation that would have the effect of reducing the capital expenditure by participating TNSP's, reducing the amount of project cost that would be incorporated into the RAB.
- Access to more favourable debt via the Clean Energy Finance Corporation or Future Fund contribution, having the effect of lowering overall capital costs of the project.

We recognise that some of these co-contribution options would require changes to the current open access rules but we felt it necessary to raise these issues in this submission to highlight the need for a revised approach.

Regardless of the method of co-contribution, the aim must be to reduce the amount of capital expenditure of the project that accrues to the participating TNSP's RAB and allocate risks appropriately such that those who have the most to gain and who are in the best position to manage volume risk are making a fair and equitable contribution to the project.

While these issues are not unique to the Riverlink project, it is more complex than a new transmission asset that connects future REZ's to the NEM. The Riverlink project is both an interconnector and a REZ's facilitator, which in itself is an efficient means of progressing, provided risk, reward and cost are allocated equitably.

Quite simply, consumers who are already dealing with final bills loaded with the enduring cost of inefficient investment and inequitable risk allocation will find it difficult to support a continuation of the status quo.

Once again, the EUAA welcomes this opportunity to make a contribution to the PADR, would welcome further dialogue with the project proponents and would be pleased to facilitate deeper engagement with our members.

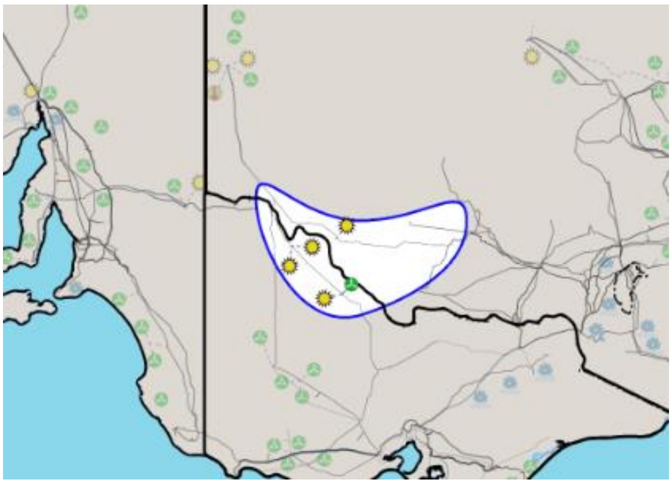
Andrew Richards

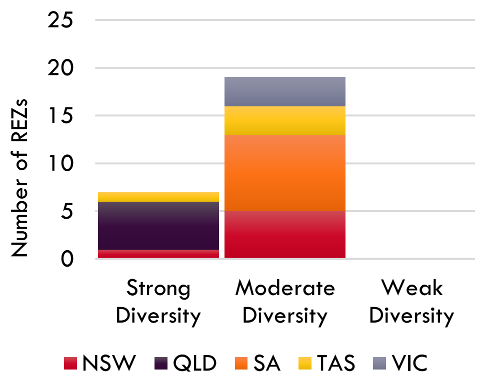
CEO

31 August, 2018

Attachments: AEMO Integrated System Plan - REZ 13 and REZ 18

Table 15 REZ 13 – Murray River

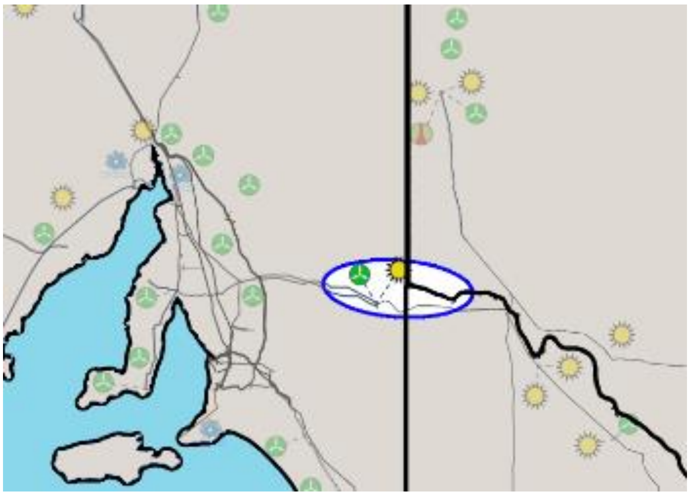
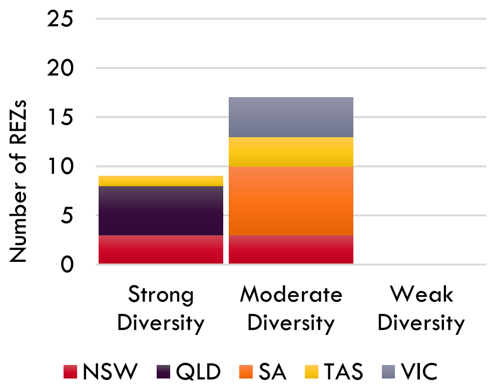
Summary	REZ Priority Level = 2
The Murray River REZ spans the western section of the New South Wales and Victorian border. The area has moderate wind and solar resources. Over 2,000 MW of solar generation is proposed for the area. The New South Wales part of this zone aligns with the area identified by the New South Wales Government as a Potential Priority Energy Zone[13].	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	C	
Potential (MW)	6,000	9,140	
Diversity	F	D	
Demand Matching Now 2030 2040	 B F F	 D C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	0 (NSW side) 300 (Vic side)	2,000 (NSW) 2,000 (VIC)	The existing network is electrically weak and the MLFs will decline sharply as new generators are connected. Capacity in Victoria is improved with 220 kV upgrades along the Buronga-Red Cliffs-Kerang-route, and new 500 kV Darlington Point-Kerang lines with the proposed SnowyLink interconnector. Capacity in New South Wales is improved with the proposed RiverLink New South Wales-South Australia interconnector.
Initial Loss Factor	A	-	
Loss Factor Robustness	E	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	3,000 (NSW) 2,300 (VIC)	3,000 (NSW) 2,300 (VIC)	0 (NSW) 1,000 (VIC)	3,000 (NSW) 3000 (VIC)	1,200 (NSW) 1000 (VIC)
Timing	2035 (NSW) 2024 (VIC)	2035 (NSW) 2024 (VIC)	2024 (VIC)	2035 (NSW) 2024 (VIC)	2037 (NSW) 2024 (VIC)

Table 20 REZ 18 – Riverland

Summary			**REZ Priority Level = Low**		
The Riverland REZ spans the South Australia, New South Wales, and Victorian border. It has moderate quality wind and solar resources. 330 MW solar generation is proposed in this REZ, for connection to the ElectraNet transmission network.					
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**		
Resource Quality	C	C			
Potential (MW)	2,000	620			
Diversity	F	D			
Demand Matching Now 2030 2040	 B F F	 D C C			
Network Limitations	**Existing**	**Upgraded**	**Network Description**		
Spare Network Capacity (MW)	200	2,000	There is no spare capacity on the South Australia side, and no connection to Victoria or New South Wales networks. The proposed RiverLink New South Wales-South Australia interconnector passes through this REZ and will enable generation to be connected. The MLF drops sharply as new generation is connected.		
Initial Loss Factor	A	C			
Loss Factor Robustness	E	-			
Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	1,950	1,950	0	2,000	1,950
Timing	2033	2032	-	2024	2036