Decision

South Australian Energy Transformation

Determination that the preferred option satisfies the regulatory investment test for transmission

January 2020

AUSTRALIAN ENERGY REGULATOR

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Contents

Executive Summary

The Australian Energy Regulator (AER) has determined that ElectraNet's preferred option identified in its South Australian Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T) application satisfies the requirements of the RIT-T.

The RIT-T is an economic cost–benefit analysis used by transmission businesses to assess and rank different electricity investment options to ensure affordable and reliable energy for consumers.

Our determination finds that ElectraNet has identified the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity (the preferred option).

Our determination that the preferred option satisfies the RIT-T is a necessary step in the regulatory approval process to enable the costs of the project to be recovered from consumers. We expect that ElectraNet and TransGrid will lodge a joint contingent project application to seek regulatory approval for the efficient costs of this project to enable these costs to be recovered from consumers.

South Australian Energy Transformation RIT-T

ElectraNet initiated a RIT-T process in November 2016 to identify a project to:

- reduce the cost of providing secure and reliable electricity to South Australia;
- facilitate the long term transition of the energy sector across the NEM to low emission energy sources; and
- enhance power system security in South Australia.

ElectraNet published the Project Assessment Conclusions Report (PACR) for the SAET RIT-T on 13 February 2019. The preferred option identified in the PACR involves constructing a new 330 kV interconnector between Robertstown in South Australia and Wagga Wagga in New South Wales. It also includes a 220 kV spur from Buronga in NSW to Red Cliffs in Victoria. The estimated cost is $1.53 billion (in nominal terms) with a completion date of 2022 to 2024.

Assessment approach and reasons for decision

For the AER to make a determination that the preferred option satisfies the RIT-T, the preferred option must be the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM). In undertaking this assessment we have had regard to:

- the reasonableness of the methodology, inputs, assumptions; and
- ensuring the modelling does not contain material errors.

If there are no errors in the net benefit calculations, the methodologies are sound, and the inputs and assumptions that affect the ranking of options are reasonable, then we consider the credible option identified as the preferred option satisfies the RIT-T.

In applying this approach in our review, we identified a number of critical assumptions and inputs that were material to the estimated benefits of the preferred option.

These critical inputs and assumptions relate to:

- South Australian gas plant usage and retirements;
- system security requirements, including the impact of system security obligations on the preferred option, the role of pumped hydro in addressing these requirements and the impact on the ranking of the credible options.

We also investigated the reasonableness of other key inputs and assumptions which are explained in detail in Appendix A.

Significance of assumptions related to gas fired generation in SA

The net benefits of the PACR preferred option are mainly dependent on inputs and assumptions regarding future gas usage in South Australia. This is because the construction of the SA-NSW interconnector enables lower cost sources of generation (e.g. black coal generation from New South Wales) to replace more expensive South Australian gas-fired generation that is assumed to need to run in the absence of the interconnector. The higher the estimated level of gas usage in the absence of the project, the higher the net benefits of reduced gas usage as a result of implementing the project.

ElectraNet's PACR assumed minimum capacity factors (MCFs) for three South Australian gas plants (Osborne, Pelican Point and Torrens B). This assumption is material to the RIT-T analysis as it results in high levels of gas generation in South Australia in the base case which the interconnector then displaces to deliver most of the benefits. The MCFs adopted in the PACR deviated from the MCFs used in AEMO's ISP (Integrated System Plan) 2018 and were not included in the PADR.

To test the robustness of the SAET RIT-T outcomes, we asked ElectraNet to update the SAET RIT-T modelling to reflect alternative inputs and assumptions. This additional modelling took into account:

- our request for ElectraNet to remove minimum capacity factors, as well as other assumptions that affect gas usage (minimum operating loads, generator cycling times, and retirement of SA gas generators) that we identified during our assessment process. These are discussed in Section 3.2 and Appendix A; and
- errors that ElectraNet identified in its modelling that led to the preferred option having higher benefits when the model was re-run (compared to when the model was run for the PACR).

The additional modelling undertaken by ElectraNet corrected for these errors and adopted our alternative inputs and assumptions. The results of this further modelling indicate that the net economic benefits of the preferred option in the central scenario remain positive, assuming interconnector costs of $1.53 billion.

However, the additional modelling also indicates that the net benefits in the central scenario may be significantly lower (about $269 million rather than $924 million) using the alternative inputs and assumptions. The net benefits in the additional modelling include:

- Avoided fuel cost benefits as a result of lower cost wind generation displacing higher cost gas generation rather than black coal and wind generation displacing gas generation in the PACR modelling.
- Avoided fixed operating costs associated with the modelled retirement of the TIPS B gas plant in South Australia.
- Avoided capital costs associated with avoided storage investment; and
- Avoided transmission investment associated with the connection of renewable energy zones.

The results of the additional market modelling confirm our concerns about the MCF assumptions for South Australian gas plants adopted by ElectraNet in its PACR. We do not consider that the MCF assumptions adopted for SA gas plants in the SAET PACR are reasonable, for the following reasons:

- These MCF assumptions force gas plants in South Australia to be dispatched 'out of merit order' and displace lower cost renewable generation (e.g. existing wind generation in South Australia) which is not an economically efficient outcome.
- The PACR modelling only applied these MCFs to gas plants in South Australia and not to other gas plants in the NEM.
- ElectraNet stated that the adoption of minimum capacity factors on gas plants in South Australia was intended to better reflect historical operation of gas-fired generation. However, the adoption of these MCFs based on historical output is not consistent with the modelling methodology adopted in the PADR which assumes a least cost approach to generator dispatch.

Overall, the effect of these MCFs is to assume the amount of gas usage of South Australian gas generators in the base case state of the world. By removing the MCF's, gas usage by selected gas plants in South Australia in the base case is lower than modelled by ElectraNet. In turn the benefits of the interconnector are reduced as less gas is displaced by coal. It is therefore likely that the adoption of the MCFs significantly overstate the modelled benefits of the interconnector.

Assumptions relating to system security requirements

Following the removal of the MCF gas-fired generation assumptions in South Australia, the additional modelling results from ElectraNet highlighted the impact of the system security assumptions on the net benefits of the preferred option. In examining the additional modelling results, we found that the overall benefit of the preferred option becomes negative if these system security assumptions are relaxed.

The SAET RIT-T adopted the Australian Energy Market Operator's (AEMO) system security assumption used in the 2018 ISP, which required two synchronous generating units to be on line at all times in South Australia in the absence of the interconnector. The SAET RIT-T further assumed that this two unit synchronous generator requirement ('two unit constraint') would be satisfied by gas plant in South Australia over the entire modelling period. The assumption that AEMO's two unit constraint would only be able to be met by the use of gas power plants is critical. This is because it forces gas plant to run at all times, resulting in higher gas usage and thereby adding costs in the base case. For this reason, we further considered whether:

- It was reasonable for the SAET RIT-T analysis to assume that two large synchronous gas units need to be online at all times in South Australia to satisfy system security requirements in the absence of the proposed interconnector; and
- A non-network alternative (pumped hydro storage) could contribute to the two synchronous generation unit planning assumption, and thereby reduce fuel costs by reducing the amount of gas usage.

Two synchronous generating unit assumption

As noted above, the two unit constraint is a system security requirement imposed by AEMO in the 2018 ISP. We consider that ElectraNet's adoption of this assumption in the SAET RIT-T is reasonable.

However, the SAET RIT-T goes further than the 2018 ISP and assumes that only gas plant in SA can satisfy AEMO's two unit constraint. AEMO did not specify in the 2018 ISP that the two unit constraint must be met by gas. Pumped hydro is another source of synchronous generation that could have been considered by ElectraNet. AEMO has subsequently advised the AER that a pumped hydro facility may be able to replace one gas generation unit for system security purposes, but that pumped hydro would not be able to satisfy the two unit constraint at all times unless paired with other synchronous generation (which in SA must be gas).

Based on this advice, we have not considered pumped hydro to be a complete substitute for gas generation in satisfying the two unit constraint. However, we have considered how pumped hydro's contribution to satisfying the two unit constraint would have affected gas generation costs.

Pumped hydro as an alternative to contribute to the two unit constraint assumption

To test whether pumped hydro may be able to reduce gas generation costs in the absence of the interconnector, we considered a pumped hydro facility which is reserved for system security purposes. We considered whether such a pumped hydro facility, in combination with gas plant, is likely to reduce the costs of satisfying the two unit constraint.

Our indicative analysis suggests that when paired with gas plant in SA, two units (100MW each) of pumped hydro may reduce the overall costs of satisfying the two unit constraint in the absence of the interconnector, but that the impact is not material to the overall net benefits of the project.

To sum up, without assumptions relating to minimum capacity factors for gas fired generation, the net benefit of the interconnector may be around $269 million in the central scenario. If pumped hydro contributes to relieving the two unit constraint assumption, this benefit may be lower by further reducing gas costs in the base case. However, changes to pumped hydro assumptions do not have a material impact on the net benefits of the interconnector and the benefits of the interconnector still outweigh the costs.

The VIC-SA interconnector

We explored the ranking of the credible options in the SAET RIT-T, including the relative performance of the lower-cost VIC-SA interconnector. This is because the preferred option had lower net benefits after removing gas fired generation assumptions and analysing the impact of two gas unit constraint assumption. Moreover, our consultant advised that the ability to alleviate the two unit constraint provided a major source of benefit for the preferred option, and other interconnector options could provide a similar benefit by also enabling the two unit constraint to be relaxed.

ElectraNet submitted that under the additional modelling, the VIC-SA interconnector option would provide a lower level of avoided fuel cost benefits (amongst other benefits) compared to the preferred option. ElectraNet submitted that this is due to network constraints between VIC and NSW, which reduce the ability for SA and VIC renewables to flow into the NSW region and thereby displace more expensive black coal generation in the NSW region. In contrast, the preferred option would enable excess SA renewables to replace some black coal generation, mainly in the NSW region.

We examined the modelling outputs for the VIC-SA interconnector. These indicate that the VIC-NSW interconnector is subject to significant congestion which supports the modelling results. They also indicate that the preferred option also provides additional benefits associated with avoided transmission network upgrades. As a result, we are satisfied that the VIC-SA option is likely to provide lower avoided fuel cost benefits than the SA-NSW option as the difference in avoided fuel cost benefits is still greater than the cost differential between the two projects.

On the basis of the information provided, we are therefore satisfied that the preferred option is likely to provide higher net benefits than the VIC-SA option.

Conclusion

Overall, we are satisfied that the updated modelling results demonstrate that the preferred option in the PACR is robust across alternative inputs and assumptions and so is likely to be the credible option that maximises the net economic benefit in the NEM. As a result we are satisfied that the RIT-T has been successfully completed.

In accordance with clause 5.16.6(b) of the National Electricity Rules (NER), our determination is that the preferred option identified by the SAET RIT-T satisfies the RIT-T.

Contingent project application and a material change in circumstances

The final step in the regulatory process involves the regulatory approval of the efficient costs of the project. We expect ElectraNet and TransGrid to lodge a contingent project application for the recovery of the proposed costs of the project. ElectraNet's SAET RIT-T indicates that the estimated costs of the preferred option are subject to a high degree of uncertainty. We also understand that there is the potential for updated proposed costs in a contingent project application to diverge from the estimated costs in the SAET RIT-T. The NER requires that the RIT-T proponent must reapply the RIT-T, unless the AER determines otherwise, in the event that there is a material change in circumstances such that the preferred option identified in the PACR is no longer the preferred option.

While our decision on this 5.16.6 application is that the preferred option satisfies the RIT-T, our assessment is that the costs and benefits of the preferred option may be more finely balanced than the PACR suggests. On this basis, any significant changes to the costs of the preferred option could have a material impact on the outcome of the RIT-T.

In the event that any updated assessment of the costs of the project (and/or any other updated assessment of the key variables that may affect market benefits) differs materially from those presented in ElectraNet's RIT-T assessment, we would expect ElectraNet to consider whether there is a change in circumstances such that the RIT-T should be reapplied, and to provide evidence of that consideration to the AER. This should include providing updated analysis demonstrating whether the preferred option identified in the PACR, in light of the issues considered in this 5.16.6 assessment and any updated cost information, continues to be the preferred option.

1 Introduction

ElectraNet and TransGrid are proposing to build a new interconnector between South Australia and New South Wales. The project is called the South Australian Energy Transformation project or SAET.

ElectraNet and TransGrid have undertaken a cost benefit assessment of the project, and have asked us to determine whether the preferred option identified in the PACR for the SAET RIT-T satisfies the RIT-T.

This chapter sets out background information relevant to our determination.

1.1 Who we are and our role in this process

The AER is the economic regulator for electricity transmission and distribution services in the NEM.[1] Our electricity-related powers and functions are set out in the National Electricity Law (NEL) and NER.

We are responsible for developing, publishing and maintaining the RIT-T and accompanying RIT-T application guidelines.[2] The RIT-T is an economic cost–benefit analysis that is used by transmission businesses to assess and rank different electricity investment options.[3] The purpose of the RIT-T is to identify the credible option[4] which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option).[5] The RIT-T application guidelines provide guidance on the operation and application of the RIT-T.[6]

Following the finalisation of a RIT-T application, a RIT-T proponent may make a written request to the AER to make a determination on whether the preferred option satisfies the RIT-T.[7] The RIT-T proponent can only make this request where the purpose of the investment options in the RIT-T application is not to address forecast reliability limitations arising on its transmission network.

1 In addition to regulating transmission and distribution in the NEM and Northern Territory, we also monitor the wholesale electricity and gas markets to ensure suppliers comply with the legislation and rules, taking enforcement action where necessary, and regulate retail energy markets in Queensland, New South Wales, South Australia, Tasmania (electricity only) and the ACT.

2 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018

3 The current RIT-T, version 1.0, was published by the AER on 29 June 2010.

4 A credible option is defined in NER, cl. 5.15.2(a) as an investment option that (a) addresses the identified need; (b) is commercially and technically feasible; and (c) can be implemented in sufficient time to address the identified need. A credible option is also an option that is identified as a credible option in accordance with paragraphs (b) or (d) of cl. 5.15.2 (as relevant).

5 NER, cl. 5.16.1(b)

6 AER, regulatory investment test for transmission application guidelines, December 2018,

7 National Electricity Rules, clause 5.16.6(a)

We note that the Energy Security Board[8] is working on new rules changes related to the transmission planning framework in particular, the ISP and the role of RIT-Ts in future. However, the SAET RIT-T is not impacted by these prospective framework changes, as the SAET RIT-T process was undertaken prior to the new framework coming into place.

1.2 Who are ElectraNet and TransGrid?

ElectraNet is a transmission business which owns and operates the transmission network in South Australia. TransGrid is a transmission business which owns and operates the electricity transmission network in New South Wales and the ACT.

ElectraNet conducted the SAET RIT-T consultation process and assessment.

Both TransGrid and ElectraNet's revenues are regulated by the AER through five year transmission revenue determinations. Both TransGrid and ElectraNet's current transmission revenue determination commenced on 1 July 2018 and will finish on 30 June 2023.

1.3 ElectraNet proposal

On 11 April 2019, ElectraNet submitted a written request to the AER that the AER make a determination on whether the preferred option identified in the SAET RIT-T satisfies the RIT-T.

At the time ElectraNet's PACR was subject to a dispute under clause 5.16.5 of the NER that we were deliberating on. The NER requires disputes to be resolved before we can undertake RIT-T preferred option assessments in accordance with clause 5.16.6 of the NER. We commenced our consideration of ElectraNet's request on 5 June 2019, the day we released our dispute determination.

1.4 The South Australian Energy Transformation RIT-T

RIT-T Process

The SAET RIT-T PACR was published by ElectraNet on 13 February 2019 after a 26 month consultation process. ElectraNet initiated its consultation process on 7 November 2016 with the following identified needs:[9]

- reduce the cost of providing secure and reliable electricity to South Australia;
- facilitate the long term transition of the energy sector across the NEM to low emission energy sources; and
- enhance system security in South Australia.

ElectraNet's Project Assessment Draft Report (PADR), published on 29 June 2018, identified six credible investment options. ElectraNet's preferred option was determined through its PACR, published on 13 February 2019. The preferred option is a new 330 kV

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8 ESB, Converting the Integrated System Plan into action, Consultation on draft ISP Rules, November 2019

9 ElectraNet, SAET Project Specification Consultation Report, 7 November 2016, p.15.

interconnector between Robertstown in South Australia and Wagga Wagga in New South Wales. It includes a 220 kV spur from Buronga in NSW to Red Cliffs in Victoria.

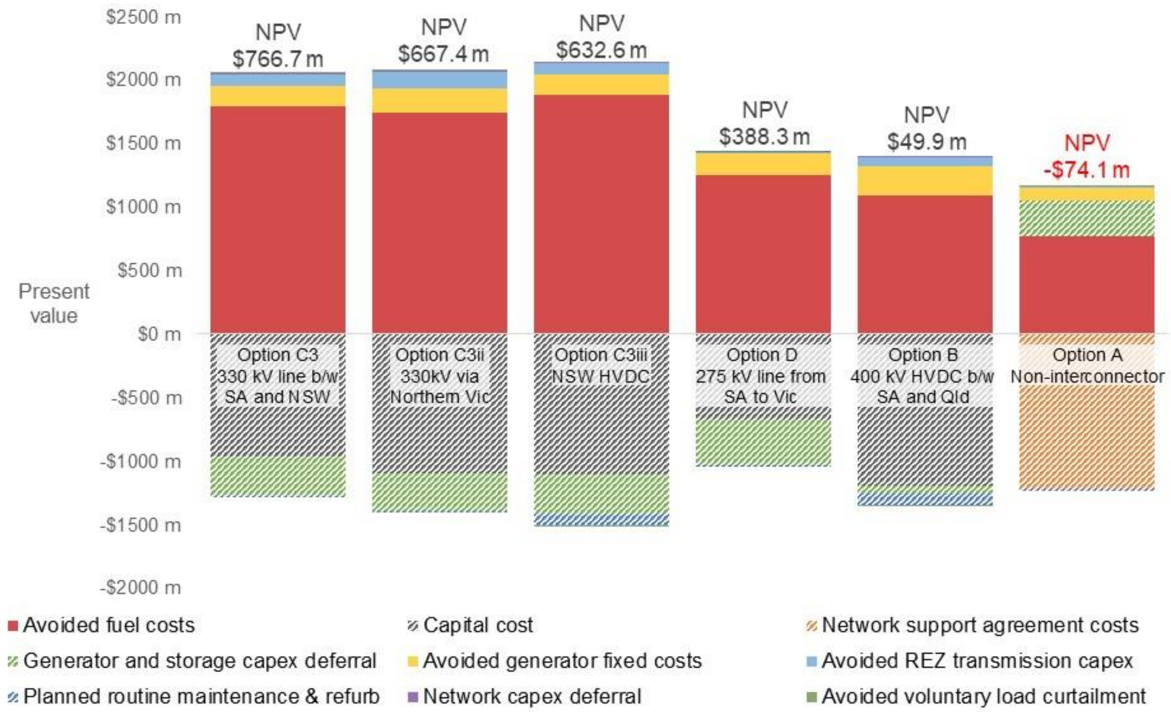
The credible options considered in the PACR, including the preferred option (C.3) are outlined in Figure 1.

Figure 1 Credible options identified in the SAET RIT-T PACR

Source: ElectraNet, SAET Project Assessment Conclusion Report, 13 February 2019, p.67

The net economic benefits of each option, including the preferred option are provided in Figure 2.

Figure 2 Estimated market cost/benefits in the central scenario



Source: PACR

The PACR stated that the preferred option for the proposed interconnector will provide up to 800 MW of notional maximum capacity[10]. The estimated cost of the preferred option (the proposed interconnector) is $1.53 billion with a completion date of 2022 to 2024.[11] These estimated costs include:

- $1,007 million for transmission lines and towers
- $495.9 million for substations; and
- $22 million associated with a special protection scheme to prevent an overloading of either the Heywood or the proposed interconnector.

Quantification of market benefits

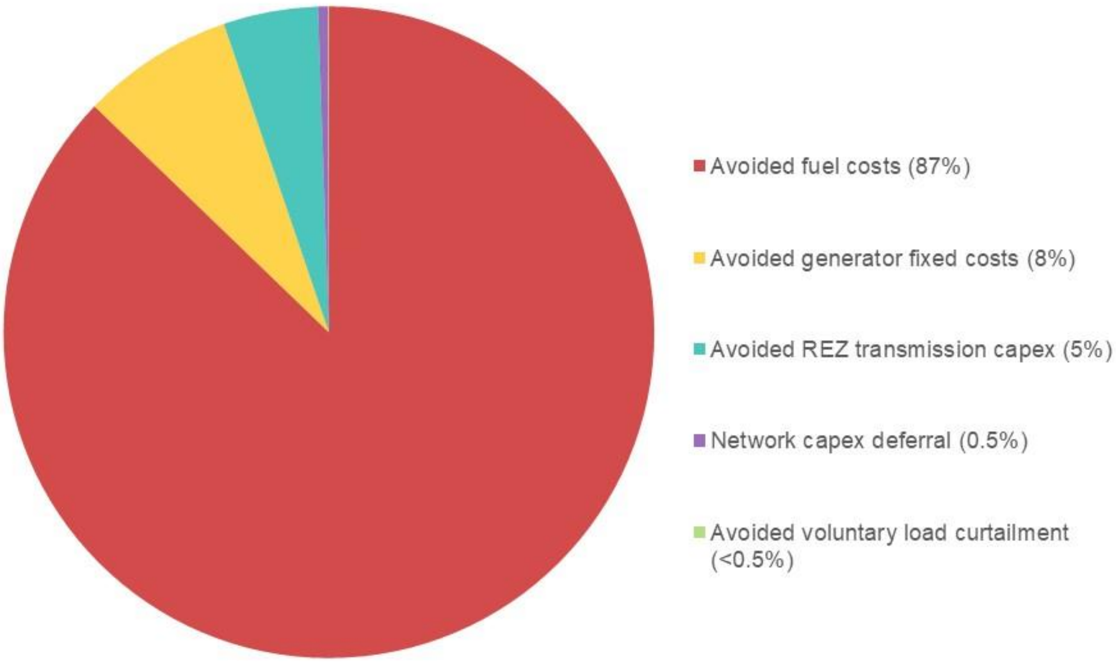
ElectraNet used a short run marginal cost energy market modelling approach, consistent with the RIT-T,[12] to estimate the net market benefits associated with the six credible options.[13]

Given uncertainty about future demand, gas prices, emissions targets and generator capital costs, ElectraNet modelled three scenarios, a low, central and high scenario. The modelling presented in the PACR estimates that the interconnector will deliver net market benefits in

10 ElectraNet, SAET Project Assessment Conclusion Report, 13 February 2019, p.9
11 ibid, p. 5-6.
12 AER, Regulatory investment test for transmission, 2010, paragraph 15(h).
13 ElectraNet, SAET Project Assessment Conclusion Report, February 2019, p. 83.

excess of $900 million, primarily driven by fuel cost savings, across three future scenarios over 21 years.[14] Figure 3 shows the classes of benefits assessed for the SAET RIT-T and their contribution to total net market benefits.

Figure 3 Gross market benefits for SAET RIT-T central scenario



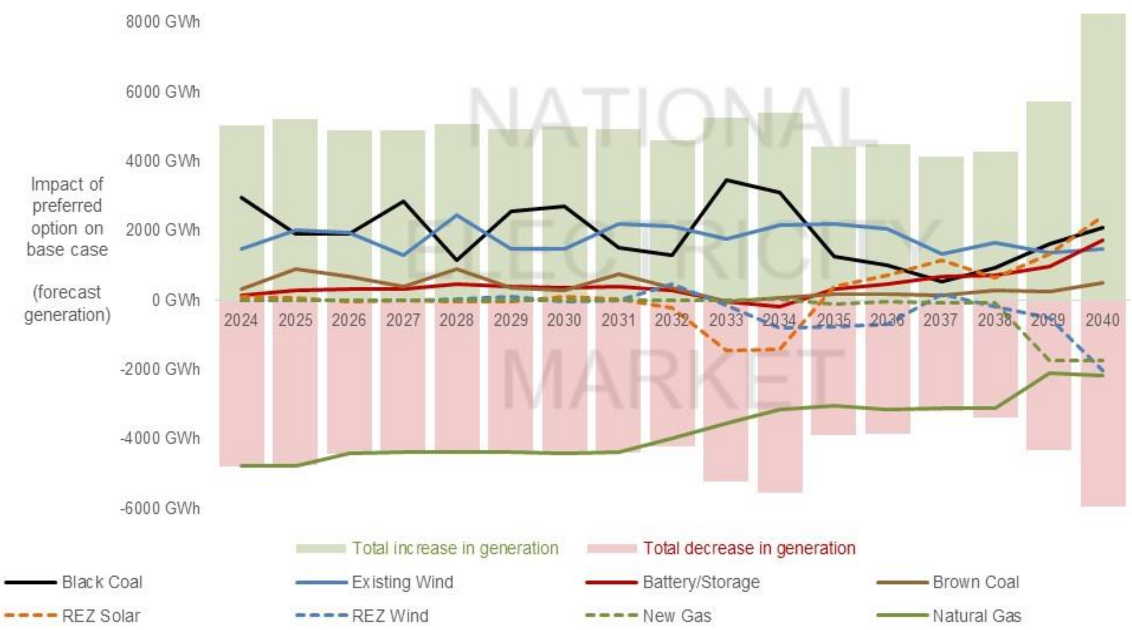
Source: ElectraNet, SAET Economic Evaluation Spreadsheet and Charts, 13 February 2019.

Note: The market modelling brings forward generator and storage capital costs in the central and low scenarios with the interconnector and this is negative market benefit.

The fuel cost savings are primarily driven by avoiding high-cost South Australian gas generation. We investigated differences in generation between the base case and the interconnector case under the central scenario. Figure 4 shows the impact of the interconnector on generation outputs across the NEM.

Figure 4: Forecast change in generation output in the central scenario across the NEM for preferred option

14 The net benefits reflect the weighted net benefits across each scenario.



Source: PACR and AER analysis[15]

This indicates that under the preferred option an average of 3.8 TWh of high cost gas fired generation in South Australia over the modelling period is replaced by:

- 1.5 TWh of lower cost black coal generation output
- 1.2 TWh of existing wind generation in South Australia
- 0.4 TWh of storage in South Australia; and
- 0.7 TWh of brown coal, solar and other generation

1.5 Why did ElectraNet request the AER make this determination?

Interaction with revenue determinations

We included the SAET RIT-T interconnector project as a contingent project in ElectraNet's revenue determination, and TransGrid's revenue determination, for the 2018-23 regulatory control period. An AER determination that the preferred option identified in the SAET RIT-T satisfies the RIT-T is a trigger event for the SAET contingent project in both TransGrid's and ElectraNet's 2018-2023 revenue determinations.

Generally, contingent projects are significant network augmentation projects that may be reasonably required to be undertaken to meet the capital expenditure (capex) objectives in

15 Figure 4 presents differences in generation between the base case and the interconnector case under the central scenario. We have included profiles only for generation types that are materially different.

the NER. However, unlike other proposed capex projects, the need for the project (and therefore the associated costs) is not sufficiently certain at the time of the revenue determination. Consequently, expenditure for such projects does not form part of our assessment of the total forecast capex that we approve in the revenue determination. The cost of the project may ultimately be recovered from customers in the future if pre-defined conditions are met. Specifically, these projects are linked to unique investment drivers and are triggered by a defined 'trigger event'. We must have regard to the need for the trigger event to be probable during the relevant regulatory control period.[16]

Specifically, in our ElectraNet and TransGrid revenue determinations, published on 30 April 2018, and 18 May 2018 respectively, we approved the SAET Interconnector as a contingent project with the following trigger:[17][18]

1. Successful completion of the RIT-T with the identification of a preferred option or options demonstrating positive net economic benefits and/or addressing reliability corrective action;
2. Determination by the AER that the proposed investment satisfies the RIT-T;
3. ElectraNet and TransGrid Boards commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER.

Our determination that the preferred option identified satisfies the RIT-T is necessary to satisfy the second element of the trigger event. Accordingly, we commenced our preferred option assessment on 5 June 2019 following the resolution of the SAET RIT-T dispute.[19] ElectraNet and TransGrid can submit a contingent project application to the AER under clause 6A.8.2 of the NER to amend their 2018-23 revenue determinations to account for the cost of the South Australian and NSW components of the SAET Interconnector project. Relevantly, AEMC's rule change in April 2019[20] allowed AER to commence the contingent project process for SAET RIT-T concurrently with the ongoing 5.16.6 review to expedite the regulatory approval process. However, despite this rule change, ElectraNet and TransGrid have not yet submitted a contingent project application to commence that process.

Our contingent project assessment is separate from this determination on whether the preferred option satisfies the RIT-T. The contingent project assessment requires a determination on the capital and incremental operating expenditure that is reasonably required by ElectraNet and TransGrid for the purpose of implementing the SAET Interconnector.

We expect TransGrid and ElectraNet to submit a joint contingent project application. While the application would be assessed separately for both ElectraNet and TransGrid's 2018-

16 National Electricity Rules, cl. 6A.8.1.

17 AER, Final Decision - ElectraNet transmission determination 2018 - 2023 Attachment 6, p.19.

18 AER, Final Decision - TransGrid transmission determination 2018 - 2023 Attachment 6, p.137-138.

19 ElectraNet lodged an application with the AER on 11 April 2019 requesting us to commence our preferred option assessment in accordance with Cl. 5.16.6 of the NER. However, we could not commence the 5.16.6 assessment until the dispute lodged by South Australian Council of Social Service on SAET RIT-T was resolved by the AER on 5 June 2019. Further details on the SAET RIT-T dispute can be found here

20 National Electricity Rules, cl. 11.114.3

2023 revenue determinations, a joint application will assist in expediting the regulatory process by allowing the AER to run a combined consultation process as opposed to separate consultation processes for the same project. This combined consultation process would also benefit stakeholders by allowing them to gain a broader overview of the project in its entirety, including the total estimated costs of the project.

1.6 Structure of this document

This document sets out our determination on whether the preferred option identified by the South Australian Energy Transformation RIT-T satisfies the RIT-T, and our reasons for the determination.

The decision is structured as follows:

- Section 2 sets out our approach to assessment of the preferred option;
- Section 3 sets out our determination on whether the preferred option identified in the SAET RIT-T satisfies the RIT-T, including the reasons for the determination;
- Section 4 sets out our determination.

2 RIT-T preferred option assessment approach

2.1 Our review process

Upon request by the RIT-T proponent, we are required to make a determination as to whether the preferred option satisfies the RIT-T. We must make and publish a determination, including reasons for the determination, within 120 business days.[21] This time is automatically extended if the AER seeks further information requests and the time taken by the RIT-T proponent to respond.

Accordingly, we were required to make and publish the SAET RIT-T determination by March 2020. This includes the time taken for ElectraNet to respond to AER's information requests.

In making the determination, we:

- must use the findings and recommendations in the project assessment conclusions report;
- may request further information from the RIT-T proponent; and
- may have regard to any other matter that we consider relevant.[22]

The NER states the purpose of the RIT-T is to identify the preferred option - namely, the credible option that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the NEM.[23] Therefore, to make a determination that the preferred option identified satisfies the RIT-T, we must be satisfied that the identified preferred option is the credible option which maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the NEM. Unless the identified need is for reliability corrective action or for certain inertia network services or certain system strength services, the preferred option must not have a negative net economic benefit.

In making our determination we assessed:

- The process - whether ElectraNet has followed the RIT-T process in accordance with the requirements of the NER and the RIT-T application guidelines. This includes a review of whether the PACR has addressed issues raised by stakeholder submissions.
- The outcome - whether the preferred option identified in the PACR is likely to be the option that maximises the net economic benefit, in present value terms. In making this assessment we consider the reasonableness of inputs, assumptions and methodologies applied to identify the preferred option.

Relevantly, we have asked questions of ElectraNet to test the reasonableness of input assumptions, but have not undertaken our own modelling.

21 National Electricity Rules, clause 5.16.6(b)(1).

22 National Electricity Rules, clause 5.16.6(b)(2)-(4).

23 National Electricity Rules, clause 5.16.1(b).

As set out in the RIT-T application guidelines, the broad steps involved in applying the RIT-T are:[24]

- Identify the need for investment. The identified need may be for a reliability corrective action or to increase the sum of consumer or producer surplus in the NEM.
- Identify the base case and set of credible options to address the identified need.
- Identify a set of reasonable scenarios that are appropriate to the credible options under consideration. A reasonable scenario is set of variables or parameters that are not expected to change across each of the credible options or the base case.
- Quantify the expected costs of each credible option.
- Quantify the expected benefits of each credible option.
- Quantify the expected net economic benefit of each credible option and identify the preferred option as the option with the highest expected net economic benefit.

We have assessed whether the SAET RIT-T satisfies the requirements, where relevant, of the above steps and whether there have been any material errors made or unreasonable inputs, assumptions or approaches applied by ElectraNet in undertaking the RIT-T.

In considering the reasonableness of key inputs and assumptions our assessment has focused on whether these have been:

- Applied consistently in the modelling;
- Adequately explained and supported by a verifiable source; and
- Reflect a realistic operation of the market.

This approach is reflected in the RIT-T guidelines which state that:

- A state of the world should be internally consistent such that all aspects of a given state of the world could reasonably coexist.[25] Therefore, we consider that inputs and assumptions are to be applied consistently when modelling each state of the world.
- RIT-T proponents use assumptions and forecasts that are transparent and from a reputable and independent source.[26] We consider that in order to provide transparency, inputs and assumptions must therefore be adequately explained and sourced where appropriate.
- The market dispatch modelling methodology adopted by the RIT-T proponent must incorporate a realistic treatment of plant characteristics.[27] Given its chosen modelling approach, we consider that this means that ElectraNet is required to adopt representations of plant characteristics that are as accurate as possible.

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24 AER, Regulatory investment test for transmission application guidelines, 29 June 2010, p.7

25 AER, Regulatory investment test for transmission application guidelines, June 2010, p.15

26 AER, Regulatory investment test for transmission application guidelines, December 2018, p.24.

27 AER, Regulatory Investment Test for Transmission, 2010, paragraph 11

In applying this approach our review tested the reasonableness of the following inputs and assumptions used in the SAET RIT-T:

- South Australian gas plant usage and retirements;
- system security constraints including the impact of system security obligations on the RIT-T analysis;
- forecast fuel costs, and pumped hydro capital costs;
- avoided transmission costs associated with 'Renewable Energy Zone' developments.

2.1.1 Consultant

To assist in our review, we engaged Frontier Economics ('Frontier') to undertake an independent review of the reasonableness of the methodology and key inputs and assumptions used in the RIT-T analysis. Our consultant was not required to undertake or replicate the cost benefit analysis undertaken by ElectraNet, as this is beyond the scope of our review. In particular, our consultant was required to:

- confirm that model outputs are credible
- advise on the reasonableness of inputs and assumptions used by ElectraNet, including the sensitivity analysis to test whether the preferred option is robust to changes in key inputs and assumptions; and
- confirm that there are no major modelling errors.

Frontier's report is available on our website.

2.1.2 Interaction with ElectraNet and AEMO

As part of our review we engaged with ElectraNet and AEMO to understand the system security obligations which underpin ElectraNet's modelling. ElectraNet states that the interconnector will improve system security and meet system security obligations at a lower cost than would otherwise be the case by:[28]

- alleviating the rate of change of frequency constraint on the operation of the Heywood interconnector, which limits the capacity of Heywood interconnector in some circumstances
- increasing the cap on the non-synchronous generation that may be on-line in South Australia due to system strength requirements; and
- reducing the risk of South Australia being islanded from the remainder of the NEM and so improving system security in South Australia.

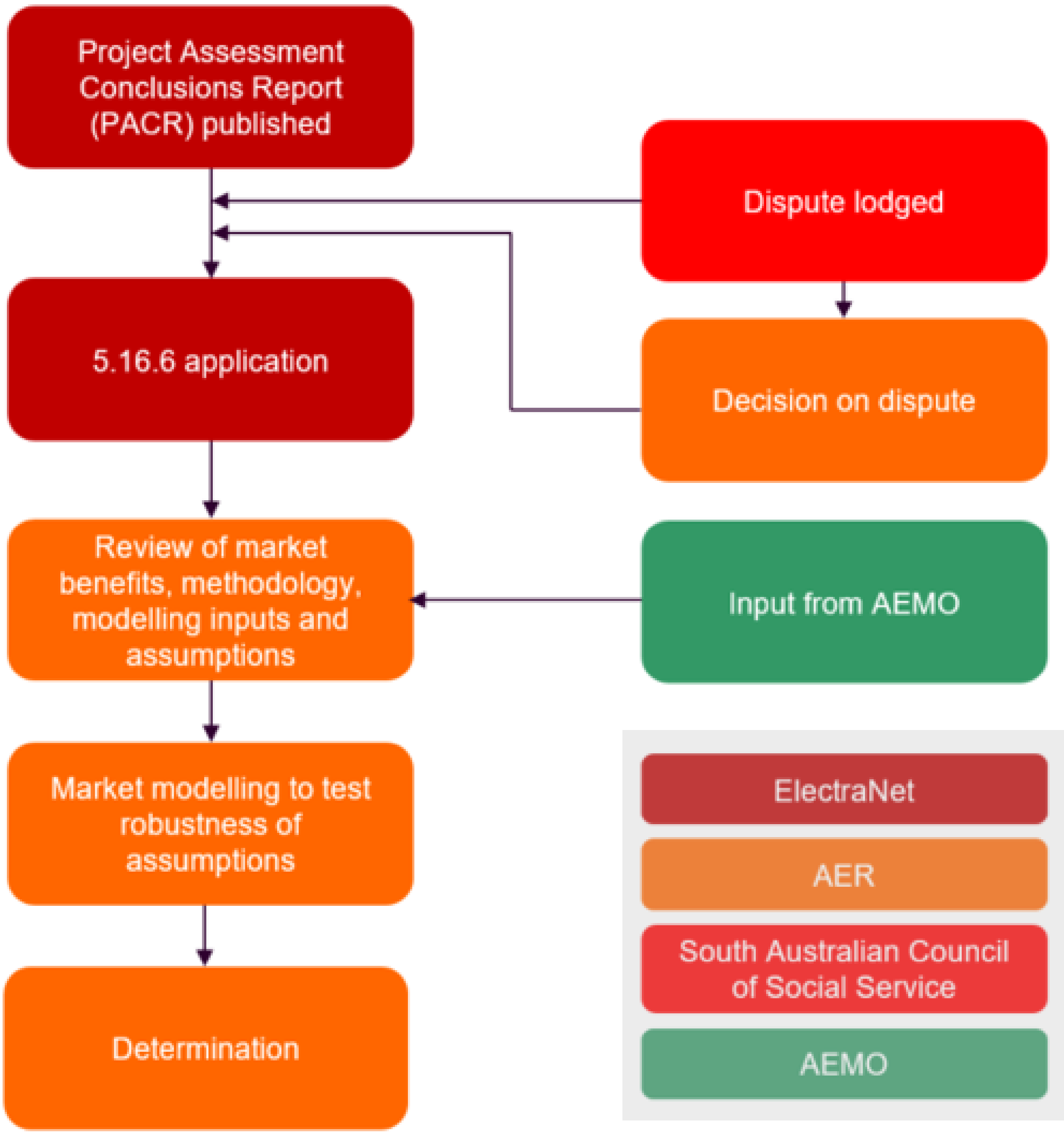
We sought information from AEMO about ElectraNet's system security obligations and the options for meeting those obligations. A copy of AEMO's advice is on our website.

28 ElectraNet, SAET RIT-T Project Assessment Conclusion Report (PACR), February 2019, p.37.

2.2 Our process

Following the receipt of ElectraNet's request for the AER to make a determination under rule 5.16.6, we undertook a targeted review of key inputs and assumptions. Our assessment process is outlined in Figure 5. Further details regarding this process are outlined in Appendix B.

Figure 5: SAET RIT-T assessment process



Source: AER

3 AER assessment of RIT-T application

This section outlines our assessment of whether the preferred option satisfies the RIT-T. In particular, it sets out the key areas of our assessment, including our assessment of the reasonableness of key inputs and assumptions used by ElectraNet in its SAET RIT-T. Where our assessment identified a concern with any aspect of the SAET RIT-T, we have considered whether this materially affects the selection of the preferred option.

3.1 ElectraNet's market modelling methodology

In order to estimate the market benefits of the interconnector, ElectraNet used a least cost expansion and operation approach based on short run marginal cost (SRMC) bidding. ElectraNet stated that this approach leads to the most efficient dispatch without the need to assess market prices or the commerciality of generators.[29]

The modelling methodology includes two integrated components:

- The long term model which models the effect of the credible options on long term investment decisions that are required to meet NEM reliability standards. Generator entry and exit is modelled in the long term model.
- The time sequential or short term model which models generator dispatch using the assumption of SRMC bidding and taking into account the fleet of generators that are made available through the long term model.

The modelling approach relies on the assumption that the design of the market will lead to prices that support entry and exit and market bidding that leads to the lowest capital, fuel and other operating costs.[30] ElectraNet stated that this assumption will hold provided that the relative order in which generation is dispatched in the time sequential model is similar to actual dispatch outcomes in the market.

3.2 Critical inputs and assumptions

ElectraNet's energy market modelling was influenced by the inputs and assumptions adopted. As such our review focused on assessing the reasonableness of key inputs and assumptions that were material to the benefits of the preferred option. As noted in Section 2, in assessing the reasonableness of these key inputs and assumptions we followed the principles set out in the RIT-T and associated application guidelines. In particular, we assessed whether the inputs and assumptions:

- are applied consistently in the modelling
- are adequately explained and supported by a verifiable source; and
- reflect a realistic operation of the market.

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29 ElectraNet, Market Modelling and Methodology Report, February 2019, p. 11.

30 Ibid, p.11.

In assessing the reasonableness of the inputs and assumptions, we investigated the inputs and assumptions that are most material to the analysis which are:

- the operation in the base case and assumed retirement in the interconnector case of gas fired generation in South Australia and in the other NEM regions
- capital costs of new entrant generation (pumped hydro); and
- the impact of system security assumptions.

We discuss other key inputs and assumptions, and how we assessed their reasonableness, in detail in Appendix A.

To test the robustness of the PACR outcomes, we requested that ElectraNet update the SAET RIT-T modelling to reflect alternative inputs and assumptions.

All additional modelling inputs and assumptions for each sensitivity test are presented in Table 1. Appendix A provides further details.

Table 1 Summary of additional modelling request

Input/assumption	Corrected PACR central	AER test 1 central	AER test 2 central	AER test 3 central
Minimum capacity factors	PACR Central • OSB - 60% • PPPS - 50% • TIPSB - 25%	Removed	Removed	Removed
SA GPG cycling and minimum loads	PACR Central	• Minimum on/off times - ACIL Allen Dataset + TIPSB updated • Min load - PACR Central + PPPS & OSB updated	• Minimum on/off times - ACIL Allen Dataset + TIPSB updated • Min load - PACR Central + PPPS & OSB updated	• Minimum on/off times - ACIL Allen Dataset + TIPSB updated • Min load - PACR Central + PPPS & OSB updated
Plant investments & retirements	PACR Central	ElectraNet Long-term model	ElectraNet Long-term model	ElectraNet Long-term model
Synchronous condensers & system security constraints	• Inertia capability - 1300MW • Non-synchronous cap - 1870MW	• Inertia capability - 4400MW • Non-synchronous cap - 2000MW	• Inertia capability - 4400MW • Non-synchronous cap - 2000MW	• Inertia capability - 4400MW • Non-synchronous cap - 2000MW
Coal prices for black coal generators	PACR Central	2018 ISP central estimate of new entrant coal prices (netback)	PACR Central	2018 ISP central estimate of new entrant coal prices (netback)
Pumped hydro costs	PACR Central ($1.4 million/MW for SA)	PACR Central ($1.4 million/MW for SA)	PACR Central ($1.4 million/MW for SA)	PACR Central ($1.9 million/MW for SA)

Source: ElectraNet, Further modelling and sensitivity analysis, October 2019

This section briefly explains the significance of these inputs and assumptions and our reasons for requesting these changes.

Operation of gas fired generation in South Australia

The operation of South Australian gas generators is a critical component of the SAET RIT-T analysis given that a significant proportion of benefits of each of the options involve avoiding the dispatch of high cost gas generation in South Australia. The higher the estimated level of gas usage in the absence of the project, the higher the net benefits of reduced gas usage as a result of implementing the project.

ElectraNet's PACR assumed minimum capacity factors for three South Australian gas plants (Osborne, Pelican Point and Torrens B). The adoption of these minimum capacity factors has a material impact on the modelled level of gas usage in South Australia. This is because it forces a significant minimum average annual gas generation in the base case and therefore has impacts on the estimated avoided fuel cost benefits arising from accessing lower cost generation from other regions with the interconnector.

We requested that ElectraNet remove this assumption in the additional modelling, for the following reasons:

- There is no need to make any assumptions about minimum capacity factors. This is because the PACR modelling already takes into account the technical generator operating parameters and system security requirements as identified by AEMO as the primary reason for adopting minimum capacity factors in its 2018 ISP. While the 2018 ISP uses minimum capacity factors, ElectraNet in some cases departs from AEMO's values.[31]
- This assumption forces gas plant[32] in South Australia to be dispatched 'out of merit order' (at a loss) and displace lower cost renewable generation (e.g. existing wind generation in South Australia) which is not an economically efficient outcome. Since this occurs only in the base case, it further adds to the fuel cost savings modelled in the PACR. This is further explained in Appendix A.
- The assumption has only been applied to gas plant in South Australia and not applied to other gas plant in the NEM. ElectraNet does not provide reasons for Osborne, Pelican Point and Torrens Island B being forced to operate with high capacity factors, but not other comparable (and in some cases, lower cost) gas generators in South Australia and other regions. Furthermore, modelled output from most other gas generators across the NEM is significantly below these required capacity factors.
- This assumption was also not adopted in the PADR and was therefore not subject to stakeholder scrutiny during the RIT-T process.

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31 Specifically, the 2018 ISP assumes a minimum capacity factor of 15 per cent for Torrens Island A (75 MW), but does not assume a minimum capacity factor for Torrens Island B. By contrast ElectraNet applies a minimum operating level of 25 per cent for Torrens Island B (200 MW) and no minimum capacity factor for Torrens Island A. This sees a higher requirement for gas with the ElectraNet assumption

32 The relevant mid merit plant in South Australia are Pelican Point, Torrens Island B and Osborne.

- ElectraNet's reasoning that the assumption was intended to better reflect historical operation of gas generation is not consistent with the modelling methodology and approach adopted in the PACR (as set out in the PACR Market Modelling Methodology Report). This methodology assumes a least cost approach to generator dispatch based on short run marginal costs.

We also requested ElectraNet to incorporate consistent operating parameters (cycling constraints and minimum generator operating loads) sourced from an independent credible source across thermal generators, as is required under the RIT-T and associated guidelines.

Further details of our analysis of this issue are set out in Appendix A.

SA gas generator retirement and capital costs of pumped hydro

We considered the retirement of gas generators in ElectraNet's modelling outputs given that:

- it has a significant effect on the avoided generation costs of the interconnector; and
- there was a significant change between the PADR and the PACR assumptions.

The PACR assumed that Torrens Island B, Pelican Point and Osborne gas generators retire upon commissioning of the interconnector in 2024. The PACR aligned the retirement timings for the above South Australian gas generators with those found in the 2018 ISP, albeit a year earlier to reflect a changed assumption of when the new interconnector could be energised.[33]

We note that ElectraNet's economic model used in the SAET RIT-T analysis is capable of modelling the retirement of generators when they become uneconomic. However, ElectraNet chose instead to use the economic retirements from AEMO's ISP 2018 modelling results as inputs to their model[34]. Given the two economic models (ElectraNet's SAET RIT-T and AEMO's ISP 2018) are different in terms of application and purpose, we consider it was not reasonable for ElectraNet to use generator retirements from AEMO's 2018 ISP. This is because the economic retirements in AEMO's 2018 ISP were outputs of their modelling. Furthermore, the 2018 ISP retirement assumptions applied to gas generators in South Australia have not been applied to generators elsewhere in the NEM. ElectraNet has not provided any reasoning for this inconsistency in approach.

We asked ElectraNet to allow its model to make retirement decisions in the additional modelling as this will affect the amount of gas usage in South Australia and therefore the benefits of the preferred option. Our reasoning and assessment is further explained in Appendix A.

Storage plant cost assumptions

The PACR modelled that pumped hydro capacity of 700MW would replace some of the assumed retiring gas generation in the interconnector case, but only in order to meet the

33 ElectraNet, SAET RIT-T PACR, February 2019, p.42
34 AEMO, ISP 2018, pg 27

reserve margin. Following publication of the 2018 ISP, TasNetworks engaged Entura to perform studies aimed at informing market modelling with a better view of potential costs and capabilities for pumped hydro energy storage across the NEM. Entura's December 2018 report[35] estimates the average cost of 6-hour storage pumped hydro in South Australia to be $1.9m/MW, rather than $1.4m/MW assumed in the PACR.

The significant difference in the costs assumed by the PACR and Entura has implications for the evaluation of the interconnector, as the modelling for the preferred option models 700MW of pumped hydro in South Australia following the development of the interconnector (and associated retirement of SA gas generators). Importantly, if the cost of building pumped hydro storage exceeds that assumed in the PACR modelling, the benefits of the interconnector would be expected to be lower than presented in the PACR.

We asked ElectraNet to undertake further modelling to adopt the Entura assumption of $1.9/m/MW for the capital cost of pumped hydro in South Australia to assess the sensitivity of this assumption on the additional modelling outcomes. Our reasoning and assessment is further explained in Appendix A.

Impact of System Security requirements

The PACR included a number of system security related obligations that affect the level of gas generator usage in South Australia. These include:

- The need to run synchronous generation to meet 'system strength' and inertia requirements in South Australia.[36]
- The application of the non-synchronous generation cap in South Australia; and
- The need to reduce flows on the Heywood interconnector to reflect the SA Government requirements to manage the rate of change of frequency in the event of an outage on the Heywood interconnector.[37]

In particular, the PACR modelling included the following measures to address the AEMO requirements without the interconnector:[38]

- A requirement for four synchronous machines. Two were modelled as synchronous condensers at Davenport and the remaining two as synchronous generator units in metropolitan Adelaide.
- A 1,870 MW South Australia system-wide cap on non-synchronous generation. The cap is dynamic and increases with exports and decreases with imports, ranging from

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35 Entura, Pumped Hydro Cost Modelling, 7 December 2018. This report was included in the planning and forecasting consultation documentation which will inform the 2020 ISP. Table 2.5 of the report contains 6 hour storage pumped hydro costs.

36 In December 2018, AEMO declared an inertia shortfall (and confirmed a previously declared system strength gap) in South Australia as part of the 2018 NTNDP.

37 AEMO limits SA RoCoF to 3 HZ/s for a non-credible trip of the Heywood interconnector in response to a Ministerial Direction issued under the Essential Services Act 1981 (SA).

38 ElectraNet, SAET RIT-T PACR, February 2019

1,220 MW (with SA importing 650 MW across Heywood) to 2,520 MW based on current limits.

- A requirement to limit flows on the Heywood interconnector to manage the rate of change of frequency in South Australia as a result of an outage of the Heywood interconnector.

AEMO also advised that the 2018 ISP included planning assumptions that (in the absence of the interconnector and following the installation of synchronous condensers to manage system strength and inertia requirements), required two synchronous generation units to be on at all times in South Australia for the purposes of:[39]

- Operating reserves for ramping up (to account for a potential drop in wind generation of around 500MW over 30 minutes)
- Secondary frequency controls for a non-credible separation event (i.e. contingency FCAS within 10 minutes)
- Operating reserves for a separation event to maintain energy balance over time required to bring fast start gas on line.

The SAET RIT-T assumes that with the preferred option, these system security requirements are no longer necessary. As a result, high cost gas generation in South Australia is no longer dispatched out of merit order for system security purposes, resulting in avoided fuel cost benefits from the preferred option. In the modelling results, these benefits are incorporated in the gross avoided fuel cost benefits and are not separately identified.

We asked ElectraNet to undertake additional modelling to include four high inertia synchronous condensers, consistent with its intended approach to address AEMO's requirements associated with system strength and inertia in South Australia. ElectraNet has proposed high inertia synchronous condensers will provide inertia of 4400MWs rather than the PACR assumption of 1300MWs. The inclusion of four synchronous condensers also enables the non-synchronous cap to be increased from the 1870MW assumed in the PACR to 2000MW.

3.3 AER assessment

To test the robustness of the preferred option PACR results, we asked ElectraNet to conduct additional modelling taking into account the issues summarised in section 3.2. This modelling also included a corrected PACR model which maintained all the same inputs and assumptions as in the PACR, however taking into account corrections of issues we identified during the assessment process as outlined in Appendix A.8. The corrections were also incorporated into AER tests 1, 2 and 3. All additional modelling inputs and assumptions for each sensitivity test are presented in Table 1.

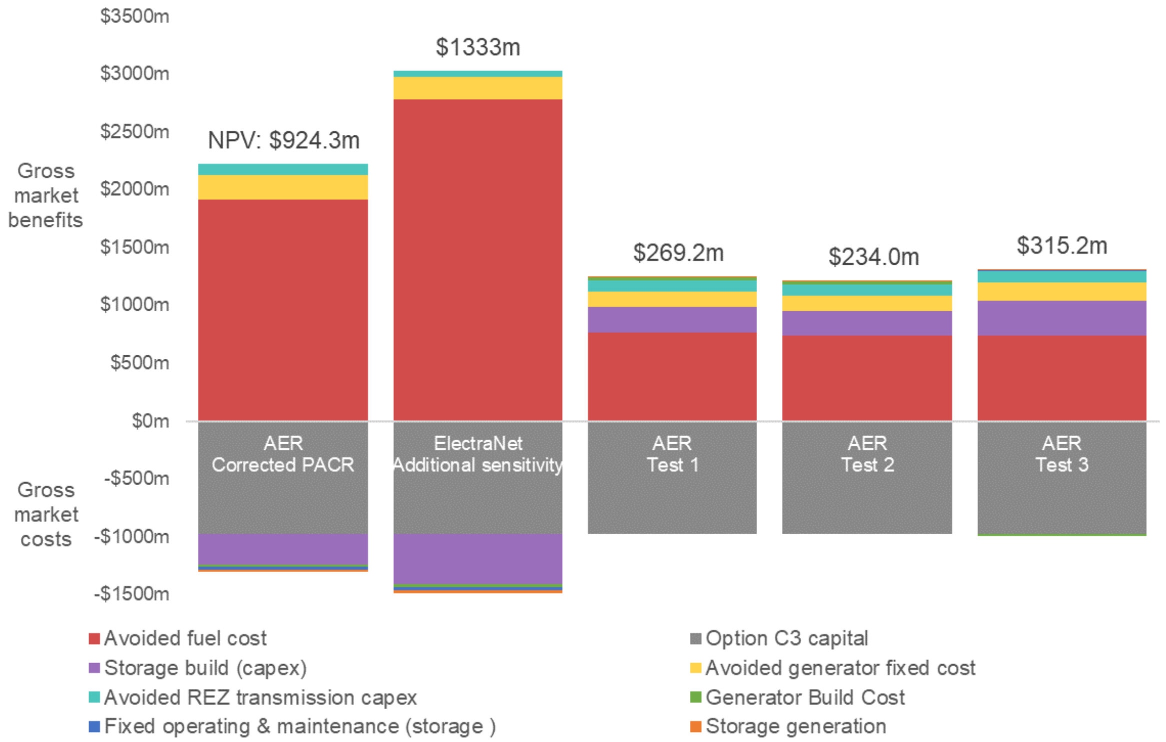
At the same time as conducting the additional modelling as requested by the AER, ElectraNet also provided updated modelling results for the central scenario associated with the inclusion of updated gas prices (available in January 2019) and generator commitments which were available before the PACR was published (referred to as 'ElectraNet additional

[39] AEMO, Assumptions on GPG usage in SA, August 2019

sensitivity'). The 'ElectraNet additional sensitivity' updated modelling included higher gas prices and more generator commitments than was assumed in the PACR modelling.

Figure 6 provides the market benefits and costs from the additional modelling requested for the central scenario.

Figure 6 Net market benefits following ElectraNet's additional modelling

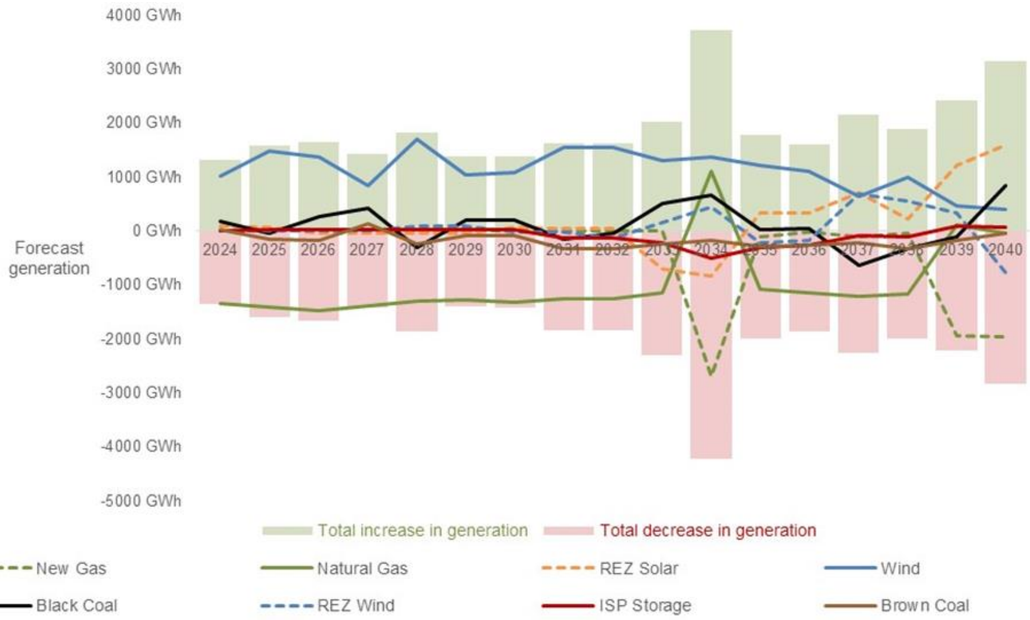


Source: AER analysis of ElectraNet Economic Evaluation Summary Spreadsheet and Charts, provided 29 October 2019
Note: ElectraNet provided revised figure of $1333.3m of gross market benefits for "ElectraNet Additional sensitivity". This was provided on 16 January 2020 in its final modelling report.

The additional modelling results requested by the AER (AER test 1, AER test 2 and AER test 3) indicate that there is a significant decrease in the net benefits of the interconnector due to a large decrease in the avoided generation costs compared to ElectraNet's PACR findings. This occurs as gas is no longer constrained to operate at high minimum capacity factors based on historical output. We undertook analysis of the generation differences between the base case and the state of the world with the preferred option under AER test 1 assumptions.

Figure 7 (below) presents the generation differences between the base case and the state of the world with the preferred option under AER test 1 assumptions.

Figure 7 Forecast change in generation output in AER test 1 across the NEM for preferred option



Source: AER analysis

When comparing this generation output profile with that of the original PACR modelling, we understand that there is less substitution of gas generation for coal and wind generation. In particular, in the PACR there is an estimated 4 TWh of South Australian gas displaced annually in the mid-2020s to early 2030s as opposed to around 1.5 TWh in the 'AER test 1' sensitivity. The analysis of the AER test sensitivities indicate:

- The gas displacement that remains is predominantly from increased wind generation in South Australia. This is because wind generation is being "spilt" under the base case as it is being constrained off to keep the gas running. With the interconnector case this doesn't occur. That is, the interconnector does not provide a material amount of coal generation to displace South Australian gas generation as it did in the PACR modelling.
- Excess wind generation in South Australia continues to be transported into the NSW region under AER test sensitivities.
- Only TIPS B retires in the interconnector case. This differs from the PACR modelling which assumed Pelican Point and Osborne also retire in the interconnector case. As a result of this difference, pumped hydro does not enter the model in 2024 to meet the minimum reserve requirements.

Assessment of additional modelling results

We have undertaken a review of the additional modelling results from ElectraNet. These results indicate that the net benefit of the preferred option may be smaller in the further modelling 'AER sensitivities' than in the PACR modelling. This is primarily due to removing the minimum capacity factor assumption on South Australian gas generators in ElectraNet's further modelling. These results indicate that once the minimum capacity factor assumption is relaxed, the benefits that the interconnector provides from avoiding gas generation costs are significantly reduced. More specifically, the overall net benefits of the interconnector option are $269m (AER Sensitivity 1), compared to the PACR results of around $900m.

In reviewing ElectraNet's additional modelling results, Frontier noted that the majority of the benefits associated with the interconnector case continue to be avoided gas generation costs in South Australia, even after the MCF assumption is relaxed. Analysis of the additional modelling results indicate that the two synchronous generator unit assumption for system security purposes is contributing a large proportion of the resultant avoided fuel cost benefits. ElectraNet assumed that these two synchronous generation units need to be gas generators. This means that, under ElectraNet's modelling, the interconnector provides savings through substitution from relatively expensive gas generation which is no longer required to run for system security purposes, to lower cost generation. Frontier questioned whether there were alternative options for satisfying the system security requirements that had not been considered in the RIT-T. In particular:

- Alternatives to gas generation to provide synchronous generation in South Australia in the absence of the interconnector; and
- Alternative interconnector options than the SA-NSW interconnector.

Frontier also reviewed the additional modelling results and identified the following key issues:[40]

- There is the potential for double counting of the benefits of avoided storage associated with the preferred option
- Other modelling issues which may impact on the market benefits of the preferred option.

Benefits from improving system security

AEMO's 2018 ISP included the planning assumption (outlined in section 3.2) that two large synchronous generating units would be required to be on at all times in South Australia, in the absence of a new interconnector to the SA region. This requirement existed even after ElectraNet installs new synchronous condensers to manage system strength and inertia requirements. AEMO considered that these two synchronous generation units would be needed for:

- Operating reserves for ramping
- Secondary frequency control following a separation event
- Operating reserves for energy balance following a separation event.

The operating reserves for ramping is to manage uncertainty in renewable generation output. The frequency control and energy balance operating reserves are required following the unplanned double circuit loss of the Heywood interconnector, which occurs on average once every three years. In South Australia the only plant available to provide these services at present is gas plant.

Based on AEMO's 2018 ISP, ElectraNet assumed in its PACR modelling that:

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[40] Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019

- the South Australian system security issues identified by AEMO and necessitating AEMO's planning assumption are likely to persist over the forecast period in the absence of a new interconnector
- given these South Australian system security issues, AEMO is likely to intervene (directing large gas generators online out of merit order) if necessary to maintain system security, and AEMO's intervention is likely to take the form of the planning assumption set out in its 2018 ISP
- to implement AEMO's 2018 ISP planning assumption, two large gas generation units would be required to provide the synchronous generation in South Australia in the absence of a new interconnector; and
- a new interconnector of at least 275 kV connecting the South Australian region to either the New South Wales, Queensland, or Victorian regions would alleviate the system security issues in South Australia.

Based on the outputs of its PACR modelling, ElectraNet submitted that the SA-NSW interconnector is the preferred option, as it provides greater net benefits than other interconnector and non-interconnector options to address the system security issues.

As the majority of the benefits associated with the preferred option interconnector are derived from avoiding this gas generation that must be on at all times in the interconnector's absence, we have examined the reasonableness of these assumptions.

Reasonableness of the assumed system security requirements

We have considered the reasonableness of ElectraNet's assumption that AEMO would require, or intervene to ensure, that two large synchronous generation units in South Australia are online at all times.

We understand from AEMO's response that once the new synchronous condensers are installed to manage system strength and inertia requirements - likely to be in 2021 - AEMO expects that it will no longer need to intervene to direct on large synchronous generating units to provide system strength and inertia services. However, AEMO also stated in its response that there will be a need to provide grid firming services such as directing on similar synchronous generation to provide for ramping, and for frequency control (when SA is islanded from Victoria as a result of the unplanned loss of the double circuit Heywood interconnector).

ElectraNet's assumption is based on AEMO's inclusion of this as a planning assumption in its 2018 ISP.

The adoption of this assumption in the RIT-T analysis means that ElectraNet has assumed that AEMO will, if necessary, exercise its intervention powers in the future in a manner consistent with its previous planning statements. We consider that it is reasonable for a RIT-T proponent to have regard to the planning assumptions of the market operator when considering the market operator's views on:

- forecasted system security issues, and

- preferred interventions to address these system security issues.

The legislative framework set out in the NEL and NER regulates the manner in which AEMO can intervene in the NEM. Under this framework AEMO when exercising its discretion to intervene in the market:

- can only intervene to maintain system security; and
- must consider the costs of its intervention.

Within the regulatory framework, AEMO has discretion in determining appropriate interventions in the market. As AEMO has not yet intervened in the market to ensure that two large synchronous generation units in South Australia are online at all times, it may be that AEMO has not considered these issues in detail in adopting its planning assumption in the 2018 ISP.

When that intervention is required, AEMO may further consider the various options to maintain system security, the degree of risk relating to system security, and of the costs of the relevant options. These considerations may lead AEMO to exercise its discretion in a manner that is not consistent with its previous planning assumptions.

The likelihood of this eventuality is difficult to ascertain. We also note that there are defined processes under the current regulatory framework for setting power system security and reliability standards, credible contingencies, and protected events. It would have been beneficial for stakeholders if AEMO's consideration of system security in South Australia, and of its preferred interventions, had been set out in greater detail through one or more of these processes.[41]

Given the evidence before us, we consider it is reasonable for ElectraNet (as the RIT-T proponent) to assume that AEMO (as the market operator) will intervene if necessary to address system security issues that AEMO has previously identified. Moreover, it would be reasonable for ElectraNet to assume that AEMO would intervene in the manner that it previously identified unless it is clear that alternative interventions would maintain the same degree of system security at lower cost.

Transparency of the two unit constraint assumption

Very little supporting information was provided in AEMO's 2018 ISP in regard to the assumption of at least two large synchronous generator units in South Australia being online at all times. This requirement was not described in any 2018 ISP documentation available to stakeholders. We understand that the assumption was incorporated into the proprietary input files for the modelling software (PLEXOS). This data, however, is only able to be

[41] The NER also include a mechanism for AEMO to transparently assess risks to power system operation caused by events that are unlikely, but would have high impacts if they were to occur. This is the Power System Frequency Risk Review (PSFRR). If AEMO believes that there is a transparent and cost-effective way of managing any of the risks it identifies in this review, it can request that the Reliability Panel declare a risk as a protected event. In 2018, AEMO undertook its first PSFRR, and made no recommendation regarding the management of the non-credible loss of the Heywood interconnector. When we asked AEMO, it confirmed that the requirement to provide for FCAS when the Heywood interconnector fails would be progressed through the 2020 PSFRR.

interrogated by users of this software. It is likely that most stakeholders would have been unaware of this assumption, which appears to be the main driver of avoided gas generation costs that arise from the SAET Interconnector.

Options to address the system security requirements

Non-interconnector option

The SAET RIT-T assumes that two units of gas plant in South Australia will be required to satisfy the requirement for two synchronous generation units to be on-line and generating at all times in the absence of the interconnector each year out to 2040.[42] The additional modelling indicates that the majority of the benefits associated with the interconnector case continue to be avoided gas generation costs in South Australia. A significant proportion of these avoided generation benefits are associated with removing the requirement for two gas units to be on line at all times for system security purposes.

Frontier advised that the additional modelling shows a difference in generation costs between the base case and the interconnector case, where there is a higher level of gas generation in South Australia in the base case predominantly due to the two unit gas generation assumption.[43] Therefore, the majority of the avoided generation costs in the additional modelling appear to be from alleviating this two unit gas generation assumption with the interconnector.

Frontier also found that in the base case, the two unit gas generation requirement causes a significant amount of wind curtailment which is alleviated in the interconnector case.[44] This arises because gas is forced on ahead of lower cost wind generation, which curtails wind generation. This wind curtailment imposes a cost in the base case. It also leads to significant benefits in the interconnector case because the gas is not forced on. Further benefits arise because any excess wind generation is transported to the NSW region where it displaces more expensive generation (e.g. black coal).

Frontier's view is that the two unit gas assumption creates a high cost counterfactual (base case) as the majority of the modelled benefit is caused by relieving this requirement. In particular, Frontier considers that pumped hydro would appear to be able to satisfy AEMO's requirement for two synchronous generation units to be on line at all times.[45] Additionally, Frontier considers that if the capital cost of a sufficient amount of pumped hydro in SA is lower than the interconnector, then pumped hydro may be the preferred option.

ElectraNet has stated that the non-interconnector option[46], which included pumped hydro storage (set out in Table 4 on page 69 of the PACR), does not meet the defined minimum

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42 The two units that are required online may be from either TIPS B, Pelican Point or Osborne.

43 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019, p.61

44 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019, p.63

45 ibid, p.81

46 The non-interconnector option is set out in table 4 of page 69 of the PACR. The elements of the non-interconnector option are comprised of the following: pumped storage (Port Augusta), Osborne cogeneration, Solar thermal at Davernport, BESS - Tallem Bend, Murraylink (transfer of FCAS), BESS (location to be determined), and minimum load control. These elements would be procured by ElectraNet under a network support contract.

system performance levels under all conditions.[47] In particular, the non-interconnector solution was found to be unable to meet the following preferred performance requirements under all operating conditions:[48]

- The capability to operate the South Australian region when connected to the rest of the NEM with no local synchronous generation online; and
- The provision of sufficient contingency FCAS or equivalent services to ensure the South Australian system can survive a contingency event of up to 650MW and remain within the Frequency Operating Standard.[49]

In considering these issues, we requested information from AEMO about whether a non-interconnector alternative such as pumped hydro storage could satisfy the requirement for two synchronous generation units to be on line at all times. In its response, AEMO stated that in the analysis undertaken in developing its 2018 ISP, pumped hydro technology was not considered a suitable alternative to addressing system security requirements compared to running two South Australian gas units.[50] This was due to technical limitations of pumped hydro generators which are unable to provide synchronous services during pumping, which then requires other alternatives to be contracted for those periods, at additional cost.[51] However, AEMO also stated that:[52]

> AEMO believes the typical choice for these synchronous generating units to be gas powered generators (GPG). That said an appropriately selected and sized pumped-hydro generator may be able to replace one of the two GPG to provide frequency and grid forming services.

Based on advice from AEMO, we understand that the relevant system security requirements include:[53]

- Operating reserves for ramping up (to account for a potential drop in wind generation of around 500MW over 30 minutes);
- Secondary frequency controls for a non-credible separation event (i.e. contingency FCAS within 10 minutes); and
- Operating reserves for a separation event to maintain energy balance over time required to bring fast start gas on line.

We understand that these are the relevant system security requirements that need to be satisfied by alternative non-interconnector options for the purpose of contributing to the two-unit synchronous generation requirement.

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47 We note that the Entura report states that the investigated non-interconnector option does not meet preferred system requirements but does meet the minimum system performance levels.

48 ElectraNet, Response to AER information request #10, 29 November

49 This contingency FCAS requirement appears to go beyond the minimum requirements as stated by Entura.

50 AEMO response to AER information request, 21 November 2019

51 AEMO response to AER information request, 21 November 2019

52 AEMO, System security in SA with and without EnergyConnect, 11 December 2019

53 AEMO, Assumptions for SA GPG in the 2018 ISP, August 2019, p.14-15

In relation to the proposed solution to addressing system security requirements, AEMO noted that[54]:

> The estimated cost for 400 MW of pumped hydro was considered to be more expensive than running two SA gas generators, even before accounting for the rest of the portfolio of other plants/contracts that would be needed to provide the full suite of necessary security services. Hence, the recommended solution of high inertia synchronous condensers combined with ensuring that sufficient synchronous GPG were retained online was found to be the most optimal way of delivering all the requirements of South Australia in combination.

AEMO also advised in a follow up response that:[55]

> …pumped-hydro technology could not replace both of the currently required gas units as it would not be available to provide grid forming services at all times, e.g. when pumping.

AEMO's advice indicates that a pumped hydro storage facility is able to satisfy the relevant system security requirements, but only when it is paired with additional measures which will result in further costs. In particular, pumped hydro could only be used in combination with SA gas plant. As a result, we do not consider that an investment in pumped hydro storage alone can meet AEMO's system security requirements[56]. Based on AEMO's advice we accept that a standalone pumped hydro storage solution is not a credible option and hence cannot be the preferred option. As discussed below, ElectraNet also provided further analysis in support of its view that pumped hydro cannot provide both system security services and time shifting of renewables.

Assessment of pumped hydro's possible contribution to system security

For the 2018 ISP, AEMO assumed that two units of TIPS B would run at all times throughout the modelling period to meet the synchronous generation unit requirement.[57] As stated previously, this differs from the way in which ElectraNet chose to implement the requirement as a constraint - namely, that two units out of one or more TIPS B, Osborne or Pelican Point must be online at all times. This is expressed at the generator unit level as (the two unit constraint):

$$TIPSB1 + TIPSB2 + TIPSB3 + TIPSB4 + PP1 + PP2 + OSB1 \geq 2.$$

where each generator unit in the constraint is binary (i.e. 1 if on and 0 if off) and TIPSB1 indicates unit one of Torrens Island B etc.[58] Therefore, ElectraNet's model has the flexibility to choose a least cost combination of these generators at each point in time over the modelling period.

54 AEMO, System security in SA with and without EnergyConnect, 11 December 2019

55 AEMO, System security in SA with and without EnergyConnect, 11 December 2019

56 AEMO, Assumptions for SA GPG in the 2018 ISP, August 2019

57 AEMO, Assumptions for SA GPG in the 2018 ISP, August 2019, pp.13

58 We also note that, for Pelican Point and Osborne, ElectraNet's constraint only includes their gas turbines (i.e. it does not include their respective steam turbines).

If pumped hydro was added to the two unit constraint expressed above in addition to the other units it should be able to contribute to this constraint when it is not pumping. This would be consistent with AEMO's advice previously stated that:

- Two synchronous units are online at all times.
- Pumped hydro units can provide services for the two unit requirement when not pumping.
- The first requirement would necessarily be met in the model. When pumped hydro is pumping, the model would turn on the next least cost form of synchronous generation e.g. a gas generator unit.

ElectraNet provided further analysis on whether a non-interconnector option (pumped hydro storage) would be economic in its model by contributing to the two-unit requirement (in combination with SA mid merit gas generators) and time shifting renewables. The hypothesis was that if pumped hydro storage provides a reduction in the generation costs in the base case that outweighs its associated capital cost then the benefits of the preferred interconnector option would be overstated.

ElectraNet's further analysis updated the additional modelling under AER test 1 assumptions to include 100MW of pumped hydro (assuming a capital cost of $1.9m/MW). ElectraNet stated that this resulted in a negative net economic benefit, demonstrating that pumped hydro would not be selected by the model as a least cost generation source in the base case state of the world. In conducting this analysis, ElectraNet assumed that pumped hydro can provide the following benefits:[59]

- time shifting of renewables
- avoiding the need for a gas unit to run to meet the two-unit constraint while the pumped hydro is generating and so avoiding high cost generation; and
- enabling earlier retirement of TIPS B and so avoiding fixed operating costs.[60]

The avoided fixed costs associated with the retirement of a unit of TIPS B are estimated by ElectraNet to be $45 million.[61] ElectraNet stated that to enable early retirement of a TIPS B unit, the pumped hydro capacity would need to increase to 200MW, resulting in an increased cost of this solution by $100 million (in net present value terms assuming a capital cost of $1.9m/MW).[62] Overall, ElectraNet estimates that the benefits identified above, for 6 hour pumped hydro storage, to be around $115 million, while the costs are estimated to be around $200 million.[63] Based on this analysis, ElectraNet concluded that pumped storage could not effectively provide both system security services and time shifting of renewables, which requires a daily operating cycle of charging and discharging to the market, on an economic basis.[64]

59 ElectraNet, Response to Frontier Economics Assessment of updated energy market modelling, 18 November 2019

60 ElectraNet considered the avoided fixed costs of TIPS B associated with introduction of pumped hydro following at request as part of our review of this additional modelling of the benefits of pumped hydro.

61 The fixed operating costs of 200MW pumped hydro are only assumed to be approximately $1 million.

62 ElectraNet, Response to AER information request #10, 29 November 2019

63 ElectraNet, Response to AER information request #10, 29 November 2019

64 ElectraNet, Response to Frontier Economics assessment of updated energy market modelling, 18 December 2019

The analysis above assumes that pumped hydro is only providing synchronous generating services when it is generating, and may therefore have understated some of the benefits of pumped hydro at times when it is idle (i.e. when not generating or pumping). In response, ElectraNet commented that while pumped hydro can provide some services when it is idle, it is not clear it can provide the full range of system security services.[65] AEMO's advice indicates that pumped hydro cannot provide the relevant system security services that are obtained through the two-unit requirement (operating reserves and secondary frequency control) when it is pumping.[66]

However, not allowing pumped hydro to contribute to the two-unit requirement at times when it is idle, and has sufficient capacity, is likely to have the effect of understating the avoided gas generation benefits of the pumped hydro facility (and therefore of overstating the avoided gas generation benefits of the interconnector). As a cross check, we considered whether pumped hydro is likely to provide a net benefit if ‘reserved’ to meet the two unit requirement in combination with SA gas plant at all times.

Overall our analysis indicates that there may be a net benefit in terms of avoided gas costs where pumped hydro replaces one gas unit (or both units) in ElectraNet's modelled constraint (see above) for a majority of the time. However, to assess the size of the benefit, it is necessary to consider the:

- amount of gas usage associated with gas plant that would be operating to meet the two unit constraint as opposed to participating in the market; and
- cost of alternative generation sources to replace the displaced gas as a result of the reserved pumped hydro.

Overall our analysis suggests that when paired with gas plant in SA, two units (100MW each) of pumped hydro may reduce the overall costs of satisfying the two unit constraint in the absence of the interconnector, but that the impact is not material to the overall net benefits of the project.

Interconnector options

Frontier advised that the ability to alleviate the two unit constraint provides a major source of benefit for preferred option (Option C3). Other interconnector options will also be able to alleviate this constraint and therefore provide this benefit. In particular, option D (SA-Vic interconnector), which has a lower capital cost by approximately $300 million, could also provide similar level of benefits from alleviating the two unit constraint.

In response, ElectraNet updated its market modelling for option D using the alternate modelling inputs set out in Table 2. ElectraNet submitted that option D resulted in lower modelled net benefits than option C and, as such, option C remains the preferred option.

65 ElectraNet, Response to AER Information request #10, 29 November 2019
66 AEMO, Response to AER information request, 21 November 2019

In examining the differences in the modelled benefits between option C and option D, ElectraNet submitted that differences in network configurations and flows under the two options result in differing ability to extract benefits from alleviating the two unit constraint.

ElectraNet submitted that when the two unit constraint is alleviated in option C (the SA-NSW interconnector), gas generation that would otherwise be forced on by the constraint can be replaced with less expensive SA and VIC wind generation, when available, and by NSW coal generation when wind is not available. Typically, this wind generation is available in the middle of the day, while in the evening and overnight the interconnector increases the capability for NSW coal to replace SA gas generation.

In addition to alleviating the two unit constraint, ElectraNet submitted that the SA-NSW interconnector provides benefits of allowing excess SA wind generation available in the middle of the day to replace coal generation, mostly in NSW.

However, ElectraNet submitted that these market benefits are materially reduced under option D (the SA-VIC interconnector) because:

- Network constraints materially reduce the ability for SA and VIC wind generation to flow into the NSW region, resulting in significantly less displacement of NSW coal generation.
- The SA-VIC interconnector construction would conclude two years later than the SA-NSW interconnector (the SA-VIC interconnector business case leverages benefits from the deeper network upgrades proposed in the Western Vic RIT-T, with the timing designed to align the proposed projects).
- The SA-VIC interconnector would have a lower capacity than the SA-NSW interconnector. This and other network constraints marginally reduce the ability for SA gas generation to be replaced by cheaper generation (predominately NSW coal) when wind generation is not available.

In addition to effects on the two unit constraint, ElectraNet submitted that modelled market benefits are reduced in option D compared to option C because:

- Most of the benefits of transmission capex avoided under option C are not avoided in option D, largely because these benefits arise predominately from the duplication of the Red Cliffs to Buronga line that is included in option C (and avoids the need for transmission upgrades to facilitate new renewable generation installed around Red Cliffs) but not option D.
- The capture of spilled SA wind generation by NSW load centres in option C allows avoidance of new storage installation in NSW that would otherwise occur, and cannot be avoided under option D (avoided storage build costs are discussed further in section below).

ElectraNet submitted that its market modelling indicates that option D has a negative net present value of about $125 million (compared to a positive net present value of option C of about $270 million, under the modelling input assumptions of AER Sensitivity Test 1). The breakdown of these benefits by category and comparison to option C is shown in Table 2.

Table 2 Comparison of additional modelling benefits under options C and D

Benefit category	Comparison of options C and D
Total option C net benefits (under the modelling input assumptions of AER Sensitivity Test 1)	About $270m
Avoided generation fuel costs	Option D lower by about $320m
Avoided storage build costs	Option D lower by about $200m
Avoided transmission network investment	Option D lower by about $100m
Other avoided generator build costs, fuel costs, and other fixed operating costs	Option D lower by about $75m
Option build costs	Option C higher by about $300m
Total option D net benefits	**Lower than option C by about $395m**

Source: ElectraNet, Response to information request #11, 6 December 2019

As indicated above, the preferred option is estimated to provide higher avoided fuel cost benefits. The majority of these higher benefits under the preferred option is associated with the ability to transport South Australian and Vic renewables to NSW. ElectraNet submitted that network constraints between VIC and NSW prevent these renewables from entering the NSW region and displacing higher cost coal generation. Frontier also identified network constraints between VIC and NSW as a relevant factor that results in high levels of spilled South Australian wind generation in the absence of the interconnector.[67]

Therefore, based on ElectraNet's further information, the market modelling results for option D, and Frontier's analysis, we are satisfied that option C remains the preferred option.

Avoided storage costs

Under the additional modelling results, the base case (AER Sensitivity 1) includes more investment in pumped hydro in South Australia and utility scale battery storage in NSW than the interconnector state of the world. Frontier advises that the additional investment in the base case in NSW utility scale battery storage does not appear to be driven by economic considerations but rather a means to meeting a reserve margin in the model.[68]

It is further noted by Frontier that it appears the reserve margin is higher in South Australia and NSW in the base case by approximately the capacity of the interconnector. Frontier also stated that SA and NSW will have coincident peak demand.[69] Therefore, allowing the interconnector to relieve a portion of the reserve margin, equivalent to the entire capacity of the interconnector in both regions, may be double-counting the benefits of avoided storage

67 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019, p.72
68 ibid, p.64-65
69 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019

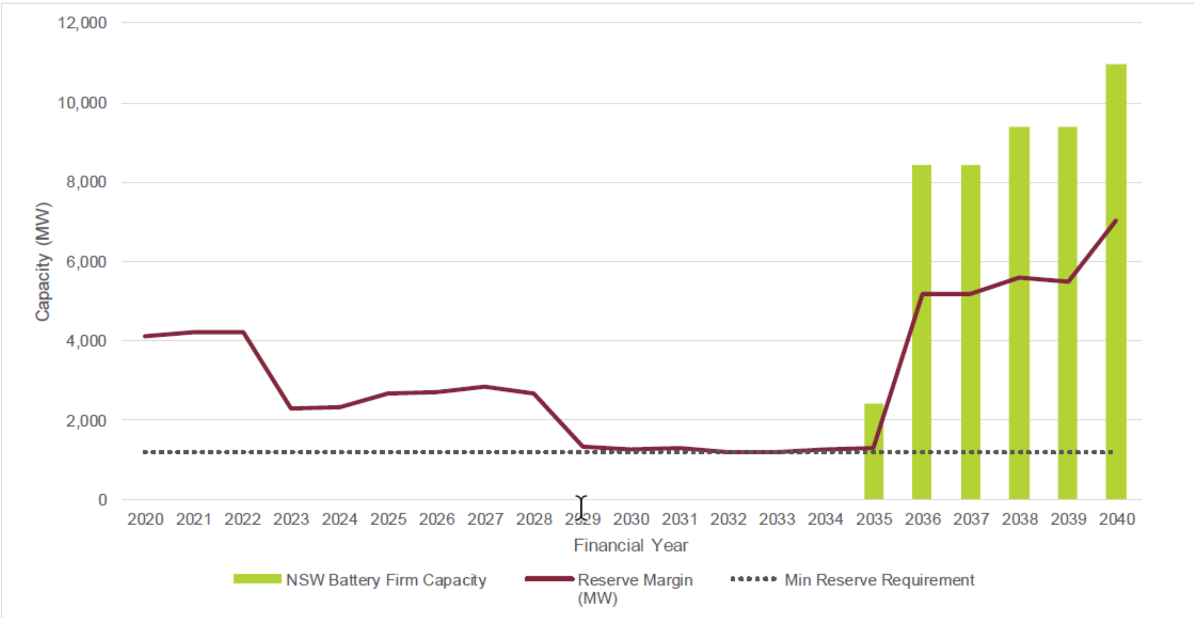
costs with the interconnector. The consequence of this would be an overstating of the avoided storage cost benefit attributed to the interconnector.

In response, ElectraNet stated that storage in NSW can provide the following services:[70]

- firm capacity to meet peak demand; and
- time shifting of renewables.

ElectraNet highlighted that the level of dispatchable capacity required in NSW is exceeded in most years under 'AER sensitivity 1' in the base case state of the world. In particular, ElectraNet submits that in NSW, there is a surplus of firm capacity from 2036 as outlined in Figure 8. ElectraNet stated that as investment in batteries commences in 2035, this indicates that the only service the storage facilities installed from 2036 onwards are providing is time-shifting of renewables.

Figure 8 NSW firm capacity (AER sensitivity 1) - base case



Source: ElectraNet, Response to AER information request #10, 29 November 2019

ElectraNet submitted that this demonstrates that storage development is not being driven by the need to meet reserve margins and so the benefits of avoided storage are not being double counted. As a result, the interconnector case reduces the need for storage to time shift renewables and therefore provides avoided storage benefits.

Frontier has also raised concerns that significant differences in prices between the 'long term model', which determines generator entry and exit decisions, and the 'short term model' which determines generator dispatch decisions, may be distorting investment signals. In particular, higher prices in the LT model may be providing investment signals which result in inefficient investment in the base case. In this case, this would suggest that there may be overinvestment in storage.

70 ElectraNet, Response to information request #10, 29 November 2019

ElectraNet disagreed that the differences in prices observed by Frontier is relevant as these prices reflect modelling outputs and are not relevant to the modelling inputs. However, we note that the model builds a significant amount of battery storage in NSW in the 2030s and as noted by Frontier, the capacity factors are low. For example, approximately 6 GW of battery storage is planted in NSW in 2036. Relevantly, we would not expect the need for significant new entrant utility scale solar capacity in circumstances where this storage capacity appears to be underutilised.

Given these issues, it is not clear as to whether the avoided storage costs in NSW associated with the preferred option under the additional modelling under 'AER sensitivity 1' are realistic . However, if the avoided storage costs in NSW are removed from the analysis, the overall net benefits of the preferred option are expected to remain positive.

Other issues

Frontier also identified some other issues related to the additional ElectraNet modelling:

- ElectraNet made undocumented/unrequested changes to coal generator behaviour in the AER "Sensitivity" cases.[71]
- The wind profiles do not always match the corresponding 2018 ISP wind profiles.
- There appears to be a disconnect between the long term (LT) and short term (ST) limbs of the RIT-T modelling where the amount of the wind energy curtailed in the ST model appears to be almost double the energy spilled in the LT model. This has the potential to distort investment signals (e.g. less storage build) and increase costs in the base case state of the world.

Our consideration of these other issues are outlined below.

Coal generator behaviour

In relation to changes in coal generator behaviour, ElectraNet replaced all minimum up and down operational parameters for coal generation with those in the ACIL Allen 'Fuel and Technology Cost Review' report. This resulted in regular two-shifting (turning on and off repeatedly in a relatively short space of time) in coal generation in the further modelling. This is likely to increase the benefit of increased interconnection, especially where the two-shifting can occur in directly connected regions.

We consider ElectraNet's change in the operation of black coal generators, while it was not a requested change, is more consistent with the ACIL Allen values which are used for thermal gas generators and is therefore a reasonable and consistent approach to the expectation that thermal generators will need to be more flexible in their operation going forward.

Wind profiles

The modelling assumes a demand shape from 2009-10, but the renewable profiles used in the modelling are based on reference year 2013-14. Using a demand trace and a renewable

71 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019, p.37

trace from different years may fail to capture the relationship between weather conditions, demand and intermittent generation.

On consistency of demand traces and renewable traces, we consider that the possibility of distorted market modelling outcomes only exists to the extent that renewables traces for 2013-14 are materially different from renewables traces for 2009-10. We have not been presented with evidence of material differences in renewable traces between 2009-10 and 2013-14.

Modelling issues

In response to the issue of disconnect between LT and ST limbs of the RIT-T model, ElectraNet disagreed with Frontier's assessment that the two limbs of the RIT-T modelling are disconnected from each other. It stated that the LT and ST models are aligned in the efficient level of storage investment required in South Australia. It further noted that the difference in the level of curtailed wind observed between the LT and ST models as highlighted by Frontier can largely be explained by the more accurate network model that accompanies the ST model, which includes a more detailed representation of inter- and intra-regional network constraints. ElectraNet also stated that the prices observed by Frontier are an output of the market modelling and not an input. ElectraNet further submitted that the price differences between the LT and the ST models therefore do not impact on the modelling results and these process are not driving investments.[72]

We consider that the wind curtailment in LT and ST limbs of the modelling is significant and that it may have the potential to distort investment signals as noted by Frontier. However, we note that the modelling reruns by ElectraNet where additional 100MW of pumped hydro was forced into the remodelling, and further AER analysis of ElectraNet's modelling outputs, did not find pumped hydro investment to be economically efficient.

Use of propriety software and lack of transparency

As discussed before, ElectraNet used a market modelling tool, PLEXOS (which is widely used in the industry, including AEMO) to undertake the SAET RIT-T analysis. We also note that the market modelling for this RIT-T was undertaken by ElectraNet in-house and while the supporting documents were published on the website, the economic model itself was not made available publically[73]. While this is not a requirement under the RIT-T and its associated guidelines, we consider it best practice that all network service providers should consider independent peer review of the economic models, particularly when propriety software, which is difficult for stakeholders to interrogate, is used.

We consider if the economic model for SAET RIT-T was conducted by external consultants with considerable modelling experience, ElectraNet would have rectified the errors in their market modelling and it would have reduced the time taken for AER in assessing the RIT-T assessment.

72 ElectraNet, Response to AER information request #12, 12 December 2019

73 We understand Oakley Greenwood undertook a limited review.

3.4 AER Conclusion

The net benefits remain positive across the additional modelling results. This demonstrates that the preferred option is robust across a range of varying assumptions. In addition, the additional modelling also indicates that the preferred option identified by ElectraNet in the PACR is likely to be the credible option that maximises the net economic benefits. Therefore, we consider that the preferred option satisfies the RIT-T. In forming this conclusion, we are satisfied that:

- The identified modelling errors do not affect the outcome of the SAET RIT-T and the preferred option remains the credible option that maximises the net benefits
- The market modelling is robust to alternative inputs and assumptions such that the preferred option remains positive and is likely to be the credible option with the highest net economic benefits.

The final step in the regulatory process involves the regulatory approval of the efficient costs of the project. We expect ElectraNet and TransGrid to lodge a contingent project application for the recovery of the proposed costs of the project. ElectraNet's SAET RIT-T indicates that the estimated costs of the preferred option are subject to a high degree of uncertainty. We also understand that there is the potential for updated proposed costs in a contingent project application to diverge from the estimated costs in the SAET RIT-T. The NER requires that the RIT-T proponent must[74] reapply the RIT-T in the event that there is a material change[75] in circumstances such that the preferred option identified in the PACR is no longer the preferred option.

While our decision on this 5.16.6 application is that the preferred option satisfies the RIT-T, our assessment is that the costs and benefits of the preferred option are finely balanced. On this basis, changes to the costs of the preferred option are more likely to have a material impact on the outcome of the RIT-T than they may otherwise do for a project where the net benefits are not as finely balanced.

In the event that any updated assessment of the costs of the project (and/or any other updated assessment of the key variables that may affect market benefits) differs materially from those presented in ElectraNet's RIT-T assessment, we would expect ElectraNet to consider whether there is a change in circumstances such that the RIT-T should be reapplied, and to provide evidence of that consideration to the AER. This should include providing updated analysis demonstrating whether the preferred option identified in the PACR, and considering the issues considered in this 5.16.6 assessment, continues to be the preferred option.

74 Unless the AER determines otherwise.

75 In the reasonable opinion of the RIT-T proponent.

4 AER determination

In accordance with clause 5.16.6(b) of the National Electricity Rules, our determination is that the preferred option identified by the South Australian Energy Transformation RIT-T satisfies the RIT-T.

Appendix A: Detailed assessment of inputs and assumptions

Appendix A provides further details on our assessment and conclusions in relation to each of the inputs/assumptions assessed as part of our review of the SAET RIT-T preferred option assessment.

A.1 Assumptions associated with the operation of gas fired generation in South Australia

As highlighted in Section 3, the operation of South Australian gas generators is a critical component of the SAET RIT-T analysis given that a significant proportion of benefits of the options involve avoiding the dispatch of high cost gas generation in South Australia.

Given the importance of the avoided SA gas generation costs, we focused our assessment on the inputs and assumptions used to derive this benefit. ElectraNet adopted a number of inputs and assumptions which have a material impact on the estimated level of gas generation in South Australia and therefore avoided fuel cost benefits of the interconnector. These key inputs and assumptions include:

- Minimum capacity factor constraints that assume minimum levels of gas usage for selected gas plant in South Australia.
- Minimum load constraints that recognise that there is a minimum stable level at which generators need to operate.
- Gas plant cycling constraints which impacts on the operating flexibility of thermal generators.
- System security constraints, which recognises the SA Government inertia requirement and AEMO's requirements for addressing system strength and inertia, including the cap on non-synchronous generation in South Australia and the 24/7 mid merit gas unit requirement.

Our assessment of these key inputs and assumptions is detailed below.

Minimum capacity factor constraints

The capacity factor of a generator refers to the proportion of its capacity that is utilised over a 12 month period and is an output of the market modelling in the PADR. For the PACR, ElectraNet deviated from the PADR by applying a minimum capacity factor constraint on selected South Australian gas plant as an input into the modelling. Relevantly, the adoption of these minimum capacity constraints has materially impacted the modelled level of gas usage in South Australia and therefore also impacted the estimated avoided fuel cost benefits associated with accessing lower cost generation from other regions with the interconnector. ElectraNet stated that this assumption was made to align their modelling with the 2018 ISP as a response to submissions to their PADR.[76]

Box 1 Application of a minimum capacity factor

A minimum capacity factor, for the purposes of ElectraNet's modelling, specifies the minimum number of MWh a generator must produce each year. For example, a minimum capacity factor of 50 per cent on a 100 MW generator would force the generator to produce at least an average of 50 MWh each hour over the entire year. The level of generation produced by the generator can fluctuate throughout the year since the model solves to ensure that the average hourly output over the year is at least 50 MWh. Continuing the example, the generator could produce 100 MWh every hour for the first 6 months of the year and then be off (produce 0 MWh) every hour for the latter 6 months of the year and this would satisfy a minimum capacity factor of 50 per cent.

The PACR modelling applied a minimum capacity factor constraint on South Australian 'mid merit' (mid merit gas) gas generators. These generators include Torrens Island B (TIPS B), Pelican Point and Osborne. This assumption forces TIPS B to run at an average hourly capacity factor of at least 25 per cent each year, Pelican Point at 50 per cent and Osborne at 60 per cent.[77] The combined capacity of these generators is 1,460 MW. This assumes that at least 38 per cent of this combined capacity is utilised over a 12 month period for each year before the assumed retirement of these generators. The PACR did not impose minimum capacity constraints on similar gas plant elsewhere in the NEM.

While the 2018 ISP used minimum capacity factors, ElectraNet in some cases departed from AEMO's values. Specifically, the 2018 ISP assumed a minimum capacity factor of 15 per cent for Torrens Island A, but does not assume a minimum capacity factor for Torrens Island B.[78] By contrast ElectraNet applied a minimum operating level of 25 per cent for Torrens Island B and no minimum capacity factor for Torrens Island A (see 5).

Table 3 Minimum capacity factors - PACR and 2018 ISP

	Minimum capacity factor (%) - PACR	Minimum capacity factor (%) - 2018 ISP
Osborne	60	60
Pelican Point	50	50
Torrens Island A	Not applied	15
Torrens Island B	25	Not applied[79]

76 ElectraNet, SAET Project Assessment Conclusion Report, February 2019, p. 41.
77 ElectraNet, SAET Market Modelling and Assumptions Data Book, February 2019.
78 AEMO, Assumption for South Australian GPG in the 2018 Integrated System Plan, August 2019, p.9.
79 In the 2018 ISP and planning assumptions, AEMO applied a minimum loading level on TIPS B of 160 MW which applied at all times.

Source: PACR and AEMO 2018 ISP

AER's assessment

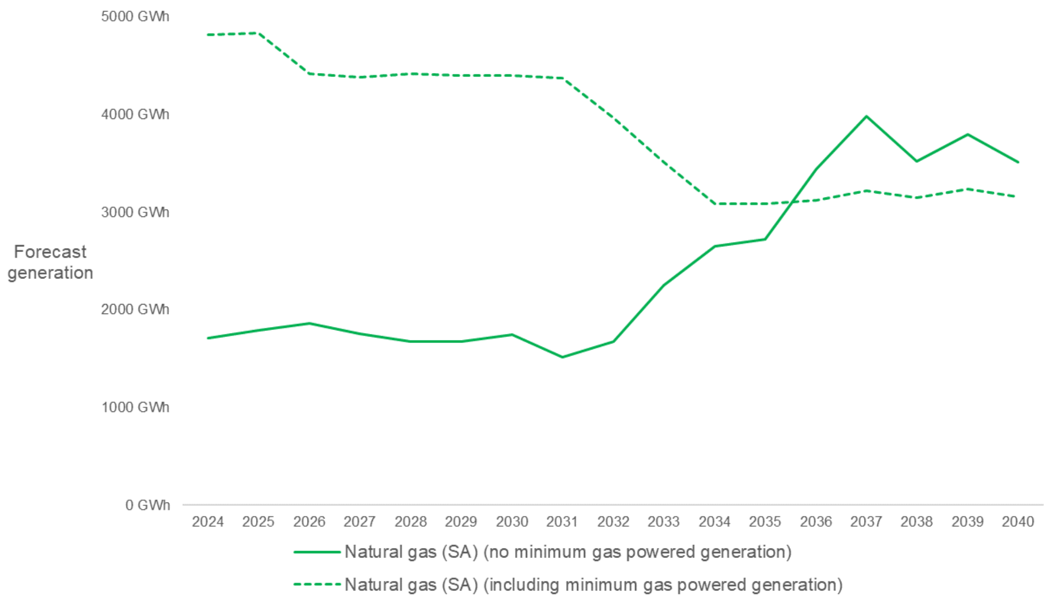
The RIT-T requires RIT-T proponents to use a market dispatch modelling methodology that incorporates a realistic treatment of plant characteristics.[80]

The adoption of minimum capacity factors for South Australian gas plant as an input on the minimum hourly average run time in the PACR modelling is a significant change from the PADR. In support of this assumption, the PACR stated that it has aligned all generator input assumptions with the ISP, including minimum operation of gas plant.[81] As this assumption was not adopted in the PADR, it was not been subject to stakeholder scrutiny during the RIT-T process.

The importance of this assumption is shown in Figure 9. The level of South Australian gas generation in the PACR central base case scenario (assuming no interconnector) is compared to estimated levels without the application of minimum capacity factors. Figure 9 shows that the minimum capacity factors imposed in the PACR modelling leads to a significantly higher amount of gas generation in SA over the modelling period than would be estimated without the constraint. As a result, the PACR estimates significantly higher gas usage in South Australia in the absence of the interconnector compared to the PADR.

The higher gas use in the PACR increases estimated fuel cost savings with an interconnector. As expected the modelled fuel cost savings are significantly higher in the PACR than the PADR.

Figure 9 Modelled SA gas generation (without the SAET interconnector)



80 AER, Regulatory Investment Test for Transmission, 2010, paragraph 11.

81 ElectraNet, SAET Project Assessment Conclusion Report, 13 February 2019, p.41.

Source: ElectraNet website, ElectraNet 5 March response

In addition, the minimum capacity factor assumptions in the modelling at times forced mid merit gas plant in SA to be dispatched 'out of merit order' and displace lower cost renewable generation in South Australia (i.e. existing wind generation). Since this occured only in the base case, it further added to the fuel cost savings modelled in the PACR.

Given the importance of the minimum capacity factor assumptions to the modelling results, our assessment of the preferred option considers the reasons for this assumption.

As noted above, ElectraNet advised that the minimum capacity factor constraint on South Australian mid merit gas plant was adopted from AEMO's 2018 ISP. AEMO advised that it used minimum capacity factors in its 2018 ISP in order to:[82]

- take into account generator technical limits
- draw on historical gas generation patterns as a predictor of future dispatch
- take into account generator gas contracts
- ensure that the required number of synchronous generators are on line for system security purposes.

We also note that ElectraNet's PACR took into account minimum stable operating levels (technical limits) and included a requirement for two generators to be on-line at all times for system security purposes. This has already addressed the technical operating requirements and system security requirements identified by AEMO as the reason for adopting minimum capacity factors.

Fuel supply considerations and operational costs

In support of the use of minimum capacity factors, ElectraNet stated that:[83]

> In the PACR, generator input assumptions were aligned with the 2018 ISP to better reflect the historical operation of plant and key system security, operational and fuel supply considerations relevant to gas fired generation in South Australia based on detailed integrated modelling by AEMO.

In respect of fuel supply considerations, we understand that AEMO undertook detailed modelling that considered gas reserve estimates and pipeline constraints in the system.[84] Moreover, AEMO stated that:[85]

> The application of such constraints with gas plant, especially steam cycle plant is to ensure that reasonable operational levels are achieved considering take or pay contracts, cycling costs, flexibility limitations or other staffing considerations, particularly where the operational levels are supported by historical benchmarks. Ignoring these operational limitations could lead to models which are unachievable in practice or at least increase operating costs.

82 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, p.8.
83 ElectraNet, Updated modelling and sensitivity, November 2019
84 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, p.6.
85 AEMO, Response to AER information request, 23 April 2019

We understand that take or pay contracts refers to gas generators' purchase of gas through contracts rather than through the short term trading market. The modelling approach adopted for the RIT-T analysis assumes that generators will bid into the NEM at their SRMC (i.e. fuel costs and variable operating and maintenance costs). However, AEMO appears to suggest that fuel costs are unavoidable because gas contracts have already been entered into, and that some gas generators in SA will run to use all of their contracted gas.

Relevantly, our consultant advised that running gas plant because they have contracted an amount of gas has not been sufficiently justified on the basis that:[86]

- The SA gas generators may participate in the wholesale spot market for gas, which enables them to purchase or sell gas outside their contracted position.
- In the PACR outcomes, SA gas generation is often dispatched at the expense of existing wind generation in SA, which is constrained off to facilitate this gas generation. In practice to be dispatched at the expense of wind generation, the gas generators would need to bid into the market at zero or negative prices, to use all of the gas they have contracted. However, this does not reflect sound commercial operation or an economically efficient outcome.
- Our consultant further advised that, to the extent that there are fixed costs that negatively impact the commercial attractiveness of operating at low capacity factors, these should already be taken into account in the market modelling.[87]

In respect of system security considerations, AEMO stated that the minimum capacity factors also reflect the need for gas generator units to be on line in South Australia to meet system security requirements.[88] For the 2018 ISP, AEMO assumed that two large units of TIPS B would be on-line as the least cost approach to meeting system security requirements. The PACR assumed that in the base case (without the interconnector) that two synchronous units will be required to be on-line to meet these system security requirements.[89] Again, while this directs gas generation to be running, this requirement has already been taken into account in ElectraNet's modelling as a specific input.

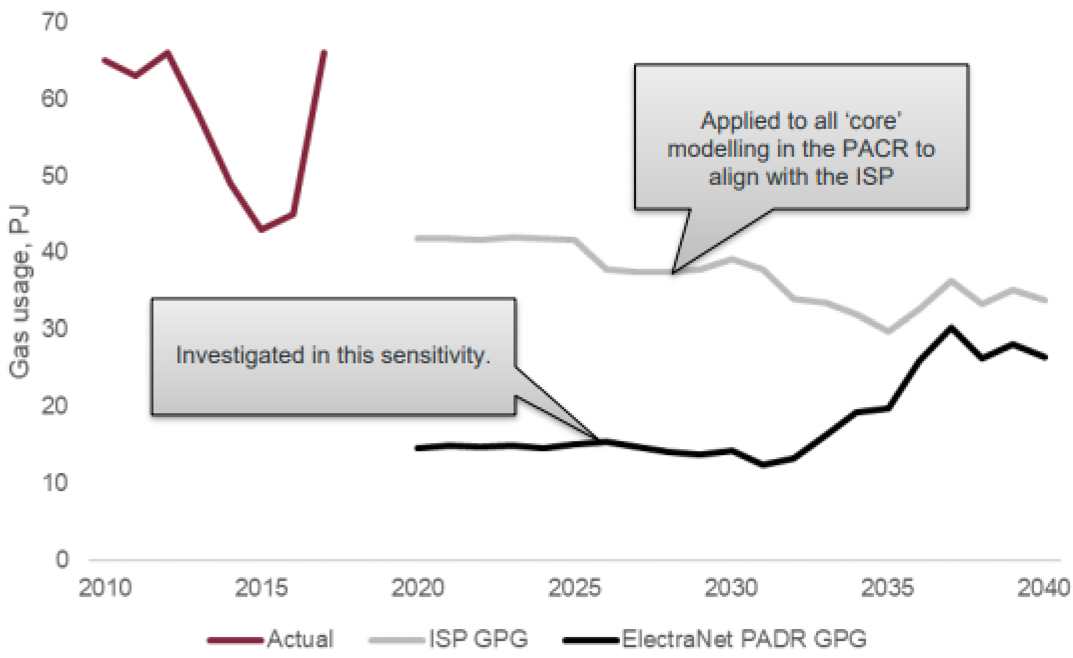
Historical utilisation of gas

ElectraNet advised that the minimum capacity factor assumption was also intended to better reflect the historical operation of South Australian gas generation. ElectraNet also stated that this is relevant as the use of 'short run marginal cost' bidding in the PACR model can result in significant underutilisation of gas generators when compared with historical utilisation.[90] Figure 10 (reproduced from the PACR) shows that aggregated historical gas usage in SA is higher than the estimated usage as modelled in the PADR and PACR. ElectraNet stated that:[91]

86 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019
87 ibid
88 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019
89 ElectraNet, SAET RIT-T PACR, February 2019
90 ElectraNet, Proposed Additional Modelling Report, August 2019, p.7.
91 ElectraNet, SAET RIT-T, additional modelling and sensitivity analysis, September 2019, p.9

In fact, despite the inclusion of minimum capacity factors on SA gas plant, the PACR modelling already results in a reduction in the energy usage of SA gas plant in 2019-20 of 30% when compared with actual gas usage in 2018-19. Usage trends indicate this is already a conservative assumption that leads to underestimating the market benefits of the preferred option.

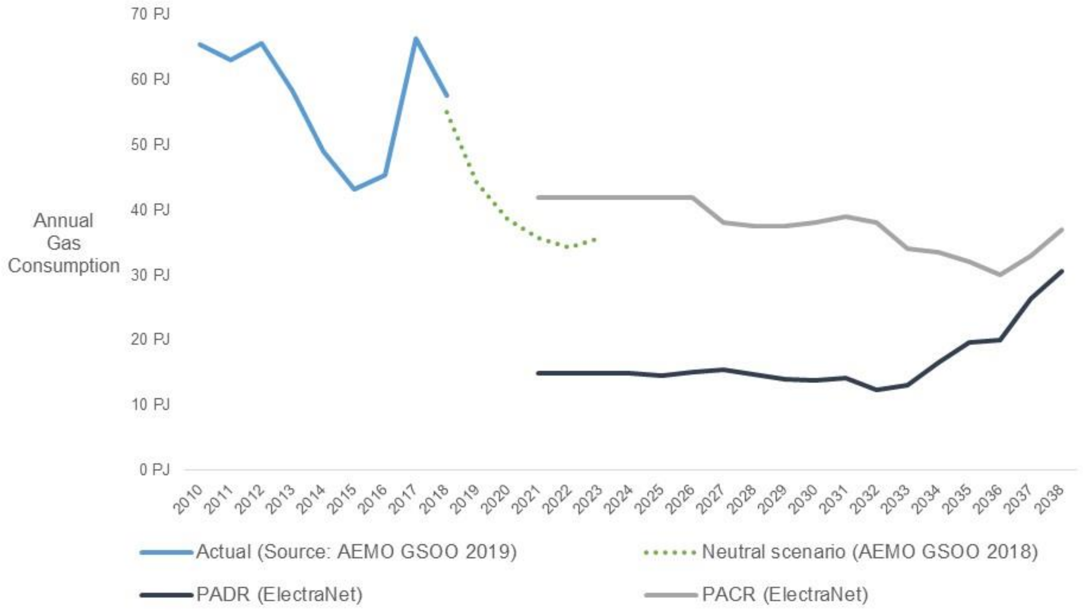
Figure 10 Aggregate gas usage for SA GPG (base case)



Source: ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019, p.111

We assume that ElectraNet has relied on actual SA gas usage from the 2018 GSOO where AEMO also provides a forecast of GPG gas usage in SA in their 2018 GSOO report. This is reproduced in Figure 11.

Figure 11 Aggregate gas usage SA (base case)



Source: AER analysis
ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019
AEMO, Gas Statement of Opportunities, June 2018

Figure 11 shows that AEMO is forecasting a significant decline in South Australian GPG gas usage up to 2024. Additionally, in the 2018 GSOO, AEMO indicated that the projected decrease in gas consumption is from projected reductions in the reliance on GPG to provide the minimal level of synchronous (gas) generation the system needs to manage system security in South Australia.[92] This highlights the limitations of forcing the market modelling to reflect the historical levels of gas usage.

Moreover, the assumption that past historical gas usage in South Australia will be representative of gas usage in the future is not consistent with ElectraNet's modelling approach. Frontier advised that:

> ElectraNet makes reference to historic output levels as part of the justification for the application of MCFs in the modelling. To make modelling assumptions with reference to historic outcomes of particular plant is not consistent with ElectraNet's chosen SRMC modelling approach. ElectraNet states in the PACR Market Modelling Methodology Report that a further benefit of SRMC modelling based approach is that it avoids making arbitrary long-term decisions about the level and nature of contracting in the NEM. To apply the MCFs for the reasons provided is to do exactly that. Basing assumptions of generator behaviour distorts the outputs of the SRMC model; framework, particularly when it is done in a selective way (only applying to certain generators and not other comparable generators).

The PACR removed the minimum capacity factor assumption as part of its sensitivity analysis, which reduced the net benefits of the preferred option. Importantly, the PACR sensitivity analysis identified the impact of changing one assumption at a time and not in combination with other changes to assumptions. We requested that the minimum capacity

92 AEMO, 2018 Gas Statement of Opportunities, June 2018, p.4.

factor assumption be removed in conjunction with other assumptions that impact on SA gas usage for the purposes of testing the robustness of the market modelling.

AER's assessment

In conclusion we are not satisfied that ElectraNet has demonstrated that its approach to modelling gas output based on historical utilisation of gas in South Australia is reasonable on the basis that:

- The PACR modelling has already taken into account technical generator minimum operating loads and system security requirements as identified by AEMO as the reason for adopting minimum capacity factors in its 2018 ISP.
- This assumption forces mid merit gas plant in South Australia to be dispatched 'out of merit order' and displace lower cost renewable generation (e.g. existing wind generation in South Australia) which is not an economically efficient outcome.
- The PACR modelling has applied this assumption to only mid merit gas plant in South Australia and not applied to other mid merit gas plant in the NEM.
- ElectraNet stated that the adoption of minimum capacity factors on mid merit gas plant in South Australia was intended to better reflect historical operation of gas generation. However, the adoption of this assumption based on historical output is not consistent with the modelling methodology adopted in the PACR.
- While the 2018 ISP uses minimum capacity factors, ElectraNet in some cases departs from AEMO's values.[93]

We asked ElectraNet to remove this assumption in the additional modelling. ElectraNet's additional modelling has removed the minimum capacity factor assumption and the results are outlined in section 3. Table 4 summarises the differences between the PACR and further modelling undertaken to test the robustness of the SAET RIT-T analysis.

Table 4 Minimum capacity factors - PACR and re-modelling assumptions

	MCF - PACR	MCF - re-modelling
Osborne	60%	Removed
Pelican Point	50%	Removed
Torrens Island B	25%	Removed

Source: PACR and AER re-modelling request

A.2 Other plant operating parameters

93 Specifically, the 2018 ISP assumes a minimum capacity factor of 15 per cent for Torrens Island A, but does not assume a minimum capacity factor for Torrens Island B. By contrast ElectraNet applies a minimum operating level of 25 per cent for Torrens Island B and no minimum capacity factor for Torrens Island A.

Market modelling needs to reasonably capture operational characteristics of generating plants and their ability to respond to rapid and frequent changes in demand. Thermal plant operating characteristics include minimum generation operating levels, start-up costs, ramp rate limits and minimum up/down times. This section focuses on the assumptions associated with plant cycling constraints (i.e. minimum up and down times) on thermal generators and minimum operating loads of generators.

Cycling constraints for thermal generators

The PACR applied cycling constraints on the South Australian mid merit gas generators. We understand that AEMO had taken into account these cycling requirements in the ISP modelling as part of its assumed minimum capacity constraints on selected gas generators in South Australia. We understand that cycling constraints were not imposed on other gas generators in South Australia in the PACR as these plants are capable of providing fast response into the market (e.g. gas peaking plant). However, the PACR also did not apply cycling constraints to mid merit gas elsewhere in the NEM outside South Australia.

Relevantly, the assumed cycling constraints on SA mid merit gas generators in South Australia will affect the gas usage levels and therefore the estimated avoided fuel cost benefits.

Minimum generator operating loads

ElectraNet stated that minimum loads assumptions are used to represent the minimum stable output levels at which generating plant can physically operate. The PACR sourced minimum loads from the 2018 ISP. For TIPS B, the 2018 ISP applied a station wide minimum load of 160MW (equivalent to 40MW per unit). The PACR applied minimum loads to the Pelican Point and Osborne generators. However, the PADR did not apply minimum operating loads to Pelican Point and Osborne. The minimum operating load assumptions are important as these assumptions affect gas usage and therefore the estimated avoided fuel cost benefits.

We also note that based on the information provided by AEMO, AEMO's reference to flexibility limitations of mid merit gas generators in SA covers minimum stable operating loads, cycling constraints and the need to recover fixed costs. In relation to gas cycling constraints, ElectraNet included cycling assumptions for selected SA gas generators in its modelling in response to a submission on the PADR. ElectraNet also considered minimum stable generator operating loads in its modelling for the PACR.

AER's assessment

In assessing the operational characteristics of generation plant, the RIT-T requires RIT-T proponents to use a market dispatch modelling methodology that incorporates a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and a realistic treatment of the network constraints and losses.[94]

94 AER, Final Regulatory Investment Test for Transmission, cl 11, June 2010

Cycling constraints for thermal generators

The PADR assumed that gas generation was flexible as no minimum up and down times were applied in the modelling. In a submission to the SAET PADR, EnergyAustralia noted that there was a lack of clarity around the technical limitations of non-coal thermal generators in the NEM. In particular, EnergyAustralia submitted that with the absence of mid merit gas cycling constraints, the modelling does not reflect the realistic operation of mid merit gas generators.[95]

In response to EnergyAustralia's submission on the PADR, ElectraNet states that all generator input assumptions have been aligned with the 2018 ISP.[96] This includes 24 hours minimum on time and 12 hours minimum off time for the South Australian mid merit gas generators (i.e. TIPS B, PPPS and OSPS). However, AEMO have indicated that they have adopted generator input values from an ACIL Allen report that AEMO published alongside the 2018 ISP.[97] The values from the ACIL Allen report are reproduced in Table 5 alongside the values assumed in the PACR.[98] Further, we note that the PACR modelling only applied cycling constraints to thermal gas generators in South Australia and not elsewhere in the NEM. ,

The ACIL Allen report provided minimum on and off time of one hour for TIPS B and a minimum on and off time of four hours for PPPS and OSPS, respectively.[99] This suggests that these gas generators are significantly more flexible than assumed in the PACR.

Table 5 Comparison of cycling constraint assumptions

	Minimum on time (hrs) - PACR	Minimum off (hrs) time- PACR	Minimum on time (hrs) - ACIL Allen[100]	Minimum off time (hrs) - ACIL Allen
NSW black coal	120	12	8	8
Osborne	24	12	4	4
Pelican Point	24	12	4	4
Torrens Island B	24	12	1	1

Source: Frontier Economics and ACIL Allen Fuel and Technology Cost Review data book, 2014

Note NSW Black coal includes Bayswater and Liddell, and the PACR assumed minimum up time is not provided

In the PACR Market Modelling Methodology Report, ElectraNet appeared to imply that the values used for minimum on and off times are derived in an attempt to prevent short start up

95 Energy Australia, Submission to SAET PADR, 31 August 2018, p.1-2.
96 ElectraNet, SAET RIT-T Project Assessment Conclusion Report, February 2019, p. 41.
97 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2018
98 ACIL Allen, Fuel and Technology Cost Review, 12 June 2014
99 ibid
100 Note: the 2018 ISP adopted the ACIL Allen assumptions minimum and down times for thermal coal generators.

and shut down cycles.[101] ElectraNet further stated that the approach ensures the forecast operation of generators matches their understanding of the capability of the fleet.

During our engagement process, ElectraNet advised that the minimum on and off times used in the PACR modelling were chosen to reflect reasonable estimates based on historical behaviour.[102] ElectraNet also stated that a reduction in assumed cycling constraints adopted in the PACR to the ACIL Allen values would result in unrealistic generator behaviour that is inconsistent with historical generator behaviour and the physical constraints of the plant. ElectraNet commented that this could potentially result in more than 10 starts per day for TIPS B which is not a realistic outcome.

We agree that technical constraints on generators should be realistic based on their physical capability. However, the fact that the mid merit gas generators in South Australia is physically capable of starting multiple times per day does not mean that it is likely to achieve the potential number of starts claimed by ElectraNet, in a modelled least cost optimisation. Attempting to estimate values of constraints on cycling in order to achieve a number of starts consistent with previous years does not take into consideration the changing generation profile over the modelling period and how the role of mid merit gas generators may change.

Indeed, ElectraNet identified this change in the role of thermal generators in their PACR Market Methodology report which states that:

> By the end of the modelling horizon the analysis shows conventional thermal generators being operated in ways quite different to today. For those coal generators still in service ElectraNet has recognised existing assumptions about continuous operation will no longer be valid and has allowed the model to economically cycle these units off with a minimum shutdown time of 12 hours. Where extreme changes have been observed, generators have been required to operate for five days a time.
>
> A 12 hour shutdown period has proven to be enough to prevent most short start up and shutdown cycles. However, this observation highlights that existing generators will be required to be more flexible than they currently are. In addition, generator operation at minimum operating levels will increase.

This suggests that all thermal generation will need to be more flexible in the future compared to historical behaviour. Further, AEMO advised that the 2018 ISP sought to give thermal generators reasonable duty cycles, however recognising that there must be flexibility for units to change to two shift operation in the face of competing lower emission alternatives.[103]

ElectraNet also commented that:[104]

> GHD advised that the reported minimum on/off times should not be used to inform long-term network planning due to the complexity of the decision making involved to start and stop plant at an operational level. Whilst plant may be physically capable of cycling as reported, the increased costs associated with adequately maintaining plant to allow such operation mean most plant are not operated in this manner in practice. For example, most maintenance programs are defined with reference to hours of

101 ElectraNet, PACR Market Modelling Methodology Report, February 2019, p.14.

102 ElectraNet, SAET RIT-T, Additional modelling and sensitivity analysis, September 2019, p.11

103 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2018

104 ElectraNet, SAET RIT-T, Additional modelling and sensitivity analysis, September 2019, p.11

> operation and/or number of starts (where one start is often equivalent to a specific number of operating hours).

We agree that the inclusion of generator start-up costs should be included in the market modelling. We proposed that the ACIL Allen estimated start-up cost be included in remodelling to test the robustness of the RIT-T analysis. However, in response ElectraNet indicated that it was not able to incorporate these costs due to limitations of the modelling. ElectraNet also considered the ACIL Allen costs based on observed cycles and are expected to underestimate the costs of a more flexible cycling operation assumed in the ACIL Allen report.[105]

To assess the costs of start-up we requested that ElectraNet provide these separately to determine the materiality of these costs. However, as previously stated in the PACR:

> ElectraNet has not included the additional costs for starting up and shutting down conventional generators. These costs, whilst significant for a commercially minded operator are not currently major costs in the NEM. The operation of the plant is captured by the minimum up and down time constraints. Including these costs in the model is expected to marginally increase the costs of dispatch and provide greater opportunities for dispatch efficiencies to be delivered by increased interconnection. Further, these costs are greatest for the coal fleets outside of South Australia and can be expected to be similar in all terminating jurisdictions of the options considered and would not impact on interconnection.

Our consultant advised that:

- It is not clear how ElectraNet has determined the minimum up-times and down times for the model and the 2018 ISP does not contain corresponding values with comparable times. It is not clear whether these values are intended to reflect technical constraints or commercial decisions a plant operator would make.
- It appears that ElectraNet has applied the constraints selectively to some generators and not others (e.g. it only applied the constraints to four gas generators in SA and did not provide any justification for why these constraints were not applied to similar gas generators in other NEM regions).

Our consultant also advised that:

> ElectraNet did not include the costs of starting and shutting generators, in favour of the minimum up and down times. These are legitimate costs that thermal generators face. To the extent that cycling behaviour becomes a material feature of the model in the later years of the simulation, we consider it important to capture this cost. Allowing plant to cycle within its technical limits, while capturing the additional cost of this behaviour, provides a reasonable estimate of the least cost operation of the network. Applying blunt up-times and down-times obscures the economic reality and distorts the cost-benefits analysis.

We agree with our consultant's advice that the minimum on and off times for South Australian gas generator assumptions have not been adequately explained nor supported by an independent credible source, including the basis for the selective application to only gas generators in South Australia. As recognised by ElectraNet and AEMO existing generators will be required to be more flexible in the future and this is particularly relevant given the long

105 ElectraNet, Response to AER Information request #6, 20 September 2019

term nature of the modelling. In order to satisfy RIT-T paragraph 11, we consider that the ACIL Allen input assumptions should be adopted as a more realistic representation of plant characteristics in the absence of any supporting sources used to inform the PACR assumptions for SA gas operation. These assumptions should also be applied to similar gas generators in the NEM.

We requested ElectraNet to adopt the ACIL Allen assumptions for SA gas plant and apply these to similar gas plant in the NEM. The exception is we have proposed that the minimum on and off times for TIPS B of four hours as per PPPS and OSPS for the purposes of testing the robustness of the RIT-T analysis.

Minimum generator operating loads

ElectraNet stated that for the PACR it has sourced minimum operating loads from the 2018 ISP. However, where minimum loads were not available, ElectraNet stated that it referred to data and cross-checked these values against market outcomes, and relevant advice from plant operators.[106]

The PACR assumptions specify a minimum operating load of C-I-C MW and C-I-C MW for Pelican Point and Osborne, respectively. However, ElectraNet advised that the modelling in the PACR applied C-I-C MW for Pelican Point. These assumptions differed from information provided by AEMO based on generator performance standards, which indicate lower minimum operating levels for these generators. These differences are provided in Table 6.

Table 6 Minimum operating loads - AEMO and PACR

	Minimum operating load (MW) - AEMO[107]	Minimum operating load (MW) - PACR
Osborne	C-I-C	C-I-C
Pelican Point	C-I-C	C-I-C
Torrens Island B	C-I-C	C-I-C

Source: PACR and AEMO, Assumptions for South Australian GPG in the 2018 ISP
Note: these minimum operating loads reflect station wide minimum loads.

ElectraNet advised that the minimum operating load for Osborne was based on a confidential submission from the operators of Osborne in 2017.[108]

ElectraNet acknowledged that:[109]

- The generator performance standards (GPS) for Osborne at the time of the PACR specified a minimum operating level for the plant of C-I-C MW.

106 ElectraNet, SAET RIT-T, additional modelling and sensitivity analysis, September 2019
107 AEMO, Assumptions regarding GPG usage in SA, August 2019
108 ElectraNet, SAET RIT-T, additional modelling and sensitivity analysis, September 2019. p.14
109 ElectraNet, SAET RIT-T, additional modelling and sensitivity analysis, September 2019. p.14

- The GPS data for Pelican Point was updated in May 2018 following a turbine upgrade, with the minimum loading level revised to C-I-C MW for the GTs and C-I-C MW for the steam turbine, providing a minimum stable output level of approximately C-I-C MW.
- ElectraNet also stated that minimum operating loads of C-I-C MW and C-I-C MW for Pelican Point and Osborne have yet to be observed by recent history. Frontier considered that ElectraNet's approach does not reflect reality where these assumptions differ from actual technical limitations and consider it is not possible to infer minimum operating loads from historic output. Further, ElectraNet have not applied minimum operating loads to other mid merit gas generators in the NEM outside of South Australia.

AER's assessment

In order to satisfy RIT-T paragraph 11, we consider that the ACIL Allen input assumptions should be adopted as a more realistic representation of plant characteristics in the absence of any supporting sources used to inform the PACR assumptions for SA gas operation. These assumptions should also be applied to similar gas generators in the NEM.

We requested ElectraNet to adopt the ACIL Allen assumptions for SA gas plant and apply these to similar gas plant in the NEM. The exception is we have proposed that the minimum on and off times for TIPS B of four hours as per PPPS and OSPS for the purposes of testing the robustness of the RIT-T analysis.

The changes in these cycling inputs for the purposes of re-modelling from the PACR are summarised in Table 7. The outcome of the further remodelling incorporating these alternative minimum operating loads is outlined in section 3.

Table 7 Cycling inputs - PACR and re-modelling assumptions

	Min on/off times - PACR	Min on/off times - re-modelling
Osborne	24/12	4/4
Pelican Point	24/12	4/4
Torrens Island B	24/12	4/4

Source: PACR and AER re-modelling request

In conclusion ElectraNet's approach to estimating minimum operating loads in the PACR are inconsistent with the following aspects of RIT-T Guidelines and RIT Application Guidelines that:

- RIT-T proponents use assumptions and forecasts that are transparent and from a reputable and independent source.[110] We consider that in order to provide transparency, inputs and assumptions must therefore be adequately explained and sourced where appropriate.

[110] AER, Regulatory Investment Test for Transmission Application RIT-T Guidelines, December 2018, p.24.

- The market dispatch modelling methodology adopted by the RIT-T proponent must incorporate a realistic treatment of plant characteristics.[111] Given their chosen modelling approach, ElectraNet should adopt representations of plant characteristics that are as accurate as possible.
- A state of the world should be internally consistent such that all aspects of a given state of the world could reasonably coexist.[112] Therefore, we consider it reasonable that inputs and assumptions be applied consistently when modelling each state of the world.

To test the robustness of the modelling we requested that ElectraNet apply a minimum operating load of C-I-C MW and C-I-C MW for Pelican Point and Osborne, respectively. We also requested that minimum operating loads be applied to all mid merit gas plant in the NEM. ElectraNet's additional modelling adopted these minimum operating loads for Pelican Point and Osborne, but has not applied minimum operating loads to mid merit gas elsewhere in the NEM. ElectraNet stated that it has not applied minimum operating loads to mid merit gas outside SA as the 2018 ISP and the ACIL Allen data set have stated these as zero.[113]

These changes in these operating inputs (operating loads) for the purposes of re-modelling from the PACR are summarised in Table 8. The outcome of the further remodelling incorporating these alternative minimum operating loads is outlined in section 3.

Table 8 Operating load - PACR and re-modelling assumptions

	Minimum operating load (MW) - PACR	Minimum operating load (MW) - re-modelling
Osborne	C-I-C	C-I-C
Pelican Point	C-I-C	C-I-C
Torrens Island B	C-I-C	C-I-C

Source: PACR and AER re-modelling request

111 AER, Regulatory Investment Test for Transmission, 2010, paragraph 11
112 AER, Regulatory Investment Test for Transmission Application RIT-T Guidelines, June 2010, p.14
113 ElectraNet, Email in Response to Information Request #6, 30 September 2019

A.3 System security obligations

As explained in section 3, the PACR included a number of system security related obligations that affect the level of gas generator usage in South Australia. These include:

- The need to run synchronous generation to meet system security needs in South Australia.[114]
- The application of the non-synchronous generation cap in South Australia; and
- The need to reduce flows on the Heywood interconnector to reflect the SA Government requirements to manage the rate of change of frequency in the event of an outage on the Heywood interconnector.[115]

These system security requirements are applied across all of the scenarios. Importantly, these requirements have been reflected in the modelling and in the absence of the interconnector result in higher gas generation as synchronous generation in South Australia is limited to high cost gas plant In particular, this requires that gas generators in South Australia be directed on when necessary by AEMO. As a result, gas generation is higher than in the absence of these obligations resulting in the dispatch of high cost gas generation over and above market driven outcomes. In addition, lower cost renewable generation will at times be constrained off by high cost gas generation (causing for example "spilled wind") and the constraint on the operation of Heywood will reduce South Australia's access to sources of lower cost generation (e.g. brown coal generation).

AER's assessment

We consider that since publication of the PACR four synchronous condensers have been approved by AEMO as the solution to meet the minimum system strength and inertia requirements.[116] We approved an economic evaluation proposing four high inertia synchronous condensers on 18 February 2019.[117] The installation of four high inertia synchronous condensers would be expected to lower generation costs in South Australia in the absence of the interconnector as this is expected to:[118]

- reduce or remove the need for generator direction to manage system strength and inertia requirements in South Australia
- increase or remove the need for the non-synchronous cap; and
- Improve the RoCoF constraint on the Heywood interconnector.

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114 These include the need for operating reserves for ramping, secondary frequency control following a separation event, and operating reserves for energy balance following a separation event. These are set out in AEMO, Assumptions for South Australian GPG in the 2018 ISP, August 2019, p. 14.

115 AEMO limits SA RoCoF to 3 HZ/s for a non-credible trip of the Heywood interconnector in response to a Ministerial Direction issued under the Essential Services Act 1981 (SA).

116 AEMO, Letter to ElectraNet - Technical Approval of Solution, 8 March 2019

117 AER, Final Decision - ElectraNet - SA system strength contingent project , August 2019

118 ElectraNet, SAET RIT-T PACR, 13 February 2019

However, this solution was not factored in the PACR modelling. We sought AEMO advice regarding the impact of the interconnector on system security requirements in South Australia given the planned installation of four high inertia synchronous condensers.

AEMO has advised that:[119]

> The ISP projected that the installation of four synchronous condensers (including flywheels) would address the identified system strength gap and the minimum synchronous component of the declared inertia shortfall. However, AEMO did not assume that the four synchronous condensers would address all the requirements for system security in South Australia.

And:[120]

> For the 2018 ISP, AEMO assumed that, following the installation of the four synchronous condensers (including flywheels) and prior to the implementation of EnergyConnect, at least two large synchronous generator units in South Australia would be required online at all times.

AEMO also stated that its detailed studies have shown that this is a minimum requirement for security of South Australia in the absence of the interconnector.[121] AEMO assumed this this minimum requirement is necessary for the following reasons:[122]

- The need for operating reserves for ramping
- Secondary frequency control following a separation event; and
- Operating reserves for energy balance following a separation event.

This assumption of at least two large synchronous generator units in South Australia online at all times was not described in any 2018 ISP documentation available to stakeholders. We understand that the assumption was included in the proprietary input files for the modelling software utilised (PLEXOS).

AEMO further stated that for the 2018 ISP it assumed that no synchronous generating units are required to be online where:[123]

- the Heywood interconnector and the proposed interconnector are intact
- there were no critical outages within the State
- normal operating conditions prevailed; and
- additional measures are in place to arrest and remediate any potential further declines in system strength (such as connecting generation and increasing metropolitan DER).

Importantly, the costs of these additional measures do not appear to have been included in the SAET RIT-T which suggests that the net benefits of the preferred option in terms of enhancing system security may have been overstated.

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119 AEMO, Assumptions for South Australian GPG in the 2018 ISP, August 2019, p.14
120 ibid
121 ibid
122 ibid
123 ibid

We have taken into account the AEMO advice that two synchronous generators are required to be on-line for system security purposes in the absence of the interconnector. This is consistent with the assumptions in the PACR. The PACR also assumed that only two synchronous condensers would be installed. However, as observed by Frontier, based on the description of the synchronous condenser solution in the PACR and the supporting Network Technical Assumption Report, ElectraNet had:[124]

- recommended the installation of four inertia synchronous condensers to AEMO; and
- updated the analysis from the PADR to supposedly account for the recommended synchronous condensers.

To test the robustness of the RIT-T analysis we requested that ElectraNet undertake additional modelling to include the installation of four high inertia synchronous condensers. Therefore, we requested that ElectraNet undertake additional sensitivity analysis with the following assumptions:

- Four synchronous condensers installed and commissioned in South Australia consistent with anticipated dates set out in ElectraNet's Economic Evaluation Report[125].
- The South Australian system-wide cap on non-synchronous generation to be increased from 1,870 MW to 2,000 MW.

For the above reasons, we requested ElectraNet to undertake further modelling with the changes as highlighted in Table 9.

Table 9 System security assumptions

	System security - PACR	System security- re-modelling
Synchronous generator units on-line	2	2
Synchronous condensers	2	4
Inertia capability	1300MWs	4400MWs
Non-synchronous cap	1870	2000

Source: PACR and AER re-modelling request

124 ElectraNet, Network Technical Assumption Report, 13 February 2019

125 ElectraNet, Addressing the System Strength Gap in SA, Economic Evaluation Report, 18 February 2019

A.3 Retirement of gas generation plant in SA and the entry of large scale storage in SA

SA gas generator retirements

The PACR assumed that Torrens Island B, Pelican Point and Osborne gas generators retire upon commissioning of the interconnector in 2024. ElectraNet state that to maintain consistency with the 2018 ISP, for states of the world with the preferred option, the PACR aligned the retirement timings for the above South Australia gas generators with those found in the 2018 ISP, albeit a year earlier to reflect a changed assumption of when the new interconnector could be energised.[126]

Further, in the absence of the interconnector, the PACR differed from the PADR and ISP, where Torrens Island B was found to progressively retire between 2025 and 2033. These differences in generator retirements outcomes are summarised in Figure 12.

Figure 12 Gas-fired generator retirements - South Australia

Source: ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019, p.42

126 ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019, p.42

The PACR provided two sensitivity tests on the retirement of SA gas generators[127]:

- Assuming that all units of Torrens Island B retire at or before 50-years of age under the base case; and
- Assuming a new interconnector has no impact on the operation of Pelican Point and Osborne (i.e. they do not retire nor change their behaviour).

ElectraNet stated that the above assumptions are considered extreme sensitivity tests. Under the sensitivity test where Torrens Island B is assumed to retire at or before 50-years of age, ElectraNet found that the expected net market benefit of the preferred option reduces by approximately $240 million. During our 5.16.6 assessment process, ElectraNet stated that for this sensitivity they did not rerun either their short term or long term model but rather undertook a desktop study. The sensitivity on the operation of Pelican Point and Osborne remaining unchanged upon commissioning of the interconnector was found to reduce the net market benefits of the interconnector by $595 million. The results of these two sensitivity tests indicate that SA gas retirements are a critical component of the analysis.

A consequence of these assumed retirements of Pelican Point and Osborne is that additional capacity is required in South Australia. This gap in capacity is met by a combination of the interconnector and model-determined investment in pumped hydro, as outlined in Figure 13.

Figure 13 Installed capacity to replace gas generator retirements - South Australia

Source: ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019, p.100

127 ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019, p.121-122.

Storage plant cost assumptions

The PACR assumed 6-hour storage pumped hydro costs of $1.4m/MW for all jurisdictions, including South Australia, consistent with 2018 ISP assumptions. For South Australia, pumped hydro of 700MW is modelled to enter the market. This brings forward storage costs in the preferred option and results in annualised capital costs of $65 million over the modelling period.

AER's assessment

As part of our assessment we considered the retirement of mid merit gas generators in ElectraNet's modelling outputs given that:

- It has a significant effect on the avoided generation cost benefits of the interconnector;
- There was a significant change between the PADR and the PACR.

The PACR assumed that Torrens Island B, Pelican Point and Osborne gas generators retire upon commissioning of the interconnector in 2024. The PACR aligned the retirement timings for the above South Australian mid merit gas generators with those found in the 2018 ISP, albeit a year earlier to reflect a changed assumption of when the new interconnector could be energised.[128]

The 2018 ISP found that the retirement of these generators coincides with the commissioning of the preferred option.[129] Importantly, in the PACR, these retirement decisions are not an outcome of the model which determines whether a generator is economic to stay in operation or retires based on end of technical life assumptions.

This is a significant change from the PADR which found that Pelican Point and Osborne continue to operate to 2040 with the preferred option. Moreover, this assumption results in higher avoided fuel cost benefits from 2024 than assumed in the PADR associated with the preferred option due to the retirement of 1460 MW of mid merit gas gas generation in South Australia, instead of 800MW as modelled in the PADR.

Given that ElectraNet's model is capable of modelling retirement of generators when they become uneconomic, we consider it is not necessary to assume economic retirements from the 2018 ISP modelling results. Particularly given the differences in models and inputs and assumptions between ElectraNet's model and the 2018 ISP. Furthermore, the assumed retirement assumptions applied to mid merit gas generators in South Australia has not been applied to generators elsewhere in the NEM. ElectraNet has not provided any reasoning for this inconsistency in approach.

Relevantly, a consequence of these assumed retirements of Pelican Point and Osborne is that additional capacity is required in South Australia. This gap in capacity is met by a combination of the interconnector and model-determined investment in pumped hydro.

128 ElectraNet, Project Assessment Conclusion Report for SAET, February 13 2019, p.42

129 However, it should be noted that the ISP modelled the SA-NSW interconnector at a capacity of 750MW as opposed to the 650MW in the PACR. Therefore retirement of gas plant in SA may be more likely in the ISP.

Storage plant cost assumptions

The PACR assumed pumped hydro capacity of 700MW would replace some of the retiring gas generation. The PADR did not assume pumped hydro would enter the market in South Australia. In ElectraNet's accompanying, 'Consolidated Non-interconnector Option' report Entura advised that pumped hydro in South Australia may be reliant on seawater rather than freshwater which would add significant costs in comparison with pumped hydro using freshwater.[130]

Following publication of the 2018 ISP, TasNetworks engaged Entura to perform studies aimed at informing market modelling with a better view of potential costs and capabilities for pumped hydro energy storage across the NEM. Entura's December 2018 report[131] estimates the average cost of 6-hour storage pumped hydro in South Australia to be $1.9m/MW, rather than $1.4m/MW assumed in the PACR.

The significant difference in the costs assumed by the PACR and Entura has implications for the evaluation of the interconnector, as the modelling for the preferred option plants 700MW of pumped hydro in South Australia following the development of the interconnector (and associated retirement of SA gas generators). Importantly, if the cost of building pumped hydro storage exceeds that assumed in the PACR modelling, the benefits of the interconnector would be expected to be lower than presented in the PACR.

We sought clarification from ElectraNet to understand if the pumped hydro costs from the Entura report were considered by ElectraNet in finalising the PACR. ElectraNet advised that this information was available at the time of publication of the PACR, albeit too late to be incorporated into the final modelling.[132] We recognise that this information was made available in the SAET RIT-T process, but we consider that it would have been reasonable for ElectraNet to consider these additional pumped hydro costs as a sensitivity in its analysis. Given the material difference in capital costs estimated by Entura and those assumed in the PACR, we requested that ElectraNet model the Entura capital cost as a sensitivity.

To this effect we asked ElectraNet undertake additional modelling incorporating:

- No plant investments or retirements be imported from other modelling results.
- Update South Australian pumped hydro costs to which provides a 6-hour storage pumped hydro cost of $1.9m/MW for South Australia, consistent with Entura's December 2018 report[133].

The changes in these generator and storage inputs for the purposes of re-modelling from the PACR are summarised in Table 10 and Table 11. The outcome of the further remodelling incorporating these changes are outlined in section 3.

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130 Entura, Consolidated Non-Interconnector Option, 5 June 2018, p.23.

131 Entura, Pumped Hydro Cost Modelling, 7 December 2018. This report was included in the planning and forecasting consultation documentation which will inform the 2020 ISP. Table 2.5 of the report contains 6 hour storage pumped hydro costs.

132 ElectraNet, email response to AER Information Request #6, 21 September 2019

133 Entura, Pumped Hydro Cost Modelling, 7 December 2018.

Table 10 Comparison between PACR and re-modelling assumption

	Generator retirements - PACR	Generator retirements- re-modelling
Osborne	assumed based on 2018 ISP	modelled
Pelican	assumed based on 2018 ISP	modelled
TIPS B	assumed based on 2018 ISP	modelled

Table 11 Comparison between PACR and re-modelling assumption

	Capital costs - PACR	Capital costs - re-modelling
Pumped Hydro SA	$1.4m/MW	$1.9m/MW

Source: PACR and AER re-modelling request

A.4 Assumptions associated with fuel costs

The RIT requires assessment of the net benefits of the proposed investment. The net benefits are estimated from modelling the benefits and costs of:

- generator entry, exit, and dispatch, and
- network augmentations;

resulting from both the base (no investment) case and the build case. Relevantly, coal and gas prices are an input into modelled generator dispatch, entry, and exit decisions.

We examined ElectraNet's forecasts for gas and black coal prices. Some stakeholders in response to the PADR expressed some concerns about the use of black coal price forecasts based on legacy contract prices. Origin Energy submitted:[134]

> It is our understanding that much of the expected market benefits from the preferred option is contingent on the price differential between coal and gas. It is unclear however what consideration has been given to some legacy coal contracts coming to an end, and the consequent increasing linkage between international and NSW coal prices. Similarly, the impact of any potential LNG import terminals in the southern states is a reasonable scenario that should be considered given recent proposals for such projects.

Delta Electricity submitted:[135]

> The current Newcastle Port price for thermal coal is currently above $5.30/GJ and is not projected to fall back to levels assumed by ElectraNet. Any additional NSW coal-fired generation arising from the SA-NSW interconnector will have a marginal cost linked to the export coal price, and the RIT-T reference case should reflect this reality.

AER's assessment

ElectraNet sourced its coal price forecasts from AEMO's 2018 ISP.[136] These coal prices are based on legacy contract prices in the near term and reflect estimates of market prices in the longer term.[137]

ElectraNet sourced forecast gas prices from AEMO's 2018 ISP for central estimates of gas prices, but adopted a wider range of high and low estimates of gas prices than the 2018 ISP. The central estimates of gas prices are similar to market prices in both the near and longer term.[138]

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134 Origin Energy, South Australian Energy Transformation Project Assessment Draft Report (PADR) Feedback, 31 August 2018, p. 1.

135 Delta Electricity, South Australian Energy Transformation RIT_T: PADR Submission, 31 August 2018, p. 2.

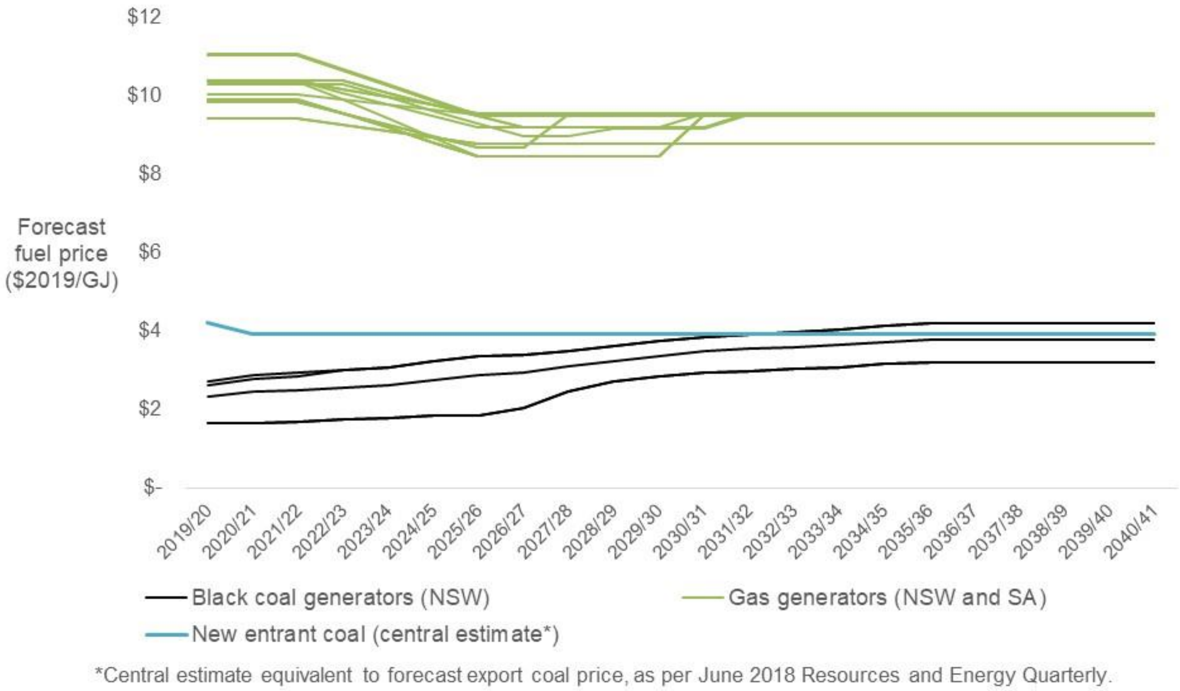
136 AEMO's 2018 ISP coal price forecasts are based on wholesale gas and coal price forecasts produced by Core Energy and Wood Mackenzie. AEMO adjusted these external forecasts in the near term to reflect recent observations of wholesale prices (AEMO, Integrated System Plan for the National Electricity Market, Appendices, July 2018, p. 95). ElectraNet's coal price forecasts are taken from AEMO's 2018 ISP forecasts and escalated from 2017 prices to 2019 prices (ElectraNet, response to AER information request, 21 June 2019, p. 3).

137 ElectraNet, response to AER information request, 22 March 2019, p. 2.

138 ElectraNet, response to AER information request, 25 February 2019, p. 6.

Therefore, near term forecasts for coal prices were less consistent with current market prices than near-term forecasts for gas prices. Consistency in approach to estimating fuel prices is an important consideration as relative prices are important for dispatch decisions and the resulting NPV modelling. Figure 14 shows the PACR forecast black coal and gas prices.

Figure 14 PACR - Forecast coal and gas prices



Source: PACR

Frontier considered that the appropriate economic cost for black coal to use in the energy market modelling (given the cost benefit framework of the RIT-T) is the opportunity cost.[139] This position appears to be supported by EnergyQuest, which stated in its advice on gas price forecasts to ElectraNet:[140]

> Note the Energy Quest forecast focusses on new sources of gas and contracts. Legacy contracts may have already locked in lower prices for the short to medium term, but pricing to users seeking to buy gas is assumed to be determined by marginal costs and new gas contracting. The longer the forecast, the more valid this assumption is.

On this basis, Frontier considered ElectraNet's gas price forecasts to be reasonable.[141] On black coal prices, Frontier submitted that this opportunity cost is better reflected in 'netback prices' (which ElectraNet used in its modelling for new entrant coal generators), rather than the existing generator-specific forecasts that are in part derived from legacy contracts.[142]

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139 Frontier Economics, Final Report- RIT-T Assessment: South Australian Energy Transformation, December 2019, p. 21.
140 Energy Quest, Advice to ElectraNet on gas price forecasts, February 2019, p. 8.
141 Frontier Economics, Final Report- RIT-T Assessment: South Australian Energy Transformation, December 2019, p. 19.
142 ibid, p. 21.

On its gas price forecasts, ElectraNet stated:[143]

> The core analysis uses a range of gas and coal prices…existing SA gas generators are assumed to pay the current export-equivalent gas price across the entire assessment period since they source their gas contracts from, or are themselves, parties exporting LNG. Therefore, if they need to run, gas needs to be procured at the current export parity price. Any new gas generators in the modelling also pay the current export-equivalent gas price.

On its black coal price forecasts, ElectraNet stated:[144]

> ElectraNet considers this assumption to be reasonable based on historic output profiles of coal fired generators and forward electricity hedging practices as base load operators. Given the cost structure and baseload duty of these units, it would not be realistic or credible to assume that coal commitments under existing contracts could be readily traded away by existing coal fired generators at prevailing market rates.
>
> It is therefore reasonable to assume that dispatch patterns would essentially be governed by coal supplied at contracted prices under existing contracts for the near term, and at projected market rates thereafter, as reflected in the modelling.

ElectraNet submitted that the use of legacy contract-based coal prices would be more realistic, as these prices are expected to more accurately reflect the near term pricing and dispatch patterns. However, Frontier considered that near-term bidding dispatch patterns of coal generators is more likely to reflect current market prices for coal (opportunity costs) than legacy contract prices.[145] We consider that the reflection of market prices for coal in current and near-term bidding and dispatch patterns is largely an empirical issue.

To test the materiality of coal price forecasts, we requested ElectraNet re-run its market modelling with market-based coal prices for coal generators that are export-exposed[146] (for non-export-exposed coal generators, ElectraNet's original contract-based prices were retained).

Under our alternate set of input assumptions, ElectraNet's re-modelled benefits from the preferred option totalled about $1.8 billion. However, changing the coal price forecasts changed the modelled benefits by only about $35 million, or about 2 per cent. The net benefits from the preferred option ranged from $234 to $269 million. On this basis, we consider that the choice of market-based coal prices or legacy-contract-based coal prices is unlikely to have a material impact on the choice of the preferred option.

AER assessment

The use of ElectraNet's coal prices that are at least partly based on legacy contracts, or the use of alternate market-based coal prices, is unlikely to have a material impact on the choice of preferred option.

143 ElectraNet, response to AER information request, 25 February 2019, p. 6.

144 ElectraNet, response to AER information request, 22 March 2019, p. 2.

145 Frontier Economics, Final Report- RIT-T Assessment: South Australian Energy Transformation, December 2019, p. 24.

146 These were considered to be Bayswater, Liddel, Eraring, Mt Piper, Vales Point, Callide, Gladstone, Kogan Creek, Millmeran, Stanwell, Tarong, and Tarong North.

A.5 Avoided unrelated transmission cost benefits

ElectraNet estimated that its preferred option would provide benefits from avoiding costs of transmission network upgrades that may otherwise be needed. ElectraNet estimated the benefits from these avoided transmission costs to be about $102 million, about 6 per cent of the overall $1.7 billion of benefits estimated from the preferred option.[147]

The benefits from avoided transmission costs are derived from ElectraNet's market modelling. ElectraNet modelled the new generation investments that may occur both with and without its preferred option. The market modelling identified six renewable energy zones in which new generation investment is modelled to occur and for which upgrades to the transmission network would then be required.

The construction of the preferred option results in economic benefits where it results in less need for transmission network upgrades than would occur without the preferred option, either through smaller upgrades or deferred timing of the upgrade. Conversely, the preferred option results in costs where it results in larger transmission upgrades or upgrades being brought forward.

In general, we consider that the approach ElectraNet has taken to estimating benefits of avoided transmission investment, and the input data and assumptions used, are appropriate. We are satisfied that the preferred option is likely to provide benefits from avoided transmission investment.

AER's assessment

As set out earlier, the preferred option results in economic benefits (costs) where it results in a reduction (increase) in otherwise needed transmission investment or a deferral (expedition) of the timing of the investment.

The need and timing for these expected transmission investments is driven by the intersection of the current transmission capacity and the modelled new generation investment. ElectraNet's market model determines when new generation is needed (for example, to replace a retiring generator or to meet growing demand) and selects the type, size, and location of new generation to be installed. New generation investment above current capacity necessitates capacity upgrades, and the upgrade is assumed to occur as it is needed to allow new generation to reach load centres.

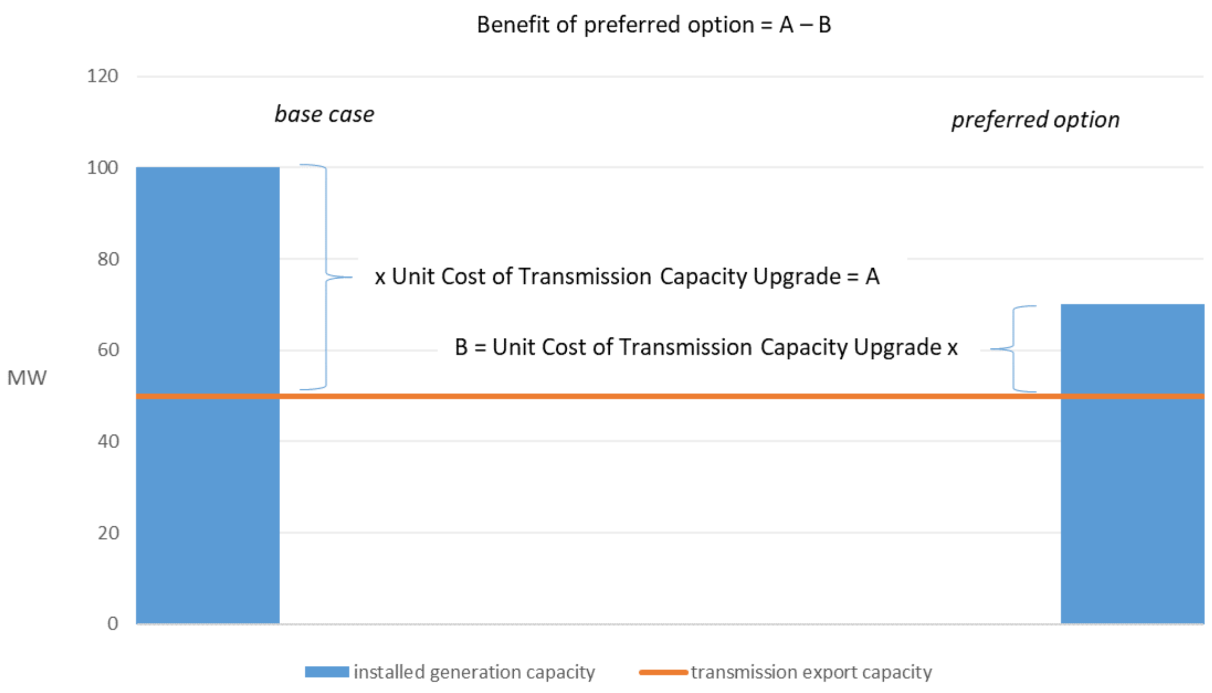
For example, the market model may determine that the optimal solution to meet demand and system security requirements is for 150MW of new wind generation to be installed in the Central West NSW zone in 2028. If the transmission network in the Central West NSW zone in 2028 has only 100MW of spare capacity, then a 50MW transmission network upgrade is required.

[147] In present value terms over the expected life of the preferred option. Benefits estimated as compared to the base case, for the central scenario, in ElectraNet's PACR modelling.

The cost of the upgrades is estimated based on the expected new generation capacity in excess of the transmission capacity in each zone (that is, the size of the required upgrade), and the unit cost of increasing the capacity of the transmission network.

Figure 15 presents a stylised example of how the benefits of avoided transmission costs resulting from the preferred option were modelled by ElectraNet.

Figure 15 Stylised example of method for estimating benefits from avoided transmission costs



Source: AER analysis

The benefits of avoided transmission investment therefore depend on three input variables:

- Current transmission network capacity
- New installed generation capacity
- Unit cost of transmission network capacity upgrades.

Input data and assumptions from these three variables are largely sourced from either AEMO's 2018 Integrated System Plan (current transmission network capacity, unit cost of upgrades) or from outputs of ElectraNet's market modelling (new installed generation capacity).[148]

We consider that sourcing input assumptions from AEMO's Integrated System Plan, which is itself developed through an industry consultative process, is a reasonable starting point based on the information available to ElectraNet at the time of its PACR.

[148] See ElectraNet's PACR market modelling and assumptions data book.

For the inputs sourced from ElectraNet's market modelling outputs, these will be the result of ElectraNet's modelling of generator decisions regarding entry into the market and exit from the market. The modelling of these entry and exit decisions is affected by ElectraNet's modelling of generator dispatch (in turn affected by relative generator operating costs), as well as input assumptions for generator capital costs, the resource capacities in each renewable energy zone, and other factors affecting transmission capability (network congestion, frequency and inertia requirements, etc).

We discuss our concerns with ElectraNet's modelling of these generator dispatch, entry, and exist decisions in section 3. As a result of these concerns, we requested ElectraNet to undertake additional market modelling based on an alternate set of input assumptions.[149] However, the results of this additional market modelling—in terms of avoided transmission investment—were not materially different from ElectraNet's PACR modelling (see subsection below). On this basis, we consider that ElectraNet's input data for the new installed generation capacity is appropriate.

Estimated benefits of avoided transmission investment

The preferred option results in economic benefits where the preferred option results in a change in one or more of the three input variables, resulting in a smaller or deferred transmission investment. ElectraNet's market modelling estimated that six renewable energy zones would require transmission investment, and that for one of these zones (Moyne) the investment would be wholly unaffected by the preferred option.

In most instances (four of the renewable energy zones) the preferred option results in economic benefits through changes to the new installed generation capacity variable. As noted above, this variable is the output of ElectraNet's market modelling of generator dispatch, entry, and exit. While we have concerns about some aspects of this modelling, we note that ElectraNet's testing of alternative modelling assumptions does not materially alter the results for avoided transmission investment. On this basis, we consider that these estimated benefits are reasonable.

In the sixth renewable energy zone, the Vic Murray zone, the preferred option results in economic benefits through changes to the current transmission network capacity. This is due to the preferred option including:

- augmentation of the Red Cliffs to Buronga line, which is in the Vic Murray zone, and
- the new SA-NSW interconnector, which includes a new 330kV line from Robertstown to Buronga to Wagga Wagga, allowing the new Vic Murray generation to be delivered past Buronga to load centres in NSW and SA.[150]

The augmentations and new assets associated with the preferred option increase the transfer capacity for generators in the Vic Murray zone. As the capacity in the Vic Murray zone is increased through the preferred option, other transmission upgrades are no longer

149 See section 3.

150 ElectraNet, Response to AER information request, 6 November 2019, p. 1.

needed to allow new generation to reach load centres. However, in the base case where the preferred option is not built, these other transmission upgrades would be needed.

These economic benefits in the Vic Murray zone represent most of the overall benefits of the preferred option from avoided transmission investment – 82 per cent of the overall $101 million of estimated benefits. These benefits are wholly determined by the assumed change in capacity when the preferred option is built, and the difference in the cost of the preferred option compared to the transmission upgrade in the absence of the preferred option. We review these cost and capacity assumptions in the subsection below.

Table 12 sets out the six renewable energy zones in which transmission upgrades were forecasted, and the impact of the preferred option on these upgrades.

Table 12 Impact of the preferred option on transmission investment

Renewable energy zones requiring transmission upgrades	Impact of preferred option on forecast transmission upgrade - impact on:		Estimated benefit of preferred option (PV)
	Timing & amount of new transmission capacity needed for new installed generation capacity	Cost of upgrade	
Vic Murray	Preferred option has no impact on timing and amount of new generation capacity. 479MW of additional transmission capacity needed. Preferred option provides 400MW of additional capacity, avoiding the need for this to be provided through further transmission investment.	Unchanged by preferred option	$83.7m
Central NSW Tablelands	Preferred option defers 273MW of transmission upgrade by three years, defers 50MW by one year, and defers 223MW by two years.	Unchanged by preferred option	$8.4m
Central West NSW	Preferred option defers 539MW of transmission upgrade indefinitely.	Unchanged by preferred option	$7.1m
Northern NSW Tablelands	Preferred defers 25MW of transmission upgrade by three years, and defers a further 279MW by one year.	Unchanged by preferred option	$2.6m
Southern NSW Tablelands	Preferred option brings forward 40MW of transmission upgrade by one year.	Unchanged by preferred option	–$0.2m
Moyne	Unchanged by preferred option	Unchanged by preferred option	$0

Source: **AER analysis, ElectraNet PACR Market Modelling Results Books**

Avoided transmission investment in the Vic Murray zone

ElectraNet estimated that 579 MW of new solar generation will be installed in the Vic Murray renewable energy zone by 2025, in addition to 300 MW of existing and/or committed solar generation in the zone. ElectraNet estimate that the construction of the preferred option will not alter the amount or timing of new generation installed in the zone.[151]

Table 13 sets out how transmission capex is forecasted to be avoided through the preferred option in the Vic Murray renewable energy zone.

Table 13 Avoided transmission investment in Vic Murray zone

	Without preferred option	With preferred option
Existing / committed generation	300 MW	300 MW
New generation	579 MW	579 MW
Total generation capacity	879 MW	879 MW
Transmission capacity before any upgrade	400 MW	400 WM
Additional transmission capacity needed	479 MW	479 MW
Transmission capacity provided through preferred option	0	400MW
Additional transmission upgrade	479 MW	79 MW
Cost of additional transmission upgrade	$187m	$31m

Source: **AER analysis, ElectraNet PACR Market Modelling Results Books**

The current capacity of the transmission network in the Vic Murray zone is about 400 MW. An additional 479 MW of transmission capacity is then estimated to be required to allow new generation in the zone to reach major load centres. Within the preferred option, ElectraNet proposed to augment the Red Cliffs to Buronga line to double its transfer capacity from 400 MW to 800 MW. A further upgrade to the transmission network is then estimated to be needed to provide a further 79 MW of transmission capacity.[152]

Without the preferred option, a 479 MW transmission upgrade is needed to allow new generation in the Vic Murray zone to reach major load centres.

151 See ElectraNet PACR Market Modelling Results Books.

152 ElectraNet, response to AER information request, 6 November 2019, p. 1.

ElectraNet estimated the unit cost of transmission upgrades outside of the preferred option to be $0.39 million per MW of transmission capacity added, resulting in an upgrade cost of:

- $31 million for an additional 79 MW of transmission capacity, in addition to the 400 MW of capacity provided by the preferred option
- $187 million for an additional 479 MW of transmission capacity in the absence of the preferred option.

Therefore the preferred option allows $156 million of transmission investment to be avoided. This investment does not occur at the same time (or all at once) in ElectraNet's market modelling,[153] so the present value of the avoided investment becomes about $118 million, with about $84 million annualised over the 2020-2040 period modelled by ElectraNet and the remainder captured within the modelled terminal value.

We consider that the approach ElectraNet has taken to estimating benefits of avoided transmission investment, and the input data and assumptions used, are appropriate. We are satisfied that the preferred option is likely to provide benefits from avoided transmission investment.

153 With the preferred option, a 79 MW transmission upgrade is estimated to occur in 2025. Without the preferred option, ElectraNet estimates a 159 MW upgrade in 2023, 160 MW upgrade in 2024, and a 160 MW upgrade in 2025.

A.6 Quantification of estimated costs

The RIT-T requires the proponent to quantify the cost of each credible option.[154] Costs are defined as the present value of the direct costs of the credible option and include classes such as the costs incurred in constructing or providing the credible option.[155]

An important distinction between the SAET RIT-T and a contingent project application is that the quantification of costs in the RIT-T does not need to conform to the capital and operating expenditure criteria and factors in the NER. ElectraNet's proposed expenditure on the project will be assessed against these factors if and when ElectraNet makes an application to the AER under rule 6A.8.2.

The preferred option is a 330kV line from Robertstown South Australia to Wagga Wagga in New South Wales with an estimated cost of $1.53 billion. This cost includes a further augmentation between Buronga in New South Wales and Red Cliffs in Victoria at a cost of $46 million. The breakdown of this cost is presented below.

Table 14 High level cost breakdown of preferred option ($million)

Item	SA	NSW	Total
Transmission lines	230	710	940
Substations, including transformers	90	210	300
Other costs, including reactive plant, SPS and delivery costs	60	230	290
Total cost	380	1,150	1,530

Source: ElectraNet, SA Energy Transformation RIT-T Cost Estimate Report, 13 February 2019, p.6.

ElectraNet stated that the source of all pricing used in the estimate is from a range of cost intelligence resources including their own corporate cost database, industry vendors, industry subject matter experts in the infrastructure and utilities sectors, cost modelling, and their own capital infrastructure pricing experience.[156]

Given the preliminary nature of the estimated costs, ElectraNet has identified the investment as being in line with a Class 4 estimate under the AACE International Recommended Practice and Estimate Classification. This implies that only 1 to 15 per cent of the scope of the project has been defined.

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154 AER, RIT-T, June 2010, paragraph 1.
155 AER, RIT-T, June 2010, paragraph 2(a).
156 ElectraNet, SA Energy Transformation RIT-T Cost Estimate Report, 13 February 2019, p.11

ElectraNet stated that the accuracy range for this estimate is -15 to -30 per cent on the low side and +20 to +50 per cent on the high side.[157] This would mean that the investment cost could reasonably be in the range of $1.07 billion and $2.23 billion.

Several stakeholders highlighted the importance of having an accurate estimate of costs given that a material increase in costs would reduce the net market benefits of the project.[158] Delta Electricity stated that ElectraNet adopted a standardised approach to derive the capital cost of the interconnector that does not appear to take into account significant hurdles such as obtaining environmental approvals and new easements.[159]

Recognising the uncertainty of the cost of the interconnector and its materiality to the net market benefit of the project, ElectraNet conducted a sensitivity test in its PACR which tested the sensitivity of the results of the PACR to the underlying costs of the interconnector.[160] This sensitivity found that the preferred option remained the same, and continued to provide positive net market benefits, under sensitivities of both 20 per cent higher and 20 per cent lower interconnector costs.

AER's assessment

In response to stakeholder submissions. ElectraNet engaged Jacobs to undertake a review of the process by which transmission line costs were derived for three of the credible options.[161] We consider that this report provides transparency of the costs of the transmission lines for stakeholders.

However, we also consider that, given that the accuracy range indicates the cost could reasonably be higher by 50 per cent, a sensitivity of 20 per cent may not adequately test the case of a cost overrun. Moreover, the RIT-T states that if there is a material degree of uncertainty in the costs of a credible option, the cost that is to be used in in applying the RIT-T is the probability weighted present value of the direct costs of the credible option under a range of different cost assumptions.[162]

While ElectraNet included a probability weighting on the transmission line per km cost within the Jacob's report, the total transmission line cost is the per km cost multiplied by the amount of km determined by the route. Given that there is a degree of uncertainty in the route, a probability weighting for this in accordance with the RIT-T may have addressed this uncertainty.

As outlined in section 3, we requested ElectraNet undertake further modelling to test the robustness of the RIT-T. ElectraNet, analysis indicates that with the further modelling

157 ElectraNet, SA Energy Transformation RIT-T Cost Estimate Report, 13 February 2019, p.12
158 ElectraNet, SAET RIT-T Project Assessment Conclusion Report, February 2019, p. 60
159 Delta Electricity, Submission to SAET PADR, 31 August 2018, p.2
160 ElectraNet, SAET RIT-T Project Assessment Conclusion Report, February 2019, p. 112.
161 Jacobs, ElectraNet Transmission Line Cost Review, 11 February 2019
162 AER, RIT-T, June 2010, paragraph 3

outcomes, the preferred option would still deliver positive net market benefits for project cost increases of around 30 per cent.[163]

[163] ElectraNet, SAET RIT-T- Additional modelling and sensitivity analysis, 31 October 2019, p.27

A.7 Terminal value

We reviewed ElectraNet's approach to estimating a terminal value in the economic analysis given the magnitude of these benefits (estimated value of $280 million). As noted by ElectraNet, the RIT-T application guidelines state that relevant and material terminal values should be included in a RIT-T where appropriate.[164] The PACR modelling has included a terminal value.[165] The inclusion of a terminal value in the analysis is reasonable given the modelling period is only 21 years and benefits will extend beyond the end of the modelling period given the proposed interconnector is assumed to have an asset life in excess of 40 years.

In estimating the terminal value to capture costs and benefits beyond the modelling period, ElectraNet assumed the remaining benefits are equal to costs. In particular, ElectraNet applied a terminal value that assumes the remaining benefits reflect the depreciated cost of the proposed interconnector at the end of the modelling period.[166] Frontier advise that this approach is reasonable given the drawback of alternative approaches to estimate the terminal value. These alternative approaches include:[167]

- Omitting the terminal value, which Frontier consider to be a very conservative approach given benefits will extend beyond the modelling period. ElectraNet also assigned a zero terminal value as a sensitivity and found that the preferred option still had a positive net economic benefit.[168] However, we consider that omitting the terminal value will understate the net benefits of the preferred option. For this reason, this is not a reasonable approach.
- Rolling forward net costs and benefits from the last year or years of the modelling period. Frontier comments that an issue with this approach is that it assumes that the pattern of cost and benefits will continue for the remainder of the interconnector's life. Our assessment indicates that this approach would result in a higher terminal value based on the PACR results, which is more favourable to the preferred option compared to the approach adopted by ElectraNet.
- Extending the modelling period to cover the full asset life, which Frontier notes has the drawback that the modelling becomes less reliable as a result of more uncertainty the longer the modelling period and at the same time the impact of this modelling is reduced due to the time value of money. Given the interconnector assets have a life of more than 40 years, these issues mean that the utility of this approach is very limited..

Having regard to these deficiencies of the alternative approaches to estimating a terminal value we consider the approach adopted by ElectraNet in the PACR to be reasonable.

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164 AER, Regulatory Investment Test for Transmission (RIT-T) Application Guidelines, December 2018, p.63

165 Where the capital cost of the interconnector are annualised, there is no need to include a terminal value. However, ElectraNet in its RIT-T modelling has not chosen to annualise the costs of the interconnector

166 ElectraNet, SAET RIT-T Project Assessment Conclusion Report, February 2019, p.185

167 Frontier Economics, Final Report - RIT-T assessment: South Australia Energy Transformation, December 2019

168 ElectraNet, SAET RIT-T Project Assessment Conclusion Report, February 2019, section 8.6.6

A.8 Other assessment considerations

This section presents our consideration of the identified need.

Identified need

As outlined in the RIT-T application guidelines, the identified need is to be expressed as the objective which the RIT-T proponent seeks to achieve by investing in its transmission network.[169] The identified need may consist of meeting reliability standards or an increase in the sum of consumer and producer surplus.[170]

The identified need in the SAET RIT-T is to provide a net benefit to consumers and producers of electricity and support energy market transition through[171]:

- Lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions;
- Facilitating the transition to a lower carbon emissions future in the NEM and the adoption of new technologies through improving access to high quality renewable resources across all regions; and
- Enhancing security of electricity supply in South Australia.

AER assessment

The purpose of the RIT-T is to identify the credible option which maximises the present value of the net market benefit to all those who produce, consume and transport electricity in the market.[172]

Both the NER and the RIT-T Guidelines, published by the AER under 5.16.2(a) of the NER, define a credible option as an option that:[173]

- addresses the identified need, that is, achieves the objectives that the RIT-T proponent seeks to achieve by investing in the network
- is commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need.

The PACR states that the non-interconnector option[174] is only considered to be capable of achieving the enhanced system security limb of the identified need.[175] As noted by Frontier,

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169 National Electricity Rules, chapter 10.

170 This means that the investment option must increase the welfare of all who produce, consume and transport electricity in the NEM as a whole and not merely transfer wealth from one class in the NEM (i.e. consumers) to another (i.e. producers).

171 ElectraNet, South Australia Energy Transformation – Project Assessment Conclusions Report, 13 February 2019, p. 34.

172 NER, cl.5.16.1(b)

173 AER, Regulatory Investment Test for Transmission (RIT-T) Application Guidelines, December 2018. This is consistent with the definition in cl. 5.12.2(a) of the NER.

174 The non-interconnector option is set out in table 4 of page 69 of the PACR. The elements of the non-interconnector option are comprised of the following: pumped storage (Port Augusta), Osborne cogeneration, Solar thermal at Davernport, BESS - Tallem Bend, Murraylink (transfer of FCAS), BESS (location to be determined), and minimum load control. These

this means that the PACR considers that the non-network option is not a credible option. However, as the non-network option is not part of the preferred option this does not affect our assessment of the preferred option.

We consider that the preferred option addresses the first and third limbs of the identified need. The impact of the preferred option on the second limb of the identified need is less clear. The preferred option is estimated to result in annual increase in black coal generation resulting in increased carbon emissions. However, while carbon emissions may be included in the modelling to reflect obligations that impact on the NEM, this need is outside the scope of the RIT-T.

Corrections to PACR model

Relevantly, ElectraNet also identified further errors in its initial PACR modelling in response to some of our information requests. Following the additional modelling undertaken by ElectraNet, the NPV results for PACR central scenario further deviated from the PACR net benefit of $765m to $924m for the preferred option. ElectraNet provided the following reasons in a response:[176]

> A large amount of data has been requested to accompany the sensitivity results, including outputs from the Long Term model. The initial advice of a corrected PACR NPV result of $870m was based on preliminary results which did not at that stage incorporate an updated Long Term model run, but rather utilised a time sequential run with updated parameters. In order to meet the AER's request for data we have now re-run the Long Term model. This has resulted in a minor (2.5%) improvement to the level of gross benefits, producing an updated $924m NPV outcome. This is predominately driven by the inclusion of the correctly escalated fuel prices.

The further modelling outcomes we asked ElectraNet to provide, include these PACR modelling corrections.

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elements would be procured by ElectraNet under a network support contract.

175 ElectraNet, SAET RIT-T PACR, February 2019, p.34

176 ElectraNet, Response to AER's Information request no.6 via email, 4 November 2019

Appendix B Timeline for preferred option assessment

- In February 2019 ElectraNet published the SA Energy Transformation PACR. In accordance with 5.16.6 the AER has business 120 days to make a determination on the project.
- On 15 March SACOSS lodged a dispute with the AER for the SAET PACR over concerns that the system security risks were not adequately addressed regarding the retirement of three SA gas generators.
- In March 2019 the AER requested more detailed model outputs of the preferred option that were not available to stakeholders to inform our review.
- In April ElectraNet provided these more detailed model outputs.
- On 30 May we identified key issues for our 5.16.6 assessment of the SAET RIT-T. These issues focused on material issues related to gas usage and the AER requested that ElectraNet remodel all the options using alternative assumptions to test the robustness of the RIT-T.
- On 5 June we commenced our formal assessment of the SAET RIT-T in accordance with 5.16.6 of the NER.
- Additionally on 5 June the AER determined that the dispute raised by SACOSS would not require ElectraNet to amend the PACR as the PACR was considered to be in accordance with the NER.
- On 6 June - 24 June, ElectraNet and the AER corresponded regarding assumptions used, the scope and depth of the remodelling requested. ElectraNet informed us they were using assumptions that had been provided by AEMO.
- From 4 July – 31 July AER requested advice from AEMO regarding the 2018 ISP system security requirements in SA with and without the proposed interconnector. This advice was provided in August 2019.
- On 19 July ElectraNet proposed amendments to our proposed alternative assumptions for rerunning the model. This proposal also identified errors to be corrected in PACR market modelling. We discussed this proposal with ElectraNet and raised concerns that ElectraNet's proposed amendments to our alternative assumptions were not explained or supported by any evidence.
- On 1 August we sent an information request seeking supporting information and clarification regarding ElectraNet's proposed amendments to our alternative assumptions.
- On 2 August ElectraNet proposed to undertake the remodelling using alternative assumptions that are more consistent with the PADR and subject to AEMO's advice on system security requirements.

- On 25 and 29 of October ElectraNet provided the AER with the final round of analysis results from requested testing on the 2 August.
- On 16 October 2019 we requested information on transmission network investment that would be avoided through the preferred option. ElectraNet provided this information on 28 October 2019.
- On 1 November we requested information on the impact of the Red Cliffs to Buronga segment of the preferred option on benefits from avoided transmission investment. ElectraNet provided this information on 6 November 2019.
- On 25 October we requested information from AEMO on the input assumptions in AEMO's 2018 ISP modelling, specifically assumptions on the operation of gas powered generation, transmission network ratings, transmission upgrade costs, and coal price forecasts. AEMO responded on 13 November 2019.
- On 18 November we requested further information from AEMO on the role of gas powered generation in providing necessary system security services in South Australia. AEMO responded on 21 November.
- On 20 November we requested further information from ElectraNet on the role of pumped hydro in its market modelling, as well as information on modelled new storage installations and spilled wind generation. ElectraNet provided this information on 21 and 22 November.
- On 25 November we requested information from ElectraNet on the role of pumped hydro to provide system security services in South Australia, the relative benefits of the option D under revised modelling assumptions, and modelled new storage installations. ElectraNet provided this information on 29 November.
- On 3 December 2019 we requested further information from ElectraNet on role of pumped hydro to provide system security services in South Australia. ElectraNet provided this information on 4 and 6 December 2019.
- On 9 December 2019 we requested information from ElectraNet on alignment between the short-term and long-term representations of its market modelling. ElectraNet provided this information on 12 and 13 of December 2019.
- On 12 December 2019 we received a letter from AEMO on wholesale market composition and effects on system security in South Australia.