Australian Energy Regulator

Mr Peter Adams
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7 September 2018

RIT Guidelines Review

Dear Peter,

Thank you for the opportunity to make a submission to the Regulatory Investment Test (RIT) Guidelines Review.

Attached to this submission is a recent report into ElectraNet's South Australian Energy Transformation RIT-T - the first of the ISP projects being advanced through the RIT process.

The Energy Project is an Adelaide-based independent energy consultancy that provides a range of services to electricity consumers. We prepared the attached report from the perspective of our clients – we are often engaged to assess capital expenditure proposals and to engage with the competitive energy markets on their behalf.

The report was financially supported by Energy Consumers Australia as part of its grants process for consumer advocacy projects for the benefit of consumers of electricity in the NEM. The views expressed in this document are our own and do not necessarily reflect the views of Energy Consumers Australia.

The attached report was intended to provide a constructive critique of the Project Assessment Draft Report (PADR) and associated documents. The premise of any interconnector investment is this: while transmission costs will increase, the impact on wholesale markets and system security will have a value to consumers that confidently exceeds the cost of the regulated infrastructure. However, once a regulated investment has been made, the risk of the benefits not appearing fall entirely to consumers. This may be for a range of reasons including Public Policy or disruptive technologies but this is why consumer scrutiny of projects such as the proposed SA-NSW Interconnector is warranted.

We have identified some implications for the AER RIT Guideline Review and these are outlined below:

1. Allocation of Costs and Benefits between regions is important to consumers

Our review of the ElectraNet SAET PADR found the allocation of costs and benefits between SA and NSW consumers appeared materially unbalanced.

A related aspect of the NEM regulatory framework is the arrangements for interregional Transmission Use of System (IRTUoS) charging. This mechanism was introduced following a 2013 review by the Australian Energy Markets Commission that aimed to better recognise the benefits transmission delivers across region boundaries[1]. The RIT-T does not require the inclusion of any estimates of the allocation of costs and benefits or the impacts of the IRTUoS regime but it would certainly help consumers engage in the RIT process if it was made available.

2. Treatment of uncertainty of future market conditions in critically important

The obvious question for consumers is whether the cost of the proposed solution exceeds the benefits. With the RIT 'Identified Need' as the project objective, it is worth reflecting on the Standard definition of risk[2]

> *risk is defined as the effect of uncertainty on objectives*

From a consumer perspective, the risks of these large Transmission projects are in the uncertainty of the market conditions that will contribute to, or hamper, the Identified Need. The implications of uncertainty in benefits needs to be reflected in both the timing of the elements of these investments and how these investments are funded.

It should also be reflected in the discount rates used in Net Present Value assessments.

3. Generators and Governments should be allowed to lower the risk to consumers of ISP investments (and REZ in particular).

Efficient risk allocation is a key consideration of AEMC's Coordination of generation and transmission investment review[3]:

> *"A key consideration … 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."*[4]

The stakeholder forums held by ElectraNet in Adelaide and Sydney highlighted the broad interest in considering co-investment opportunities.

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[1] www.aemc.gov.au/rule-changes/inter-regional-transmission-charging
[2] AS/NZS ISO 31000:2009 Risk management - Principles and guidelines
[3] https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi
[4] AEMC Discussion Paper, Coordination of Generation and Transmission Investment. April 2018 Page 64

4. Changes to the framework have been flagged by COAG EC, how do we use the current tranche of RITs and the ISP to evolve the framework and advance the NEO?

Our recent review of ElectraNet PADR has coincided with the AER's Review of the Regulatory Investment Test Guidelines and the July 2018 Release of the inaugural AEMO Integrated System Plan (ISP). Further, COAG Energy Council 10 August 2018 stated:

> *"Ministers also asked that in addition to the consultation on the current ISP that is underway, the ESB should identify a work program (including possible changes to the RIT-T) and convert the ISP to an actionable strategic plan. The ESB Chair should take the lead on its delivery and report back to the December 2018 meeting."*

This will also overlap with the AEMC Coordination of generation and transmission investment review. The AER RIT Guideline Review has limitations to its scope but some changes are necessary now. However, given further changes are flagged, this an opportunity for consumers to maximise the lessons learned from the current open RITs. This includes a significant number of Repex projects under the RIT framework as well as major Transmission Projects such as ElectraNet's RiverLink and AEMO's Western Victoria Renewable Integration RIT-T.

I recommend the AER consider how it can facilitate the summary review of all RITs, identify trends and issues and inform any future changes to the framework.

I look forward to participating further in the AER's work on this important subject.

Sincerely,

Dr Andrew Nance

Director

Encl.

ElectraNet

Submission: SA Energy Transformation RIT-T Project Assessment Draft Report (PADR): The Proposed RiverLink Interconnector from a Consumer Perspective

7 September 2018

Contents

This project was funded by **Energy Consumers Australia** (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

1 Executive Summary

ElectraNet has released the Project Assessment Draft Report (PADR) for the SA Electricity Transformation Regulatory Investment Test (SAET RIT-T) and the preferred option, is a $ 1.5 billion 800MW 330 kV double circuit from Robertstown in SA to Wagga in NSW.

The premise of any interconnector investment is this: while transmission costs will increase, the impact on wholesale markets and system security will have a value to consumers that confidently exceeds the cost of the regulated infrastructure. However, once an investment has been made, the risk of the benefits not appearing fall entirely to consumers. This is why consumer scrutiny is warranted.

Overall, it is easy to be convinced that greater interconnection in the NEM can serve the long-term interests of consumers. Further, an SA-NSW connection as identified in the ISP, is intuitively likely to deliver benefits.

But not at any cost.

ElectraNet is, in effect, proposing that a regulated investment in a $1.5 billion interconnector between SA and NSW will, on balance of probabilities, reduce power bills in both regions by more than enough to justify the expenditure. ElectraNet have described the project as a "no regrets" solution in the PADR. This project has critiqued the proposal from a consumer perspective to test this assertion.

This project has engaged with ElectraNet and consumers (and their advocates) in both Adelaide and Sydney. Questions have been sent to, and many answers received from, ElectraNet. Detailed modelling results have been released to all stakeholders as a result of this engagement.

The 'net market benefits' modelled by ElectraNet and used to demonstrate the likelihood that this is an investment in the long-term interests of consumers rely on a stable electricity policy environment. Based on recent experience, consumers may consider this an optimistic assumption. As a result, and to aid consideration of options, the costs and benefits of different options have been re-calculated on a 15-year time frame - from 2018 to 2033 - to see which options emerge as "no regrets" over the medium term compared to those that require longer term assumptions for the business case to be made (the 2040 timeframe of the original analysis and AEMO's Integrated System Plan). This analysis reveals a very different story – ElectraNet's preferred option from the PADR no longer ranks that highly - and emphasises the potential misallocation of risks in the current regulatory framework.

This project has also identified a significant imbalance in costs and benefits between ElectraNet customers and TransGrid customers.

Reflecting on the above, an investment framework that more efficiently allocates risks and costs is needed in order to advance the long-term interests of consumers with respect to Transmission investment in the NEM. This is outside the scope of this submission and we will report on this further to Energy Consumers Australia.

Here, we outline a number of findings from our own analysis of the modelling results and NPV analysis:

- The costs of the non-interconnector option appear to be materially overestimated
- The allocation of costs and benefits between SA and NSW consumers appears materially unbalanced
- From the analysis performed for this project, a prima-facie case exists for tuning the scale and timing of increased interconnection between SA and NSW in order to optimize the cost to consumers.
- Further, given the apparent imbalance between costs and benefits of the preferred option between SA and NSW consumers, a more strategically timed approach to the NSW elements may better align costs and benefits for NSW consumers.

Analysis of modelling results suggests a staged approach may deliver a more cost effective solution that also distributes the costs and benefits between the regions more fairly. ElectraNet and TransGrid are encouraged to explore options that include elements of Option A (the non interconnector option) with staged investment in the NSW elements of the project. This could include elements of Option C2, C3 and C3i. Perhaps a C2i option (C2 + Series Compensation) would be an appropriate initial investment that could be considered.

In summary, the PADR and associated documents have not convinced us beyond reasonable doubt that the preferred option is in the long-term interests of consumers.

2 The Proposed Project

AEMO's 2018 Integrated System Plan (ISP) refers to the interconnector as Riverlink.

The need to investigate the project has its origins in South Australia's high penetration of renewables and expansive pipeline of prospective projects. However, the need was clearly underlined by the South Australian System Black event of September 2016 and validated by a co-contribution of $500,000 towards the study by the South Australian Government[5].

The RIT-T has considered a 'no new interconnector' option (Option A) as well as options to connect to Queensland (Option B), NSW (Option C) and Victoria (Option D).

The ISP classifies RiverLink in "Group 2" of the preferred development path for the NEM. However, while the ISP supports further interconnection, it does not evaluate the option in detail. That is the role of the RIT process. This review acknowledges the ISP recommendation to *"Establish new transfer capacity between New South Wales and South Australia of 750 MW"* and that the SAET RIT-T is the first example of implementing a key ISP recommendation (albeit the SAET RIT commenced before the ISP was conceived).

[5] We note that final reports by AER and AEMC into the September 2016 event are still be published

2.1 The Identified Need

In the case of a Regulatory Investment Test, the project objectives are articulated in the 'identified need'. The identified need for this RIT-T, as stated in the PSCR, is to deliver net market benefits and support energy market transition through:

- lowering dispatch costs, initially in South Australia, through increasing access to supply options **across regions**.
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies, through improving access to high quality renewable resources **across regions**.
- enhancing security of electricity supply, including management of inertia, frequency response and system strength in South Australia.

The Identified Need is expressed in three parts. The third, broadly capturing the need to improve security of supply in SA has been largely dealt with via a number of initiatives that have been, or will soon be, implemented. To be clear, while the timing of the RIT has coincided with the South Australian System Black event of September 2016, many of the system security issues were known and the RIT investigations had already commenced and actions since will address these needs before an Interconnector can be delivered.

As acknowledged in the PADR, the RIT-T has instead focused on the need to manage the costs of the broader energy transition. The need to lower wholesale prices in SA is well accepted by consumers. As a region with around 50% of generation coming from wind and solar, the need to manage the transition and to share renewable resources across regions is perhaps less well accepted.

The business case presented in the RIT-T is based on reduced fuel costs (less gas consumed in SA, more renewables consumed in NSW) and this would appear to directly address the first two elements of the Identified Need.

The obvious questions for consumers is whether the cost of the proposed solution exceeds the benefits. The NEM covers large distances with low customer density by international standards. It is worth bearing in mind that solutions that suit other markets may not necessarily stack up in the NEM context.

With the 'Identified Need' as the objective, it is worth reflecting on the Standard definition of risk[6]

risk is defined as the effect of uncertainty on objectives

From a consumer perspective, the risks of this project are in the uncertainty of the market conditions that will contribute to, or hamper, the Identified Need.

In response, this project has pursued three main lines of inquiry:

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[6] AS/NZS ISO 31000:2009 Risk management - Principles and guidelines

- Has Option A – the non-interconnector option – been given fair treatment?
- The distribution of costs and benefits between SA and NSW consumers
- Are combinations of elements of the existing scenarios, and/or potential staging of the investment, worthy of further consideration?

Each of these is presented in the following sections.

3 Option A - the non-interconnector option

The RIT has included an option that could meet the Identified need without new interconnection. This option combines a number of technologies to provide a South Australian region of the NEM that can confidently withstand the sudden loss of the Heywood Interconnector at full import or full export. Inertia, Fast Frequency Response and, as a last resort System Integrity Protection Schemes, are all relevant attributes of this option.

The option allows for some expansion of renewables in SA and the displacement of gas although not to the degree of some of the interconnector options canvassed.

A number of questions were raised at the Public Forums / Deep Dives regarding this option. The cost information published by both Entura and ElectraNet has been heavily redacted for confidentiality reasons. ElectraNet subsequently published additional information on their website[7]. Specifically, a document 'The total cost of the non-interconnector option' that stated:

> *"The performance of the combined non-interconnect solution against the key criterion of ensuring South Australia withstands a non-credible loss of the Heywood Interconnector without a system wide black out and against other criteria specified in the supplementary information paper can be found in Entura's Consolidated non-interconnector report.*
>
> *Entura identified the following combination of solutions as best meeting the identified need.*
>
> *1. Two grid scale battery storages*
>
> *2. Solar Thermal Power Station*
>
> *3. Augmentation of Murraylink to allow transmission of Frequency Control Ancillary Services*
>
> *4. Pumped Hydro storage*
>
> *5. Grid support with existing gas fired generation*
>
> *6. Minimum load control*
>
> *Based on submissions the costs of providing this solution is as follows:*
>
> - *Total capital cost of $1.4B in 2018*
> - *Present value of total operating costs of $1.2B*

[7] www.electranet.com.au/projects/south-australian-energy-transformation/

- *Total present value costs of $2.6B"*

To assess this, Consumers need to answer two questions:

- Is this a reasonable technical solution?
- Are the cost estimates reasonable?

This review has not attempted to delve deeply into the technical solution. In response to the first question, there is still some uncertainty around the technical standards for parameters such as Inertia and System Strength but on the basis that this is a professional analysis of the electricity system's response to a defined event (the loss of the Heywood Interconnector) it is assumed to be reasonable.

In relation to the second question, the costs of this option are modelled as annual 'network support payments' with a Net Present Value of around $1.2 billion. The summary provided by ElectraNet implies that this is around 45% of the total capital value of the assets of $2.6bn. This intuitively seems to be a high proportion of the total capital costs given that most of these assets can also participate in the NEM and generate value beyond the role described for Option A.

To investigate this further, publicly available information has been compiled for each element of the Option and, when combined, compared to ElectraNet's estimates. This review has found ElectraNet's estimate of the total capital cost appears significantly higher than necessary.

The technologies are summarized in Table 3.1 from the Entura Report:

SAET RIT-T - Consolidated Non-interconnector Option
ENTURA-ECA29

Revision No: 1.0
5 June 2018

Table 3.1: Summary table of required

			Contribution to:				
Ref	**Technology/location**	**Nameplate**	**Inertia or FFR[6] inertia equivalent**	**Fast FCAS**	**System strength**	**Voltage control**	**Region**
1.	Pumped storage – Cultana	120 MW[7]	420 MWs	15 MW	600 MVA		Eyre Peninsula
2.	Osborne Cogeneration	180 MW	550 MWs	30 MW	150 MVA		Metropolitan
3.	Solar thermal – Davenport	120 MW	660 MWs	60 MW	600 MVA		Upper North
4.	Battery – Tailem Bend	150 MW	Expected to exceed 1,000 MWs (FFR)	75 MW	0 MVA		South East
5.	Murraylink – Berri	200 MW		40 MW	0 MVA		Riverland
6.	Battery – Tailem Bend	150 MW	Expected to exceed 1,000 MWs (FFR)	75 MW	0 MVA		South East
7.	Minimum load control						

From Entura's Table 3.1, each element is discussed below:

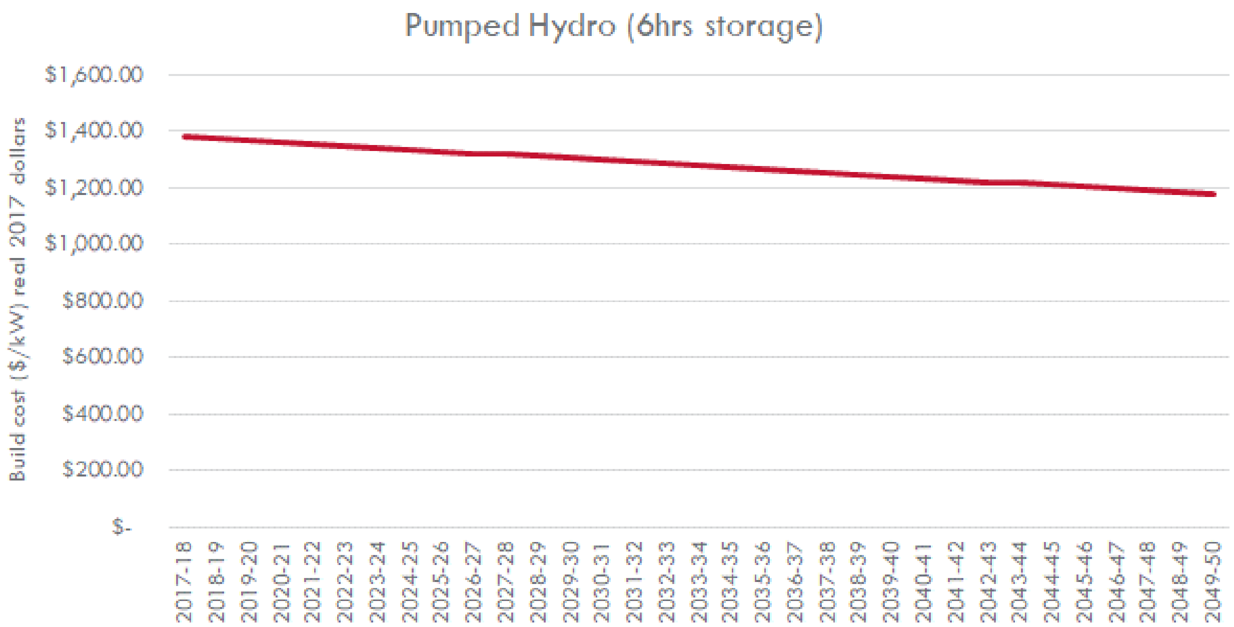
3.1 120MW Pumped Storage:

Energy Australia's Cultana Project is used as the example here[8]. The Project's September 2017 ARENA Knowledge Sharing Report states:

> *"The current concept design [225MW, 680MW.s inertia] has a total estimated capital cost of $477 million ±30%, which is a level of accuracy typical for a study at this stage of design development."*

This implies that the Entura requirement for a smaller, 120MW plant contributing 420MW.s of inertia might have a capital value of up to $300m (420/680*$477m).

As shown below, AEMO's 2018 ISP Assumes capital costs of new build Pumped Hydro with 6 hours storage of around $1.3m/MW, equal to around $160m for a new 120MW plant, around half the cost used in the analysis (although the volume of storage in each case may not be the same).



3.2 Osborne Cogeneration

The Entura report (p26-27) states:

> *"ATCO Power Australia own and operate a 180 MW combined cycle gas turbine (CCGT) plant at Osborne near Adelaide comprising a 120 MW gas turbine, heat recovery steam generator (HRSG) and 60 MW steam turbine. Until 2013 the steam turbine typically did not operate and instead the available steam was used by a neighbouring industrial plant…*

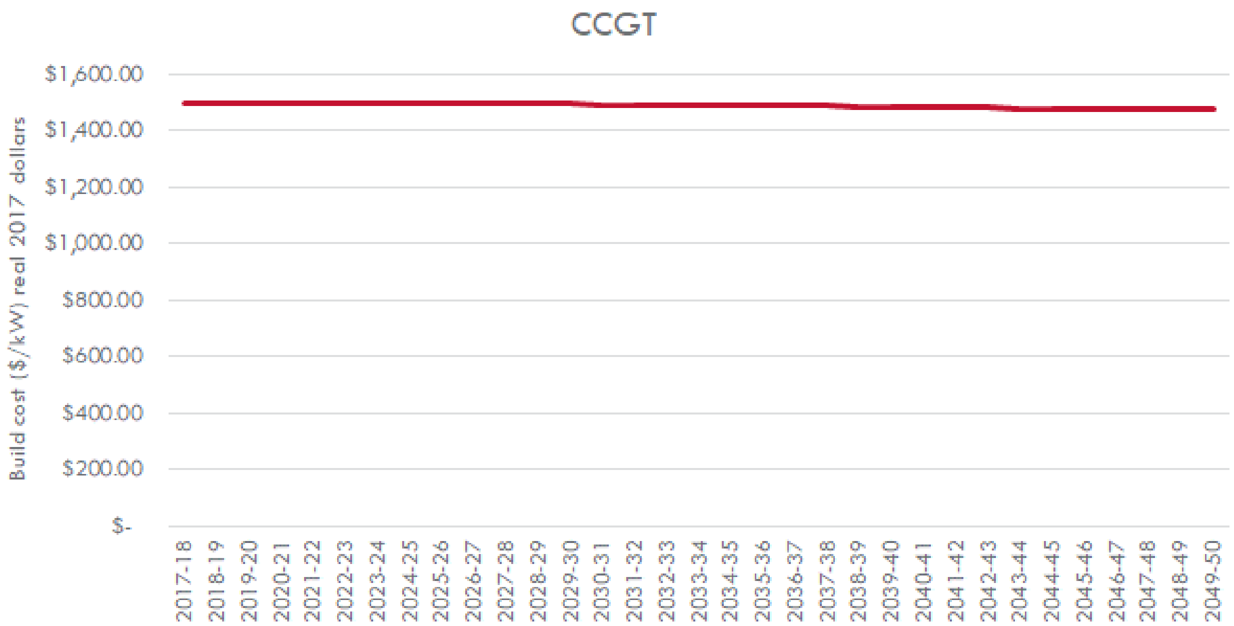
[8] www.energyaustralia.com.au/about-us/energy-generation/energy-projects/pumped-hydro

The plant presently provides voltage control in line with the NER requirements and participates in all eight FCAS markets.

ATCO Power Australia have examined the technical viability of making … modifications to their plant that would allow them to provide additional ancillary services."

AEMO's 2018 ISP modelling suggests that once an interconnector is built, this plant would exit the market. ElectraNet's modeling does not seem to agree with this view but, admittedly, does not test for "revenue sufficiency" either. The implication is that the plant has limited options and the cost of the services should be relatively competitive (but above costs to operate).

AEMO's 2018 ISP Assumes capital costs of new build CCGT of around $1.5m/MW, equal to around $270m for a new 180MW plant.



The capital value that should be attributed to converting the plant to a system support rather than energy generation role has been estimated as 50% of the capital cost of a new build: $0.75m/MW for 180MW = $135m. A conservative estimate would be $150m.

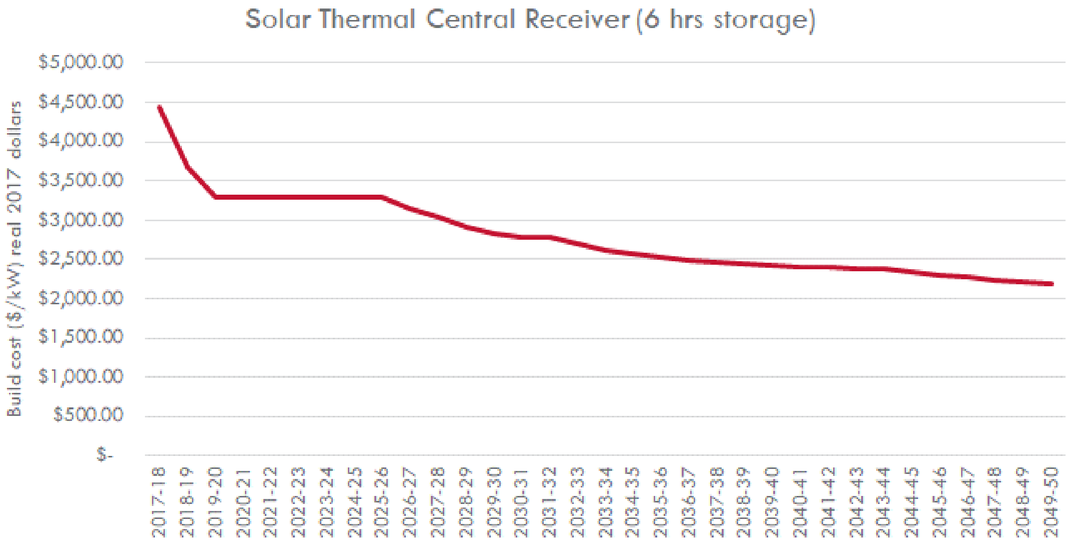
3.3 120MW Solar Thermal

Solar Reserve's Aurora Project is a 150MW Solar Thermal Project[9] whose output is contracted to the South Australian Government[10]. The capital costs of the project have been reports as being

[9] https://solarreserve.com/en/global-projects/csp/aurora

[10] https://aurorasolarthermal.com.au/2017/08/solarreserve-signs-agreement-sa-government/

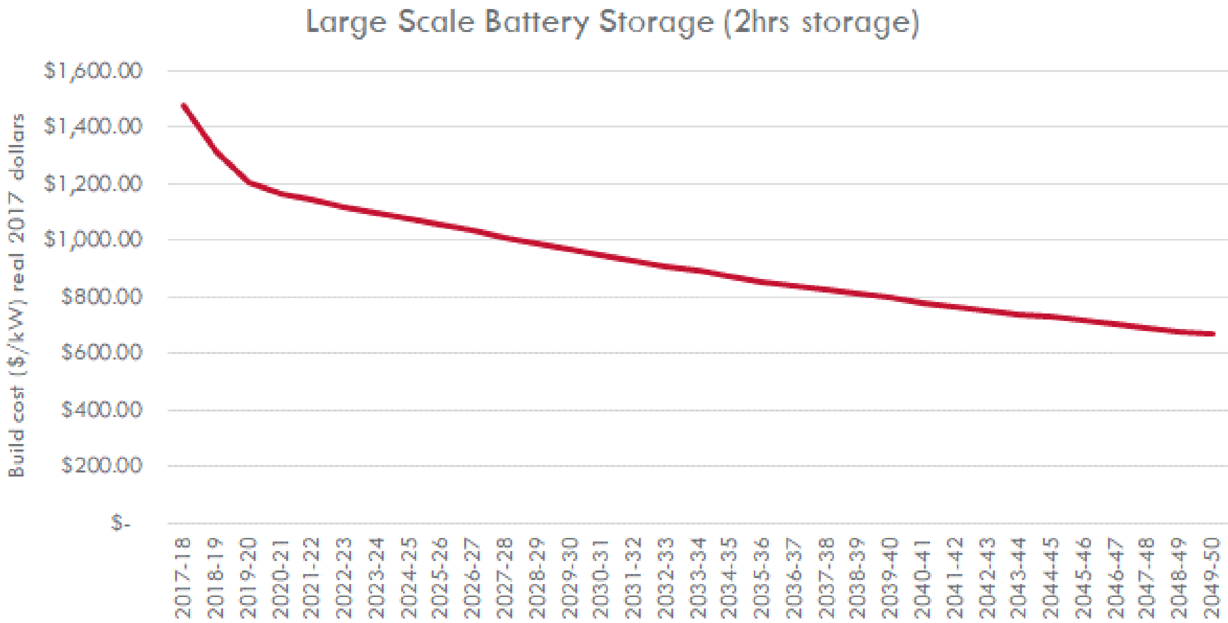
between \$650m and \$750m[11]. AEMO's 2018 ISP Assumes capital costs of around \$3.5m/MW, equal to around \$420m for 6 hours of storage (compared to Aurora's 8[12]).



For this analysis, a conservative capital cost of \$750m has been included.

3.4 150MW Battery x 2

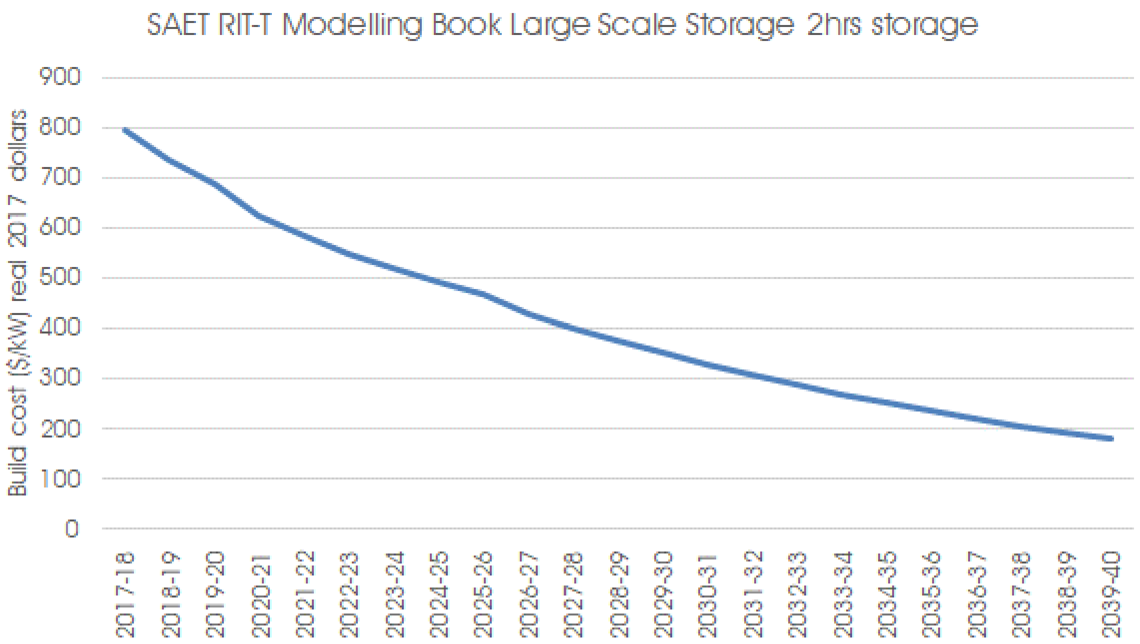
AEMO's 2018 ISP price assumptions suggest battery prices around \$1.2m/MW or \$360m.



[11] https://reneweconomy.com.au/how-solar-tower-and-storage-won-on-costs-81155/, https://reneweconomy.com.au/solarreserve-may-add-70mw-solar-farm-port-augusta-solar-tower-46154/

[12] http://www.abc.net.au/news/2017-08-14/solar-thermal-power-plant-announcement-for-port-augusta/8804628

ElectraNet's SAET RIT-T Modelling Book indicates lower values of below $800k/MW:



For this analysis battery prices around $1.0m/MW or $300m have been assumed.

3.5 Murraylink Control Upgrade

the 2018-23 MurrayLink Determination[13] includes a complete 'Control System Upgrade' valued at $25.3m. Presumably, an upgrade to provide the FCAS functionality would cost no more than this.

3.6 Minimum Load Control

The PADR describes this as:

> *"A wide area control of embedded storage and/or rooftop solar such that SA demand does not fall below such a level that positive grid demand cannot be maintained when the SA network is islanded. Minimum load control is estimated to begin to be required in 2025"*

PADR discusses the cost of this at p56:

> *"The majority of the non-interconnector option components would be procured by ElectraNet under a network support contract (to be recovered as a regulated cost pass through), and would not involve any direct operating and capital expenditure associated with that component. The exception is the installation of minimum load control to enable the control of solar PV installations, which would be directly invested in by ElectraNet."*

[13] AER Final Decision Murraylink transmission determination 2018-23 Attachment 6 – Capital expenditure April 2018

From PADR Table 5, it is assumed that the capex and opex associated with the Minimum Load Control are $3m and $1m pa respectively:

SOUTH AUSTRALIA ENERGY TRANSFORMATION PADR 29 JUNE 2018

Table 5 – Non-interconnector option components

Component (Network support agreement)	Average annual contract cost ($m)	Capital cost ($m)	Operating cost ($m)	Available from
Pumped Storage (Port Augusta)				
Osborne cogeneration				
Solar thermal at Davenport				
BESS – Tailem Bend				
Murraylink (Transfer of FCAS)				
BESS (location to be determined)				
Minimum load control				
Total combined cost	**$130**	**3.0**	**1.0**	**2020-23**

3.7 Cost Summary

In summary, from publicly available information, capital costs for the elements described in the Entura report appear to total around $1.5 billion:

Ref	Technology/location	Nameplate	Capex Est ($m)
1	Pumped storage – Cultana	120 MW	$ 300
2	Osborne Cogeneration	180 MW	$ 135
3	Solar thermal – Davenport	120 MW	$ 750
4	Battery – Tailem Bend	150 MW	$ 150
5	Murraylink – Berri	200 MW	$ 25
6	Battery – Tailem Bend	150 MW	$ 150
7	Minimum load control	NPV	$ 15
			$ 1,525

However, the Solar Thermal plant for example would be an expensive way to procure the identified need if it were not able to be significantly offset by the asset's energy value. Osborne Cogen has been conservatively priced at half of its replacement value so, overall, there are likely to be opportunities to optimise the portfolio cost. In our view $1,500m represents a conservative estimate.

3.8 Findings

ElectraNet convert the Entura findings into annual payments of approx $130m and model them to have an NPV of $1,150m out to 2040. This corresponds to over 75% of the estimated capital value of $1,500m. This seems to be too high given the other energy market services most of these assets can provide (the Osborne Cogen, Murraylink upgrade and Minimum Load Control elements are perhaps more restricted to network and ancillary services). Even re-applying the 45% from the ElectraNet document implies an NPV of less than $700m, only 60% of the value used by ElectraNet. Even this seems conservatively high. An open tender for the network support services required and/or the further development of system security markets would plausibly deliver the identified need at even lower cost.

In summary, publicly available information suggests that the cost of Option A has been overstated in the RIT-T analysis.

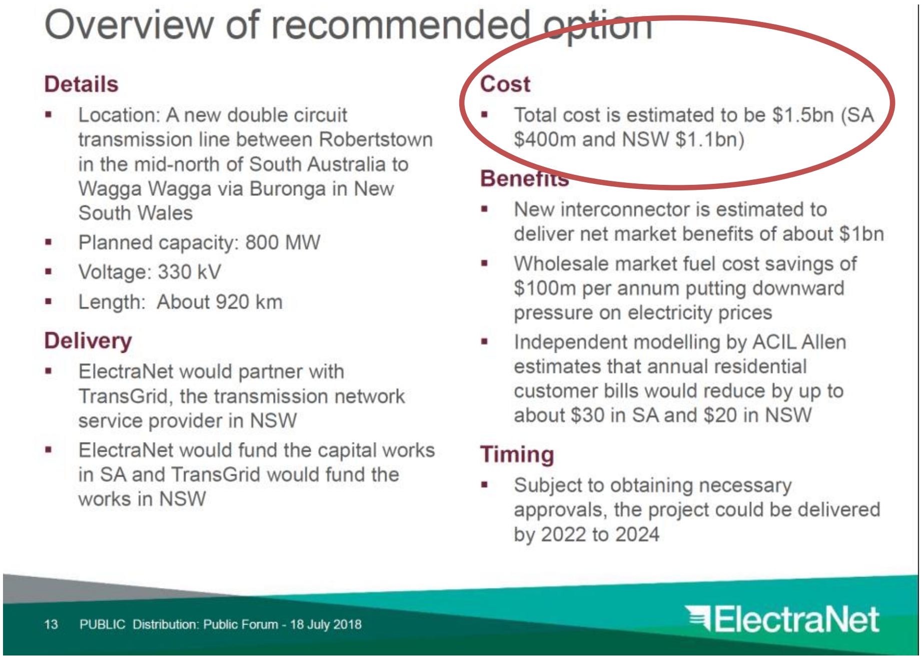
4 The allocation of costs and benefits between SA and NSW consumers

The ACIL Allen report commissioned by ElectraNet estimates the impacts on wholesale prices in NSW and SA. From Table 3.3 *"Summary of Reduction in Projected Wholesale Spot Price Due to the New Interconnector, Nominal"* it is possible to estimate the Net Present Value of these benefits by multiplying these prices by the average volume of electricity sold in each region (71.3TWh and 12.6TWh) and discounting these dollar values by 8.5% (6% discount rate plus 2.5% CPI).

The modelling period is to 2040 and this yields an estimated $556m to NSW and $831m to SA (and a total estimate of the benefits to 2040 of $1,386m to 2040). This is a 60:40 ratio of benefits between the two jurisdictions (SA:NSW). Considering the benefits out to 2033, and out to 2050 however reveals a more balanced result with the ratio between SA and NSW being closer to 55:45.

NPV $m	NSW	SA	NSW	SA
from 2019 to 2033	$463m	$530m	47%	53%
from 2019 to 2040	$556m	$831m	40%	60%
from 2019 to 2050	$854m	$1,006m	46%	54%

However, according to ElectraNet's initial estimates, *costs* under the preferred option are skewed toward NSW - $1.1bn vs $0.4bn in SA (approx. 73% NSW, 27% SA):



A related aspect of the NEM regulatory framework is the arrangements for interregional Transmission Use of System (IRTUoS) charging. This mechanism was introduced following a 2013 review by the Australian Energy Markets Commission that aimed to better recognise the benefits transmission delivers across region boundaries[14]. The RIT-T does not require the inclusion of any estimates of the allocation of costs and benefits or the impacts of the IRTUoS regime but it would certainly help consumers engage in the RIT process if it was made available.

4.1 Findings:

The allocation of costs and benefits seems imbalanced between SA and NSW consumers. Combined with the following observations regarding the benefits modelled over 15 years compared to 22 years, this implies that expenditure in NSW (and hence costs) is perhaps too far in advance of the need (i.e. the benefits accrue well after the initial investment).

By implication, ElectraNet is encouraged to explore options that include elements of Option A (the non interconnector option) with staged investment in the NSW elements of the project. From the analysis performed for this project, a prima-facie case exists for 'tuning' of the scale and timing of increased interconnection between SA and NSW.

[14] www.aemc.gov.au/rule-changes/inter-regional-transmission-charging

5 Are combinations of elements of the existing scenarios, and/or potential staging of the investment, worthy of further consideration?

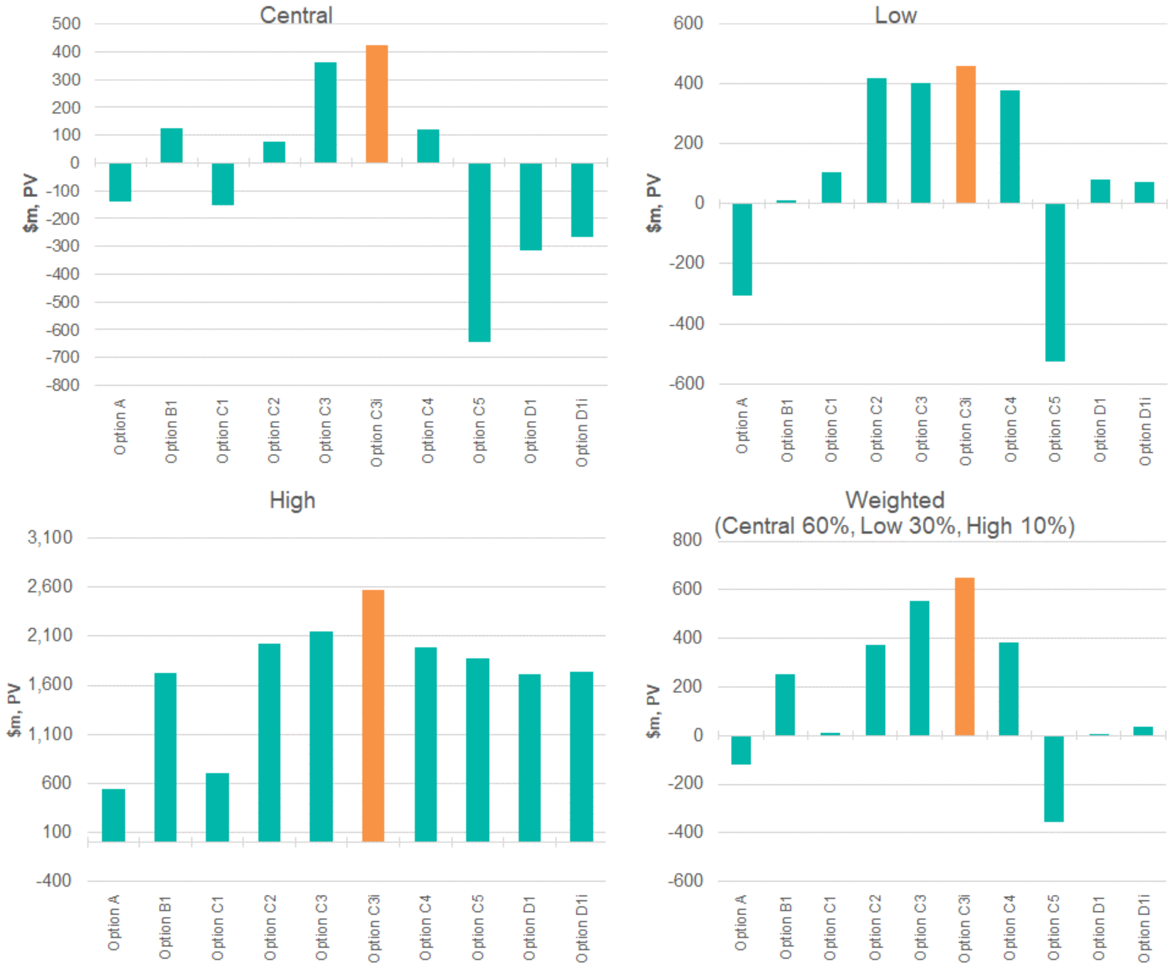
This review acknowledges the ISP recommendation to "*Establish new transfer capacity between New South Wales and South Australia of 750 MW.*" and that the SAET RIT-T is the first example of implementing a key ISP recommendation (albeit the SAET RIT commenced before the ISP was conceived). From this starting position, this review has focussed on the various sub-options of Option C – the SA -NSW option. The full set of options considered by the RIT are listed below:

Option	
A	Least cost non-interconnector option in SA
B	HVDC from north SA to Qld
C.1	New DC link from Riverland SA to NSW ('Murraylink 2')
C.2	275 kV line from mid-north SA to Wagga Wagga NSW, via Buronga
C.3	330 kV line from mid-north SA to Wagga Wagga NSW, via Buronga
C.3i	330 kV line from mid-north SA to Wagga Wagga NSW, via Buronga, plus series compensation (or similar)
C.4	330 kV line from mid-north SA to Wagga Wagga NSW, via Darlington Point
C.5	500 kV line from Northern SA to east NSW
D	275 kV line from central SA to Victoria
Di	275 kV line from central SA to Victoria plus series compensation (or similar)

The PADR published the following comparison of the options based on the net present value of each option (reflecting both expenditure and benefits over time) evaluated out to 2040.

Figure E.3 – Estimated net market benefits for each scenario

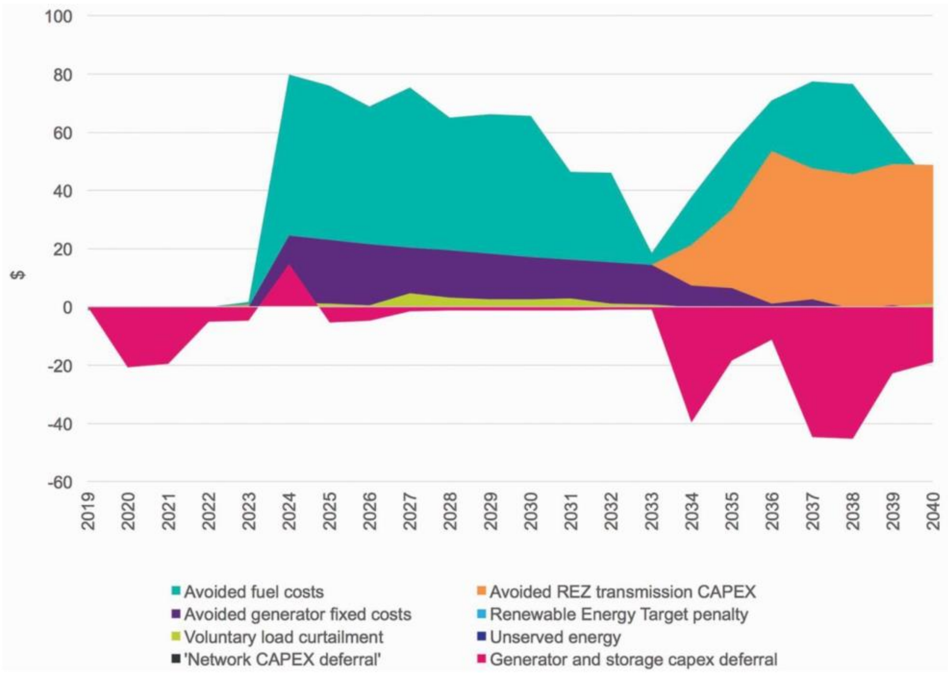
However, upon release of the modelling results by ElectraNet on 22 August 2018, a data entry error was noted by this review that misallocated the modelled 'avoided REZ Transmission costs' benefits in the Central scenario. Correcting for this, the above charts have been redrawn by this review below:



This does not appear to materially change the preferred option but, also lowers the overall benefits across all options from that shown in the Weighted chart due the originally published results being for a H:C:L weighting of 25%:50%:25% despite the chart's title (10%:60%:30% weighting).

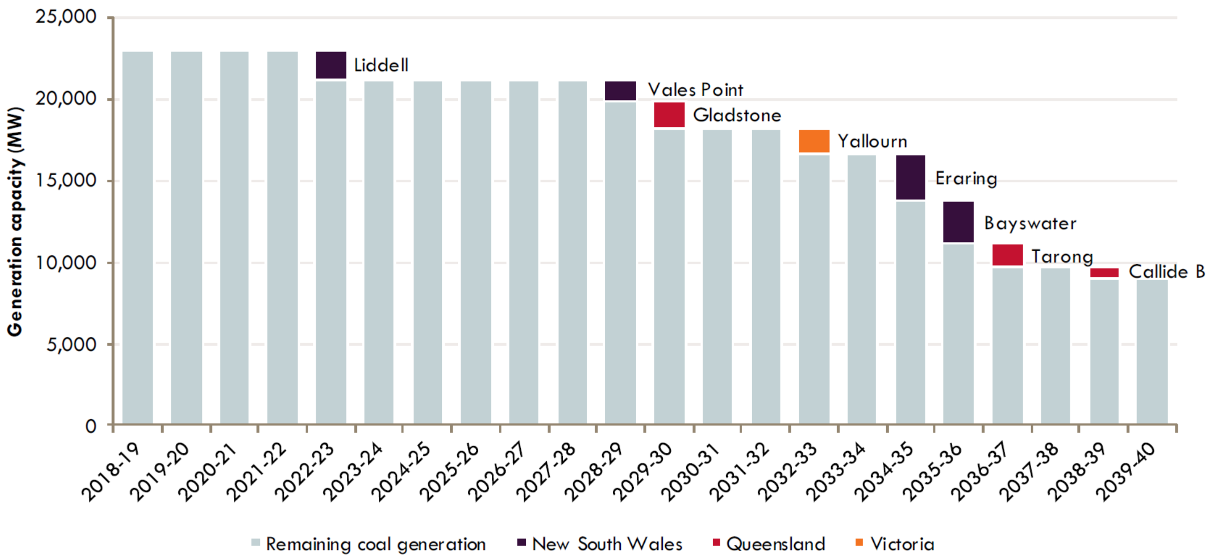
Another aspect of interest for consumers is the timing of the expenditures compared to the timing of the benefits. The following chart from the PADR illustrates how the benefits manifest over time in the central scenario for the preferred option:

Figure 7 – Breakdown of gross market benefits for Option C.3.i over time – central scenario



In order to reflect the modelled inflexion in benefits at 2033 (a period of coal plant closures and an accelerated period of investment in renewable generation in both regions) and recent energy policy uncertainty, the above analysis was repeated over a 15-year time frame to 2033 instead of the original analysis to 2040. This has the effect of being less reliant on the benefits of future policies and, for example, the approach to Renewable Energy Zones.

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



The results over 15-years show that ElectraNet's preferred option, Option C3i, is no longer the one that delivers the maximum net market benefit. Using ElectraNet's scenario weightings, the non-interconnector option, Option A, would clearly be the preferred option under the current scenario weightings. Under an equal weighting of all scenarios, several other options compete for the title of 'preferred'.

Similar analysis has been performed by keeping the time period to 2040 but excluding the category 'avoided REZ transmission capex' as many consumers and representatives contacted for this review expressed a view that alternate funding mechanisms for REZ development, incorporating generator contributions, need to be developed in order to more fairly allocate risks.

In this case, the PADR comparison charts have been redrawn below. This shows that the QLD option becomes the preferred option in the central scenario but the weighted results affirm C3i as the preferred option.

In a similar vein, the NPV results appear to be quite sensitive to the Terminal Value used in the analysis (the residual value of the assets at 2040) and to discount rates.

5.1 Implications for consumers

From a consumer perspective, the sensitivity of the results illustrated above has implications for the risk to consumers discussed earlier. Uncertainty in benefits needs to be reflected in both the timing of the elements of these investments and how these investments are funded. The question of alternate funding approaches is beyond the scope of this submission, but issues of project timing are relevant:

As noted earlier, the allocation of costs and benefits seems imbalanced between SA and NSW consumers. Combined with the observations above regarding the benefits modelled over 15 years compared to 22 years, there is an implication that expenditure in NSW (and hence costs) is perhaps too far in advance of the need (i.e. the benefits accrue well after the initial investment).

By implication, ElectraNet and TransGrid are encouraged to explore options that include elements of Option A (the non-interconnector option) with staged investment in the NSW elements of the project. This could include elements of Option C2, C3 and C3i. Perhaps a C2i option (C2 + SVC) would be an appropriate initial investment that could be considered.

Further, the choice of 6% real as a "commercial discount rate" is not reflective of the risk facing consumers and should be revisited. We note that ElectraNet has referred to testing boundary values but we were unable to find this in the analysis of discount rates:

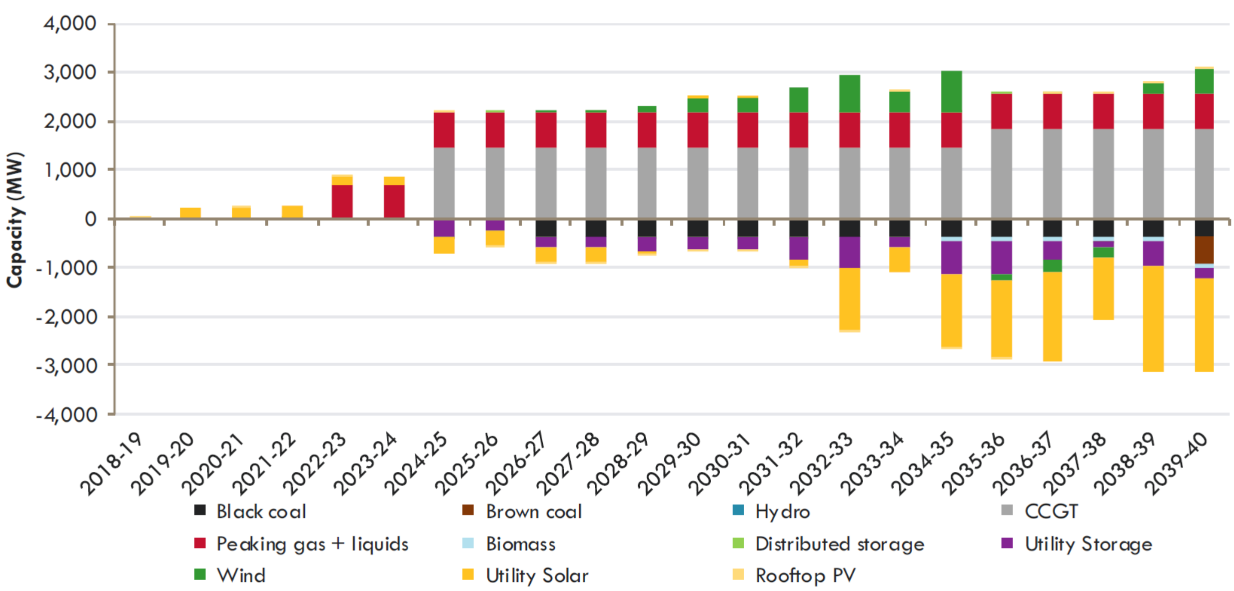
> *PADR p70: "We have identified the key factors driving the outcome of this RIT-T, and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change."*

6 Concern regarding unintended consequences

Participation in the public fora and deep dives in both Adelaide and Sydney allowed us to hear the concerns of a number of stakeholders regarding the impact on closures of generators. Of note, and not fully discussed at these events is that the ISP modelling of the impact of RiverLink is the rapid closure of not just Torrens Island Power Station as evident in the ElectraNet modelling results but Pelican Point and Osborne Cogen as well. This represents closure of all three of what are (or used to be) considered the mid-merit plants in SA. The remaining generation fleet is the existing gas and diesel peaking plants and an expanding portfolio of wind and utility-scale solar farms.

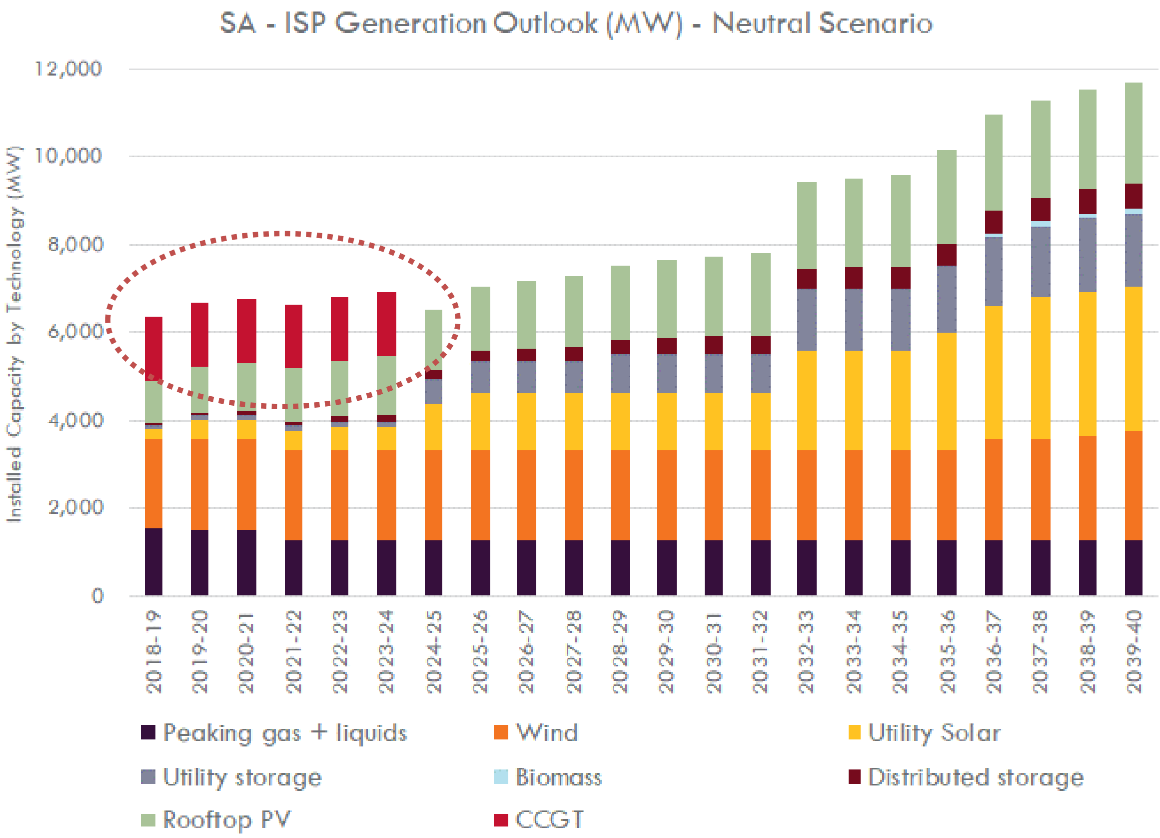
This is acknowledged in the footnote to AEMO's 2018 ISP Figure 23:

Figure 23 Projected installed capacity, no interconnector reference, relative to Neutral case



The 'increased' CCGT capacity for this scenario is due to the continued operation of South Australian GPG in this scenario, relative to the Neutral case, which would allow GPG to mothball or retire due to the introduction of increased interconnection via the RiverLink interconnector.

Analysis of AEMO's published ISP data illustrates this more clearly for South Australia:



Informally, it is understood that AEMO and ElectraNet have confidence that a power system that is well over 90% based on solar and wind would be able to sustain interconnector failures and operate as an island[15]. Presumably this is due to imminent investments in synchronous condensers and, later, the synchronous nature of solar thermal plant and pumped hydro facilities that are expected to be part of the mix.

However, it is important for consumers to understand that the business case for the proposed interconnector is founded on reduced expenditure on gas powered electricity generation. The cost of gas in Australia has increased substantially in recent years on the back of our Liquefied Natural Gas (LNG) industry and, to be clear, the modelling indicates that if gas was priced at historic levels below $5/GJ, the business case interconnector can't be made at current estimates of costs.

[15] Also see commentary by Dylan McConnell from the Climate and Energy College in RenewEconomy article South Australia will be at 100% renewables by 2025 – market operator (August 17, 2018): https://reneweconomy.com.au/south-australia-will-be-at-100-renewables-by-2025-market-operator-52312

7 Conclusions

The PADR and associated documents have not convinced us beyond reasonable doubt that the preferred option is in the long-term interests of consumers. In summary, from the analysis performed for this project, a prima-facie case exists for tuning the scale and timing of increased interconnection between SA and NSW in order to optimize the cost to consumers.

Further, given the apparent imbalance between costs and benefits of the preferred option between SA and NSW consumers, a more strategically timed approach to the NSW elements may better align costs and benefits for NSW consumers.

From a consumer perspective, the implications of uncertainty in benefits needs to be reflected in both the timing of the elements of these investments and how these investments are funded. The question of alternate finding approaches is beyond the scope of this submission.

As noted earlier, the allocation of costs and benefits seems imbalanced between SA and NSW consumers. Combined with the observations above regarding the benefits modelled over 15 years compared to 22 years, there is an implication that expenditure in NSW (and hence costs) is perhaps too far in advance of the need (i.e. the benefits accrue well after the initial investment).

By implication, ElectraNet and TransGrid are encouraged to explore options that include elements of Option A (the non interconnector option) with staged investment in the NSW elements of the project. This could include elements of Option C2, C3 and C3i. Perhaps a C2i option (C2 + Series Compensation) would be an appropriate initial investment that could be considered.

Broader implications for the RIT process and its interaction with the ISP will be made in a subsequent report to Energy Consumers Australia.