20 DECEMBER 2019

RIT-T ASSESSMENT: SOUTH AUSTRALIA ENERGY TRANSFORMATION

A FINAL REPORT PREPARED FOR THE AER

EXECUTIVE SUMMARY

Introduction

Frontier Economics has been engaged by the Australian Energy Regulator (AER) to independently assess the economic analysis and modelling undertaken by ElectraNet in support of its South Australian Energy Transformation (SAET) RIT-T application.

ElectraNet submitted the Project Assessment Conclusions Report (PACR) supporting the SAET RIT-T on February 13, 2019. The AER commenced the formal RIT-T process under 5.16.6 of the NER on June 5, 2019.

Frontier Economics was engaged to advise on the reasonableness of ElectraNet's:

- Inputs and assumptions used in the RIT-T, such as the choice of, and justification provided for demand, generator costs and operating parameters, and renewable investment options.
- Methodology adopted for assessing net economic benefits, such as whether a suitable range of credible options have been considered and whether the market development modelling is undertaken appropriately.
- Adequacy of any sensitivity analysis, to test whether the identification of the preferred option is reasonably robust to changes in key parameters.

ElectraNet's RIT-T Analysis

The identified need driving the analysis of investments described in the PACR was the following:[1]

> *to create a net benefit to consumers and producers of electricity and support energy market transition through:*
>
> *• lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions;*
>
> *• facilitating the transition to a lower carbon emissions future 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.*

ElectraNet investigated four credible options (including variants of one of these options) to address the identified need in the PACR. These options comprised both a predominantly local South Australia non-interconnector option (which consists of both network and non-network components) as well as options involving new interconnectors to each of the three neighbouring NEM states (Queensland, New South

[1] ElectraNet, *SA Energy Transformation RIT-T*, Project Assessment Conclusions Report, 13 February 2019, page 34.

Wales and Victoria). Three variants of the NSW interconnector options were considered. The options are summarised in ElectraNet's PACR as in **Figure 3**.

Figure 1: Summary of the credible options considered in ElectraNet's PACR

Overview	Capital cost	Annual contract cost	Notional Maximum Capability (MW)[10]	
			Heywood	New interconnector
'Non-interconnector' option				
Option A – Least cost non-interconnector option in South Australia	$3m	$110m[11]	650	–
An interconnector to Queensland				
Option B – 400 kV HVDC between north South Australia and Queensland	$1.98b	–	750	700
New South Wales interconnector options				
Option C.3 – 330 kV line between Robertstown in mid-north South Australia and Wagga Wagga in NSW, via Buronga, plus Buronga-Red Cliffs 220 kV	$1.53b	–	750	800
Option C.3ii – 330 kV line between Robertstown in mid-north South Australia and Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point	$1.73b	–	750	800
Option C.3iii – HVDC transmission between Robertstown in mid-north SA and Darlington Point via Buronga; HVAC line between Darlington Point and Wagga Wagga in NSW, plus Buronga-Red Cliffs 220 kV	$1.64b	–	750	800
A new interconnector to Victoria				
Option D – 275 kV line from Tungkillo in South Australia to Horsham and Ararat in Victoria	$1.15b	–	750	650

Source: ElectraNet PACR, page 9.

These credible options were evaluated in Central, High and Low scenarios reflecting different combinations of key assumptions. ElectraNet also performed a number of sensitivities and robustness tests on the core modelling.

ElectraNet's modelling found that Option C3 – an interconnector between mid-north South Australia and central and western New South Wales – is expected to deliver the highest net market benefit in all three scenarios, providing what ElectraNet described as a "no regrets" solution. The Central scenario net benefit was estimated to be in the order of $765m NPV and the result was found to be robust to the sensitives and robustness tests undertaken.

Due to a number of issues raised by Frontier Economics over the course of our review, the AER requested that ElectraNet undertake additional modelling. This additional modelling incorporated changes to several key assumptions in the modelling. The net benefit in the Central scenario in this further modelling was around $270m[2].

Assessment of input assumptions

[2] ElectraNet modelled several additional cases in the further modelling. The NPV presented here relates to the case that, in our view, incorporated the best available information at the time.

We considered a number of key input assumptions used in ElectraNet's modelling in our review. In forming our assessment of the input assumptions used by ElectraNet to estimate the market benefits of the identified options in the SAET RIT-T we considered:

- The extent to which the input assumptions aligned with recent, credible sources of information.
- The extent to which these assumptions have been incorporated consistent with a best practice approach to market modelling.

Demand forecasts used in the modelling were sourced from a reputable publication and the selection of demand forecast cases chosen for the modelling was appropriate. We raised an issue where the demand profiles used are not coincident with renewable profiles, which means demand and intermittent renewable output are likely to move in unrealistic ways. This issue was not modified in the further modelling and the directional effect on the RIT-T cost-benefit analysis is unclear.

The fuel prices used in the modelling were sourced from a reputable publication and were generally applied to the modelling correctly. However, we raised an issue with fuel prices assumed in the modelling in that the short-run marginal cost of existing coal generation reflects legacy coal contract prices. The assumptions used suggest that the value of coal is equal to the price paid for it, i.e. the 'accounting' cost. However, we consider that the appropriate economic cost for coal to use in the energy market modelling (given the cost-benefit framework of the RIT-T) is the opportunity cost. The further modelling undertaken by ElectraNet included scenarios with a netback estimate of coal prices for generators with export-exposed coal sources.

The plant cost assumptions used in the modelling were sourced from a reputable publication and generally applied correctly in the modelling. We noted that the cost of pumped hydro used in the modelling was, in our experience, very low, at around $1,400/kW for six-hour pumped storage. The further modelling undertaken by ElectraNet included a scenario with a higher cost for pumped storage.

The emissions constraints and renewable policies applied in the modelling were sourced from appropriate and recent sources and applied correctly in the modelling. We raised an issue where it appears that the emissions constraint did not appear to be binding in at least one of the modelling runs. The particular run in question was not part of the scenarios included in the further modelling.

Security and related constraints were included in ElectraNet's modelling to reflect security-related power system operating requirements. These security and related constraints generally focused on South Australia, which has a high proportion of variable renewable energy. We consider including security and related constraints to reflect realities of power system operation to be appropriate. However, the assumptions underpinning some of these constraints were not transparent in the PACR, and in some cases these constraints were not adequately explained or justified. We noted that one particular constraint – a minimum capacity factor applied to South Australian gas generators – was driving much of the net benefit of the interconnector options, and was inadequately explained or justified. After several rounds of information requests with AEMO and ElectraNet, it was determined that the further modelling should not include this constraint. Another security constraint requiring a minimum of two synchronous units to be online at all times remained in the further modelling. Our analysis indicates this constraint drives a large fraction of the net benefit in the further modelling.

Plant operating parameters were generally sourced from a reputable publication and generally applied to the modelling correctly. However, a number of changes were made to published assumption sets that had the effect of reducing flexibility of the South Australian generation system, in some cases without adequate justification, and in some cases without applying these changes equally across the NEM. We considered that these changes are likely to increase the resulting net benefit in the interconnector cases. The further modelling included several changes to the operating parameters applied in the modelling to ensure they reflected the best available information at the time.

We noted that ElectraNet's PACR modelling included exogenous retirement assumptions for most of South Australian gas generation capacity on commissioning of the interconnector options. This assumption was based on modelling done by AEMO, which utilised differing assumptions and a different modelling methodology. The further modelling included scenarios where these exogenous retirements were not applied.

Assessment of methodology

ElectraNet's approach to undertaking the complex task of market modelling and cost benefit analysis to support a RIT-T was, in our view, generally appropriate.

ElectraNet considered seven credible options in the PACR in addition to the 'do nothing' option. These credible options are designed to satisfy the identified need, which is set out in the PACR and preceding reports. Generally, we consider these credible options appropriate. However, the non-interconnector option presented as a credible option is noted by ElectraNet as not satisfying the identified need and therefore not meeting the criteria to be a credible option. We also noted that the non-interconnector option did not consider the best information available at the time about the installation of synchronous condensers in South Australia, which were included with different assumptions in the non-interconnector option. ElectraNet omitted several benefit categories from its presentation of the non-interconnector option results in some scenarios, making the net benefits appear artificially low. The further modelling accounted for the best available information at the time with regard to the installation of synchronous condensers. The further modelling did not include an updated non-interconnector option.

We consider ElectraNet's market modelling methodology to be generally in line with best practice, and the tools it has used in undertaking this market modelling to be appropriate. ElectraNet employs a least-cost modelling approach with short-run marginal cost (SRMC) offers to determine wholesale market benefits of the credible options considered. ElectraNet undertakes its market modelling in two related stages, which reduces the size and complexity of the problem considerably:

- The first stage is a long term capacity expansion model (**LT model**), where an investment path is determined. The long term model is simplified so the investment problem is tractable.
- The second stage is a short term simulation model (**ST model**), which takes the investment path as determined by the LT model, and calculates market outcomes at an hourly level. The ST model simulates generator dispatch, storage behaviour, interconnector flows and secondary outcomes at a more granular level than considered in the LT model.

We note this approach is in line with best practice, however there are a number of measures that need to be undertaken to ensure that the LT and ST models do not 'disconnect', i.e. it is important that outcomes in the ST model reflect outcomes in the LT model, or else the basis for investment in the LT model is flawed. We note that if long-term model investment results appear materially non-optimal once run through the short-term model, this information should be fed back to the long-term model to ensure that inefficient investment outcomes do not inadvertently misrepresent costs or benefits.

We also note that while we agree with the choice of a least-cost SRMC approach as adopted by ElectraNet, the use of a number of input assumptions, such as assumed minimum capacity factors based (in practice) on historical output levels, would violate the conditions of such an approach.

ElectraNet includes a terminal value for options with assets that outlive the assessment period of the modelling (financial years ending 2020 to 2040). This terminal value is calculated as a pro-rata share of capex in an asset's lifetime that falls outside the assessment period, which is discounted to the date the assessment period ends and added as a cost reduction in the net benefit calculation. We consider ElectraNet's terminal value methodology appropriate.

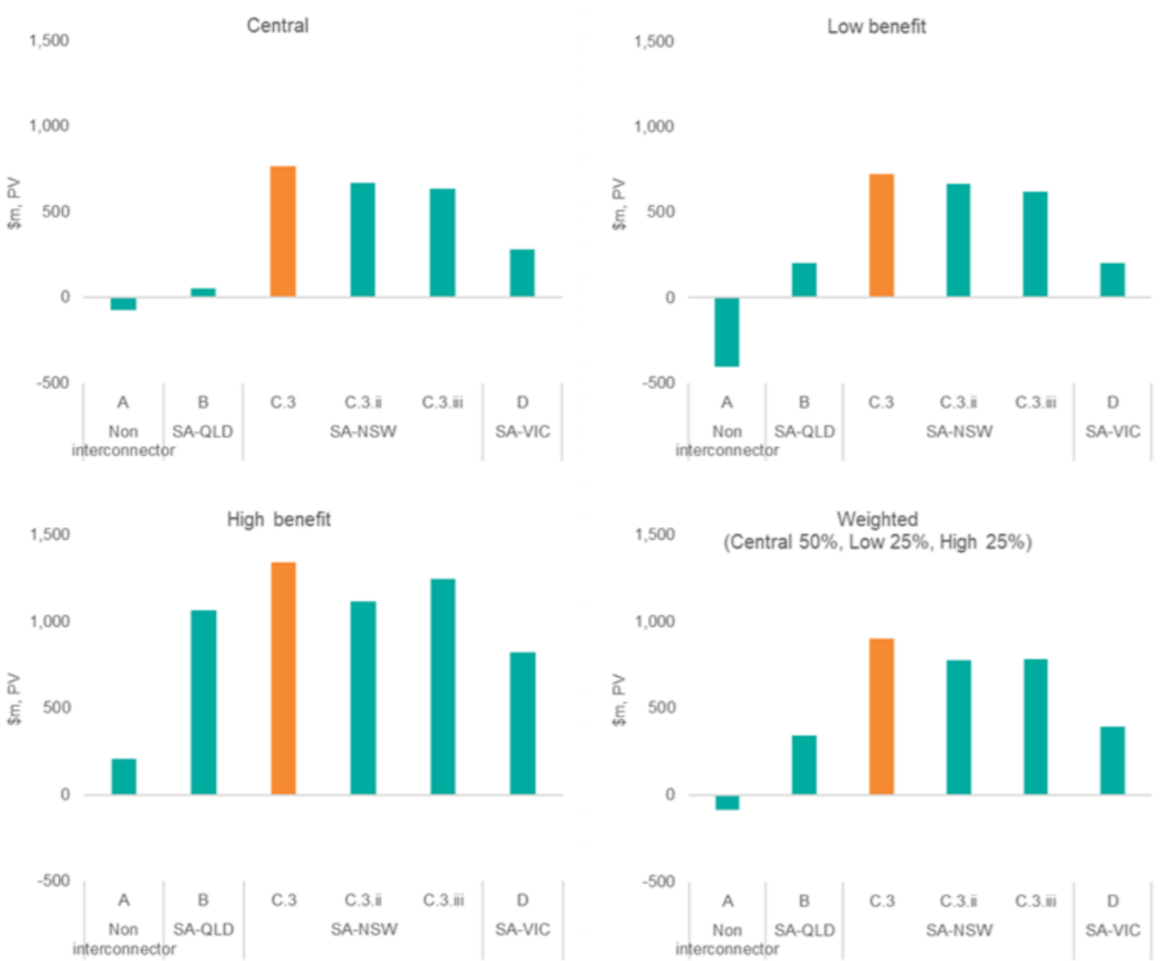
Assessment of results and conclusions

In the PACR, ElectraNet assessed each credible option identified against a range of scenarios and sensitivities. Based on this analysis, ElectraNet has concluded that the preferred options is Option C3, which includes:

- A 330 kV line between Robertstown in midnorth South Australia and Wagga Wagga in NSW, via Buronga
- A Buronga-Red Cliffs 220 kV line

Figure 18 presents ElectraNet's estimated net market benefits for each scenario and a weighted outcome, comprising 50% central and 25% low and high case outcomes. In each scenario, Option C3 is the preferred option and materially net beneficial.

Figure 2: Estimated net market benefits for each scenario



Source: PACR Figure E.3

As requested by the AER, ElectraNet's further modelling only considered Option C3, and generally found reduced benefits to the interconnector option. The further modelling case ElectraNet refer to as 'AER Sensitivity 1' reflects, in our view, the best information available at the time. The net benefit of the C3 option in the Central scenario of 'AER Sensitivity 1' was $269m.

In assessing the PACR modelling in general, and the result for Option C3 in particular, we note the result is characterised by several key assumptions that drive the main outcomes. A large fraction of the benefits for Option C3 in the PACR modelling central case can be attributed to minimum capacity factors and other assumptions that we do not consider reasonable based on the evidence provided.

The further modelling amended a number of the key issues in the PACR modelling, and the resulting net benefit was lower. We consider that this is primarily due to the removal of the minimum capacity factor constraint on South Australian gas generators in ElectraNet's further modelling. Our analysis indicates a different security constraint – the 'two unit' minimum generator constraint on South Australian gas – accounts for a large portion of the benefit in the further modelling.

Despite limited time to review ElectraNet's further results, we raised several issues that arose or became apparent in the further modelling outputs. These issues include:

- Concerns that benefits in the further modelling are overstated: There appear to be a number of issues with the further modelling and we think that benefits in the modelling are overstated. These include a disconnect between the ST and LT models resulting in inefficient investment, potential double-counting of the interconnector in reserve margin constraints, and assumptions around highly flexible black coal generation.
- That the alternatives to alleviate the two-unit minimum constraint – which is crucial to the determination of net benefits – have not been explored. We consider the case for pumped hydro to enable the relaxation of this constraint.
- That the preferred option may change under the further modelling assumptions: Our analysis indicates that the ability to alleviate the two-unit minimum constraint in the further modelling is a major source of benefit via a net cost reduction in the Option C3 state of the world. We consider it is likely that a reasonable portion of this value would also be attributable to the other interconnection options considered in the PACR.

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1 INTRODUCTION

Frontier Economics has been engaged by the Australian Energy Regulator (AER) to independently assess the forecast gross market costs and benefits of new interconnector and network options in South Australia prepared to support ElectraNet's South Australian Energy Transformation (SAET) RIT-T application. This report presents our assessment of the analysis undertaken by ElectraNet and its consultants as presented in the SAET Project Assessment Conclusions Report (PACR).

1.1 Background

The SAET PACR is the last report in ElectraNet's SAET RIT-T application. It builds on the Project Specification Consultation Report (PSCR) and Project Assessment Draft Report (PADR) published by ElectraNet, in accordance with RIT-T procedures set out in the National Electricity Rules (NER) s5.16.4.

As required by the NER ElectraNet has nominated a number of credible options to satisfy the identified need the RIT-T application seeks to address. According to the opening statement of the PACR, these options are aimed at:

- reducing the cost of providing secure and reliable electricity to South Australia in the near term, and
- facilitating the longer-term transition of the energy sector across the National Energy Market (NEM) to low emission energy sources.

In the PACR, ElectraNet have considered one non-network option and three network options; one of the network options has three variants. The non-network option, which was included in the analysis after the PADR as a result of stakeholder consultation, consists of a number of network support agreements and non-network system augmentations. The different network options consist of various configurations of an interconnect between South Australia and one of New South Wales, Queensland, and Victoria. Differences in these configurations include the route, DC or AC current type and voltage levels.

ElectraNet's preferred option is a new 330 kV AC interconnector between South Australia and New South Wales via Buronga. The benefits of the preferred option relevant to the assessment of gross market costs and benefits and therefore this report[3] include:

- Lower fuel consumption costs due to different patterns of generation dispatch;
- Changes in generation investment costs due to differences in timing, location, and levels of generation investment decisions; and
- Differences in the timing of expenditure, due to the avoidance or deferral of other transmission investment.

ElectraNet submitted the PACR on February 13, 2019. The AER commenced the formal RIT-T process under 5.16.6 of the NER on June 5, 2019.

[3] A number of other benefits are canvassed in the PACR, for example, lowering of retail prices, improved wholesale contract liquidity in South Australia, and reduced emissions. In the context of a RIT-T, these benefits are not relevant.

1.2 Frontier Economics’ engagement

Frontier Economics has been engaged by the AER to assist in reviewing the economic analysis and modelling undertaken by ElectraNet in support of the SAET PACR. Specifically, we have been engaged to advise on the reasonableness of ElectraNet’s:

- ***Inputs and assumptions used in the RIT-T*** – such as the choice of, and justification provided for:
    - Demand forecasts.
    - Unserved energy costs.
    - Plant capital and operating costs.
    - The components of each reasonable scenario used to assess the project, such as the inclusion of appropriate ‘committed’ and ‘anticipated’ projects expected to occur over the analysis timeframe.
    - The probability or likelihood attributed to each reasonable scenario.
- ***Methodology adopted for assessing net economic benefits*** – such as:
    - Whether a suitable range of credible options has been considered.
    - Whether appropriate market development modelling has been undertaken to properly establish the ‘modelled projects’ arising under each state of the world applicable to each credible option and reasonable scenario.
    - Whether all suitable categories of benefits and costs have been properly taken into account and valued.
- ***Adequacy of any sensitivity analysis*** – to test whether the identification of the preferred option is reasonably robust to changes in key parameters.

In assessing the reasonableness of ElectraNet’s inputs and assumptions, methodology and sensitivities we have considered the most recent and credible information sources, best practice modelling techniques and methodologies, and economic principles.

1.3 Structure of this report

This report sets out our assessment of the reasonableness of the economic analysis and modelling undertaken by ElectraNet in support of the SAET RIT-T PACR. This report is structured as follows:

- **Section 2** presents an overview of the modelling and analysis undertaken by ElectraNet in support of the RIT-T.
- **Section 3** sets out our assessment of the inputs and assumptions used in the PACR and additional modelling.
- **Section 4** provides our assessment of the methodology adopted for calculating net benefits presented in the PACR and additional modelling.
- **Section 5** includes our assessment of the results the conclusions in the PACR and additional modelling.

2 ELECTRANET'S RIT-T ANALYSIS

This section provides an overview of the modelling and analysis undertaken by ElectraNet in support of the RIT-T. This includes the modelling and analysis set out in ElectraNet's PACR as well as additional work undertaken by ElectraNet in response to issues raised by us and the AER through the course of our review of ElectraNet's modelling and analysis for the PACR.

2.1 ElectraNet's PACR modelling and analysis

ElectraNet released the PACR for the SAET RIT-T on February 13, 2019.[4]

Identified need

The identified need driving the investments described in the PACR was the following:[5]

> *to create a net benefit to consumers and producers of electricity and support energy market transition through:*
>
> *• lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions;*
>
> *• facilitating the transition to a lower carbon emissions future 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.*

4 ElectraNet, *SA Energy Transformation RIT-T*, Project Assessment Conclusions Report, 13 February 2019.

5 ElectraNet, *SA Energy Transformation RIT-T*, Project Assessment Conclusions Report, 13 February 2019, page 34.

Credible options

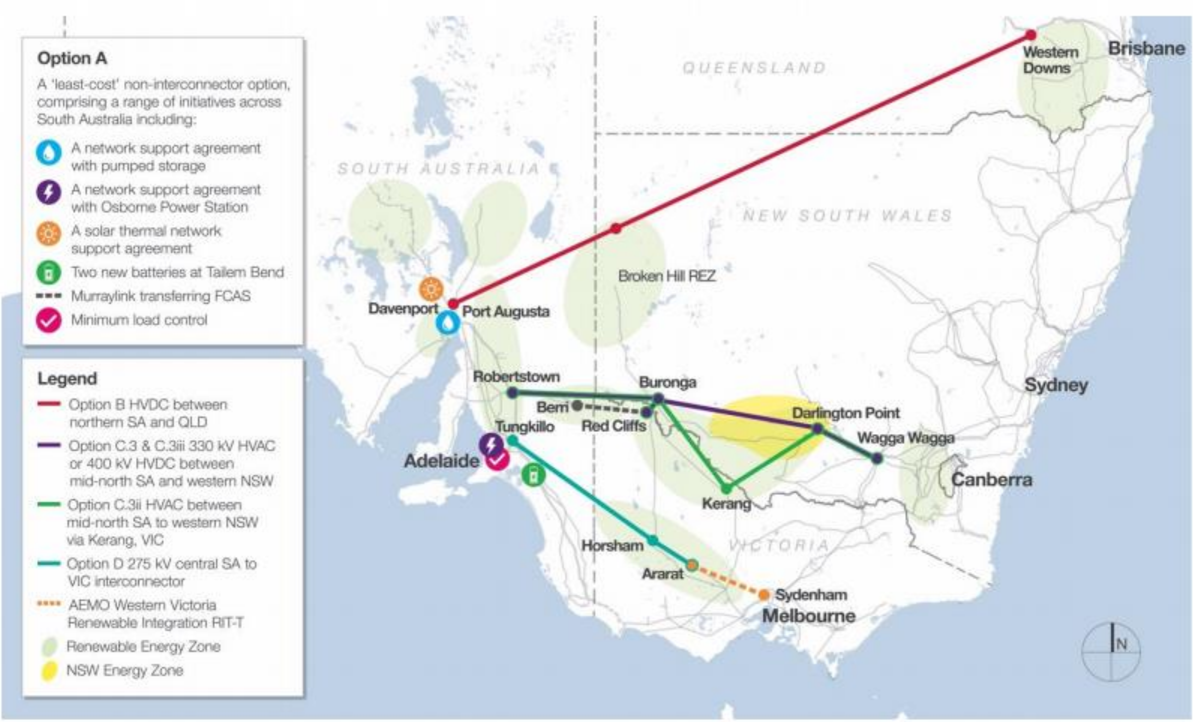
ElectraNet's PACR investigated four credible options (including variants of one of these options) to address the identified need. These options comprised both a predominantly local South Australia non-interconnector option (which consists of both network and non-network components) as well as options involving new interconnectors to each of the three neighbouring NEM states (Queensland, New South Wales and Victoria). Three variants of the NSW interconnector options were considered. The options are summarised in ElectraNet's PACR as in **Figure 3** and **Figure 4**.

Figure 3: Summary of the credible options considered in ElectraNet's PACR

Overview	Capital cost	Annual contract cost	Notional Maximum Capability (MW)[10]	
			Heywood	New interconnector
'Non-interconnector' option				
Option A – Least cost non-interconnector option in South Australia	\$3m	\$110m[11]	650	–
An interconnector to Queensland				
Option B – 400 kV HVDC between north South Australia and Queensland	\$1.98b	–	750	700
New South Wales interconnector options				
Option C.3 – 330 kV line between Robertstown in mid-north South Australia and Wagga Wagga in NSW, via Buronga, plus Buronga-Red Cliffs 220 kV	\$1.53b	–	750	800
Option C.3ii – 330 kV line between Robertstown in mid-north South Australia and Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point	\$1.73b	–	750	800
Option C.3iii – HVDC transmission between Robertstown in mid-north SA and Darlington Point via Buronga; HVAC line between Darlington Point and Wagga Wagga in NSW, plus Buronga-Red Cliffs 220 kV	\$1.64b	–	750	800
A new interconnector to Victoria				
Option D – 275 kV line from Tungkillo in South Australia to Horsham and Ararat in Victoria	\$1.15b	–	750	650

Source: ElectraNet PACR, page 9.

Figure 4: Overview of credible options considered in ElectraNet's PACR



Source: ElectraNet PACR, page 10.

Scenarios

ElectraNet's PACR modelled the costs and benefits of these credible options under a number of different scenarios. ElectraNet developed these scenarios to "reflect different combinations of assumptions about future market development, as well [as] other factors that are expected to affect the relative market benefits of the options considered."[6] The three scenarios modelled in ElectraNet's PACR are summarised in **Figure 5**, and the key input assumptions that vary between the scenarios are summarised in **Figure 6**. The input assumptions for each of these scenarios were based on AEMO's 2018 Integrated System Plan (ISP) and 2018 Electricity Statement of Opportunities (ESOO). To determine the weighted net benefit, ElectraNet have assumed a weighting of 50% for the central scenario and 25% for each of the low scenario and the high scenario.

Figure 5: Summary of future scenarios considered in ElectraNet's PACR

Central Scenario	Low Scenario	High Scenario
Reflects the best estimate of the evolution of the market going forward, and is aligned in all material respects with AEMO's ISP neutral scenario	Reflects a state of the world with low gas prices, low demand and no emissions reduction targets over and above the existing LRET	Reflects a state of the world with high gas prices and high demand, alongside aggressive emissions reduction targets

Source: ElectraNet PACR, page 11.

6 ElectraNet, *SA Energy Transformation RIT-T*, Project Assessment Conclusions Report, 13 February 2019, page 11.

Figure 6: Summary of key input assumptions that vary between scenarios considered in ElectraNet's PACR

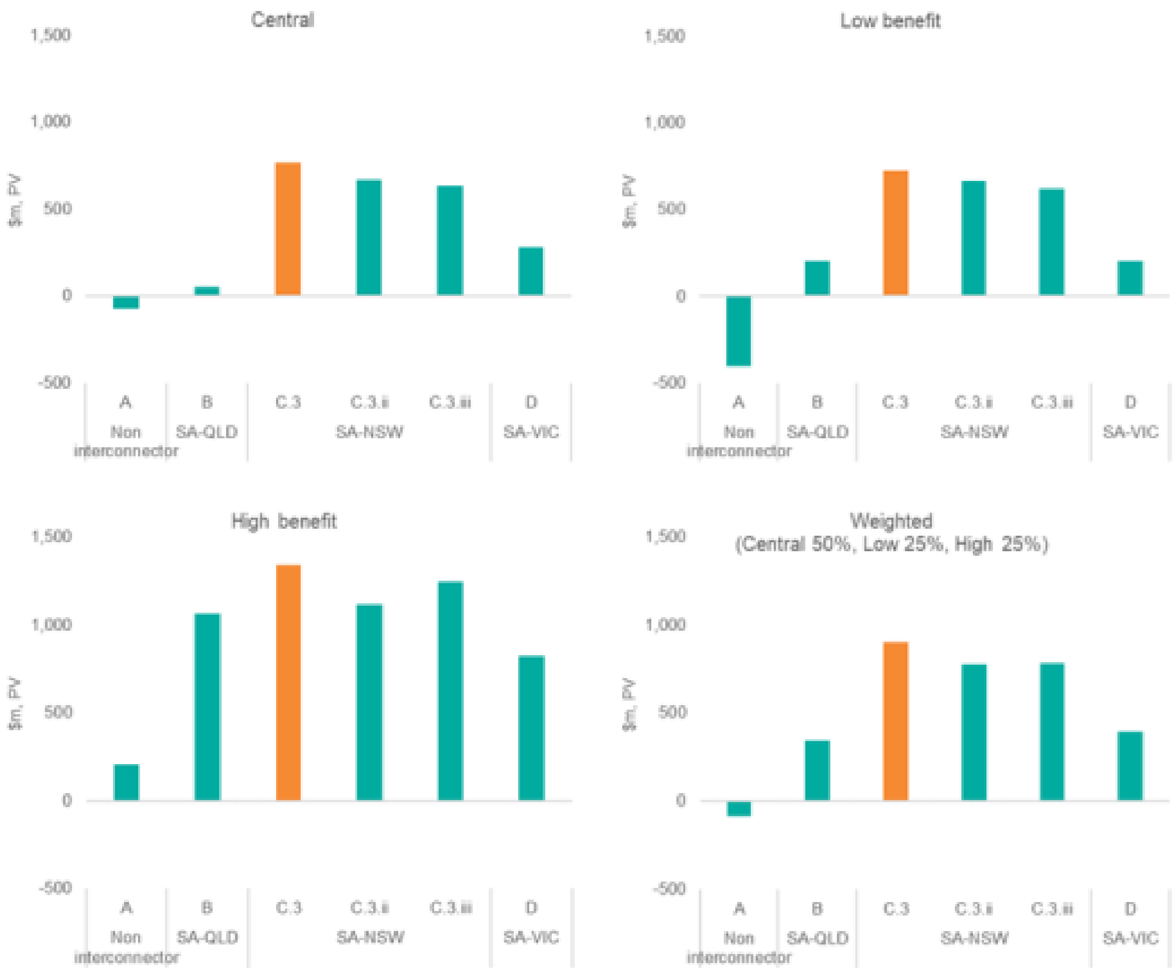
Variable	Central Scenario	Low Scenario	High Scenario
Electricity demand (including impact from distributed energy resources)	AEMO 2018 ESOO neutral demand forecasts	AEMO 2018 ESOO slow change demand forecasts	AEMO 2018 ESOO fast change demand forecasts plus potential SA spot load development of 345 MW
Gas prices – long-term	$9.17/GJ (AEMO ISP Neutral scenario)	$7.40/GJ ($0.62/GJ lower than AEMO ISP Slow change)	$11.87 GJ in Adelaide ($1.68/GJ higher than AEMO ISP Fast change scenario)
Emission reduction renewables policy – in addition to Renewable Energy Target (RET)	Emissions reduction around 28% from 2005 by 2030 (AEMO ISP Neutral scenario; Federal government policy)	No explicit emission reduction target beyond current RET	Emissions reduction around 52% from 2005 by 2030 (AEMO ISP Fast change scenario)
Jurisdictional emissions targets	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030		
SA inertia requirement – RoCoF limit for non-credible loss of Heywood Interconnector	3 Hz/s (current SA Government requirement)		
Generator capital costs	AEMO 2018 ISP	15% lower than central scenario	15% higher than central scenario

Source: ElectraNet PACR, page 92.

ElectraNet's modelling found that Option C3 – an interconnector between mid-north South Australia and central and western New South Wales – is expected to deliver the highest net market benefit in all three scenarios, providing what ElectraNet described as a "no regrets" solution. The estimated net market benefits are summarised in **Figure 7**.

As a result, Option C3 was identified as the preferred option in ElectraNet's PACR. ElectraNet also noted that Option C3 has net benefits that are materially higher than the next highest ranked option in each scenario, so that the results of the RIT-T are not dependent on scenario weightings.

Figure 7: Estimated net market benefits of each option in each scenario



Source: ElectraNet PACR, page 12.

Sensitivities

ElectraNet's PACR tested the robustness of the assessment to a wide range of sensitivities. These sensitivities test the underlying assumptions from AEMO's ISP and address points raised during consultation, including "higher than anticipated New South Wales coal prices, different assessment periods, lower costs for non-interconnector support, lower avoided transmission costs associated with connecting Renewable Energy Zones (REZs) and the interaction with the coincident Western Victorian Renewable Integration RIT-T."[7] In particular, the sensitivities considered in ElectraNet's PACR are:[8]

- higher than anticipated NSW coal prices;
- the potential for a South Australia-Queensland interconnector option (Option B) to defer the second stage of a QNI upgrade;
- the impact of the Western Victoria Renewable Integration augmentation not going ahead;
- removing the minimum operation constraints on South Australia gas plants;
- assuming all units of Torrens Island B retire at or before 50-years of age under the base case;
- assuming a new interconnector has no impact on the operation of Pelican Point and Osborne (i.e., they do no retire nor change their behaviour);
- lower assumed avoided REZ transmission cost benefits;
- lower assumed non-network costs;
- lower HVDC costs compared to HVAC costs;
- a shorter assessment period;
- removing terminal values from the assessment; and
- other general sensitivities, i.e., discount rates, capital cost estimates.

ElectraNet's modelling found that interconnector options between South Australia and New South Wales consistently deliver greater net benefits under each sensitivity than the other credible options.

2.2 ElectraNet's additional modelling and analysis

The AER requested ElectraNet undertake additional modelling in response to issues we raised with the AER over the course of our review. The results of ElectraNet's additional modelling are presented in a supplementary report from ElectraNet, provided to the AER on October 31, 2019.[9]

Credible options

ElectraNet's additional modelling involved running additional scenarios for the Base Case and the preferred option (Option C3). ElectraNet's additional modelling did not include running the additional scenarios for all of the identified options considered in ElectraNet's PACR. The other options were not included in AER's request for further modelling primarily due to the turnaround time for modelling results.

7 ElectraNet, *SA Energy Transformation RIT-T*, Project Assessment Conclusions Report, 13 February 2019, page 12.

8 ElectraNet, *SA Energy Transformation RIT-T*, Project Assessment Conclusions Report, 13 February 2019, page 94.

9 ElectraNet, *SA Energy Transformation RIT-T*, Additional modelling and sensitivity analysis, 31 October 2019.

Scenarios

The key variations to ElectraNet's PACR modelling that were requested are summarised by ElectraNet in **Figure 8**.

Figure 8: Key variations to ElectraNet's PACR modelling requested by the AER.

Item	Requested variation in modelling input
1	**Minimum capacity factors** Remove minimum capacity factors on South Australian gas plant in both the short term and long-term models.
2	**Gas plant cycling and generator minimum load assumptions** Thermal plant cycling assumptions for gas plant should be based on assumptions from the "Fuel and Technology Cost Review – Data" published alongside the 2018 ISP and applied NEM-wide or removed, with the following exception: • a minimum on/off time of 4 hours for Torrens Island B power station, consistent with cycling assumptions for Pelican Point and Osborne power stations. Generator minimum load assumptions to be based on AEMO 2018 ISP modelling assumptions, and no additions to be made unless sourced and applied to all generators of the same type, with the following exceptions: • a minimum load of [redacted] for Pelican Point power station consistent with its approved Generator Performance Standards (GPS). • a minimum load of [redacted] for Osborne power station consistent with the input currently assumed for AEMO's 2019/20 ISP.
3	**Plant investments and retirements** No plant investments or retirements should be imported from other modelling results (e.g. SA gas plant retirements). Exogenous closures should be based on end of life dates as published by AEMO.
4	**Synchronous condensers and system security constraints** The modelling should account for 4 synchronous condensers being in place at their anticipated installation date and any other system security constraints should be appropriately adjusted (e.g. the non-synchronous cap).
5	**Coal prices for export-exposed black coal generators** Export-exposed black coal generators should adopt the ISP 2018 Central estimate of new entrant coal prices (netback) sourced from the 2018 ISP database, Central estimate for new entrants. Export-exposed black coal generators include Bayswater, Liddell, Eraring, Mt Piper, Vales Point B, Callide B, Callide C, Gladstone, and Stanwell.
6	**Pumped hydro costs** Pumped hydro capital costs of $1.9m/MW for South Australia based on the updated assumptions contained in the Entura report released in December 2018.

Source: ElectraNet additional modelling and sensitivity analysis, page 6.

Reflecting these variations, ElectraNet were asked to model the following cases, as summarised by ElectraNet:

- AER Case 1 – tests items 1-5 from **Figure 8** together, but excludes updated pumped hydro costs (item 6);
- AER Case 2 – tests items 1-4 from **Figure 8** together, but excludes variations to coal prices for export-exposed black coal generators (item 5) and updated pumped hydro costs (item 6);
- AER Case 3 – tests the impact of all items from **Figure 8** together.

In addition, ElectraNet undertook the following updates to their modelling:

- Corrections to PACR modelling – ElectraNet corrected a number of errors with model inputs and post-processing of model outputs that were identified as part of modelling the additional AER sensitivities. These corrections were included in each of the AER cases discussed above, as well as the Updated PACR Central Scenario discussed below.
- Update PACR Central Scenario – ElectraNet ran an additional case that involved updating gas price input assumptions and updating generation investment commitments.

Based on this modelling, ElectraNet found that Option C3 had positive net benefits under each of the cases requested by the AER, although the net benefit was materially lower than the PACR Central Scenario. ElectraNet also found that the net benefit of Option C3 was materially higher under the Updated PACR Central Scenario than under the original PACR Central Scenario. The additional cases that ElectraNet modelled, and the results of these cases which ElectraNet refer to as ‘AER sensitivities’, are summarised in **Figure 9**.

Figure 9: Summary and results of additional cases

Corrected PACR Central Scenario	AER Sensitivity 1	AER Sensitivity 2	AER Sensitivity 3	Updated PACR Central Scenario
Minimum capacity factors				
PACR Central • OSB – 60% • PPPS – 50% • TIPS B – 25%	Removed	Removed	Removed	PACR Central • OSB – 60% • PPPS – 50% • TIPS B – 25%
SA GPG cycling and minimum loads				
PACR Central (see Tables 2 & 3)	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	PACR Central (see Tables 2 & 3)
Plant investments and retirements				
PACR Central	ElectraNet Long-term model	ElectraNet Long-term model	ElectraNet Long-term model	PACR Central
Synchronous condensers and system security constraints				
• Inertia capability – 1,300 MWs • Non-synchronous cap – 1,870 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW
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)	PACR Central
SA Pumped hydro costs				
PACR Central ($1.4m/MW)	PACR Central ($1.4m/MW)	PACR Central ($1.4m/MW)	Entura Report ($1.9m/MW)	Entura Report ($1.9m/MW)
Gas price				
AEMO 2018 ISP	AEMO 2018 ISP	AEMO 2018 ISP	AEMO 2018 ISP	AEMO 2019/20 ISP
Committed Generation				
AEMO generator information published 2 Nov 2018	AEMO generator information published 2 Nov 2018	AEMO generator information published 2 Nov 2018	AEMO generator information published 2 Nov 2018	AEMO generator information published 21 Jan 2019
NPV Results				
924	269	234	315	1,543

Source: ElectraNet additional modelling and sensitivity analysis, page 26.

3 ASSESSMENT OF INPUT ASSUMPTIONS

This section provides an assessment of the input assumptions that ElectraNet has used to assess the market benefits of the identified options in the SAET RIT-T. We provide an overview of the input assumptions, before presenting in turn our assessment of input assumptions relating to demand, fuel prices, plant costs, emissions constraints and renewable policies, security and related constraints, plant operating parameters, pumped hydro and South Australian gas plant retirements. We then summarise our findings and conclusions

3.1 Overview of input assumptions

For the PACR, ElectraNet has generally aligned key input assumptions used in its market modelling with those used by AEMO in the modelling for the ISP. In some cases, ElectraNet has extended or modified the assumptions produced by AEMO for the ISP.

ElectraNet's inputs are described at a high level in the PACR. The accompanying Network Technical Assumptions Report[10] and Consolidated Non Interconnector Option Report[11] provide more detail on technical assumptions around the interconnector and non-interconnector options. ElectraNet has released an Excel workbook that contains a selection of modelling assumptions used in the PACR modelling. In some cases, we have requested additional data or clarification on the input assumptions used by ElectraNet in their modelling via the AER.

In forming our assessment of the input assumptions used by ElectraNet to estimate the market benefits of the identified options in the SAET RIT-T we considered:

- The extent to which the input assumptions aligned with recent, credible sources of information.
- The extent to which these assumptions have been incorporated consistent with a best practice approach to market modelling.

3.2 Demand

PACR modelling

Demand forecasts used in the PACR modelling are sourced from AEMO's 2018 ESOO publication[12]. Forecasts consist of annual sent-out energy (in GWh) and as-generated maximum demand (in MW), for each region. ElectraNet has modified AEMO's demand forecast for use in their 'High' scenario, discussed below. ElectraNet did not report the actual demand modelled in their market modelling assumptions book.

[10] Network Technical Assumptions Report, 13 February 2019, available at https://www.electranet.com.au/wp-content/uploads/projects/2016/11/Network-Technical-Assumptions-Report.pdf

[11] Consolidated Non-interconnector Option, Entura, 5 June 2018, https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SAET-RIT-T-Consolidated-Non-interconnector-Option-Entura-5-June-2018.pdf

[12] 2018 Electricity Statement Of Opportunities, August 2018, available https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

As discussed in Section 4.3, ElectraNet's wholesale model does not model outcomes for each five-minute dispatch interval or each half-hour trading interval. Rather, in order to reduce run time their electricity market model identifies a subset of dispatch intervals to model. In particular:

- In the capacity expansion model (the LT model), ElectraNet modelled around 2,920 'load blocks' per year, aggregating each day into eight segments; and
- In the short term model (the ST Model), ElectraNet modelled load on an hourly basis.

Demand traces are derived from actual regional demand data from 2009-10. This year was selected because it pre-dates significant adoption of behind-the-meter generation[13]. These demand traces are scaled to the ESOO demand forecasts noted above. In the LT model, demand is scaled to 10% probability of exceedance (POE10) peak demand levels. In the ST model, demand is scaled to POE50 peak demand levels and extrapolated on a pro-rata basis to individual nodes (busses) in the NEM, 78 of which are in South Australia. This was done to enable a more detailed representation of physical limitations of transmission in the NEM.

In the High scenario, a 345MW "spot load" is added to high demand forecasts. This spot load is added on a constant basis, i.e. 345MW is added for every hour of every day of the year. The basis for this load is not discussed in the PACR or associated reports, although it is mentioned briefly in the PSCR Market Modelling Approach and Assumptions Report. ElectraNet noted in discussion that this load relates to potential mines growing out in far north South Australia, with no supporting network build assumed.

Our assessment of the PACR modelling

We support ElectraNet's use of demand forecasts from AEMO's 2018 ESOO publication. It is appropriate to generate detailed profiles via scaling from these forecasts to enable ElectraNet's market modelling.

However, we have concerns with two aspects of the demand used in ElectraNet's modelling.

- First, the modelling assumes a demand shape from 2009-10, but the renewable profiles used in the modelling are based on reference year 2013-14. In market modelling exercises, particularly in systems with substantial and growing shares of intermittent generation, it is crucial to preserve the correlation between demand and renewable output. For example, demand is high during heat waves; if wind generation tends to be low during these heat waves then there will be the need for other sources of supply to meet demand. Using a demand trace and a renewable trace from different years will fail to capture this relationship between weather conditions, demand and intermittent generation. On the other hand, solar generation is likely to be high during heat waves, contributing to the challenge of meeting high demand. This failure to capture the relationship between weather conditions, demand and intermittent generation is a problem for both centralised renewable generation and behind-the-meter generation (rooftop solar PV), which is netted off from demand in a pre-modelling input preparation step. Failing to preserve the correlation between demand and renewable output undermines the validity of the modelling results produced.
- Second, the assumption of an additional 345MW spot load appears highly speculative and is not sufficiently justified. This load represents an increase of around 20-25% to energy consumption in the high demand forecast, and is therefore a significant change to demand. From ElectraNet's assessment of the difference between the POE10/POE50 demands on gross modelled market benefits[14], it is reasonable to assume that this assumption increases the benefit of the interconnector options.

[13] PACR Market Modelling Methodology Report, p20

[14] PACR Market Modelling Methodology Report, p20

Further modelling

We did not propose any modelling of alternative demand assumptions be undertaken by ElectraNet and, as far as we are aware, ElectraNet did not undertake any modelling of alternative demand assumptions. We note that the additional modelling requested only considered the Central scenario demand assumptions.

3.3 Fuel prices

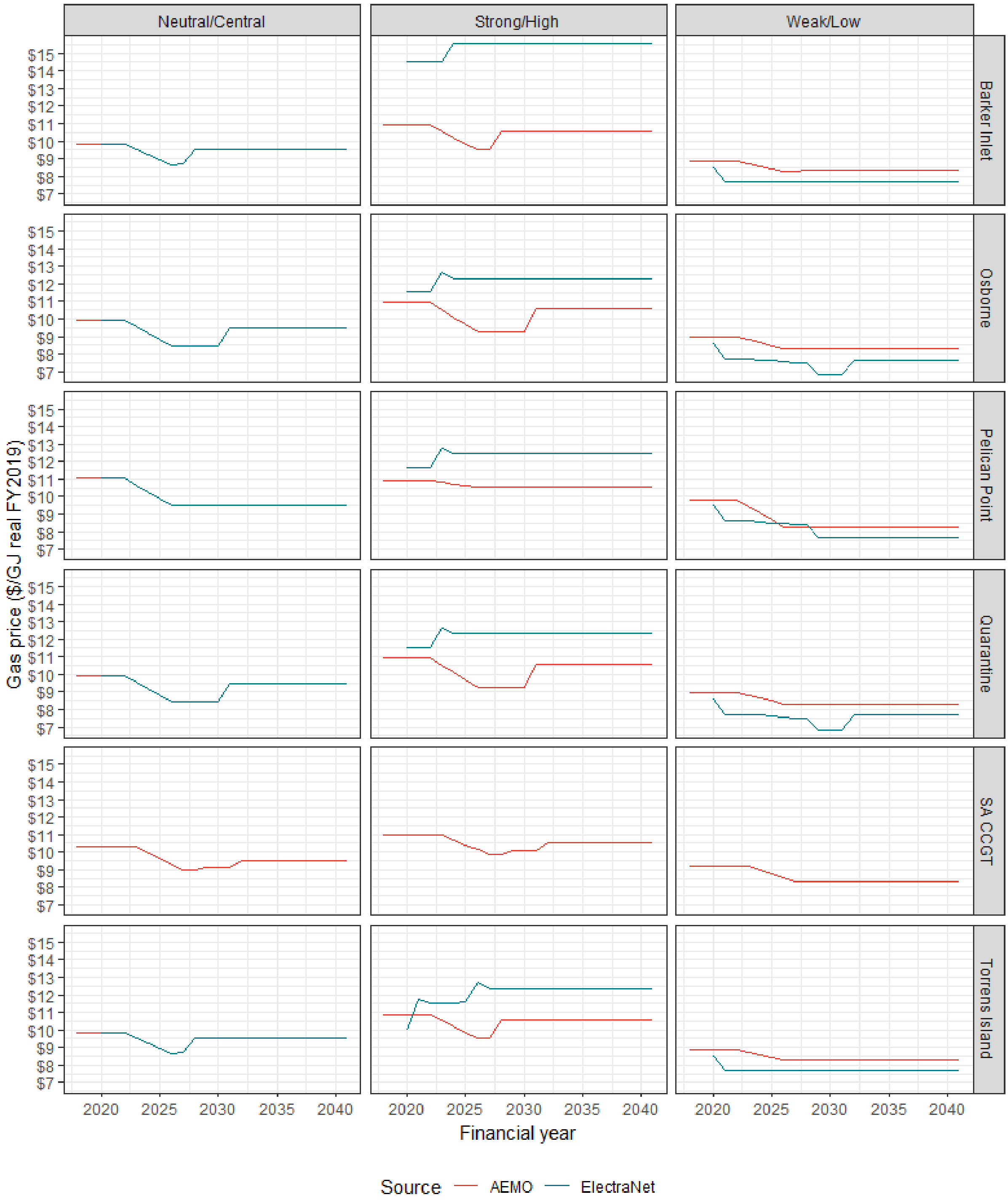
Fuel cost assumptions have a large impact on the potential net benefits of an interconnector to South Australia, particularly in the PACR modelling. Gas used by generators in South Australia can be substituted with cheaper generation or stored electricity from other regions via an interconnector, and therefore represents an avoidable cost in the RIT-T. In the preferred option in the PACR modelling (Option C3, a SA-NSW interconnector), this cheaper generation is generally in the form of black coal. The larger the difference in price between these fuel sources, the greater the benefit of substitution of black coal generation for gas generation.

3.3.1 Gas prices

PACR modelling

Gas prices in the central scenario are based on AEMO’s 2018 ISP central scenario gas prices. ElectraNet commissioned consultant EnergyQuest to extend the range of gas price forecasts in response to a submission to the PADR. EnergyQuest were commissioned to produce a higher high case gas price forecast and a lower low case gas price forecast. A comparison between AEMO’s 2018 ISP assumptions and the forecasts used in the RIT-T application for the most relevant gas generators to the RIT-T application is presented in **Figure 10**.

Figure 10: Comparison of modelled gas prices



Source: Frontier Economics analysis of AEMO ISP 2018 and ElectraNet PACR data

Note: SA CCGT refers to the entrant generator price

The gas prices modelled have a wider range than AEMO's ISP assumptions. Generally, the increase in the high case relative to the ISP is proportionately higher than the decrease to the low case.

EnergyQuest notes in its Gas Price Forecast Review[15] published alongside the PACR, that the AEMO and ElectraNet low case for gas delivered to Adelaide is outside its house forecast range, and below EnergyQuest's estimates of the long-term cost of domestic production.

Our assessment of PACR modelling

We consider the gas prices modelled reasonable. AEMO's 2018 ISP central scenario gas prices are a recent and credible source of input assumptions. We consider, based on publicly available information and our own expertise, that EnergyQuest's estimates of high and low gas prices are reasonable.

Further modelling

The AER did not propose any modelling of alternative gas price assumptions be undertaken by ElectraNet.

However, as part of the Updated PACR Central Scenario modelled by ElectraNet as part of its additional modelling and sensitivity analysis, ElectraNet has updated its central gas price forecast to more recent, and higher, gas prices forecasts released by AEMO.

3.3.2 Coal prices

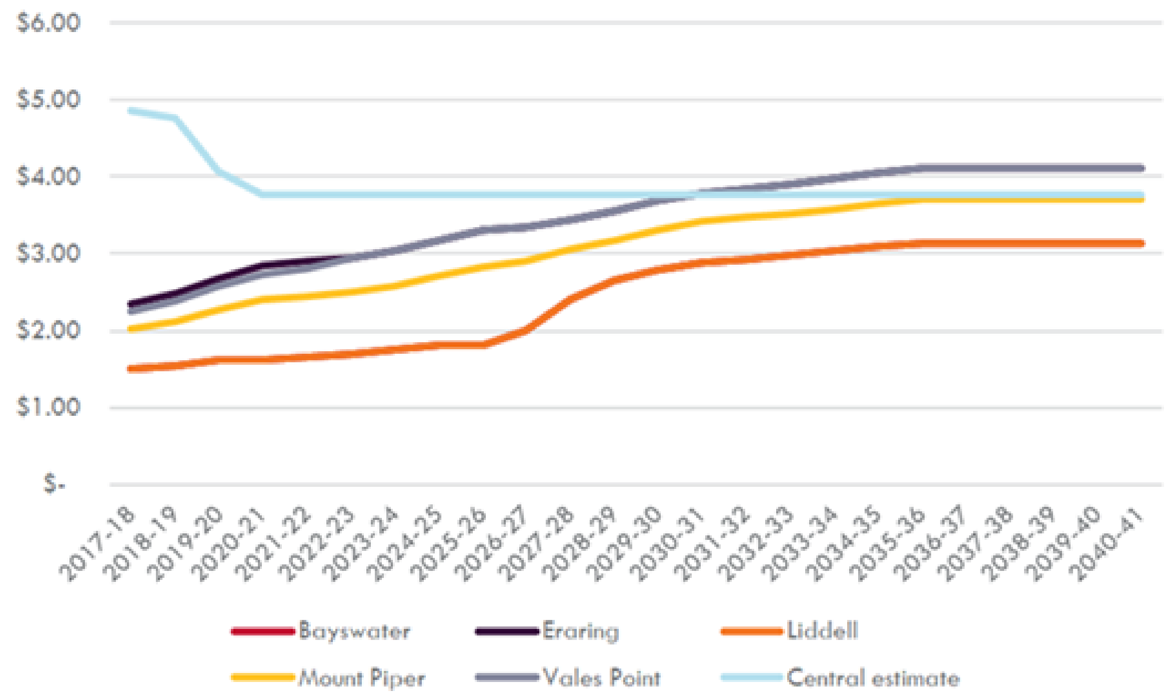
PACR modelling

The PACR adopts coal price assumptions from the 2018 AEMO Integrated System Plan (ISP). We understand that these prices are originally based on a May 2016 report prepared by Wood Mackenzie for AEMO[16]. The report has not been updated during the ISP process in subsequent years and remains the most recent publicly available source used by AEMO in its planning publications. AEMO's 2018 ISP coal prices for a selection of the most relevant generators to this RIT-T are presented in **Figure 11**.

15

16 Wood Mackenzie, May 2016, *Coal Cost Projections, available* https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/AEMO_Coal-cost-projections_approach_20160512.pdf

Figure 11: Coal prices for a selection of generators, real $/GJ 2017



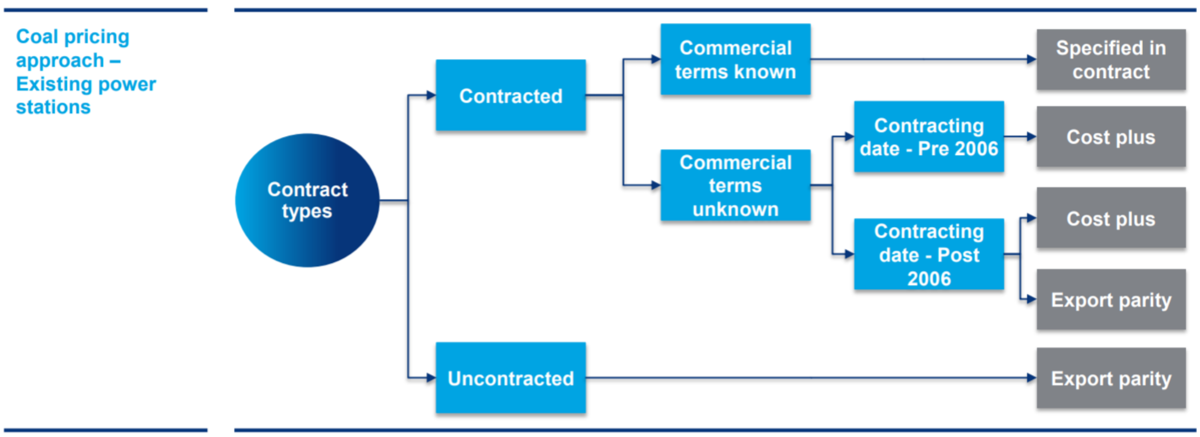
Note: Bayswater and Liddell are have the same values, so only the Liddell line is visible

Source: Chart generated from ISP 2018 data

Also presented in **Figure 11** is AEMO's central estimate of coal prices for new coal generators, based on AEMO's coal netback price estimate (which is an export parity price). AEMO notes in the 2018 ISP assumptions book that the "*central estimate [is] equivalent to forecast export coal price, as per June 2018 Resources and Energy Quarterly report, converted to AU$/GJ - @6000kCal/kg, 1USD=0.75AUD).*"

Wood Mackenzie's coal price methodology for existing power stations is summarised in **Figure 12**. Coal prices for existing generators are derived from actual contract values where available, or where actual contract values are not available cost-plus estimates, export parity or a mix of the two. Export parity prices are based on international price forecasts at the time (early 2016).

Figure 12: Summary of Wood Mackenzie coal price methodology for existing power stations



Source: Wood Mackenzie, Coal Cost Projections, May 2016

Our assessment of PACR modelling

We have reservations about ElectraNet's assumption (derived from the 2018 ISP) that the short-run marginal cost of existing coal generation reflects legacy coal contract prices. The assumptions used in the RIT-T wholesale market modelling assume that the value of coal is equal to the price paid for it, i.e. the 'accounting' cost.

However, we consider that the appropriate economic cost for coal to use in the energy market modelling (given the cost-benefit framework of the RIT-T) is the opportunity cost. The opportunity cost varies depending on the extent to which the coalmine supplying generators is able to export its output:

- For generators buying coal from mines with the potential to export, we consider the AEMO ISP 2018 new entrant coal price, a netback price, is a better reflection of the economic cost than the generator-specific prices applied by ElectraNet. This is because a generator's decisions about whether to increase or decrease electricity generation and coal use – that is, its marginal decisions – should be made having regard to the marginal cost of increasing or decreasing electricity generation and coal use. Even if a generator is using coal supplied under a long-term contract to increase its electricity generation, the economic value of using that coal is the value of that coal in its next most valuable use. In export exposed mines this involves selling that coal on the export market or, alternatively, storing that coal on site to avoid purchasing additional coal at export parity at some point in future. The generator-specific prices applied by ElectraNet may be a more accurate reflection of the average price paid for coal, but this is not relevant for the economic analysis required to support the RIT-T.
- For a non-export exposed coalmine, the contracted price is the best publicly available estimate of the opportunity cost. We consider this an appropriate cost to employ in the RIT-T modelling.

The table below sets out a summary of which coal power stations we consider would be exposed to export pricing.

Table 1: Export-exposed status of coal mines

STATION	MINE	EXPORT-FACING	NOTE
Bayswater	Wilpinjong	Y	
	Mangoola	Y	
	Liddell	Y	
	Mt Arthur Coal	Y	
Liddell	Wilpinjong	Y	
	Mangoola	Y	
	Liddell	Y	
Eraring	Myuna	N	
	Newstan	Y	
	Mandalong	Y	
Mt Piper	Springvale	Y	Reported supply issues
Vales Point B	Newstan	Y	
	Chain Valley	Y	
Callide B	Callide & Boundary Hill	Y	
Callide C	Callide & Boundary Hill	Y	
Gladstone	Callide & Boundary Hill	Y	
	Rolleston	Y	
Kogan Creek	Kogan Creek	N	
Millmerran	Commodore	N	
Stanwell	Curragh	Y	
Tarong	Meandu	N	
Tarong North	Meandu	N	

Source: Frontier Economics analysis, various sources

The AER wrote to ElectraNet on March 5, 2019 with queries regarding these coal price forecasts. These queries are replicated in the table below, along with the ElectraNet response.

Table 2: ElectraNet response to AER queries on coal prices

AER REQUEST	ELECTRANET RESPONSE
Does ElectraNet consider the use of coal prices based on a May 2016 forecast reasonable, given international prices have doubled since then?	ElectraNet has used the latest coal price forecasts available for the purposes of the RIT-T analysis and these have been the subject of detailed review and consultation. The core scenarios in the PADR and the PACR use the coal cost inputs that were consulted on as part of AEMO's annual planning processes and reviewed as part of the ISP. ElectraNet notes that these estimates will continue to be reviewed and updated over time and AEMO is currently in the process of updating its coal price forecasts. In response to submissions, ElectraNet tested the impact of a higher coal price and its effects on New South Wales coal generator retirements. This involved a sensitivity assuming $6.80/GJ black coal fuel costs for New South Wales generators, as suggested by Delta Electricity, which is significantly higher than the ISP forecasts. The PACR shows that assuming these higher coal prices decreases the estimated net market benefits of the preferred option, but even under these extreme assumptions the net market benefit remains materially positive (refer Section 8.6.4). This provides confidence that the outcome of the RIT-T remains robust to higher coal prices.
Does ElectraNet consider the use of coal prices based on legacy contract prices rather than current opportunity costs reasonable, particularly given modelling results suggest an increase in fuel consumption?	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. In the sensitivity modelling, the higher forecast rates have been modelled to commence within the first 2 years of commissioning of the interconnector or prior for all major New South Wales coal fired generators in any event, so the impact of this assumption on the assessment is considered to be minimal. Ongoing investment in renewable generation in NSW will tend to displace coal fired power below contracted levels. AEMO lists 1,520 MW of committed renewable generation in NSW. This will offset increased fuel consumption from coal fired generators and allow for the increased flows across the new interconnector to be largely supplied by coal fired power at the forecast rates assumed.

Source: ElectraNet, 22/3/2019, Response to AER information request dated 5 March 2019 (received via email)

The 2018 ISP gas and coal prices are ostensibly derived from similar methodologies by different consultants (CORE and Wood Mackenzie respectively). The described methodologies include a mix of known contract levels and opportunity costs, namely international prices in the form of a netback price. However, while the methodologies described are similar, it is clear from the reported results that the gas prices are essentially netback prices, whereas the coal prices are largely based on legacy contract prices.

As discussed above, our view is that economic modelling in a RIT-T should consider economic costs, which means considering both netback coal and gas prices where relevant (e.g. export exposed). AEMO's gas prices are either contract prices that reflect netback (e.g. tied to a netback price) or actual netback prices, and so we consider these the relevant prices to use. The coal prices are clearly dominated by legacy contract prices, so we do not consider these relevant (in this context) for most black coal generators.

We note that a number of submissions made to the PADR suggested that higher coal prices should be tested[17]. In response to this, ElectraNet modelled a sensitivity with NSW black coal prices of $6.80/GJ and changes in assumptions around how and when black-coal fired power stations are able to retire.

Further modelling

In requests for further modelling, the AER included a request for several modelling cases that substitute netback black coal prices for legacy contract prices assumed in the PACR modelling. Specifically, the cases ElectraNet refers to as AER Sensitivity 1 and AER Sensitivity 3 assume that export-exposed black coal generators (including all black coal generators in NSW) have a coal price equal to AEMO's export parity coal prices.

3.4 Plant cost assumptions

PACR modelling

Capital costs for new generation and storage options and fixed and variable operating costs for existing and new generation are all sourced from AEMO's ISP. ElectraNet has not made any changes to these assumptions of which we are aware.

Our assessment of PACR modelling

For the most part, we consider the plant cost assumptions used by ElectraNet to be reasonable, and AEMO to be a reasonable publicly available source to use.

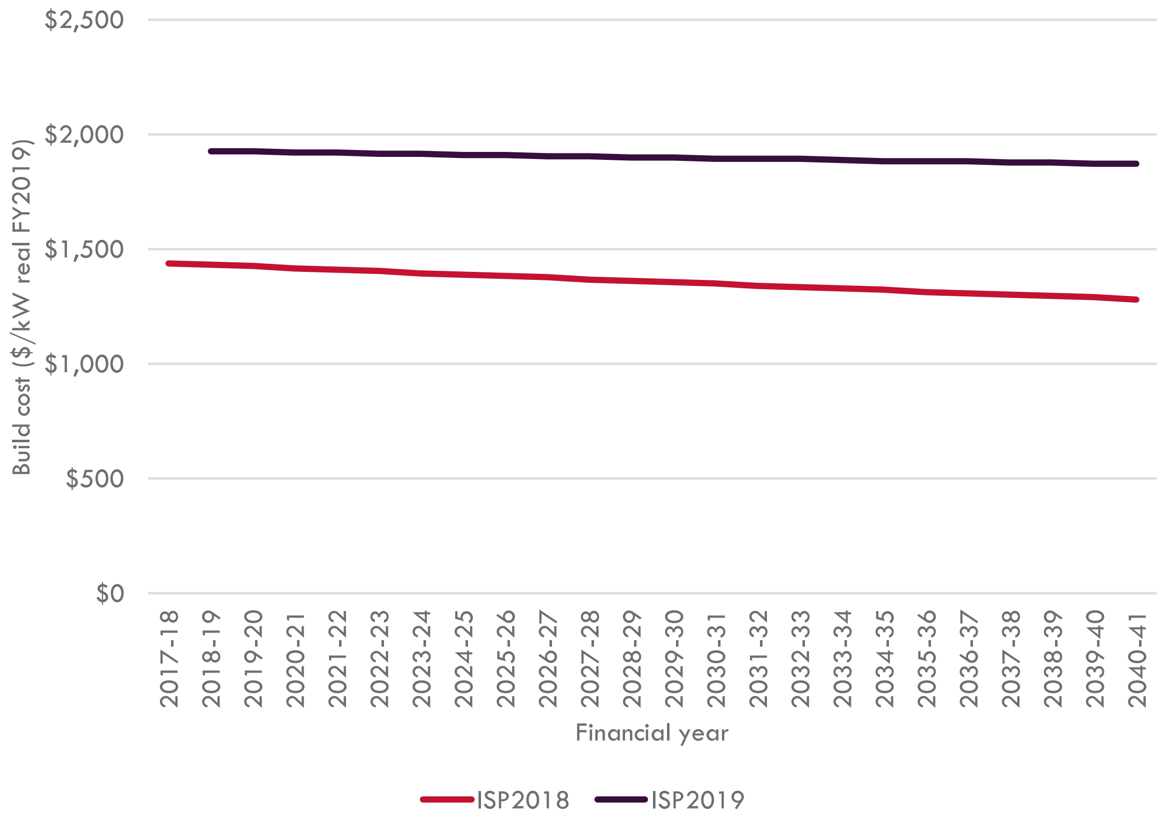
However, the pumped hydro cost assumed by ElectraNet (derived from the ISP) is, in our experience, low for South Australian projects. We note that several reports[18,19] commissioned by AEMO for the 2019 ISP, have substantially revised AEMO's pumped hydro costs for South Australia. These assumptions are compared in **Figure 13**.

[17] ElectraNet, 13/2/2019, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, pg 140.

[18] GHD, AEMO cost and technical parameter review, 2018, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

[19] Entura, 2018 Pumped Hydro cost modelling, 2018, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf

Figure 13: Build cost of pump hydro storage (6 hour)



Source: Frontier Economics analysis of AEMO ISP 2018 and 2019 assumption workbooks

We also note that the 2019 ISP includes a build limit of 500MW on South Australia pumped storage, based on the Entura report referred to above.[20]

This has potential implications for the evaluation of the interconnector in the PACR modelling, as the modelling for Option C3 builds significant pumped hydro capacity (in excess of 500MW) in South Australia following the development of the interconnector (and associated assumed retirement of South Australian gas generators). If the cost of building pumped hydro storage exceeded that included in the modelling, the benefits of the interconnector would be lower than modelled outcomes in the PACR scenarios.

Further modelling

In requests for further modelling, the AER included a request for a modelling case that uses a higher capital cost assumption for pumped hydro generation Specifically, the case ElectraNet refers to as 'AER Sensitivity 3' assumes that the capital cost for pumped hydro generation is equal to the capital cost from the Entura report.

[20] Entura, 2018 Pumped Hydro cost modelling, 2018, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf

3.5 Emissions constraints and renewable policies

PACR modelling

The modelling accounts for national emissions targets, the Large-Scale Renewable Energy Target and state-based renewable energy targets in Queensland and Victoria. The input assumptions for each of these are sourced from AEMO's ISP.

For the Queensland Renewable Energy Target (QRET), ElectraNet has adopted AEMO's Neutral BAU scenario.

For the Victorian Renewable Energy Target (VRET), ElectraNet has adopted AEMO's assumptions which include a 40% renewable energy generation target by 2025. On November 8 2018, the Victorian Government announced a planned increase of VRET from 40% in 2025 to 50% in 2030[21].

Our assessment of PACR modelling

We consider the input assumptions relating to emissions and renewable policies modelled by ElectraNet to be reasonable. We consider it unlikely that implementing alternative assumptions for VRET to reflect an announcement of a 50% target by 2030 would materially impact relative modelling results.

However, it is not clear that these emissions constraints have been binding in all cases modelled. The PACR states that the market modelling includes carbon emission constraints in the Central (28% by 2030) and High (52% by 2030) scenarios. These carbon emission constraints are based on AEMO scenarios from the 2018 ISP. In the PACR, ElectraNet stated that emissions data for each scenario was published on its website along with the PACR.[22] This information was not published online.

We were provided with emissions data for the Base case and Option C3 modelling in the High, Central and Low scenarios[23]. Based on this data, it appears the emissions constraints were binding in (at least) the High scenario of these model runs. We were also provided detailed dispatch data from the 'no minimum operation levels on SA gas generators' sensitivity. Based on the relative output from coal, gas, and renewables in this sensitivity relative to the main modelling, the results did not appear consistent with the stated emissions constraint in the 'High' scenarios. This implies the constraints were omitted from the modelling in the sensitivity. For example, in the 'no min GPG sensitivity' C3 Option case, the aggregate 2040 output of NSW black coal, QLD black coal and VIC brown coal generators is modelled to be 11.6TWh, 33.8TWh and 23.9TWh respectively. If 100% of the output was assumed to come from the generator with the lowest emissions intensity in each category, this would result in emissions of 65.9Mt, well above the limit of 53.8Mt. This pattern is observed in every year of the modelling period.

For other sensitivities, we were not provided dispatch results, and so were unable to verify whether these constraints were applied in the dispatch modelling stage.

The AER raised a query with ElectraNet on whether the emissions constraint in the High scenario had been satisfied. ElectraNet responded with the following statement[24].

> *We confirm that in the high scenario carbon emission constraints are satisfied. For completeness, we note that a minor violation of 0.01% is reported in the time sequential*

21 See https://www.danandrews.com.au/policies/increasing-victorias-renewable-energy-target-and-boosting-jobs

22 Electranet,13/2/2019, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, pg 50.

23 Response to AER information request dated 5th March 2019

24 ElectraNet response to AER information request, 20th September 2019

model for a single year in 2038. No violation is recorded in the LT model in any year and specifically in 2038.

It is not clear whether ElectraNet's comments are referring to a specific High scenario model run or all High scenario model runs in general. In any case, it remains unclear how the emissions constraint could have been applied in the High scenario of this particular modelling sensitivity.

Further modelling

As part of our review of ElectraNet's PACR we recommended that ElectraNet include these constraints in both the capacity expansion model and dispatch model. Carbon emission output from each model were requested to demonstrate these constraints are met.

3.6 Security and related constraints

PACR modelling

South Australia's energy mix, comprising a high proportion of variable renewable energy (VRE) and relatively few thermal generators, has led to a number of security issues in recent years. These issues include a lack of inertia, requiring measures to limit the rate of change of frequency (RoCoF) in the region, and reduced system strength measured by fault level shortfalls at specific points in the network, requiring generation to be directed on.

ElectraNet models a number of security-related constraints in its wholesale market modelling. A constraint limits the levers a least-cost model can use to minimise costs, and can therefore have important implications for model results. For example, a security-related constraint may force thermal generators to run 'out of merit' at certain times to provide inertia when inertia levels would otherwise be low. These constraints change between the Base case and the option cases. A selection of the security-related constraints that change from the Base case to the preferred option case in ElectraNet's modelling is presented in **Table 3**.

Some of these security-related constraints reflect assumptions about the level of inertia provided outside of the constraints themselves. In the Base case, ElectraNet assumes there are two synchronous condensers located at Davenport providing inertia of 650 MWs each (MWs or megawatt seconds are a measure of inertia).

In June 2018, AEMO declared a fault level shortfall or deficit of system strength in South Australia[25]. In July 2018, AEMO declared a minimum threshold level of inertia for South Australia of 4,400 MWs[26]. In December 2018, AEMO recommended via the 2018 National Transmission Network Development Plan that ElectraNet procure 4,400 MWs of inertia services through synchronous condensers or contracting

[25] AEMO, System Strength Requirements and Fault Level Shortfalls, 29 June 2018, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf

[26] AEMO, Inertia Requirements and Shortfalls, 29 June 2018, p21, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf

with synchronous generation[27]. In the Network Technical Assumptions Report, ElectraNet note the following[28].

> *ElectraNet is addressing the declared system strength gap outside of this RIT-T process. Since the SAET RIT-T technical assessment ElectraNet has recommended to AEMO that the installation of four large synchronous condensers will meet the system strength gap. The proposed system strength solution will enable the South Australian power system to be operated without directing synchronous generators on for system strength purposes.*

In an economic evaluation published around the same time as the PACR, ElectraNet proposed a solution of four synchronous condensers that provide 1,100 MWs of inertia each with an estimated capital cost of $160 million[29]. This solution is not included in the PACR modelling. ElectraNet note that this was due to the final form of the synchronous condenser solution to address the fault level shortfall declared by AEMO not being settled until after the PACR modelling was conducted[30].

[27] AEMO, 2018 National Transmission Network Development Plan, 21 December 2018, p20, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf

[28] Network Technical Assumptions Report, p10 https://www.electranet.com.au/wp-content/uploads/projects/2016/11/Network-Technical-Assumptions-Report.pdf

[29] Addressing the System Strength Gap in SA, Economic Evaluation Report, February 2018, https://www.electranet.com.au/wp-content/uploads/2019/02/2019-02-18-System-Strength-Economic-Evaluation-Report-FINAL.pdf

[30] ElectraNet, *Additional Modelling and Sensitivity Analysis*, 31 October 2019

Table 3: Selected security constraints that change from the Base case to the preferred option state of the world

CONSTRAINT	ELECTRANET DESCRIPTION	FRONTIER ECONOMICS NOTE	IN BASE	IN C3
Minimum SA Gas Units Generating	Minimum 2 online gas generators in South Australia.	Related to system strength[31] and a number of additional factors outlined in Section X. At least two of Osbourne's GT, Pelican Point's GTs, or TIPS B units online at any given time.	Y	N
Heywood RoCoF Constraint - Export	Limit Heywood Interconnector transfers in Vic-SA direction under conditions of low power system inertia in South Australia, in order to limit the Rate of Change of Frequency to below 3 Hz per second for the non-credible co-incident trip of both circuits of the Heywood interconnector.	Related to inertia.	Y	N
Heywood RoCoF Constraint - Import	Limit Heywood Interconnector transfers in SA-VIC direction under conditions of low power system inertia in South Australia, in order to limit the Rate of Change of Frequency to below 3 Hz per second for the non-credible co-incident trip of both circuits of the Heywood interconnector.	Related to inertia.	Y	N
Import Heywood-SE Lines flow	Limit the combined backward flows on Heywood Interconnector (SA export on Heywood).	Limited to 650MW in Base, 750MW in C3.	Y	Y
Import Heywood-SE Lines flow	Limit the combined forward flows on Heywood Interconnector (SA import on Heywood).	Limited to 650MW in Base, 750MW in C3.	Y	Y
NSCAS - Non synchronous constraint - SA	Network support and control ancillary services constraint.	Caps the amount of non-synchronous generation online in SA under certain conditions. Related to system security.	Y	N

Source: Analysis of ElectraNet's response to AER information request dated 5th March

[31] AEMO, Transfer Limit Advice – South Australian System Strength, December 2018, available https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf

Our assessment of PACR modelling

It is reasonable to include security and related constraints in market modelling to support the SAET RIT-T. It is also reasonable for security and related constraints to vary between scenarios, given the scope for various interconnector configurations to influence security requirements in South Australia. However, given the potential for security constraints to influence the modelling results, it is important these constraints reflect the most recent and accurate assessment of those constraints.

Accordingly, our view is that ElectraNet should have included a synchronous condenser solution providing 4,400 MWs of inertia in their wholesale market modelling, at least as a sensitivity.

AEMO's declaration of a fault level shortfall and minimum inertia threshold level signalled the need for urgent action, for which an interconnector was not a feasible option. Section 4.4 of the Economic Evaluation Report contained a summary of options considered to meet the system strength gap in South Australia, but which were not progressed as they could not be considered technically and/or economically feasible to meet the urgent system strength requirement. One of these was 'Network reinforcement options'. ElectraNet made the following statement[32]:

> *Network reinforcement options potentially lower system impedance and increase fault levels, contributing to system strength. These options include 275 kV tie-ins, installation of additional transformers, stringing vacant circuits and new transmission lines. However, based on the relative cost and technical effectiveness of these options, they are not considered to be credible options.*
>
> *While it is noted that a new interconnector could also contribute to improving system strength across the network, the expected timeframe for implementation falls well outside the required window for action, and any contribution to addressing the shortfall is expected to be relatively modest.*

Furthermore, ElectraNet was working on the Economic Evaluation for the synchronous condensers at the same time as the PACR. The PACR contains a number of statements on the synchronous condensers, including in response to stakeholder comments. Some of these are summarised in **Table 4**.

[32] Electranet, 18/2/2019, *Addressing the System Strength Gap in SA Economic Evaluation Report*

Table 4: PACR discussion of synchronous condenser

COMMENT	PAGE
Following submissions on the PADR, ElectraNet has engaged Entura to investigate the opportunity for non-network solutions to help ensure satisfactory network performance (in terms of inertia, RoCoF and FCAS) for the current network arrangement during the interim period before the energisation of a new interconnector. This consideration has been in addition to the new synchronous condensers ElectraNet is procuring to address a system strength shortfall	78
The cap on non-synchronous generation has been modelled. Details of the non-synchronous cap can be found in the network technical assumptions report. The Base case requirement is for four synchronous machines. Two are supplied by synchronous condensers at Davenport and two synchronous generators in the PACR. There was a two synchronous generation unit requirement assumed in the PADR.	133
The current system strength shortfall in South Australia needs to be addressed urgently and cannot wait for the development of a new interconnector. Synchronous condensers are needed urgently now whether a new AC or DC link is ultimately built, and are planned to be in place by 2020	139
ElectraNet is addressing the declared system strength gap outside of this RIT-T process. ElectraNet has recommended to AEMO that four large synchronous condensers will meet the system strength gap. These synchronous condensers are needed in SA urgently and are assumed in the Base case. They are no longer assumed in the preferred option	139
Synchronous condensers are being implemented to meet the urgent need to address a system strength shortfall in South Australia. The synchronous condenser solution is included in the Base case for the consideration of all options in this PACR. Synchronous condensers have been removed from the scope of the preferred option since the PADR	205

Source: Electranet,13/2/2019, SA Energy Transformation RIT-T Project Assessment Conclusions Report

Based on the description of the synchronous condenser solution in the PACR and the Network Technical Assumption Report it is clear that ElectraNet had recommended the installation of four synchronous condensers to AEMO and considered the installation of the synchronous condenser solution likely. In addition, it suggested it had updated the analysis from the PADR to account for the synchronous condensers. This synchronous condenser solution is described as meeting the minimum system strength requirement, and efficiently meeting the minimum inertia threshold level in South Australia. However, in its market modelling for the PADR ElectraNet only assumed the installation of two synchronous condensers, hence the requirement for the modelling constraints outlined above.

In practice, the effect of including two synchronous condensers, rather than four, is to constrain the operation of the system in the counterfactual (Base) case, leading to higher than efficient gas output, and wind generation being constrained off (or spilled). Overall, this increases costs in the Base case, increasing the relative benefit in the Option C3 case when the constraints are relieved, by assumption, due to the construction of the interconnector.

We consider that including only two synchronous condensers, rather than four, is not an appropriate assumption for the market modelling used to produce the SAET RIT-T, as it does not reflect likely outcomes, or the best information that would have been available to ElectraNet at the time, particularly given ElectraNet is responsible for the synchronous condenser solution.

Further modelling

As part of our review of ElectraNet's PACR we recommended that the modelling assume the installation of four synchronous condensers in all scenarios. The AER requested that further modelling account for four synchronous condensers with flywheels attached, providing 4,400MWs of inertia. ElectraNet modified the non-synchronous cap constraint to give effect to the addition of these synchronous condensers. The non-synchronous cap constraint was adjusted from 1,870 to 2,000MW. These changes were incorporated in each of the additional modelling cases, referred to by ElectraNet as 'AER Sensitivity 1', 'AER Sensitivity 2' and 'AER Sensitivity 3'.

After several rounds of correspondence with ElectraNet and AEMO, it was determined that the minimum two-unit constraint was required for reasons other than system strength, as remedied by the synchronous condensers. AEMO provided the following justifications for the two-unit minimum requirement, which are summarised in **Table 5**:

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

ElectraNet assume that only existing South Australian gas generators are able to provide the services required, and hence must make up the two units. The two-unit minimum constraint was included in each of the cases referred to as 'AER Sensitivity 1', 'AER Sensitivity 2' and 'AER Sensitivity 3'.

Figure 14: AEMO's planning assumptions around synchronous generating units required

Table 1 Planning assumptions for the 2018 ISP

Power System Requirement	Planning assumptions used in the 2018 ISP				
	At least 4 synchronous generating units	At least 3 synchronous generating units	At least 2 synchronous generating units	At least 1 synchronous generating unit	No synchronous generating units
SYSTEM NORMAL, REQUIREMENT FOR POWER SYSTEM SECURITY					
System strength & fault current	NOW				SYNCONS / ENERGY CONNECT
Operating reserves for ramping			NOW / SYNCONS		ENERGY CONNECT
SYSTEM NORMAL REQUIREMENT TO SURVIVE 1-IN-3 YEAR SEPARATION EVENT†					
Grid formation				NOW / SYNCONS	ENERGY CONNECT
Inertia and RoCoF				NOW‡	SYNCONS / ENERGY CONNECT
Primary frequency control				NOW / SYNCONS	ENERGY CONNECT
Secondary frequency control			NOW / SYNCONS		ENERGY CONNECT
Operating reserves for energy balance			NOW / SYNCONS		ENERGY CONNECT
SYSTEM NORMAL MINIMUM REQUIREMENT					
Minimum requirement	NOW		SYNCONS		ENERGY CONNECT

† A "non-credible" separation event has occurred approximately once every three years since NEM start. With Energy Connect, the separation risk would be reduced.

‡ RoCoF risk is currently managed with a 3 Hz/s RoCoF constraint on the Heywood interconnector.

Source: AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019

3.7 Plant operating parameters

The PACR and further modelling contains assumptions relating to restrictions on the operating parameters of a number of thermal generators in the NEM. Some of these assumptions are sourced from AEMO's 2018 ISP. ElectraNet has made a number of additions and changes to AEMO's 2018 ISP assumptions.

3.7.1 Up and down times

PACR modelling

Minimum up and down times refer to an operating limit placed on a generator that restricts operating patterns such that, once started, the generator must run for the minimum up time, and once stopped, must remain off for the minimum down time. Strictly, these parameters relate to technical operation, i.e. are not economic in nature. Minimum up and down times are only applied in ElectraNet's ST modelling.

In ElectraNet's PACR modelling, all coal generators in the NEM are assigned a minimum down time, and most are assigned a minimum up time. Four South Australian gas plant are also assigned minimum up and down times. From discussions with ElectraNet, we understand that it has 'calibrated' these values to expectations of economic operation of each plant and they are not sourced from publicly available data, which accords with descriptions in the PACR[33].

AEMO published a technical assumptions workbook[34] alongside the 2018 ISP, which included minimum up and down times for each generator. The values in this workbook for minimum on and off times for generators are substantially lower than the values assumed in ElectraNet's PACR modelling. Both sets of values are presented in **Table 5**, with the ACIL Allen figures referring to the figures published alongside the 2018 ISP.

[33] See, for example: ElectraNet, *SA Energy Transformation RIT-T PACR Market Modelling Methodology Report, 13 February 2019, p14: "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 at a time."*

[34] Available https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/Historical/Fuel_and_Technology_Cost_Review_Data_ACIL_Allen.xlsx

Table 5: Minimum up and down time assumptions (hours)

STATION	REGION	FUEL	MINIMUM UP TIME (PACR)	MINIMUM DOWN TIME (PACR)	MINIMUM UP TIME (ACIL ALLEN)	MINIMUM DOWN TIME (ACIL ALLEN)
Callide B	QLD	Black Coal	120	12	8	8
Callide C	QLD	Black Coal	120	12	8	8
Gladstone	QLD	Black Coal	120	12	8	8
Kogan Creek	QLD	Black Coal		12	8	8
Mount Piper	NSW	Black Coal	120	12	8	8
Stanwell	QLD	Black Coal	120	12	8	8
Tarong	QLD	Black Coal	120	12	8	8
Tarong North	QLD	Black Coal	120	12	8	8
Bayswater	NSW	Black Coal		12	8	8
Eraring	NSW	Black Coal	120	12	8	8
Liddell	NSW	Black Coal		12	8	8
Vales Point	NSW	Black Coal	120	12	8	8
Wallerawang	NSW	Black Coal	120	12	8	8
Loy Yang A	VIC	Brown Coal		12	16	16
Loy Yang B	VIC	Brown Coal		12	16	16
Osborne	SA	Natural Gas	24	12	4	4
Pelican Point	SA	Natural Gas	24	12	4	4
Torrens Island Power Station A	SA	Natural Gas	24	12	1	1
Torrens Island Power Station B	SA	Natural Gas	24	12	1	1

Source: Frontier Economics analysis of PACR Market Modelling and Assumptions data book, and ACIL Allen Fuel and Technology Cost Review data book

Our assessment of PACR modelling

ElectraNet's PACR ST modelling imposes minimum up and down times on thermal generators in the NEM, particularly coal generators and a subset of South Australian gas generators. The assumptions used by ElectraNet are a deviation from those published alongside AEMO's ISP.

Adopting minimum up and down times in market modelling as a proxy for the economic decision making associated with start-up and shut-down costs is not unreasonable, however we make several observations about ElectraNet's approach:

- ElectraNet's determination of the minimum up-times and down-times for the model is not transparent. The 2018 ISP doesn't contain corresponding values with comparable times. We understand these values are intended to reflect commercial decisions a plant operator would make.
- It appears that ElectraNet has applied the constraints selectively to some generators and not to others. For example, it only applied the constraints to four gas generators, all in South Australia. It did not provide any justification for why the constraints were not applied to similar gas generators in other regions in the PACR or associated reports. ElectraNet noted in a response to an information request[35] that these assumptions were a result of stakeholder feedback around gas-powered generation flexibility and solar output in South Australia.
- ElectraNet did not include the costs of starting and shutting down generators, using minimum up and down times as a proxy. In response to an information request, ElectraNet subsequently tried to include start costs in the ST model, but the model would not solve in a reasonable time. Applying actual start-up and shutdown costs is preferable to adopting heuristic up and down times.
- AEMO publishes the ACIL Allen 'Fuel and Technology Cost Review' alongside the 2018 ISP, which contains a range of technical parameters for existing generators and new entry candidates including minimum up-times and down-times and the cost to restart.[36] For gas generators, the ACIL Allen database estimates minimum up-times and down-times to be approximately 1-4 hours, and to apply to generators across the NEM, not just Pelican Point, Osborne and Torrens Island. For coal generators, they are approximately 8-16 hours. These assumptions are substantially different to those adopted by ElectraNet as shown in **Table 5**.

The AER sought additional information from AEMO on the reasonableness of minimum up-times and down-times and the application by ElectraNet. The query and AEMO response are presented in **Table 6**.

[35] ElectraNet, Response to email of 1 August 2019, 13 August 2019

[36] ACIL Allen, 2014, *Fuel and Technology Cost Review Data*

Table 6: AEMO response to AER query on thermal plant cycling assumptions

AER REQUEST	AEMO RESPONSE
ElectraNet have applied limitations on the cycling of NEM-wide coal generators and SA gas generators – specifically minimum on/off hours. Were similar constraints applied in the ISP modelling? Are the assumptions applied by ElectraNet on minimum on/off times (24hrs/12hrs respectively) for all SA gas plant reasonable? Is there any reason why these should apply only to gas plant in SA and not other regions?	Where practical, AEMO has applied technical limitations to generators to reasonably reflect real-world constraints, as outlined in the previous point. This is limited to simpler capacity factor limits in the capacity outlook models but may include unit commitment optimisations in detailed time sequential validations. While we have not reviewed the constraints applied by ElectraNet, we are familiar with the approach. The use of minimum uptime / downtime constraints is reasonable to apply in detailed time-sequential modelling to reasonably capture unit commitment decisions by plant operators. Unit commitment optimisation determines which generating units to switch on, and for how long. Apart from the dispatch cost, this optimisation also includes the generator units' assumed start-up cost, minimum uptime and minimum stable level. There may be periods when it is optimal to keep generators on at low generation levels, even when making a loss, to avoid the cost of restarting later. This methodology solves each day at a time (24 hours) simultaneously and includes an additional day of look ahead at less granular resolution to inform unit commitment decisions towards the end of the 24 hours. Otherwise, units may choose to shut down towards midnight without considering the cost of restarting the next day. The 2019-20 ISP will continue to apply these methodologies. These are not necessarily SA-specific; best practice would apply this to all thermal plant which face daily, operational commitment decisions. In the absence of coal generation in South Australia, it's reasonable to apply this method to SA gas plant, given the relative baseload role these generators have compared with gas generators operating in mid-merit / peaking modes in other regions.

Source: Email from AEMO to AER, 23/4/2019

In lieu of the ability to model actual start costs, including some form of heuristic proxy, such as minimum up and down times, is reasonable in our view. However, how these are determined should be transparent, and the effect of these assumptions should be made clear, for example in a sensitivity. Inspecting modelling runs with and without the minimum up and down times (for example, on South Australian gas) would ensure that the assumptions are doing what they are intended to do, and not inadvertently overstating costs.

Further modelling

We recommended a modelling run where ElectraNet's 'calibrated' minimum up and down times on South Australian gas generators were replaced with the minimum up and down times provided by AEMO along with the ISP 2018 assumptions workbook. The intent of this change was to observe whether ElectraNet's 'calibrated' minimum up and down times were necessary to obtain reasonable operation of gas-fired generation in South Australia, and whether they were inadvertently increasing costs, particularly in the counterfactual (base) state of the world These changes were incorporated in each of the additional modelling cases requested, referred to by ElectraNet as 'AER Sensitivity 1', 'AER Sensitivity 2' and 'AER Sensitivity 3'.

We note that ElectraNet also replaced all minimum up and down for coal generation with the values in the ACIL Allen 'Fuel and Technology Cost Review' spreadsheet. 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. It is unclear that coal generators in NSW would be able to reliably two-shift in this way. If they cannot, then ElectraNet's further modelling is likely to overstate the benefits of interconnection between South Australia and the major black coal regions (NSW and Queensland).

3.7.2 Minimum loads

PACR modelling

Minimum load assumptions refer to the minimum stable level at which a generation unit can operate.

ElectraNet bases minimum load assumptions on AEMO's 2018 ISP, with a number of changes. These changes are detailed in **Table 7**.

Table 7: Differences in minimum load assumptions, ElectraNet PACR and ISP 2018

GENERATOR	REGION	FUEL	ELECTRANET (MW)	AEMO (MW)
LD03-4	NSW	Black Coal	[redacted]	Not included
GSTONE5-6	QLD	Black Coal	[redacted]	Not included
STAN-4	QLD	Black Coal	[redacted]	Not included
TARONG#4	QLD	Black Coal	[redacted]	Not included
Torrens Island A	SA	Natural Gas	[redacted]	Not included
Torrens Island B	SA	Natural Gas	40	160
Dry Creek	SA	Natural Gas	[redacted]	Not included
Hallett GT	SA	Natural Gas	[redacted]	Not included
Ladbroke Grove	SA	Natural Gas	[redacted]	Not included
Mintaro	SA	Natural Gas	[redacted]	Not included
Osborne	SA	Natural Gas	[redacted]	Not included
Pelican Point	SA	Natural Gas	[redacted]	Not included
Quarantine	SA	Natural Gas	[redacted]	Not included

Source: Frontier Economics analysis of the PACR Market Modelling and Assumptions data book and the ISP 2018 assumptions

The majority of changes relate to South Australian gas generators having values applied to them, where there were none in AEMO's ISP 2018 modelling[37]. These generators have values applied to them on a station level, where the other minimum load assumptions from the ISP are on a generator unit[38] basis.

Our assessment of PACR modelling

It is not unreasonable to include minimum loads in market modelling used to produce estimates of market benefits for a RIT-T. However, it is important that that assumptions used reflect the most recent and accurate information, and consistently applied to generators across the NEM.

ElectraNet's PACR modelling diverged from AEMO's ISP 2018 modelling to apply minimum loads on additional generators. The majority of the changes relate to South Australian gas generators having values applied to them, where there were none in AEMO's modelling. ElectraNet noted in an information request made by the AER that the reason for the application of these minimum loads was to support the implementation of security constraints, for example the two minimum unit constraint. It also became apparent that, in some cases, ElectraNet had inferred minimum loads from historical levels of output.

We make several observations on ElectraNet's approach to minimum loads:

- Minimum loads were applied to South Australian gas generators rather than all equivalent gas generators in the NEM. To consider the impact of interconnection in an unbiased manner, these constraints should be applied consistently to all generators of the same type regardless of region. Otherwise, interconnection provides access to unrealistically flexible substitutes to local generation, overstating benefits.
- We note that it is not possible to infer minimum load constraints from historic output. Even if we've never seen a particular plant operate at 100MW or below, we can't simply infer it can't. On the other hand if we have seen it operate at 100MW we can infer that it can do that.
- The assumptions presented in the PACR and the associated reports and workbooks did not source these assumptions which deviate from the ISP.

We have reservations around ElectraNet's approach to minimum loads in the PACR, relating to the source of the values modelled and the consistency in approach.

Further modelling

The AER requested that in further modelling, minimum loads for gas generation be applied on a consistent basis and clearly sourced. This led to the values outlined in **Table 8**. These changes were incorporated in each of the additional modelling cases, referred to by ElectraNet as AER Sensitivity 1, AER Sensitivity 2 and AER Sensitivity 3.

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37 We note that the ISP included a minimum operating level for TIPS B in lieu of a minimum capacity factor. As stated in AEMO's note titled 'Assumptions for South Australian GPG in the 2018 Integrated System Plan', August 2019: "*In the case of TIPS B, a minimum operating level rather than a minimum capacity factor was applied in modelling to utilise TIPS B as the least-cost approach to satisfy the critical system strength constraint (minimum number of units of appropriate size to deliver required fault level outcomes at the designated fault level nodes in South Australia). The system security constraint was relaxed once the new double circuit interconnector, EnergyConnect, was commissioned, between 2022 to 2024 in the 2018 ISP.*"

38 Stations are typically made up of a number of units, so station level is a higher level of aggregation than unit level. The ISP had one entry at a station level, Torrens Island B.

Table 8: Comparison of minimum loads for South Australian gas plant

STATION	PACR	FURTHER MODELLING
Osborne	145	[redacted]
Pelican Point	160	[redacted]
Torrens Island B units 1-4	40	40

Source: ElectraNet: Additional modelling and sensitivity analysis, 31 October 2019

3.7.3 Minimum capacity factors

PACR modelling

The PACR includes minimum capacity factor assumptions for some gas generators operating in South Australia, which are based on ISP 2018 assumptions with several modifications. The minimum capacity factors modelled for South Australian gas generators are outlined in **Table 9**.

Table 9: South Australian gas generator minimum capacity factors

GENERATOR	MIN CF (%) – PACR	MIN CF (%) – ISP 2018
Osborne	60%	60%
Pelican Point	50%	50%
Torrens Island A	Not included	15%
Torrens Island B	25%	Not included[39]

Source: PACR Market Modelling and Assumptions Databook, AEMO ISP 2018 Modelling Assumptions v2.4

In the base and non-interconnector option states of the world, these minimum capacity factors apply until plant retirement. In the interconnector options, they apply until the interconnector comes online, at which point the generators are retired by assumption.

Based on information provided by AEMO to the AER, we understand that the minimum load assumption in the 2018 ISP for Torrens Island B is based on all four of its generation units being online at the same time ($4 \times 40MW = 160MW$). For the ISP, AEMO assumed that all four units would be online at all times, as this was assumed at the time to be the least cost solution to meet the security requirements in South Australia discussed in Section 3.6. No minimum capacity factors were modelled for Torrens Island B, as the effect was covered by the minimum load assumptions. ElectraNet did not adopt the same assumption that all four units of Torrens Island B must be online at all times, so it based its minimum load value on one unit of Torrens Island B (40MW).

39 As noted earlier, the ISP included a minimum operating level for TIPS B in lieu of a minimum capacity factor.

Our assessment of PACR modelling

ElectraNet's PACR modelling imposes minimum capacity factors on three gas generators in South Australia – Osborne, Pelican Point, and Torrens Island B. It does not impose minimum capacity factors on other generators.

The minimum capacity factors applied by ElectraNet are based on values applied in the 2018 AEMO ISP modelling, with several differences in the treatment of Torrens Island A and B, which are not discussed in the PACR. The ISP assumptions workbook states that the modelling assumptions are based on internal analysis on historical generator performance. This explanation is repeated in the PACR Market Modelling and Assumptions databook, referring to 'AEMO analysis of historical generator performance'. The PACR does not include a substantive discussion of the minimum capacity factor assumptions, stating[40] simply that:

> *The PACR now aligns all generator input assumptions with the ISP, including minimum operation of South Australian gas plant*

In its response to an AER query on the minimum capacity factors on the 22nd of March, ElectraNet deferred again to the AEMO ISP, stating[41]:

> *ElectraNet has applied the minimum operational constraints on the major GPG plant in South Australia as adopted by AEMO in the ISP. The constraints required Pelican Point, Osborne and Torrens Island to be operated at minimum levels over the course of the year*

Oakley Greenwood commented on the minimum capacity factors in its External Review of the RIT-T, stating[42]:

> *Minimum levels of gas for generation are applied in modelling to reflect assumptions that generators that may be called on to run occasionally for an extended period will find it necessary to contract for a minimum volume and associated transport*

It is not clear from the Oakley Greenwood review whether the explanation of minimum gas capacity factors is based on a justification provided by ElectraNet or based on Oakley Greenwoods interpretation of the minimum capacity factors.

As the minimum capacity factor assumptions were based on the AEMO ISP, the AER submitted an information request to AEMO on the April 11 2019, seeking additional information on the minimum

[40] Electranet, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, 13 February 2019, pg 41.

[41] ElectraNet, *Response to AER information request dated 5 March 2019 (received via email), 22 March 2019*

[42] Oakley Greenwood, *SA Energy Transformation RIT-T External Review,* February 2019, pg 9.

capacity factors and other modelling questions. With regards to the minimum capacity factors, AEMO responded:

> *In the capacity outlook model, unit commitment cannot be modelled accurately due to the relative coarseness of the model. Instead, constraints such as minimum capacity factors and minimum operational levels are applied to some thermal units, particularly those which are marginal and potentially subject to intermittent operation. This avoids these generators operating with unreasonable duty cycles as they gradually get displaced by lower cost, variable renewable energy, but allows some flexibility for the units to adapt by potentially changing to two shift operation.*
>
> *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 fuel 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 which would significantly increase operating costs.*
>
> *AEMO undertook the modelling in three stages. The final stage is hourly, time sequential modelling which allows us to review the future operating mode of generators and to fine tune the constraints imposed in the optimisation stage. AEMO has invested in advanced tools to more thoroughly complete that analysis, recognising the importance of the modelling reflecting reality*

AEMO's response suggests the following:

- That minimum capacity factors, if applied, should only be applied in this manner in the capacity outlook (LT) model, not the dispatch (ST) model which can model unit commitment with more detail.
- That the basis of the constraints appears to be in line with the Oakley Greenwood interpretation, that these gas generators must operate with output at a certain level to be operationally or commercially viable.

We were provided an updated response from AEMO[43] in August 2019. This response confirms that its minimum capacity factors were only applied in capacity outlook (LT) model, but states the reasons for the constraints on South Australian gas generation were to ensure the forecasts reflected a combination of goals and were realistic, including:

- Considering generator technical limits.
- Reflecting typical utilisation based on historical profiles of generation and expectations of future dispatch, and also reflecting typical annual gas consumption requirements.
- Ensuring that the required minimum number of synchronous generations were on-line for system security purposes.

[43] AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019

We do not consider that the explanations provided by ElectraNet or AEMO provide sufficient justification for the inclusion of minimum capacity factors on South Australian gas generation, particularly in the context of ElectraNet's ST modelling. Our reasons for this view are as follows:

- There is a wholesale spot market for gas, the Short Term Trading Market (STTM), operated by AEMO which covers the South Australian market. The South Australian gas generators may participate in this market, which allows them to purchase or sell gas outside their contracted position. Many gas generators purchase gas through long-term contracts, rather than exclusively through the STTM. This provides a reliable supply of gas, and tends to have lower average prices. However, just because a generator has contracted a certain volume of gas, it has no obligation to consume it. It may on-sell in the spot market gas that it does not require for its own use. An efficient operator would trade gas in the spot market wherever the marginal value of selling that gas exceeds the value of consuming it to produce electricity.
- Alternatively, gas generators may choose to contract a lower volume of gas, and purchase from the spot market where required to top-up. We note this may result in higher average prices per GJ than purchasing through contracts, however, it would be a more efficient strategy than over-contracting and consuming gas purely because it has been purchased. We note that in the PACR results, South Australian gas generation is often produced at the expense of wind generation, which is constrained off to facilitate the gas generation. In practice, to be dispatched at the expense of wind, the gas generators would need to bid at zero or negative prices, simply to offload the quantity of gas they had contracted. This does not reflect sound commercial operation or an economically efficient outcome. To adopt a minimum capacity factor for the purpose of accounting for generators gas contract position implies there is no opportunity cost to consuming contracted gas, which is not the case given the potential to access the Australian East Coast gas market.
- To the extent that there are fixed costs that negatively impact the commercial attractiveness of operating at low capacity factors, these should be reflected in the fixed operating and maintenance operating cost category.
- The minimum capacity factor limits are applied selectively to a subset of gas generators in South Australia. **Table 10** presents the modelled capacity factors for a selected subset of large gas generators in the Base case Central scenario. As demonstrated by this table, a number of power stations in South Australia and other regions operate at very low capacity factors for extended periods of time. ElectraNet does not provide a justification for why Osborne, Pelican Point and Torrens Island B are required to operate with high capacity factors, but comparable (and in some cases, lower cost) gas generators in South Australia and other regions are not required to. Furthermore, output from most other gas generators is significantly below all of the capacity factor limits for multiple years. There is a considerable inconsistency in the treatment of South Australian gas generators compared to other gas generators in the NEM. This inconsistency is likely to have important implications for the relative benefits of the options considered in the SAET RIT-T.

ElectraNet and AEMO make reference to historic output levels as part of the justification for the application of minimum capacity factors in the modelling. However, making modelling assumptions with reference to historic outcomes of particular plant is inconsistent with ElectraNet's chosen modelling approach as set out in the PACR Market Modelling Methodology Report: "*a further benefit of SRMC based approach is that it avoids making arbitrary long-term decisions about the level and nature of contracting in the NEM*"[44]. By calibrating minimum capacity factors for South Australian gas plant on historic levels, ElectraNet are making arbitrary long-term decisions about the level and nature of contracting in the NEM.

[44] ElectraNet, *SA Energy Transformation RIT-T PACR Market Modelling Methodology Report, 13 February 2019, p11*

Table 10: Selected gas generator capacity factors – Base state of the world, central scenario

GENERATOR	REGION	AVE CF (%) 2020-24	AVE CF (%) 2025-29	AVE CF (%) 2030-34	AVE CF (%) 2035-39
Osborne	SA	60.3	60.1	60.4	61.7
Pelican Point	SA	49.7	49.9	49.9	50.0
Torrens Island A	SA	-	-	-	-
Torrens Island B	SA	24.9	24.9	24.9	-
Barker Inlet	SA	0.5	1.4	0.5	3.4
Swanbank	QLD	42.7	0.4	57.7	63.0
Darling Downs	QLD	2.5	29.6	58.2	55.0
Condamine A	QLD	19.5	2.2	60.6	64.7
Newport	VIC	0.0	0.2	0.8	-
Smithfield	NSW	0.8	6.9	24.6	13.4
Tallawarra	NSW	24.7	38.3	69.1	35.1

Source: Frontier Economics analysis of ElectraNet modelling

These minimum capacity factors drive a large proportion of the avoided fuel cost benefit, which is the largest benefit category in the interconnection options, including the preferred option.

Overall, we do not think the justification for the minimum capacity factor assumptions is supported by economic theory or market evidence, and these constraints violate the internal consistency of ElectraNet's PACR model. We recommended that the minimum capacity factor be removed from South Australian gas generators in the Base case and Option C3 modelling.

Further modelling

We recommended that further modelling not include minimum capacity factors on South Australian gas generators, and that if these minimum capacity factors are intended as a proxy for some security constraint then those actual security constraints should be included in the modelling instead. These changes were incorporated in each of the additional modelling cases, referred to by ElectraNet as AER Sensitivity 1, AER Sensitivity 2 and AER Sensitivity 3.

3.7.4 Heat rates

PACR modelling

The heat rate of a power station is an expression of its efficiency, and is used to convert joules of primary energy in to electricity output. Heat rates are typically expressed in GJ/MWh, and an average point estimate is used in lieu of varying heat rates relating to levels of output, ambient temperature and other relevant factors.

ElectraNet has based heat rates used in its modelling on AEMO's 2018 ISP. All values used are identical, with the exception of Pelican Point and Osborne, two gas generators in the South Australian region. ElectraNet has specified separate heat rates for the Pelican Point and Osborne gas turbine (GT) and steam turbine (ST) components. In its Market Modelling Methodology Report, ElectraNet explains this as follows *"Combined cycle generators in South Australia that are represented as steam and gas turbines have had the gas turbine heat rates increased and the steam turbine heat rates increased to reflect the average heat rates of the ISP".*[45] The report does not clarify where ElectraNet sourced the alternative assumptions for the Pelican Point and Osborne GT and ST heat rates.

Our assessment of PACR modelling

Assumptions used in RIT-T analysis should embody the best information available at the time. Increasing the technical accuracy of modelling combined cycle gas turbines, such as Pelican Point and Osborne, will in principle improve the analysis.

However, we have several concerns with the way these generator parameters have been changed:

- CCGT plant in other regions should treated consistently by adopting different heat rates for their gas and steam units. Modelling heat rates for CCGT generators in South Australia in this way, but not CCGT generators elsewhere in the NEM, is likely to increase the modelled benefits of interconnection.
- The heat rate assumptions adopted by ElectraNet for the Pelican Point and Osborne GTs and STs made are not sourced.

Further modelling

As part of our review of ElectraNet's PACR we did not recommend any changes with respect to heat rates, focusing instead on recommending changes to other likely more material issues.

3.8 South Australian gas plant retirements

PACR modelling

The PACR includes an assumption that a number of mid-merit South Australian gas generators would retire immediately upon the commissioning of any of the interconnector credible options. In particular, the PACR assumes that the following generators retire simultaneously in Option C3 with the introduction of the interconnector in 2024:

- Pelican Point
- Osborne
- Torrens Island B.

This assumption reflects a result obtained by AEMO in the ISP, with the timing of the gas plant retirement adjusted in the PACR modelling to reflect different timing of the interconnector entry.

In contrast, these generators are required to operate in the Base case (as outlined in Section 3.7.3, relating to minimum capacity factors). As a result of the assumed retirement of gas plant additional capacity is required in South Australia to meet the reserve margin under the interconnector credible

[45] The gas turbine heat rate was increased, and steam turbine heat rate decreased.

options. This gap is filled by a combination of the interconnector and model-determined investment in pumped hydro, as illustrated in **Figure 15**.

Figure 15: Installed major gas capacity in South Australia under Option C3

Source: PACR Figure 13

Our assessment of PACR modelling

ElectraNet assumes that Osborne, Pelican Point, and Torrens Island B (the same set of generators to which it applies minimum capacity factor assumptions in the Base state of the world) retire simultaneously with the introduction of the interconnector. The retirement of these generators in the interconnector options is an assumption – not a modelled outcome – and not supported by evidence about the generators reaching the end of their technical life or being uneconomic to operate. ElectraNet states the assumption is based on aligning assumptions with the 2018 AEMO ISP[46].

The 2018 ISP contains limited information on the specific basis for the assumptions, however contains the following text when describing the key differences in 'No interconnector development reference' case relative to the Neutral scenario[47]:

> *Continued operation of existing GPG. The RiverLink interconnector reduces risks associated with power system security in South Australia, leading to lower overall utilisation of GPG in that state. Without the development of the RiverLink interconnector in*

[46] Electranet,13/2/2019, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, pg 41.

[47] AEMO, July 2018, *Integrated System Plan*, pg 47

this scenario, GPG utilisation continues to be much higher than all other scenarios which develop that interconnector. This is shown in Figure 23, which continues to keep in service some existing GPG beyond 2025, after the RiverLink interconnector would be developed in the Neutral scenario. No new CCGT plant is forecast in this scenario until 2036.

The AER sought additional information from AEMO on the basis for the gas retirement assumptions. The query and AEMO response are presented in **Table 11**.

Table 11: AEMO description of South Australian gas retirement in the ISP

AER REQUEST	AEMO RESPONSE
ElectraNet has assumed that Osborne, Pelican Point, and Torrens Island B retire immediately when the NSW to SA interconnector is commissioned, based on the 2018 ISP. Are these retirements endogenous in the ISP modelling? At which stage of the modelling are these retirements determined? Are these retirements sensitive to minimum capacity factor constraints, thermal cycling, or any security constraints imposed? Is there any other non-renewable investment in SA after the retirement of these gas plant?	During the optimisation stages (the IM and DLT phases) of the ISP we identified a number of possible operational and development combinations of the SA GPGs and the NSW-SA interconnector. The ISP tested various permutations of these gas retirements (including not retiring them) to identify the least cost approach for each scenario and the overall plan recommended. The retirements were outcomes of these analyses based on the optimised decisions of the most efficient future system development, applied consistently across each scenario. The option to retire TIPSB, OSB and PP with the commissioning of the NSW-SA interconnector was identified as a credible, economically efficient, development path across the scenarios explored. This was primarily driven by the reduction in fuel and FOM costs. Current and forecast gas price in southern and eastern Australia placed all gas fired generation in a difficult competitive position in the ISP. In addition, the Torrens Island generators are relatively high operating cost, inflexible and inefficient generators compared to modern gas turbines. The lowest cost solution was determined to be a portfolio of lower cost, diverse renewables supplemented with storage and supported by transmission investment. As part of the ISP, AEMO reviewed the security issues associated with such a course of action and was satisfied that with appropriate measures, including synchronous condensers, security could be maintained. We note that the ISP analysis was based on least cost modelling, consistent with the approach required in a RIT-T analysis. The outcomes modelled in this manner would not necessarily reflect those a participant might make driven by market prices.

Source: Email from AEMO to AER, 23/4/2019

AEMO's response makes it clear that the retirement of the South Australian gas generators is based on a system least cost optimisation. It doesn't necessarily reflect the type of decisions made by a commercial operator, for example retiring a generator that is not covering its operating expenses through market revenue. It is clear from AEMO's response it is imposing a requirement for South Australian gas fired generators to operate at high minimum capacity factors. As outlined in Section 3.7.3, we do not consider these assumptions reasonable. We consider it unlikely that it would be a least cost option to simultaneously retire several gas generators unless they were constrained to operate in non-economic manner, particularly given that new generation investment is then required to meet the reserve constraint.

ElectraNet has not exogenously retired any other generators by assumption outside of technical end-of-life assumptions; this treatment is applied only to these South Australian gas generators. We also note that the LT model used by ElectraNet has the capability to allow economic retirement of generators before the end-of-technical life. ElectraNet uses this capability for modelling the High, and Low scenarios, allowing for generator retirements that differ from the Central Scenario, and differ from the retirement schedules in the ISP. We do not consider there is reasonable justification for the selective treatment of gas generators in South Australia between the scenarios modelled by ElectraNet. We recommend that ElectraNet adopts a consistent approach to generation retirement across all scenarios, and allows all generators the option for economic retirement.

Further modelling

As part of our review of ElectraNet's PACR we recommended that no exogenous retirements be applied, other than retirements which are committed at the time of modelling or reflect end-of-technical life assumptions. ElectraNet's further modelling does not include the retirements of South Australian gas generators assumed in the PACR modelling.

3.9 Summary and conclusion

Overall, our view is that there are a number of material issues with the input assumptions relied on by ElectraNet for the PACR modelling. These are summarised briefly below:

- The operation of generation in South Australia is highly, and in some cases, artificially constrained by assumptions imposed in the modelling. Some of these assumptions come from the ISP, others directly from ElectraNet. The key assumptions include:
  - High minimum capacity factors applied to a number of South Australian gas generators (but not similar generators elsewhere in the NEM), forcing them to run at high cost in the Base case
  - South Australian gas generators constrained to operate for a minimum of 24 hours on, and 12 hours off, and with minimum load constraints (none of which constraints are applied to other gas generators in the NEM)
  - Several South Australian gas generators are retired by assumption when the interconnector is commissioned.

  Overall, the effect of these assumptions is to artificially constrain the operation of South Australian gas generators in the Base state of the world, at significant cost. In the interconnector states of the world, the South Australian gas generators are retired by assumption, allowing that cost to be avoided. This likely overstates the modelled benefits of the interconnector.
- The detail provided in the PACR and associated reports to support the assumed impact of the interconnection options on security is limited:
  - The Base case modelling includes a number of constraints related to system security in South Australia, which are removed or modified in the interconnector cases. The removal of constraints leads to lower modelled generation costs in the interconnector cases
  - However, there is little to no evidence provided in the PACR or associated reports to support the relaxation of these constraints. In subsequent discussions with ElectraNet and AEMO, more information on these security constraints has been provided.
- ElectraNet's proposed four synchronous condenser solution has not been modelled:

  - Security constraints modelled should be updated to reflect these.
  - By omitting the four synchronous condensers, the PACR modelling overstates the impact of the interconnectors on security and market outcomes.
- The coal price assumptions adopted by ElectraNet underestimate the economic cost of coal:
  - A significant proportion of benefits in the interconnector options arise from the substitution of relatively high cost gas generation (in South Australia) for relatively low-cost coal generation (in NSW).
  - Given the RIT-T framework coal price assumptions used in the modelling should reflect economic pricing principles, and be based on marginal opportunity cost. For export-exposed coal generators, the netback coal price is the appropriate estimate of marginal opportunity cost (which is higher than the costs assumed by ElectraNet).
  - The coal prices adopted underestimate the economic cost of coal generation and overestimate the benefits of switching from gas generation.

A number of these input issues were remedied in ElectraNet's further modelling. These include:

- Reductions to artificial constraints on South Australian gas generation, including removed minimum capacity factors, reduced minimum up/down times, and removed exogenous retirement assumptions.
- Relaxed security-related constraints to account for the likely addition of four synchronous condensers providing 4,400MWs to the South Australian system.
- Coal prices reflecting economic costs, rather than accounting costs.

However, a number of issues with input assumptions remain in the further modelling:

- 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 trace from different years will fail to capture the relationship between weather conditions, demand and intermittent generation.
- ElectraNet's further modelling results in regular two-shifting in coal generation. It is unclear that coal generators in NSW would be able to reliably two-shift in this way. If they cannot, then ElectraNet's futher modelling is likely to overstate the benefits of interconnection between South Australia and the major black coal regions (NSW and Queensland).

We are not able to estimate the effect that these outstanding issues have on ElectraNet's modelling results.

4 ASSESSMENT OF METHODOLOGY

This section provides an assessment of the methodology that ElectraNet has used to assess the market benefits of the credible options identified in the PACR and the further modelling. We begin by providing an overview of ElectraNet's methodology, before considering the approach to addressing the identified need, the modelling approach and the estimation of terminal value. We conclude by presenting our summary and conclusions.

4.1 Overview of methodology

ElectraNet has considered seven credible options in the PACR in addition to the 'do nothing' option. These credible options are designed to satisfy the identified need, which is set out in the PACR and preceding reports.

For each credible option, ElectraNet has undertaken wholesale market modelling of the NEM to determine wholesale market benefits, which are input into an economic evaluation model to calculate net benefits. ElectraNet's wholesale market modelling methodology is described at a high level in the PACR and in more detail in the accompanying PACR Market Modelling Methodology Report. A wholesale market modelling results spreadsheet was published alongside the PACR, as well as the economic evaluation model that calculates the net benefits.

We understand that this RIT-T application is not for reliability corrective action.

Our assessment of the methodology used by ElectraNet to estimate the market benefits of the credible options of the SAET for the RIT-T involves an assessment of:

- The alignment between the identified need and the options considered
- The consistency between the modelling approach and best practice modelling methodologies.

4.2 Identified need and options considered

PACR methodology

ElectraNet outlines the identified need in Section 3 of the PACR, replicated in **Box 1**. The identified need has three 'limbs' or components:

- reduced dispatch costs;
- increased security of supply in South Australia; and
- improving access to renewable resources across all regions.

Box 1: The identified need

"*The driver for the investments being considered under this RIT-T is to create a net benefit to consumers and producers of electricity and support energy market transition through:*

- *lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions;*

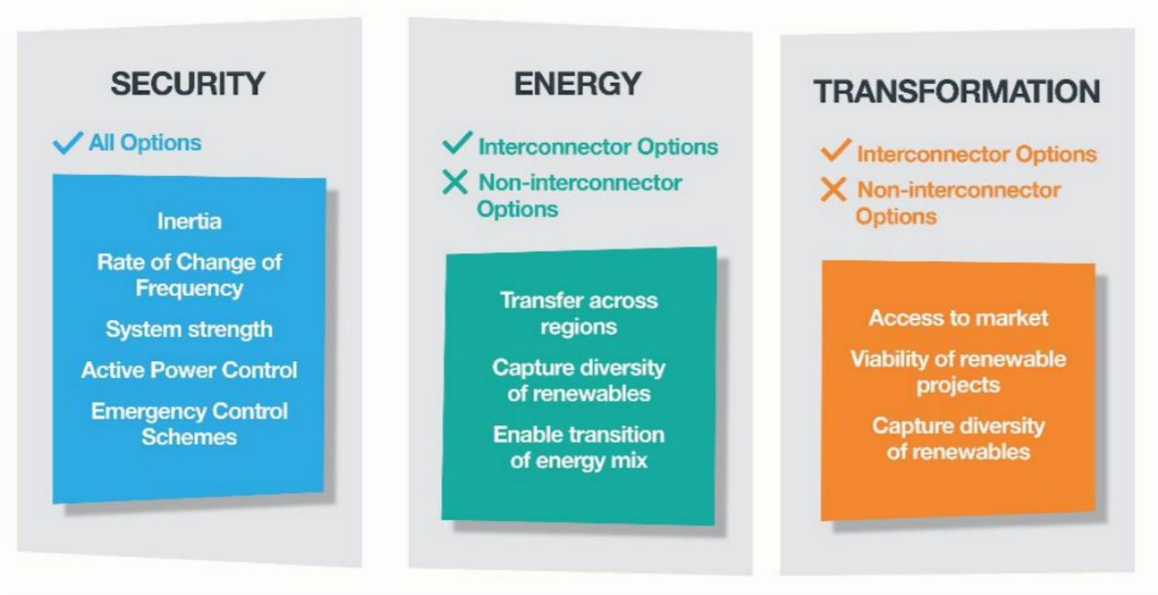
- *facilitating the transition to a lower carbon emissions future in the NEM and the adoption of new technologies through improving access to high quality renewable resources across all regions; and*
- *enhancing security of electricity supply in South Australia.*

This 'identified need' remains consistent with that identified in the PADR."

Source: PACR pg 34

ElectraNet provides a figure in the PACR which goes into more detail on each limb of the identified need (reproduced in **Figure 16**). The "Energy" column appears to correspond to the reduced dispatch cost bullet point in **Box 1**.

Figure 16: Ability of the options to contribute to meeting the three limbs of the identified need



Source: PACR p34

As outlined in the NER s5.15.2(a)(1), credible options are options that address this identified need.

ElectraNet has developed a number of credible options designed to satisfy the identified need, which have evolved over the course of the application process. As discussed in Section 2 these options are:

- **Option A:** a non-interconnector option comprising a number of network support agreements and local system augmentations.
- **Option B:** A 400 kV HVDC link between South Australia and Queensland.
- **Option C:** A link between South Australia and New South Wales, with three variants:
  - **C3:** A 330 kV line between Robertstown in midnorth South Australia and Wagga Wagga in NSW, via Buronga, plus Buronga-Red Cliffs 220 kV
  - **C3ii:** A 330 kV line between Robertstown in midnorth South Australia and Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point

- **C3iii:** A HVDC transmission between Robertstown in mid-north SA and Darlington Point via Buronga; HVAC line between Darlington Point and Wagga Wagga in NSW, plus Buronga-Red Cliffs 220 kV

- **Option D:** A 275 kV line from Tungkillo in South Australia to Horsham and Ararat in Victoria.

These options are summarised graphically in **Figure 17**.

Figure 17: Overview of options (and variants) assessed

Source: PACR p10

Our assessment of PACR methodology

ElectraNet has considered a range of technical and locational configurations for interconnection and a non-interconnector option in the PACR. ElectraNet has considered plausible technical options connecting South Australia to each NEM region except for Tasmania, and have considered numerous technical configurations to NSW, the region where ElectraNet has identified interconnection is most likely to be beneficial.

Under 5.15.2(a)(1) of the NER, a credible option is an option (or group of options) that addresses the identified need. ElectraNet notes in the PACR that the non-interconnector option only contributes to system security, and does not address the other limbs of the identified need[48]. ElectraNet states that the non-interconnector option should therefore not be considered a credible option.

It is not clear that all of ElectraNet's interconnector credible options meet the identified need. For at least some of the credible options considered, including the preferred option, emissions are higher, renewable investment is lower, and new renewable dispatch is lower (although overall renewable output is higher) than in the Base state of the world. It is not clear this is consistent with the 'low carbon' identified need,

48 Electranet,13/2/2019, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, p9

namely "*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*."

There is little detail in the PACR and associated reports on the security benefits of the proposed interconnector options. ElectraNet discusses a range of security benefits that the interconnector provides, and assumes the relaxation of a number of security-related market constraints in South Australia in cases where an interconnector is developed. However, limited evidence and detail is provided for the nature and magnitude of these benefits and the changes to constraints.

We note that ElectraNet has received approval from the AER and technical approval from AEMO for the installation of four synchronous condensers to address the current system strength gap in South Australia. Installation of the four synchronous condensers was not taken into account in the PACR, but was reflected in ElectraNet's further modelling.

The interconnector will provide some security benefit. However, for the reasons above, it is difficult to comment on the efficacy of the interconnector options toward addressing the security pillar of the identified need.

Further modelling methodology

The further modelling assumptions reflect updated information about the state of system security in South Australia. This includes a set of constraints that reflect the installation of four synchronous condensers providing 4,400MWs of inertia, and the removal of constraints that were, at least in part, proxying security issues (see Section 3.7.3 for a discussion of the minimum capacity factors imposed).

We note that in the further modelling results, changes to security assumptions are a key source of benefit. This is discussed in Section 5.2.

4.3 Modelling approach

PACR methodology

ElectraNet employs a least-cost modelling approach with short-run marginal cost (SRMC) offers to determine wholesale market benefits of the credible options considered. The RIT-T Guideline stipulates that proponents' market development modelling must be undertaken on a least cost and, where appropriate, market driven basis[49].

A least cost approach takes the perspective of a central planner, requiring any endogenous investments to be net beneficial to the system as a whole. Investment and retirement decisions arise where system-wide benefits, such as changes in overall fuel or operating costs, exceed investment or retirement costs. ElectraNet's modelling assumes generator offers reflect short-run marginal costs, noting that this approach includes the presumption that *"the design of the market will lead to prices that support entry and exit and market bidding that leads to the lowest underlying capital and fuel and other operating cost*".

ElectraNet undertakes its market modelling in two related stages, which reduces the size and complexity of the problem considerably:

- The first stage is a long-term capacity expansion model (**LT model**), where an investment path is determined. Instead of half-hourly or five-minute modelling, ElectraNet simplifies the modelling requirements by dividing each day of each year modelled in to 8 sequential 'load blocks' over which dispatch and investment decisions are evaluated. This equates to 2,920 sequential periods per year modelled in a non-leap year. To further simplify the problem, ElectraNet cuts the modelling horizon

49 2010 Regulatory Investment Test for Transmission, s21

into three, so that three eight-year blocks of 2,920 discrete periods (2,928 in a leap year) per year are modelled.

- The second stage is a short-term simulation model (**ST model**), which takes the investment path as determined by the LT model, and calculates market outcomes at an hourly level. The ST model simulates generator dispatch, storage behaviour, interconnector flows and secondary outcomes at a more granular level than considered in the LT model. We understand ElectraNet's ST model determines market outcomes on an hourly basis (rather than 30-minute trading intervals or five-minute dispatch intervals) to reduce run times.

ElectraNet undertakes both stages of modelling for each state of the world and each scenario. Results from the ST model are used to populate the economic evaluation model that calculates the net benefit of each of the credible options.

The PLEXOS market modelling software is used to derive gross market benefits.

Assessment of PACR methodology

ElectraNet's use of a least-cost, SRMC based approach is reasonable in our view. The PLEXOS market modelling software is a suitable choice for calculating gross market benefits for this RIT-T.

Modelling investment and market outcomes in the NEM at a five- or 30-minute level over the PACR assessment period (20 years), while properly accounting for technical, economic and policy constraints, is intractable with the tools reasonably available today. It is necessary to reduce the market modelling problem in some way so it becomes tractable. How the problem is reduced involves trading off accuracy in different aspects of the modelling problem. Typically, this involves modelling 'representative' demand points rather than a full set of demand points, and relaxing various constraints, such as generator technical operating limitations.

Generally, ElectraNet's approach to reducing the problem is not unusual and, in our view, is reasonable. The key trade-offs ElectraNet has made are:

- Splitting the model into runs for investment and dispatch risks outcomes being out of sync between the models. That is, if the investment modelling stage is over-simplified, there may be substantial differences in the outputs between the two models, meaning the dispatch result in the short-term model represents an 'out of equilibrium' outcome. For example, modelling investment and related dispatch outcomes on a single average demand point per year would result in very different dispatch outcomes once that investment path was modelled in an hourly short-term model. This investment result is unlikely to be a good representation of a cost optimal system as modelled in the short-term model.
- Splitting the assessment period into three eight-year periods removes foresight of the model and may lead to inefficient investment outcomes and/or boundary effects. That is, the model may make inefficient investment decisions in the 2020s because it has no visibility over changes in trends in the 2030s.

We note that this approach requires checks to ensure that outcomes in each model are consistent and the models do not 'disconnect'. The long-term and short-term models will never reflect outcomes exactly – the acceptable level of difference between the two is a judgement call. However, if long-term model investment results appear materially non-optimal once run through the short-term model, this information should be fed back to the long-term model to ensure that inefficient investment outcomes do not inadvertently misrepresent costs or benefits. We discuss related issues with ElectraNet's approach in detail in Section 5.2.

While we agree with the choice of a least-cost SRMC approach as adopted by ElectraNet, the use of a number of input assumptions, such as assumed minimum capacity factors based on historical output levels, would violate the conditions of such an approach. These input assumptions, and their implications for a least-cost SRMC approach, are discussed is Section 3.

Further modelling methodology

The AER did not request changes to ElectraNet's modelling methodology, other than to request the modelling bases used to compare options were consistent (that is the same window periods and same run years).

4.4 Terminal value

PACR methodology

ElectraNet includes a terminal value for options with assets that outlive the assessment period of the modelling (financial years ending 2020 to 2040). This terminal value is calculated as a pro-rata share of capex in an asset's lifetime that falls outside the assessment period, which is discounted to the date the assessment period ends and added as a cost reduction in the net benefit calculation. This is an implicit assumption that benefits beyond the assessment period will be equal to residual costs. ElectraNet states this as follows: *"inclusion of a terminal value for asset costs is consistent with approaches adopted more generally for cost benefit analysis, and avoids the need to project future benefit streams beyond the assessment period, which are subject to greater uncertainty."*

Our assessment of PACR methodology

We consider ElectraNet's approach to estimating the terminal value – assuming benefits beyond the assessment period are equal to costs – to be reasonable. We have considered several alternative approaches to formulating a terminal value, each of which has significant drawbacks:

- **Omitting** any terminal values. This doesn't account for the fact that the length of asset lives exceed the length of the assessment period. It assumes there are no benefits beyond the modelling period. We would consider this a very conservative assumption.
- **Rolling forward net costs or benefits** from the last year or years of modelling. There are a number of issues with this approach. It assumes that the pattern of costs and benefits will continue for the remainder of the asset's life.
- **Extending the modelling** to cover the full asset life: Energy market modelling results become both more uncertain and less impactful on the cost-benefit analysis (CBA) (due to time discounting) for each forecast year. Extending the modelling to cover the technical life of an interconnector would be difficult in practice, and results towards the end of the period would be less reliable in any event.

Further modelling methodology

The AER did not request changes to ElectraNet's approach to estimating the terminal value.

4.5 Summary and conclusion

Overall, we consider the approach that ElectraNet has used to assess the market benefits of the credible options identified in the PACR to be reasonable. There are a number of challenges and trade-offs in modelling a complex system over a long period, and feeding the results to a CBA framework. ElectraNet has made reasonable methodological choices to structure their assessment of market benefits.

However, in our view ElectraNet has not provided sufficient evidence that any of the options it presented in the PACR satisfy all of the three components of the identified need. It is not clear that the non-interconnector requirement has not been satisfied, as a credible non-interconnector option has not been provided (ElectraNet states that the non-interconnector option only satisfies one of three components of the identified need). Based on ElectraNet's PACR modelling, some of the interconnector options, including the preferred option, are associated with higher emissions and lower investment in new renewable energy. It is not clear this is consistent with the 'lower emissions future' component of the identified need, and could therefore considered as credible options under the definition provided in the NER. The outcomes for emissions in the further modelling are more favourable with regard to the emissions limb of the identified need. However, no further investigation of non-interconnector options was considered in this further modelling.

Section 4.3 provides a discussion of potential issues arising from splitting the wholesale market model into LT and ST components. In Section 5.2, we note that it does not appear that ElectraNet have managed these issues adequately.

5 ASSESSMENT OF RESULTS AND CONCLUSIONS

This section provides an assessment of the results and conclusions of ElectraNet's assessment of the market benefits of the identified options. We begin by summarising ElectraNet's results and conclusions, before presenting our assessment.

5.1 ElectraNet's results and conclusions

PACR modelling results and conclusions

As discussed, ElectraNet has identified and assessed eight credible options for the PACR; a business as usual Base case and seven options that reflect investment in a wide variety of different network capacities and routes.

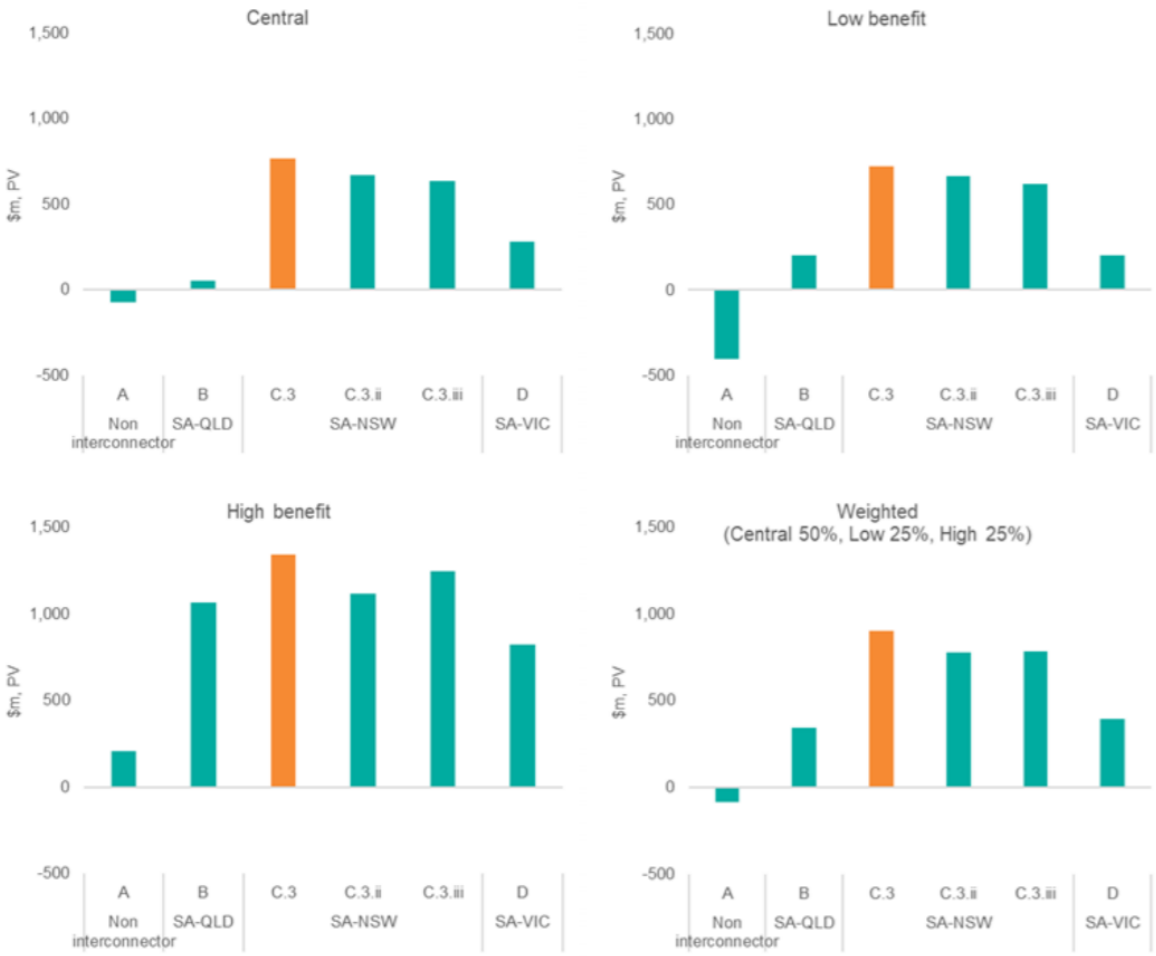
ElectraNet has assessed each of these eight credible options against a range of scenarios and sensitivities. Based on this analysis, ElectraNet has concluded that the preferred option is Option C3, which includes:

- A 330 kV line between Robertstown in midnorth South Australia and Wagga Wagga in NSW, via Buronga
- A Buronga-Red Cliffs 220 kV line

ElectraNet's analysis finds that Option C3 has a net market benefit, and is the preferred option and net beneficial in a weighted average of scenario outcomes, and in all sensitivities and robustness tests.

Figure 18 presents ElectraNet's estimated net market benefits for each scenario and a weighted outcome, comprising 50% central and 25% low and high case outcomes. In each scenario, Option C3 is the preferred option and materially net beneficial.

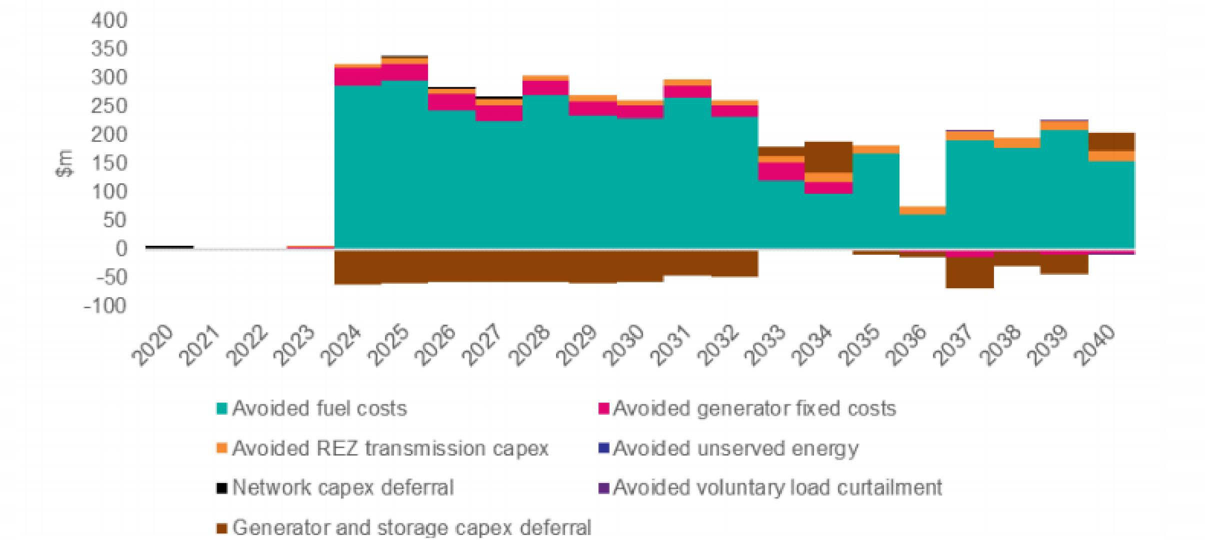
Figure 18: Estimated net market benefits for each scenario



Source: PACR Figure E.3

Figure 19 presents a breakdown of the costs and benefits of the preferred option in the central scenario over time. The majority of market benefits are derived from avoided fuel costs, and to a lesser extent avoided generator fixed costs. For a number of years, the C3 case has higher capital costs (brown) than the base case, reflecting the investment in pumped hydro on commissioning of the interconnector.

Figure 19: Breakdown of gross market benefits for Option C3 (SA-NSW interconnector) under the central scenario



Source: PACR Figure 12

Further modelling results and conclusions

As part of its further modelling, ElectraNet provided a ‘Corrected’ Central scenario which amended several errors. This is discussed Section 5.2.

In addition to this Corrected Central scenario, ElectraNet was also requested to undertake additional modelling to address issues we raised with the AER over the course of our review, as we discussed in sections 3 and.4 In our view, the first modelling run requested, which ElectraNet have named ‘AER Sensitivity 1’, incorporates the set of assumptions that represents the best information at the time the PACR was conducted.

ElectraNet find the relative and net benefits for AER Sensitivity 1 as presented in **Table 12**. The net benefit under this scenario is reported as approximately $270m. The drivers of this net benefit are predominantly differences in generation cost outcomes ($764m), storage build costs ($221m), and generator FOM costs ($132m).

Table 12: Comparative and net benefits, ‘AER Sensitivity 1’, preferred option

VALUE TYPE	BENEFITS	NPV(‘000$)
NPV Delta (C3 – Base)	Generation Cost	$763,746
	Storage Generation Cost	$3,696
	Generator FOM Cost	$131,815
	Storage FOM Cost	$3,588
	Transmission Build Cost	$103,354
	Generator Build Cost	$19,087
	Storage Build Cost	$220,976
NPV	**Total**	**$1,246,261**
NPV	C3 Cost	-$977,055
NPV	**Net Benefits**	**$269,205**

Source: ElectraNet response to Information request #6, 31 October 2019

5.2 Our assessment

PACR modelling

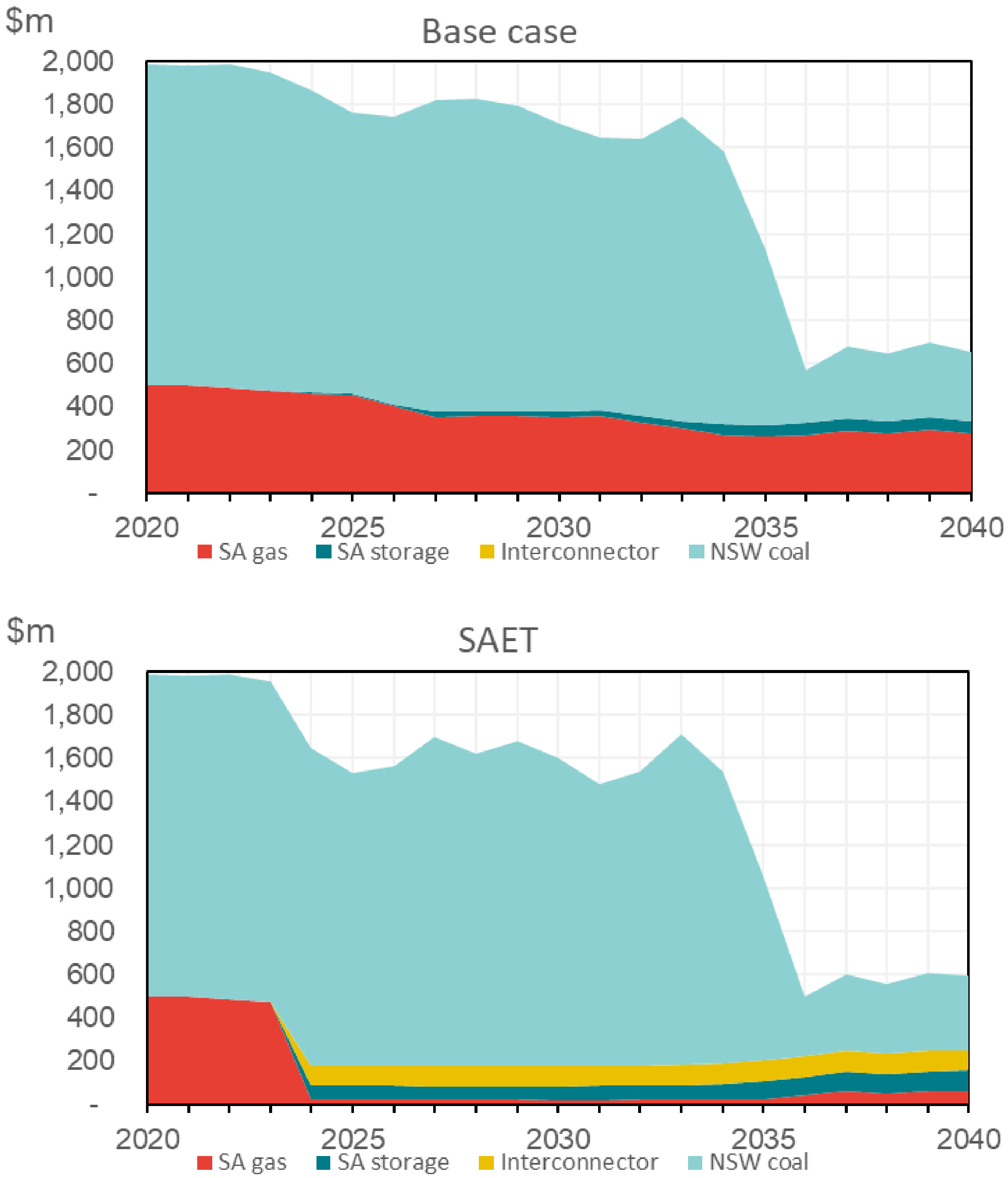
In our view, the PACR modelling in general, and the result for Option C3 in particular, is characterised by several key assumptions that drive the main outcomes. Most of the benefits for Option C3 in the PACR modelling central case can be attributed to the following:

- In the counterfactual (base) state of the world, the assumed minimum capacity factors for gas plant in South Australia impose a large cost that the model cannot avoid.
- In the C3 case, the interconnect is built in 2024 with several flow on effects:
  - Most gas capacity in South Australia is retired by assumption when the interconnector is commissioned, alleviating the large cost of gas generators being forced to run to an assumed minimum capacity factor in the counterfactual (base) case.
  - The output that was provided by South Australian gas in the counterfactual is substituted for cheaper NSW black coal output via the interconnector.
  - To meet a reserve margin constraint, a 700MW pumped hydro plant is built to the cost of around $1 billion in 2024. This plant is infrequently utilised.

The magnitude of each of these components is outlined in **Figure 20**, which compares the counterfactual (base) case with Option C3 for the Central scenario. Note that the costs shown in this figure are not the all the costs that feed into the CBA; however, they are the key costs that drive the result of the CBA.

In the first chart in **Figure 20**, the red area reflects the cost of South Australian gas generation, the majority of which is forced on and unavoidable by the model. The second chart shows the difference in the cost of generation once the gas generators are retired and the forced cost is alleviated. This cost is replaced with the cost of the interconnector, shown in yellow, the cost of pumped storage to meet the reserve margin, shown in dark teal, and an increase in output from black coal, shown in light teal. The net effect of these changes between cases explains the vast majority of the result in the PACR modelling.

Figure 20: Comparison of key cost drivers in the Base and C3 states of the world, PACR modelling, Central case



Source: Frontier Economics analysis of ElectraNet modelling output

The analysis set out above demonstrates the constraints and exogenous assumptions discussed in Section 3 drive the majority of the benefits for the preferred option. As we discussed in Section 3, we do not consider that these constraints and exogenous assumptions have been adequately tested in sensitivities, documented in the PACR and associated reports, or justified.

For these reasons, further modelling was requested.

Further modelling

Our reasoning on the PACR modelling also applies to the 'Corrected PACR' run ElectraNet included in the further modelling. We consider the further modelling, and in particular 'AER Sensitivity 1', presents a scenario incorporating the best available information at the time. The rest of this section relates to 'AER Sensitivity 1' unless otherwise specified.

The net benefit of the interconnector in Option C3 is smaller in the further modelling 'AER sensitivites' than in the PACR modelling. This is primarily due to the removal of the minimum capacity factor constraint on South Australian gas generators in ElectraNet's further modelling.

We have had limited time to review and analyse ElectraNet's further modelling. Reflecting these time constraints, and the limited accompanying write up of these results from ElectraNet, this section sets out:

- A brief summary and analysis of ElectraNet's further modelling, focusing on the 'AER Sensitivity 1' scenario.
- Several issues we have identified over the course of our review, including a disconnect between the LT and ST models, particular aspects of storage investment results, and the status of the preferred option.

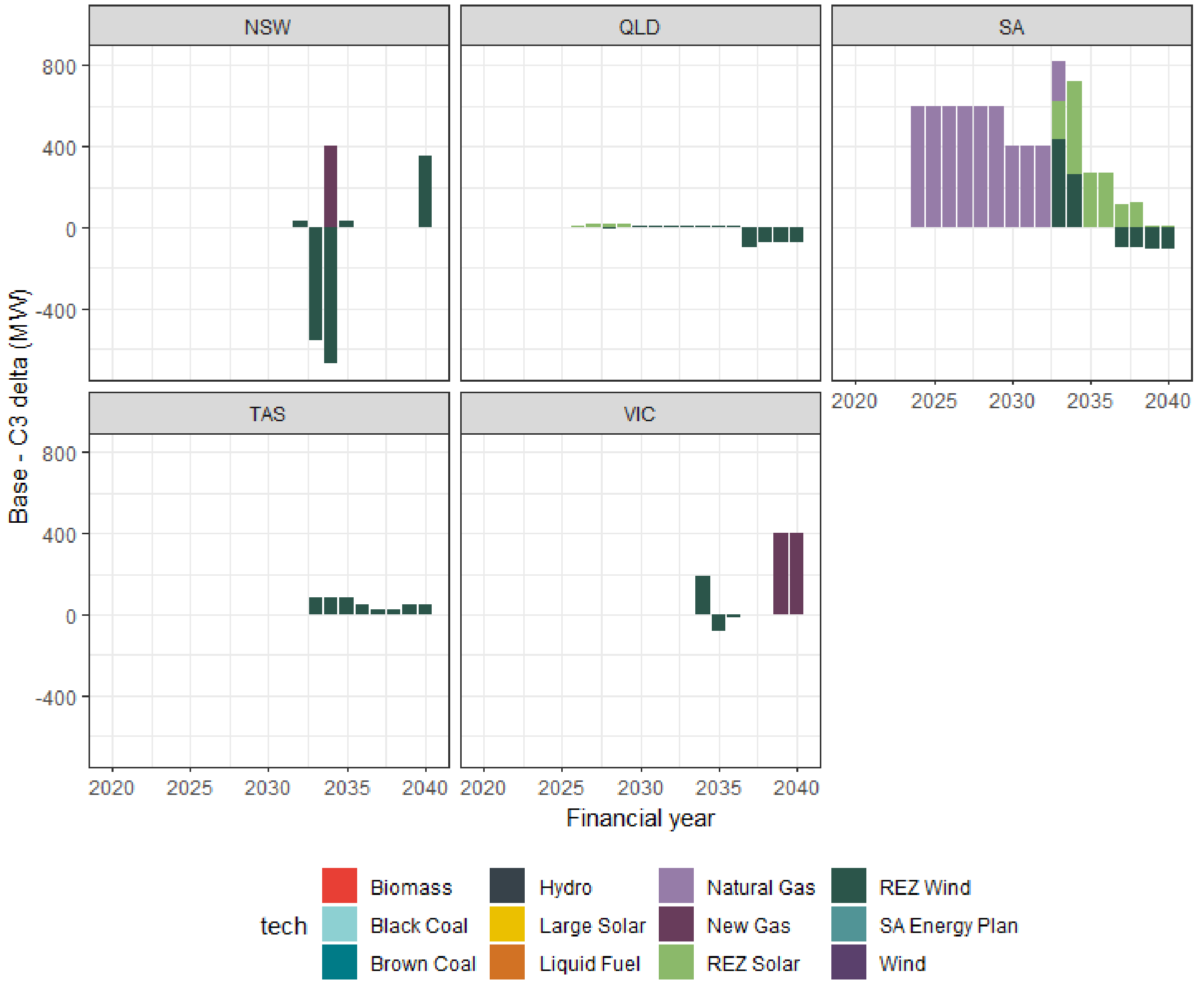
This analysis informs the conclusions presented in the next section.

Summary of further modelling

ElectraNet's further modelling presents Base and C3 states of the world that are in closer alignment than they were in the PACR modelling. The key differences in the states of the world, which drive most of the results, are the presence of the interconnector in the C3 state of the world, and the alleviation of the two-unit constraint when the interconnector is commissioned. These cases do not include a number of constraints that were present in the PACR that drove key outcomes, for example the minimum capacity factor assumption on South Australian gas and the exogenous retirements of South Australian gas generators.

The investment results for generation in the Base and C3 states of the world are similar in the further modelling. **Figure 21** presents differences in generation investment results between the Base and C3 states of the world, broken down by region and fuel type. While there are differences in some years in regions outside South Australia, these differences generally do not persist as the overall investment paths between cases do not differ substantially. The main difference is in South Australia, which sees later retirement of Torrens B in the Base case (likely for reserve margin reasons) and investment in solar and wind brought forward more materially than in other regions.

Figure 21: Year-on-year differences in generation investment, Base and C3 cases, 'AER Sensitivity 1'



Source: Frontier Economics analysis of ElectraNet modelling output

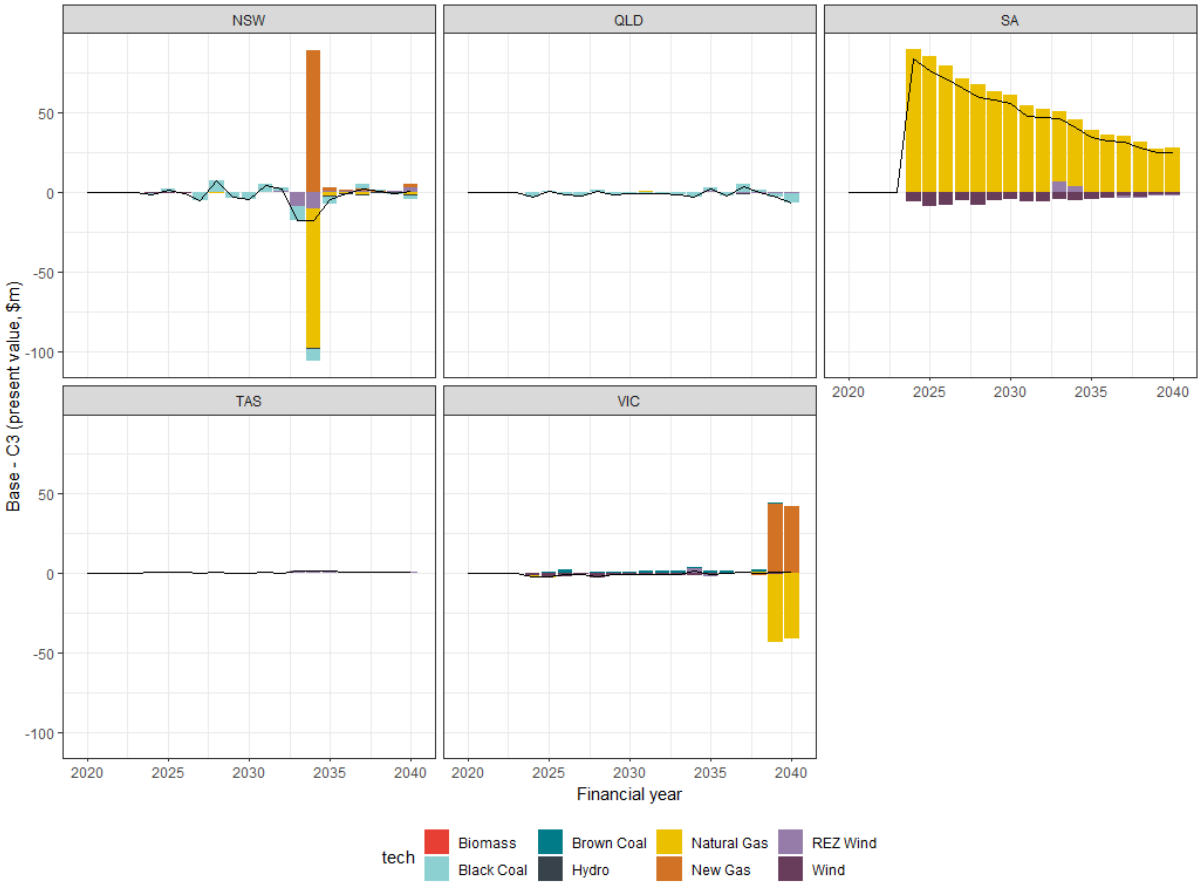
Note: REZ Wind and REZ Solar refer to entrant (i.e. modelled) wind and solar; Wind and Large Solar refer to existing (committed) wind and solar.

Generation costs between the Base and C3 states of the world are the largest benefit category in the further modelling cost-benefit analysis by a wide margin. Cost differences between the Base and C3 states of the world, in present value terms and broken down by region and fuel type, are illustrated in **Figure 22**. The lines in **Figure 22** represents the net difference between costs in each state of the world. In most regions and most years, the net difference is close to zero, except for South Australia where there is a large and persistent difference in costs of gas generation.

The primary driver of differences in generation costs between the Base state of the world and Option C3 in the further modelling relates to the large volume of output from South Australian gas-fired generation in the Base state of the world. The majority of this gas output is attributable to the two-unit constraint, although the direct cost output is only partially[50] attributable.

[50] If the constraint were not in place, and the gas did not run, the energy would need to be sourced elsewhere

Figure 22: Generation cost differences between the Base and C3 states of the world, 'AER Sensitivity 1'



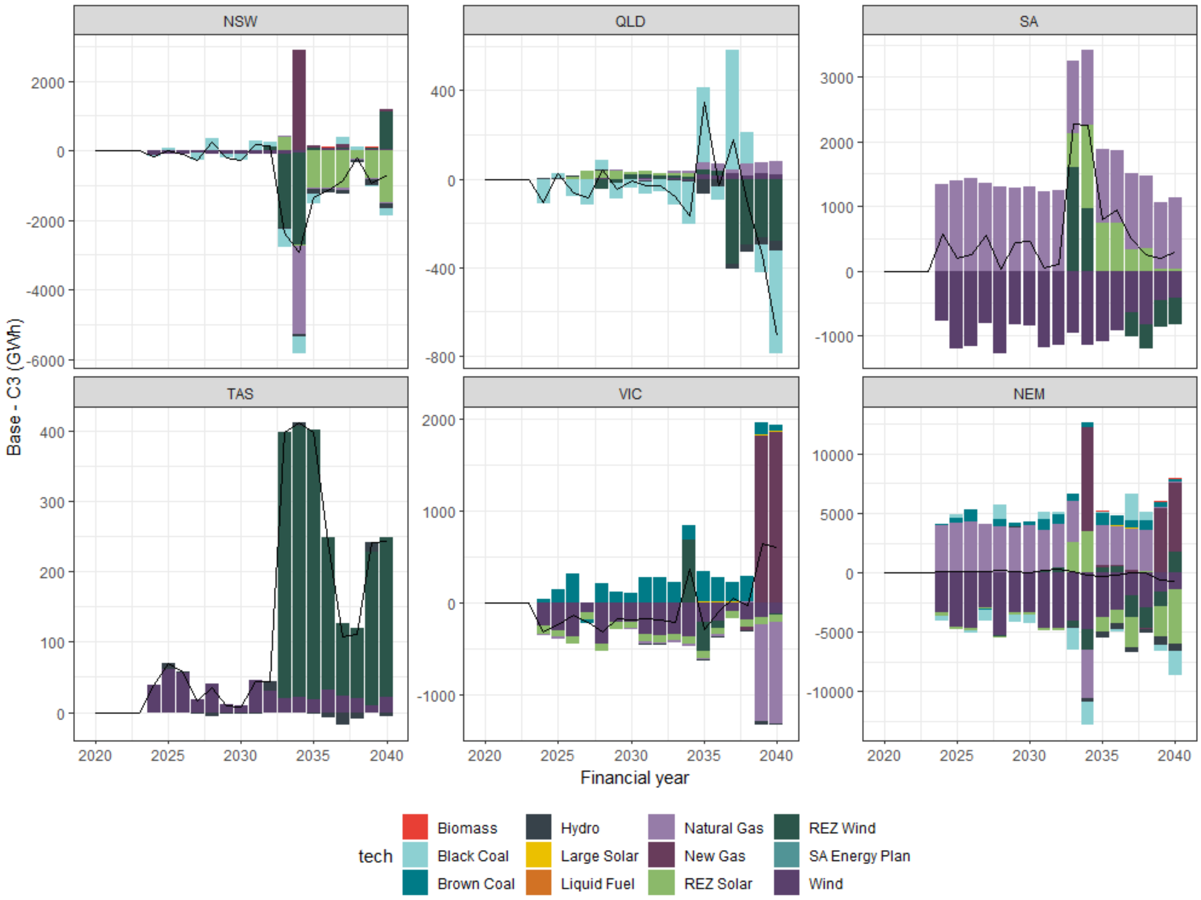
Source: Frontier Economics analysis of ElectraNet modelling output

Figure 23 illustrates the difference in output between the base and C3 states of the world, broken down by region (including the whole NEM) and fuel type. The lines in **Figure 23** represent the net difference between costs in each state of the world. While there are differences within and between regions, output in the NEM overall is largely unchanged between the two states of the world as indicated by the flat line around zero in the NEM facet of the chart.

Figure 23 shows that NSW generation output at an annual level is largely unchanged in the presence of the new interconnector until around 2033, nine years after commissioning. The notable output differences presented include the higher level of in South Australian gas in the Base state of the world, and the reduced output from existing wind[51] in South Australia and Victoria. The higher level of South Australian gas is attributable to the two-unit constraint. The reduced output from existing wind is a result of curtailment, discussed in the following section.

51 On the chart, existing wind is denoted as 'Wind', and new build wind is 'REZ Wind'

Figure 23: Output differences between the Base and C3 states of the world, ‘AER Sensitivity 1’



Source: Frontier Economics analysis of ElectraNet modelling output

Note y-axis scale differences

Issue 1: Disconnect between the LT and ST models

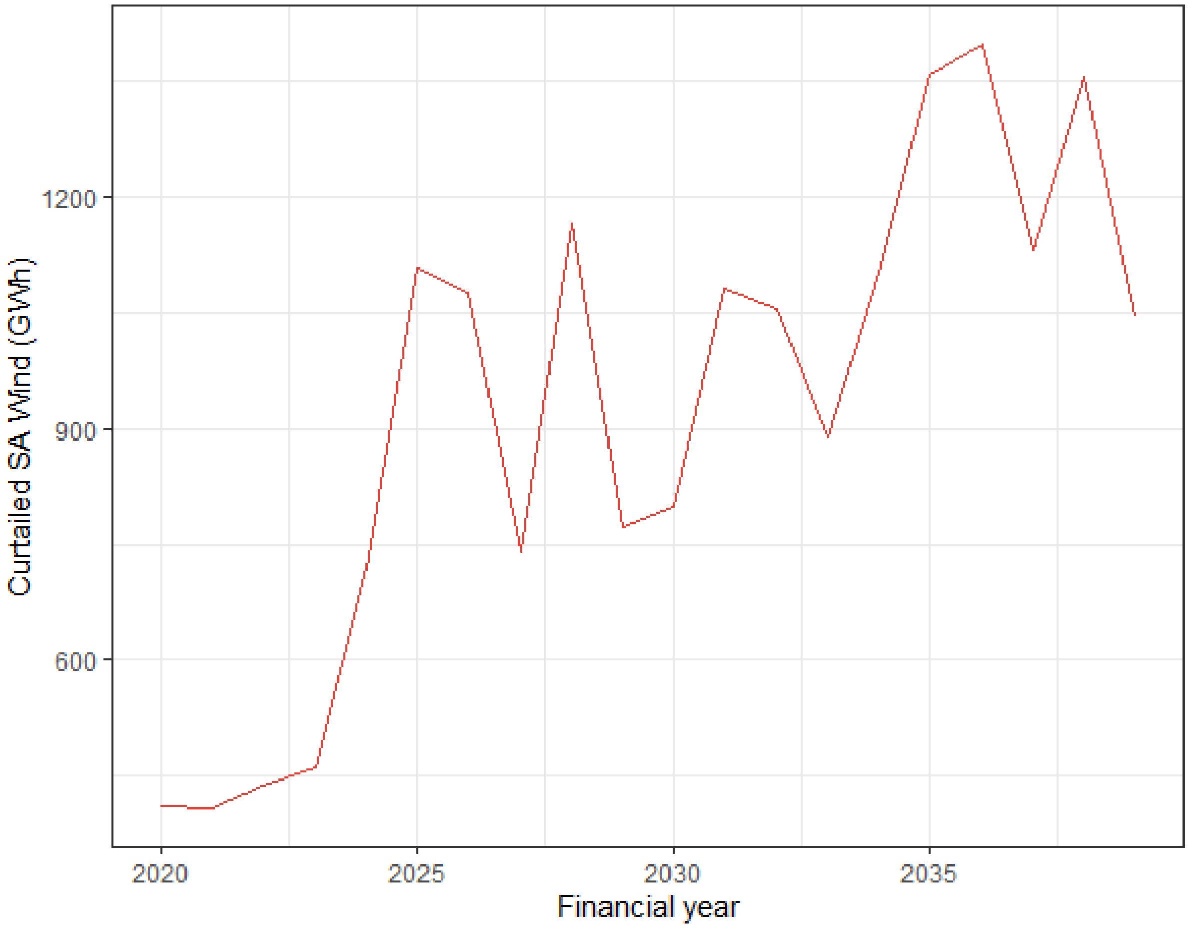
Our analysis indicates that model disconnect problem described in Section 4.3 is present in ElectraNet’s further modelling. The model disconnect problem arises where outcomes in the ST model do not reflect outcomes in the LT model. That is, the LT model is not representative of the system it is designed to represent, as measured by outcomes in the ST model.

The model disconnect issue is evident in a comparison of prices between the LT and ST models in the further modelling. Average prices between the two models diverge materially from around 2030 in all regions with differences in the order of $20/MWh to $55/MWh. This indicates that outcomes in the LT model, which drive investment, are not reflective of outcomes in the best representation of how the system actually operates, i.e. the ST model. For example, average prices in 2033 in South Australia in the Base state of the world are around $74.50/MWh in the LT model and around $39.20/MWh in the ST model. Investment decisions are made on the basis of outcomes that drive an average marginal price of $74.50/MWh. However, when these investment decisions are applied in the ST model – which includes more detail on how the system is able to operate – the simulated average marginal price is $39.20/MWh. This demonstrates that the investment decisions derived by the modelling are based on outcomes that do not reflect ‘reality’ as determined by the ST model, and are therefore suboptimal.

The disconnect between the LT and ST model is also apparent in the shape of prices across the day. In NSW in 2036, for example, the LT model sees price signals of around $160/MWh on average in the evening, whereas the same investment in the ST model produces outcomes of around $60/MWh for the same time period. Another example is the impact of solar, which reduces prices in both the ST and LT models during daylight hours. However, the resulting daylight hour prices are higher in the LT model than in the ST model, which means the LT model is likely to invest in solar that does not make sense (e.g. may lead to curtailment) in the ST model.

It appears that inefficient investment caused by this disconnect issue leads to substantial generation curtailment in the further modelling. **Figure 24** illustrates the quantum of curtailed wind in GWh in the Base state of the world. From 2020 to 2023-2024 the magnitude of curtailed wind is in the ballpark of recent historical curtailed wind in South Australia reported by AEMO[52] at 268GWh for financial year 2018-2019. From 2023-2024, the amount of curtailed wind in the model in South Australia increases from around 400 GWh to between approximately 750 and 1,500 GWh. We noted some curtailment of South Australian wind under Option C3, but not to the same extent, as can be inferred from **Figure 23**.

Figure 24: Curtailed wind in the Base state of the world, 'AER Sensitivity 1'



Source: Frontier Economics analysis of ElectraNet modelling output

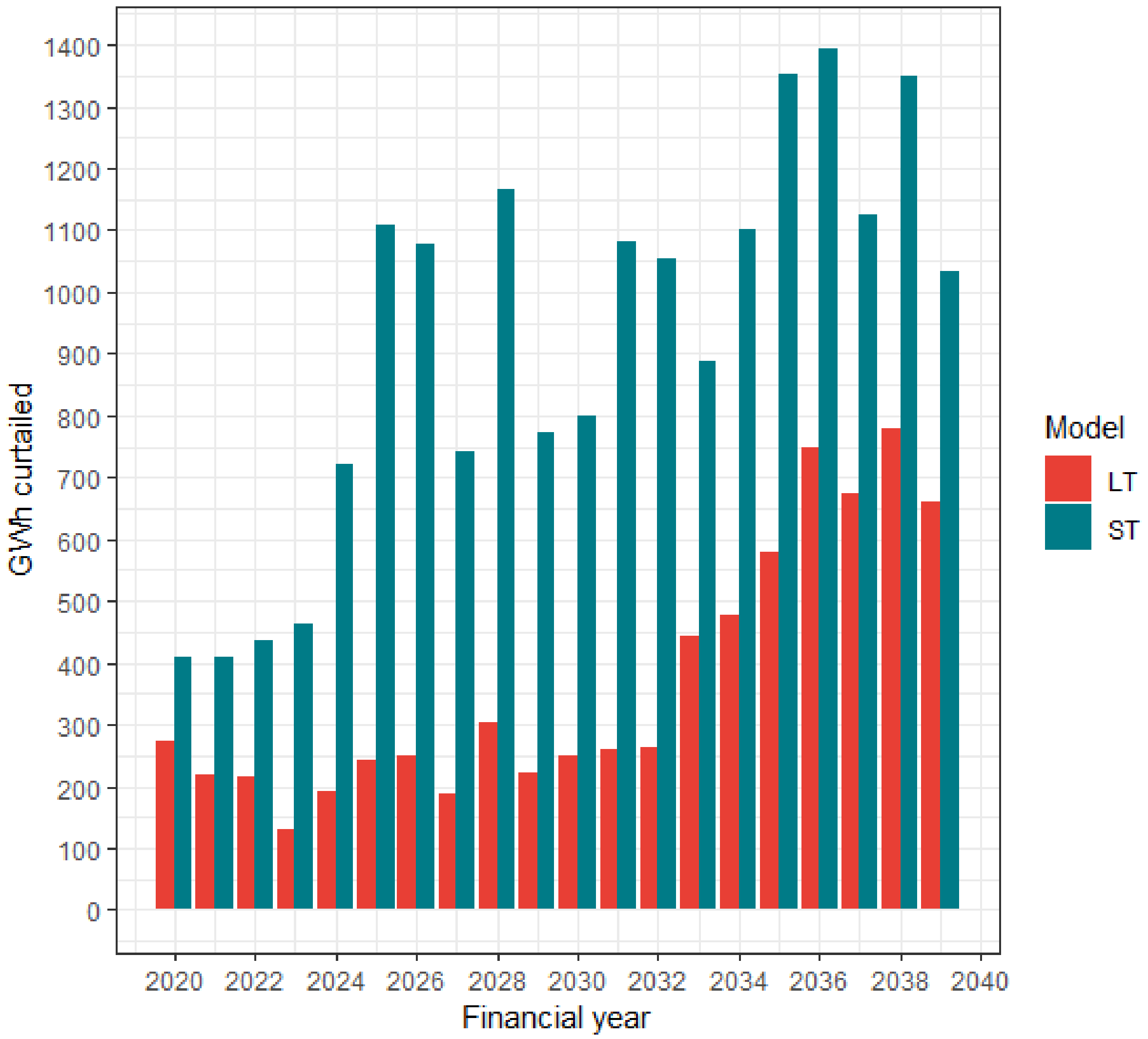
[52] AEMO QED Q2 2019, available https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q2-2019.pdf (see associated data book)

We identified several indirect reasons for this spilled wind in our analysis of ElectraNet's modelling data. These include:

- High levels of rooftop and utility solar in South Australia and Victoria
- Victorian interconnectors being constrained north to NSW and south to Tasmania, particularly during times of solar output
- Some Victorian brown coal having a lower SRMC than wind (meaning wind is spilled before brown coal output is reduced)

The disconnect between the LT and ST models are evident in comparisons of the amount of wind curtailed in the LT model vs the amount of wind curtailed in the LT model. These differences are illustrated in **Figure 25**.

Figure 25: Curtailment differences in South Australian wind generation between the LT and ST models in the base state of the world, 'AER Sensitivity 1'



Source: Frontier Economics analysis of ElectraNet modelling output

Note – this chart includes only committed South Australian wind generators that have corresponding ISP profiles. REZ (uncommitted) wind and Hallett 4/5 are not included.

The LT model does not see nearly as much wind curtailed as in the ST model, meaning that the signals, for example, to build storage or not build additional solar, are muted. This will to lead to inefficient investment paths, and in this case, increase costs in the Base state of the world.

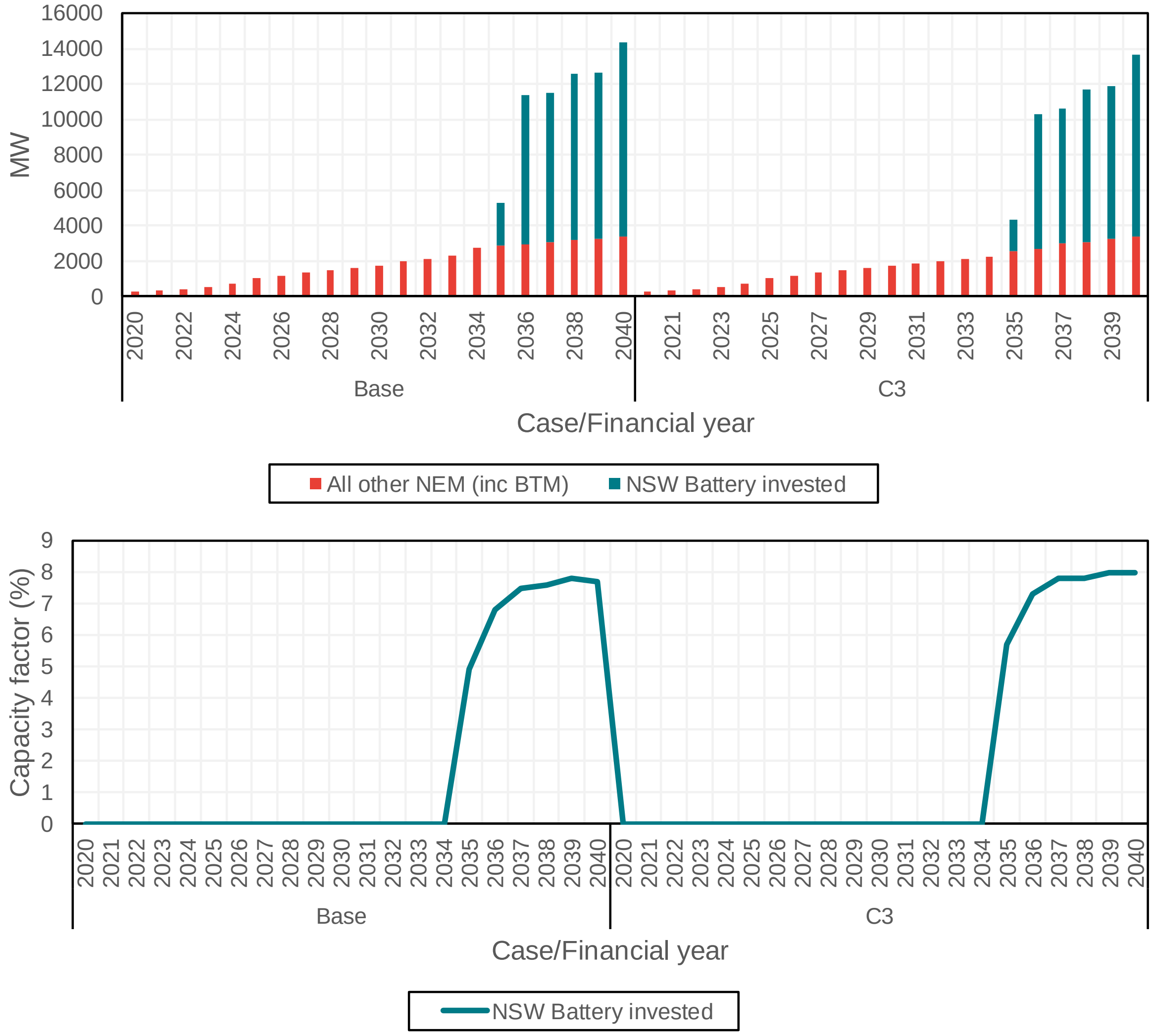
Issue 2: Storage investment results

The storage build cost category is one of the main sources of net benefit in ElectraNet's further modelling. We investigated high levels of NSW utility-scale battery investment (>10GW) which drives the majority of the benefit in this category.

The storage build cost category is $221m more expensive in the Base state of the world than the Option C3 state of the world due to more investment by the model in Northern SA pumped hydro and NSW utility-scale batteries. These contribute $64m and $157m NPV respectively to the total build cost category difference – that is, there is NPV $64 million worth of Northern SA pumped hydro and NPV $157m of NSW battery built by the model in the Base case that is not built in Option C3.

While additional storage in the Base state of the world is a likely outcome without the presence of an interconnector, the battery investment in NSW is substantial and appears to be driven by factors other than pure economics. In both the Base and Option C3 states of the world, a large amount of NSW battery is built, but infrequently utilised, as illustrated in **Figure 26**. **Figure 26** illustrates the total amount of storage in the NEM in the top panel, including behind the meter storage, compared with the magnitude of NSW battery investment. The bottom panel illustrates the capacity factor of this NSW battery in each state of the world, which ranges from 5-8%, which roughly corresponds to one daily cycle or less for two hour storage.

Figure 26: Investment levels and capacity factor of storage in ‘AER Sensitivity 1’

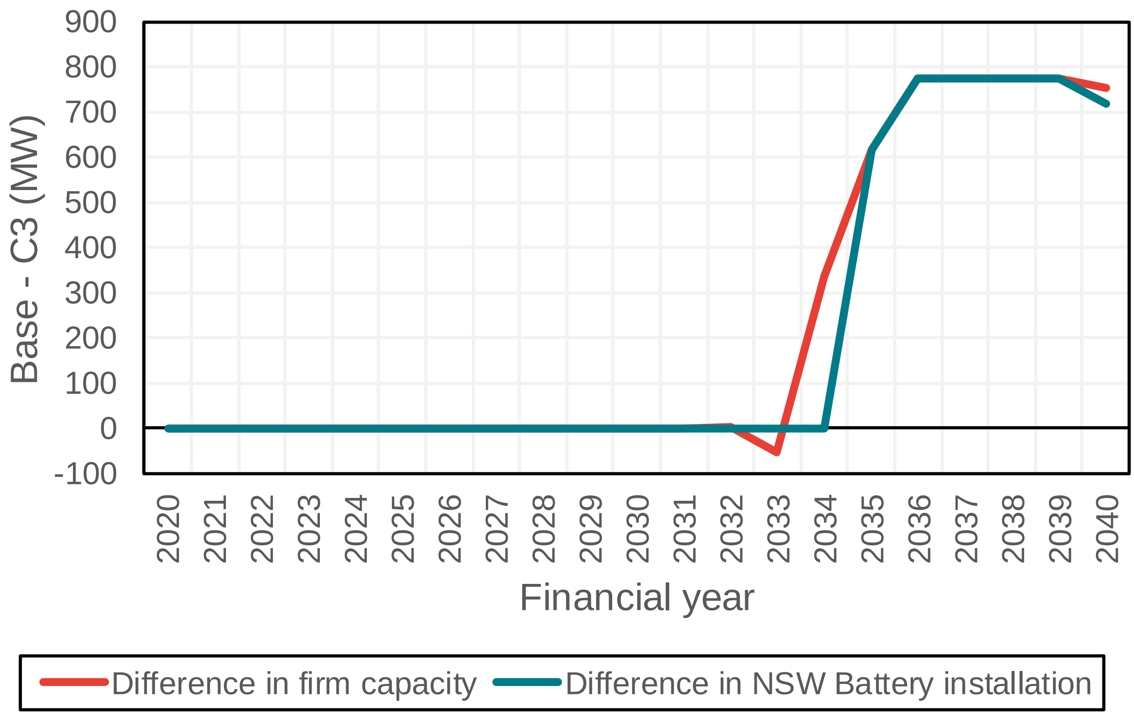


Source: Frontier Economics analysis of ElectraNet modelling

It appears that this battery investment is a result of the reserve margin constraint binding in NSW from 2033. Modelled investment in batteries increases over time as peak demand grows, and these batteries have low utilisation rates. Battery storage is one of the cheapest forms of non-derated generation available – i.e. one of the cheapest ways of meeting the reserve margin constraint.

The difference in firm capacity between the base and C3 states of the world is mostly constant from 2036, suggesting that the firm capacity requirements (i.e. the total reserve margin) in the base case are approximately 775MW higher in the base case than in the C3 case. The difference in firm capacity from the Base and C3 cases is illustrated in **Figure 27**.

Figure 27: Difference in firm capacity and utility battery investment, NSW (Base – C3)



Source: Frontier Economics analysis of ElectraNet modelling

The difference in the firm capacities in each state of the world appear to be the approximate capacity of the interconnect. If the reserve margins do differ by this value, the impact of the interconnector in a reduction of the reserve margin is being counted in both South Australia, where the firm capacity attributable to interconnection increases from 50MW to 850MW with the introduction of the interconnector, and in NSW, where the reserve margin reduces as described. As AEMO forecasts coincident peak demand, this means the impact of the interconnector would be double-counted. The magnitude of this impact is $156m NPV[53], the value attributable to the difference in NSW battery invested, or approximately 58% of the net benefit.

Issue 3: Preferred option

We have considered whether the preferred option (Option C3) would remain the preferred option if all other options considered in the PACR were also tested under the assumptions used in the further modelling.

Our analysis indicates that the ability to alleviate the two-unit minimum constraint in the further modelling is a major source of benefit via a net cost reduction in the Option C3 state of the world. We consider it is likely that a reasonable portion of this value would also be attributable to the other interconnection options considered in the PACR.

Furthermore, the role of NSW black coal in reducing total costs in the interconnector cases in the further modelling is diminished, with more NSW black coal output in the base state of the world than in the C3 state of the world. In contrast, NSW black coal was a material benefit in the C3 state of the world in the PACR modelling, which contributed to Option C3 being selected as the preferred option.

[53] Less a comparatively small amount to account for the storage not able to be utilised if not invested in

As the residual benefits of interconnection appear less material than the ability to alleviate the two-unit minimum constraint, interconnector options considered by ElectraNet that have lower capital costs – such as Option D, the interconnector with Victoria, which has a capital cost that is around $300 million lower than Option C3 – appear likely to provide comparable levels of benefit to Option C3, but at a lower capital cost.

5.3 Conclusion

For the reasons outlined in the preceding sections, we are of the view that the PACR modelling does not present a robust estimate of the net benefits of the options canvassed.

We have had less time to review ElectraNet's further modelling. However, in our limited review, we have identified three main issues which are discussed in sections 3, 4, and 5. These issues include:

- that we think that benefits in the AER sensitivities are overstated.
- the alternatives to alleviate the two-unit minimum constraint – which is crucial to the determination of net benefits – have not been explored[54].
- that the preferred option may change under the further modelling assumptions

These are discussed in the following sections.

Benefits overstated in AER sensitivities

We have outlined several aspects to ElectraNet's further modelling that may indicate that benefits in the AER sensitivities are overstated.

In Section 5.2, we noted that investment outcomes, as determined by the LT model, are inefficient once assessed in the ST model. This means ElectraNet's investment results from the LT model do not make sense in context of the 'real world' as assessed in the ST model. The investment outcomes provide the basis for the costs and benefits determined in the ST model which are used in the cost-benefit analysis for the RIT-T. In Section 4.3, we noted that there will always be some degree of disconnect between ST and LT models of this type, and the extent to which a disconnect is reasonable is subjective. Our analysis in Section 5.2 indicates that the disconnect in this instance is material.

In Section 5.2, we noted that the interconnector appears to benefit the reserve margin on the South Australia and NSW sides, i.e. the benefit of the interconnector in meeting peak demand may be being double counted. If this is the case, then we estimate that the benefit of the interconnector is being overstated by around $160m NPV.

In Section 3.7.1, we noted that ElectraNet's further modelling included substantial levels of coal two-shifting. This is likely to increase the benefit of increased interconnection, especially where the two-shifting can occur in directly connected regions.

There are a number of other issues identified which are less clear in terms of directional impact on ElectraNet's result, for example the demand traces not reflecting other traces used in the model, as described in Section 3.

[54] We note that the PACR included a non-interconnector option. However, this non-interconnector option was a not a credible option under the definition provided by the RIT-T, and it did not reflect the best assumptions around security (i.e. the four synchronous condensers) at the time.

Alternatives to alleviate the two-unit minimum constraint

In Section 5.2, we noted the importance of the two-unit minimum constraint to the net benefit result observed in ElectraNet's further modelling. In Section 3.6, we noted the reasons AEMO had provided for the existence of the two-unit (and one-unit) minimum constraint.

We have concerns that this constraint is fundamental to the business case of the interconnector option, but no alternatives to alleviate it have been canvassed.

Based on AEMO's description of planning assumptions requiring synchronous units to be directed on, we see no reason why pumped hydro would not satisfy these requirements and be able to alleviate the two-unit (and one-unit) minimum constraints. If the presence of additional pumped hydro were able to relieve the need to have one or two gas units operating, and if the LT model had visibility over costs arising in the ST model (i.e. the LT model was more likely to make efficient investment decisions), then we consider that new investment in pumped hydro in South Australia may well be able to provide similar benefits to Option C3. And, if the capital cost of new investment in pumped hydro in South Australia is lower than the capital cost of Option C3 (and the other interconnector options) new investment in pumped hydro in South Australia may be the preferred option.

The status of the preferred option

As outlined in Section 5.2, we have concerns that Option C3 may not be the preferred interconnector option under the assumptions utilised in the further modelling. Further, a non-interconnector option (as described above) may also be preferable.

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