Hon Dan
van Holst Pellekaan MP

Government of South Australia

MEM18D0875

Mr Rainer Korte
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Dear Mr Korte

Thank you for the opportunity to comment on your Project Assessment Draft Report for the SA Energy Transformation RIT-T. I attach a submission for your consideration.

We are committed to providing South Australians with an electricity system that is affordable, reliable and secure. To achieve this, we have committed to a suite of energy reforms including strengthening the network, making storage work and rewarding consumers for managing their own electricity demand.

As you are aware, a key component of our energy policy is to have in place, by mid-2021, an interconnector between South Australia and New South Wales. Modelling produced by ACIL Allen has shown that interconnection, coupled with our other policies and broader developments in the market, will see a substantial fall in wholesale electricity prices.

Work undertaken by ElectraNet in the SA Energy Transformation RIT-T and by the Australian Energy Market Operator in development of the Integrated System Plan has supported our view that an interconnector between South Australia and New South Wales will provide substantial consumer benefits as soon as it becomes operational.

Modelling obtained by ElectraNet from ACIL Allen estimated that the interconnector would reduce annual residential customer bills by up to $30 in South Australia and $20 in New South Wales.

We are committed to deliver these savings to consumers as soon as possible and have committed up to $14 million for an early works package to accelerate delivery of the interconnector. In addition, PwC and Jacobs were engaged to undertake independent analysis of project variants to accelerate market benefits through a phased delivery of the interconnector.

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Technical assessment by PwC and Jacobs of project variants ruled out single circuit and HVDC options due to cost, limited capacity and minimal network security benefits. Project variants that warranted further analysis all related to a phased delivery of the Robertstown-Buronga-Wagga solution.

PwC and Jacobs found that there is an opportunity to accelerate and energise a first phase of the interconnector by 2021 with initial benefits flowing from that point onwards. Early energisation of Robertstown-Buronga would provide South Australia access to solar and wind generation around Broken Hill and Buronga. It would also allow South Australia to export its renewable generation to NSW during the evening.

Modelling shows that whilst there are additional costs associated with phased delivery, they are offset by the accelerated delivery of market benefits. Importantly, the report highlights that to realise the full benefits of integrating with NSW there is a requirement to construct the link to Wagga Wagga.

Project variants also considered whether there is merit in progressing the Buronga to Red Cliffs extension concurrently with the first phase. The construction of this line is relatively minor and will strengthen the Buronga grid connection. PwC and Jacobs consider this will allow additional import and export of generation and enhance network security.

We consider there is merit in ElectraNet considering a phased approach to delivery of the Robertstown to Wagga solution to bring forward benefits for consumers.

If it will not delay concluding the RIT-T, ElectraNet should also consider the merit of the Buronga to Red Cliffs extension to meeting the objective of facilitating South Australia's energy transformation, while improving system security and helping lower electricity prices. I acknowledge that in the absence of the consideration of this extension under the SA Energy Transformation RIT-T, it will be considered in the Western Victoria Renewable Integration RIT-T.

Thank you again for the opportunity to comment on the SA Energy Transformation RIT-T and I trust that the attached submission is of assistance in bringing forward benefits for South Australian consumers.

My Department for Energy and Mining will continue to work with you to progress the project and will support you where practical in pursuing the recommendations in the submission.

Yours sincerely

Hon Dan van Holst Pellekaan MP
Minister for Energy and Mining
20 / 9 / 2018

Enc.

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SOUTH AUSTRALIA ENERGY TRANSFORMATION PADR FEEDBACK

Final Report

SEPTEMBER 2018

D18124217

Attribution to: Department for Energy and Mining, the Government of South Australia, South Australia Energy Transformation PADR feedback September 2018.

Executive Summary

The South Australian government has publicly supported a proposal for a new interconnector from South Australia (SA) to New South Wales (NSW) in order to improve system security, reliability and affordability for households and businesses in SA.

The SA Department for Energy and Mining (DEM) has closely monitored ElectraNet's investigation of interconnector and network support options as part of the Regulatory Investment Test for Transmission (RIT-T).

In this submission, DEM has considered and assessed alternative project variants that can complete early works before 2022 and potentially accelerate market benefits through a phased delivery of the interconnector.

ElectraNet's preferred project option between SA and NSW generates net market benefits of around $1 billion which could be delivered from 2022-2024 onwards.

ElectraNet has published a Project Assessment Draft Report (PADR) as a second formal step in the South Australia Energy Transformation (SAET) RIT-T process. The identified needs of the PADR include:

- lowering dispatch costs through increasing access to supply options across regions
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies, through improving access to high quality renewable resources across regions
- enhancing security of electricity supply, including management of inertia, frequency response and system strength in SA.[1]

ElectraNet has investigated four broad options including:

A. non-network option

B. interconnector between SA and Queensland (QLD)

C. interconnector between SA and NSW including the preferred option C.3i from Robertstown to Wagga with series compensation

D. interconnector between SA and Victoria (VIC).

The preferred option, C.3i, generates the highest net benefits in all three scenarios (low, central and high)[2] and could be delivered between 2022 and 2024.

[1] ElectraNet, 2018-07-06-SAET-PADR-Final.pdf, 29 June 2018, p.5

[2] The central scenario represents the best estimate of the evolution of the market going forward while the low and high scenarios represent the lower and upper end of the potential range of realistic net benefits from the options.

There are opportunities to accelerate early works and energise a first phase interconnector by 2021 with initial benefits flowing from that point onwards.

There are diverse views on the construction timelines of the project. DEM considers that a number of opportunities should be investigated and validated to reduce project delivery timeframes. Such opportunities include adopted strategies such as the use of multiple construction teams and early contractor involvement.

Acceleration outcomes are also likely to come from opportunities in the approvals process. It is feasible that regulatory approvals could be in place by mid-2019 and land approvals by the end of 2019 (with a focused prioritisation on the Robertstown-Buronga works).

Combined with minor works variations, this could see early energisation achieved along with a project completion date of 2023 for the full interconnector from SA through to Wagga Wagga. To achieve such acceleration, it is likely some works or related commitments may be required in advance of achieving all approvals.

In this report, DEM has considered and assessed alternative project variants that can complete early works by 2021 and potentially accelerate market benefits through a phased delivery.

Analysis of DEM's project variants has adopted the assumptions of the ElectraNet modelling (to the extent possible).

DEM initially assessed five project variants. Project variants focus on the energisation of the Robertstown-Buronga interconnector (approximately 330 kilometres) by 2021 before completion of the project works from Buronga to Darlington Point and Wagga Wagga (approximately 550 kilometres) by 2023. Some of the proposed variants include an extension of the 220 kV transmission line between Buronga and Red Cliffs for enhanced security.

A technical assessment framework was developed from ElectraNet's network technical assumptions and tailored for DEM's objectives. Three out of five project variants satisfied the preliminary technical review and advanced to the next stages of analysis including the estimation of capital and operating costs and market modelling. Refer to Table 1.

A key point for phased development works is that the interim capacity of import into SA can be supported by south west NSW solar and wind generation. Registered renewable generation in Broken Hill and around Buronga amount to 250 MW. A further range of unannounced generation along the 220 kV network between Buronga and Darlington point amount to in excess of 500 MW. This will generally support import into SA without overloading the existing NSW network.

Table 1 – Project variants proposed for cost benefit analysis by DEM

Ref	Description	Thermal limit (MW)	N-2 transient limit (MW)	
		Post contingency	Combined import limit (400 MW load relief)	Combined export limit (500 MW generation trip)
C2	Robertstown-Wagga 275 kV line via Buronga	600	800	950
C.3i	Robertstown-Wagga 330 kV line via Buronga, plus series compensation	800	1,300	1,450
C.2i	Early works Robertstown-Buronga 275 kV double circuit with additional 220 kV from Buronga to Red Cliffs and final upgrade to C.3i	600	850	1,000
C.2ii	Early works Robertstown-Buronga 275 kV single circuit and final upgrade to C.3i	300	650	850
C.3ii	Early works Robertstown-Buronga 330 kV double circuit with additional 220 kV from Buronga to Red Cliffs and final upgrade to C.3i	800	950	1,050

Key

(light grey)	Existing ElectraNet project option
(teal)	DEM project variant (cost benefit analysis undertaken)

Source: Jacobs analysis, ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018

To enable comparison with the results of ElectraNet's PADR, the analysis of DEM's project variants has adopted the assumptions of the ElectraNet modelling (to the extent possible).

Key reference assumption books include the network technical assumptions[3], market modelling report,[4] the market modelling and assumptions databook[5] and the basis of capital cost estimates.[6]

Overall, project variants can deliver early works; any project acceleration will bring forward benefits and the costs of such acceleration and associated variations will likely be offset by the timing and quantum of these benefits.

Figure 1 shows the net market benefits under all scenarios considered and the weighted scenarios outcome. The net benefits for each project option are calculated by subtracting the PV of costs from the PV of gross market benefits, as outlined in Sections 2, 3 and 4.

The additional costs associated with the early works variant predominantly result from impacts to construction being undertaken in more complex settings eg live line works during the final phase to Wagga Wagga. However, modelling indicates that these costs are offset by the accelerated delivery of market benefits. Variant C.3ii shows a marginally higher NPV in the 'Central' scenario and C.2i

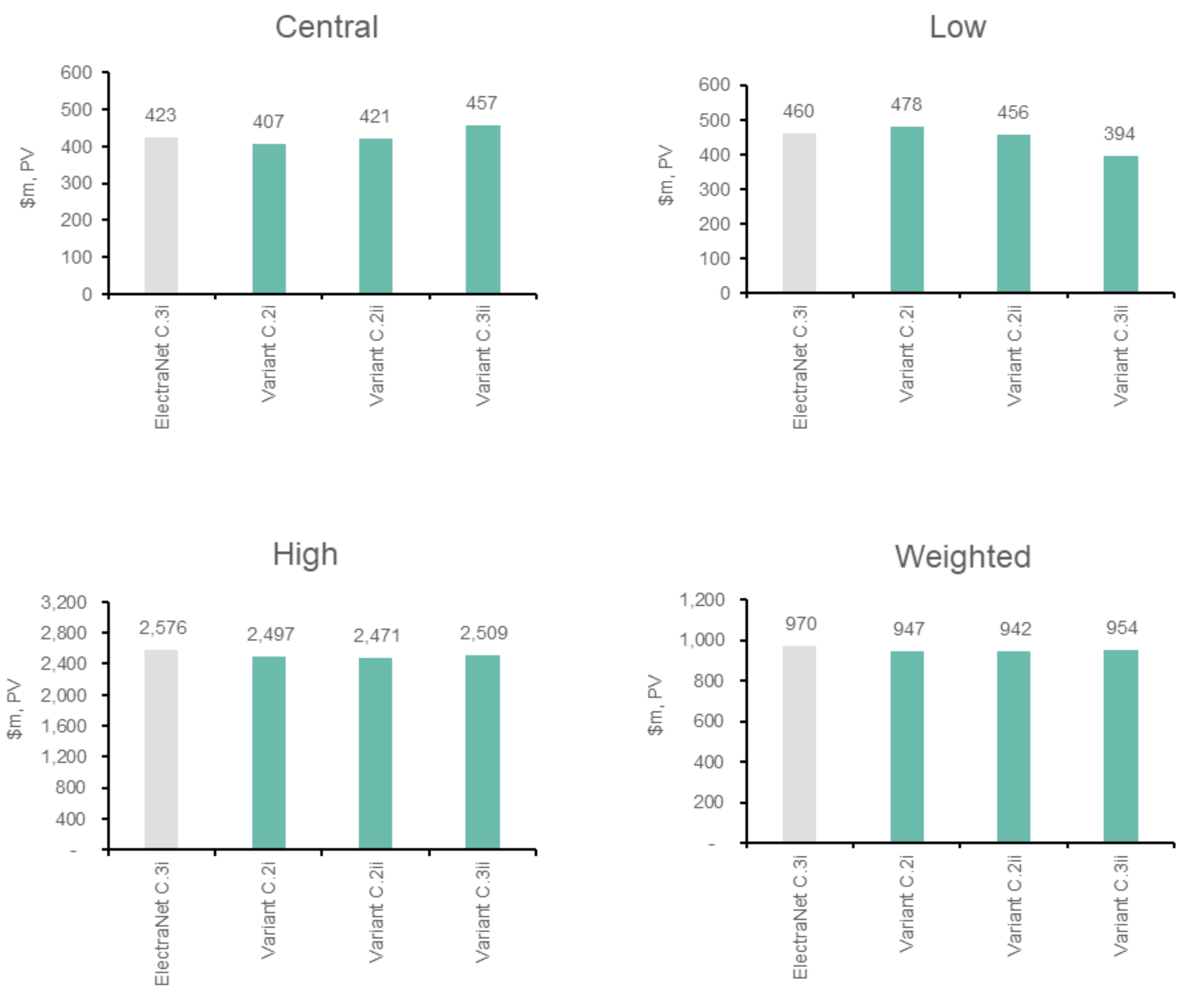
[3] ElectraNet, SAET-RIT-T-Network-Technical-Assumptions.pdf, June 2018
[4] ACIL Allen, Market-modelling-impact-new-interconnect_report-04072018.pdf
[5] ElectraNet, 2018-07-09 SA-Energy-Transformation-Modelling-and-Assumptions-Data-Book.pdf
[6] ElectraNet, SAET-RIT-T-Basis-of-Estimate-for-PADR.pdf, June 2018

shows a marginally higher NPV in the ‘Low’ scenario. Key drivers of these benefits include avoided fuel costs, avoided generator fixed costs and generator and storage capex deferral.

Under some scenarios the net market benefits are marginally lower than those estimated for ElectraNet’s preferred option C.3i. We note that some are also higher. The modelling outcomes indicate within the accuracy achievable in the time available for developing this report, that the variants are worthy of further investigation and consideration by ElectraNet. Further modelling should be undertaken to understand whether additional value (beyond early realisation of benefits) is achievable.

Additional benefits of program acceleration such as de-risking major program delay points are likely, although the value of risk adjustments have not been quantified as a result of such outcomes.

Figure 1 – Net market benefits – all scenarios



Source: ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018, PwC and Jacobs analysis

Note: Weightings have been applied to each scenario in line with ElectraNet’s approach; central 50%, low 25%, high 25%.

Key

Existing ElectraNet project option

DEM project variant

Further work is required to validate all of the assumptions including the net market benefits and to agree the regulatory approval process for the project variant

The findings of this analysis show that there is potential for early works of ElectraNet's preferred option C.3i to generate almost identical net market benefits ($954 million versus $970 million Weighted NPV). We recommend that this early works variant is considered in the design of project delivery. We understand that this variant can be considered in the current RIT-T process given the proposed variation is relatively minor and has distinct timing advantages to South Australia as increased system security is available earlier than under an unphased construction approach.

Buronga-Red Cliffs extension

Two of the three proposed variants include an extension of the 220 kV transmission line between Buronga and Red Cliffs. Currently the Buronga-Red Cliffs extension is considered in the Western Victoria Renewable Integration RIT-T. AEMO was granted a PADR extension for this RIT-T to 31-Dec-2018 in order to respond to the Integrated System Plan (ISP) and the SA-NSW interconnector studies. This section of the transmission network is contingent on the commissioning of the SA-NSW interconnector. Preliminary modelling of the Buronga-Red Cliffs extension has been analysed by AEMO under an alternative reference case where the SA-NSW interconnector is already assumed to be in place in its totality.

Consultations with the AER have indicated that the Buronga-Red Cliffs project variant could be incorporated into the SAET RIT-T process without disrupting the current SAET approvals pathway and timeframes.

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Glossary

Term	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COP21	21st Conference of the Parties to the UN Framework Convention on Climate Change held in Paris in December 2015
DEM	Department for Energy and Mining (South Australia)
DSP	Demand Side Participation
FCAS	Frequency Control Ancillary Services
FOM	Fixed Operating and Maintenance Costs
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
ISP	Integrated System Plan
LRET	Large Scale Renewable Energy Target
MRL	Minimum Reserve Level
NCAS	Network Control Ancillary Services
NEG	National Energy Guarantee
NEM	National Energy Market
NER	National Electricity Rules
NPV	Net Present Value
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PST	Phase Shifting Transformer
PV	Photovoltaic
QRET	Queensland Renewable Energy Target
QLD	Queensland
RET	Renewable Energy Target
REZ	Renewable Energy Zones
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rate of Change of Frequency
SA	South Australia
SAET	South Australia Energy Transformation
SIPS	System Integrity Protection Scheme
SRAS	System Restart Ancillary Services
SVC	Static VAR Compensator
TNSP	Transmission Network Service Provider
VIC	Victoria
VOM	Variable Operating and Maintenance Costs
VRET	Victoria Renewable Energy Target
WACC	Weighted Average Cost of Capital

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1. Technical assessment of project variants

ElectraNet's PADR has assessed four key project options including:

A. Non-network option

B. Interconnector between South Australia (SA) and Queensland (QLD)

C. Interconnector between SA and New South Wales (NSW)

D. Interconnector between SA and Victoria (VIC).

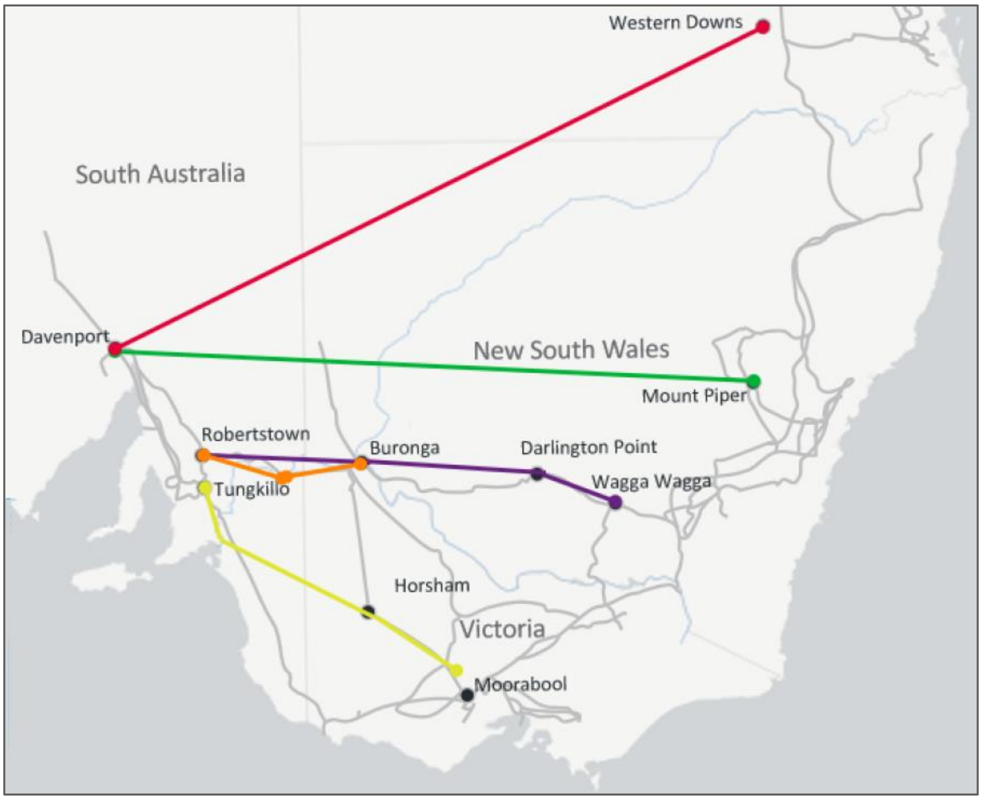
The PADR investigated six variants to the project option C between SA and NSW.

An additional five variants have been considered by DEM to assess the delivery of early works by December 2021 including any necessary staging changes. This technical assessment is designed to identify project variants which merit further analysis of net market benefits.

1.1. Overview of project variants

Project variants have been developed as early works versions of the options presented by ElectraNet in their RIT-T submission. Refer to Figure 2 and Table 2 for a map and description of the variants. Each project variant is assessed in further detail in Section 1.3 below.

Figure 2 – Overview of the options (and variants) assessed in ElectraNet's PADR and DEM's response



Source: ElectraNet, 2018-07-06 SAET PADR Final, Figure E.2

Table 2 – Key of the options (and variants) assessed in ElectraNet's PADR and DEM's response

	Ref	Description	Source
	A	Non-network	ElectraNet's PADR
	B	Davenport-Western Downs HVDC	ElectraNet's PADR
	C.1	MurrayLink 2 HVDC upgrade	ElectraNet's PADR
	C.1i	MurrayLink 2 HVDC upgrade (no staging)	DEM variant
	C.2	Robertstown-Buronga-Darlington Point 275 kV	ElectraNet's PADR
	C.2i	Robertstown-Buronga 275 kV double circuit	DEM variant*
	C.2ii	Robertstown-Buronga 275 kV single circuit	DEM variant*
	C.3	Robertstown-Buronga-Darlington Point-Wagga 330 kV	ElectraNet's PADR
	C.3i	Robertstown-Buronga-Darlington Point-Wagga 330 kV plus series compensation	ElectraNet's PADR
	C.3ii	Robertstown-Buronga 330 kV double circuit	DEM variant*
	C.3iii	Robertstown-Buronga 330 kV single circuit	DEM variant*
	C.4	Robertstown-Wagga 330 kV (bypassing Buronga	ElectraNet's PADR
	C.5	Davenport-Mt Piper 500 kV	ElectraNet's PADR
	D	Tungkillo-Horsham 275 kV	ElectraNet's PADR

Source: ElectraNet, 2018-07-06 SAET PADR Final, Figure E.2

1.1.1. Early works

All project variants, except C.1i, include a final phase to upgrade and complete the works outlined in ElectraNet's preferred option C.3i ie to extend and/or duplicate the line from Buronga to Wagga and upgrade to 330 kV as required.

1.1.2. Buronga-Red Cliffs 220 kV extension

An important element for the higher capacity variants, including C.2i, C.3ii and C.3iii is the construction of a second Buronga-Red Cliffs 220 kV line to strengthen the Buronga grid connection. This line is approximately 20 kilometres in length and the estimated capital cost is approximately $21 million.

The extension would allow additional import and export of generation via the new interconnector. It is designed to enhance network security eg in the event of various outages in NSW, including an outage of the Buronga-Red Cliffs line. Constraints on the Buronga-Red Cliffs 220 kV transmission line, as well as other transmission lines in Western Victoria, may otherwise constrain the transfer capacity of the SA-NSW interconnector.

The Integrated System Plan (ISP) has also identified that the Buronga-Red Cliffs extension would support large-scale renewable generation development (mainly solar), providing increased transfer capacity from Victoria to NSW.

Currently the Buronga-Red Cliffs extension is considered in the Western Victoria Renewable Integration RIT-T. AEMO was granted a PADR extension for this RIT-T to 31-

Dec-2018 in order to respond to the Integrated System Plan (ISP) and the SA-NSW interconnector studies. Consultations with the AER have indicated that the Buronga-Red Cliffs project variant could be incorporated into the SAET RIT-T process without disrupting the current SAET approvals pathway and timeframes.

1.1.3. Export limitations

Transfer limits apply to the potential export of renewable energy from SA to the NEM. The early works of the 275 kV and 330 kV project variants (and to a far lesser degree ElectraNet's final phase project options) provide limited capacity for SA to export renewable energy to the NEM during the day. This is due to the high level of existing, under construction and planned solar PV penetration in the region around Buronga, Red Cliffs and Balranald.[7]

When the final phases are complete, the connection points at Buronga, Darlington Point and Wagga will permit generation to be evacuated onto the high capacity interconnector. Not all generation will flow onto these lines because of the natural division of power flows between parallel networks.

At night, with no solar PV generation, there will be substantially more capacity for SA to export power to the NEM. If sufficient new renewable energy projects come on-line in SA or south-west NSW, generation constraints will likely be required because of the transfer limits.

ElectraNet did not raise this issue in the PADR as the PADR options were complete end-to-end projects. In this context, the early works of DEM's project variants require the export from SA into NSW to be absorbed by the local network from Buronga, without having the higher capacity parallel network for greater transfer as would occur with the ElectraNet options.

These constraints do not impact on export through the Heywood interconnector. Provided there is sufficient phase shifting on the phase shifting transformers (PSTs), then combined export can be directed between the two interconnectors in various proportions.

ElectraNet's PADR includes an HVDC option to Queensland and a 500 kV option to Mount Piper (C.5). ElectraNet's analysis indicated that the relatively higher costs of these options were not outweighed by materially higher market benefits, except in the 'high' scenario. Given the relative costs and benefits of the 500 kV lines for alternate connection points, this report has not considered a 500 kV option between Robertstown and Wagga.

1.1.4. Special purpose equipment

All project variants have assumed that 50 per cent series compensation has been applied on the transmission lines on the basis of the reactive losses that could arise.

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[7] Jacobs analysis indicates that the evacuation of SA export from Buronga onto existing infrastructure, together with the current volume of renewable energy projects under construction including photovoltaic (PV) projects in south-west NSW and north-west Victoria, including future prospective PV projects, effectively contribute to the erosion of the transmission capability.

In addition, it has been assumed that +/-200MVAr static VAR compensators (SVC) have been installed at Robertstown and Buronga. An SVC has also been assumed at Darlington Point for project variant C.3iii.

ElectraNet's proposed interconnector C.3i shows the addition of PSTs at Buronga. These transformers allow the MW flow to be controlled and this feature could be highly desirable.

However, in the event of a network contingency, the PSTs will act to maintain a relatively constant MW transfer. This regulating response is not instantaneous but is subject to a definite time delay as the PSTs tap to their new operating positions. As with any interconnector operating in parallel with another, due consideration will be required to address line loading and constraint issues, and also the potential for circulating power between the interconnectors. Selection and design of appropriate controls, either through market scheduling and or local controls will ensure a properly coordinated response.

1.2. Assessment methodology

DEM's project variants have been assessed against a multi-criteria assessment framework which closely parallels that applied by ElectraNet in the PADR but has been tailored for DEM's objectives.

Key variations to ElectraNet's technical assessment framework are outlined below:

- The options selected are those that have been assessed as capable of delivering early works by December 2021.
- The preliminary technical assessment focuses on the transfer limit early works whereas ElectraNet's assessment was based on a fully completed project. Transfer limits are considered for all project phases in Sections 3 and 4 of this report (market modelling and net present value).
- Transfer capacity for the Heywood interconnector is based on the contingent loss of both circuits. History has shown that such events do occur and, as such, network security is a highly weighted assessment criterion in DEM's assessment framework. DEM's assessment is based on the capability offered by the variant but also operating within and up to the transfer limit envelope defined by ElectraNet.
- In DEM's assessment scenario, transfer limits were based on network thermal capacity, expected local PV generation around Buronga and ElectraNet's defined combined import capability. ElectraNet's assessment has principally been the operation of the network within its thermal rating and up to the transient stability limit, including through the use of 100 MW of battery injection and load shedding where required, for the loss of one interconnector.
- A benchmark indicator was developed by DEM to consider the cost of the early works relative to the transfer limit installed ($/MW based on a Thermal limit).
- Considerations for system strength in the DEM framework were based on ElectraNet's limits applied in their PADR. No independent calculation was undertaken to validate or otherwise the generator caps or the rate of change of frequency (RoCoF) inertia calculations.
- For the remaining criteria, including load shedding, the assessment was consistent with ElectraNet's approach and where relevant, based on any direct numeric assessment ElectraNet had undertaken eg the transient stability limit.

Table 3 – Assessment framework for DEM project variants

Criteria	Assessment factors
Network security	• Capacity of the interconnector and the consequential load shedding required to maintain flows within the interconnector rating • Degree of load shedding and whether this can be accommodated within the battery response.
Delivery date	• Ability of early works of the project variant to meet a 2021 delivery date
Thermal limit	• Thermal rating of the early works interconnector project variant, or where the variant is a single circuit, then 300 MW limit applies • Where the variant is a double circuit, its rating is considered equal to that for a single circuit.
Combined import limits	• Based on advice in ElectraNet's PADR and consideration to the maintenance of transient stability limits and the use of load shedding and battery response to extend import capability.
System strength	• Assessment considers the degree to which the interconnector adds to the system strength through the relative impedance of its interconnection to the remainder of the NEM • Assessment considers the natural consequence of adding additional transmission lines which increases the interconnectivity between points and provides more pathways for the fault current to flow, resulting in higher fault levels ie increased system strength.
$/MW transfer limit	• Preliminary benchmark of early works capital costs relative to the early works MW transfer limit before advancing to detailed market modelling and cost benefit analysis
Rate of change of frequency	• Maintenance of synchronism with the remainder of the NEM means SA system frequency is maintained at NEM frequency, thereby eliminating any RoCoF events. • Assessment considers the degree of load shedding required to maintain the interconnector within its thermal limits and hence remain in service.
Frequency control ancillary services	• Assessment considers the improved security of supply ie the ability of the project variant to provide a second pathway to the remainder of the NEM and hence provide improved opportunity for generators outside SA to participate indirectly in the FCAS market in SA.
Inertia	• The greater network interconnectivity and improvement in system strength offered by the interconnector provides for improved transient stability. The degree of interconnectivity impacts on effective contribution of additional inertia.
Load shedding	• The degree of load shedding is dependent on the interconnector's capacity, and maintaining its flow within that capacity, and on the transient stability limit impact on combined total import.

Source: Jacobs analysis

The purpose of the framework is to identify project variants which satisfy an initial desktop review of technical feasibility and which merit further investigation for cost benefit analysis based on the criteria outlined in Table 3. Selected variants are analysed in Section 2 onwards.

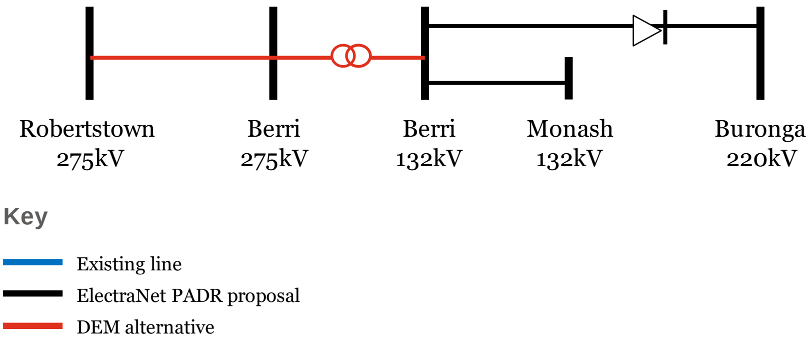
The technical criteria in this analysis are considered from the perspective of their value and benefit to SA. However, the interconnectivity of the network does imply that just as SA will benefit positively from the wider NEM, likewise and for the same reasons the NEM will benefit from the greater connectivity of SA into the NEM. Market modelling in Section 3 onwards considers the benefits to the broader NEM.

1.3. Option modelling

1.3.1. C.1i MurrayLink 2 HVDC upgrade (no staging)

Variant C.1i proposes to build Murraylink 2 with a single 275 kV line from Robertstown to Berri. This differs from ElectraNet's proposed option in that the double circuit 275 kV from Robertstown to Berri and the two transformers at Berri are minimised to a single circuit and one transformer. The HVDC link itself remains at 300 MW thermal limit.

Figure 3 – Diagram of variant C.1i



Source: ElectraNet, SAET-RIT-T-Network-Technical-Assumptions.pdf, June 2018, Jacobs analysis

Table 4 – Variant C.1i technical assessment

Criteria	Description
Network security	Transfer is too small to counteract loss of Heywood interconnector.
Delivery date	2021
Thermal limit	300 MW
Combined import limit	800 MW
System strength	Project variant does not contribute significantly to the fault level.
Early works capex estimate	$813 million
$/MW transfer limit	$2.71/MW
Rate of change of frequency	A supply imbalance would still exist if Heywood flow was larger than the MurrayLink 2 capacity. Rate of change would be slower. May provide more time for loads and generators to respond.
Frequency control ancillary services	Can potentially provide FCAS but needs to be validated.
Inertia	Does not increase system inertia except via control scheme to provide "synthetic" inertia
Load shedding	Transfer is too small to counteract loss of Heywood interconnector. Load shedding is required.

Source: Jacobs analysis

Given the relatively high price and limited capacity, this project variant has been excluded from further analysis of market modelling and net market benefits.

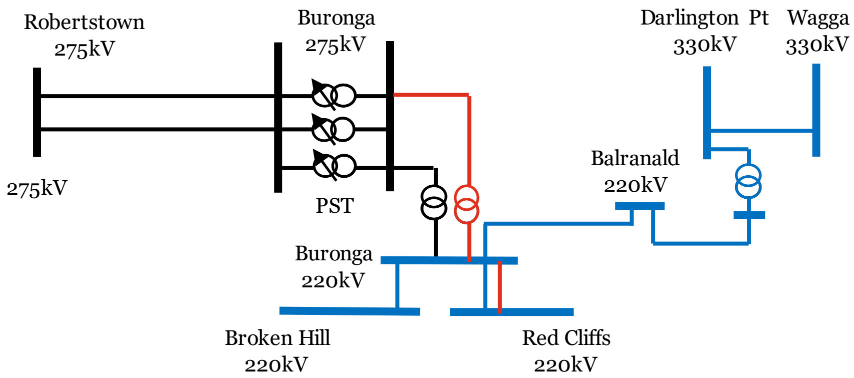
1.3.2. C.2i Robertstown-Buronga 275 kV double circuit

Variant C.2i phases ElectraNet's preferred option C.3i as follows:

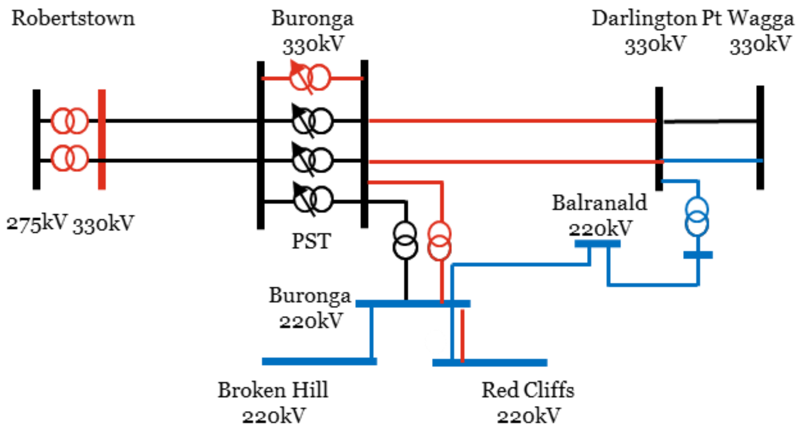
- Early works installs a double circuit from Robertstown to Red Cliffs 275 kV (built at 330 kV) and duplicates 20km Buronga-Red Cliffs 220 kV line (for security).
- Final phase to upgrade the line to 330 kV with new transformers installed at Robertstown, Buronga and Red Cliffs and completes the 330 kV upgrade by extending to Wagga

Figure 4 – Diagram of variant C.2i

Early works



Final phase



Key

Existing line
ElectraNet PADR proposal
DEM alternative

Source: ElectraNet, SAET-RIT-T-Network-Technical-Assumptions.pdf, June 2018, Jacobs analysis

Table 5 – Variant C.2i technical assessment

Criteria	Description
Network security	Network security maintained but transfer capacity is less than the Heywood capacity hence resulting in limited load shedding or battery response.
Delivery date	December 2021
Thermal limit	600 MW
Combined import limit	850 MW
System strength	Improved system strength through AC interconnection.
Early works capex estimate	$553 million
$/MW transfer limit	$0.92/MW
Rate of change of frequency	Effectively eliminated but may require some load shedding or battery response to keep the interconnector within rating.
Frequency control ancillary services	Cannot provide FCAS as there is no dynamically controlling equipment to regulate line flows. However, the improved access to other NEM could permit other NEM generators to provide inter-regional FCAS.
Inertia	Synchronism maintained with remainder of NEM effectively providing additional inertia.
Load shedding	If the combined import is less than the thermal limit, then no load shedding is required. If the combined import is at the combined import limit, then 250 MW of load shedding and battery response is required

Source: Jacobs analysis

This 275 kV variant reduces the initial capital expenditure as it does not require 330 kV works at Robertstown in the first instance. This variant provides redundancy and would allow up to 600 MW transfer capacity (thermal limit).

It is assumed that the transmission line, Buronga switchyard and phase shifting transformers (PST) are built to 330 kV standard but operated at 275 kV until the final 330 kV stages to Darlington Point-Wagga are complete. It is further assumed that 200MVAr SVC's are located at both Buronga and Robertstown along with 330 kV-rated series compensation.

When upgrading to 330 kV, the 275/220 kV transformers at Buronga would become "stranded". It is unique that, under this project variant, Buronga is the only location in the NEM where 275/220 kV voltages would be tied. Consequently, after upgrade, their value in Australia would be zero. Transformers typically have a minimum 40-year life but the service expected in this project could be in the range 3 to 10 years, hence much of its physical value would remain.

Early works will have limited capability of accepting MW transfer from SA during the day due to the high level of existing, under construction and planned solar PV penetration in the region around Buronga, Red Cliffs and Balranald. This limitation is lifted on completion of final works in line with ElectraNet's preferred option C.3i.

This project variant is taken forward for inclusion in the market modelling and net market benefit analysis.

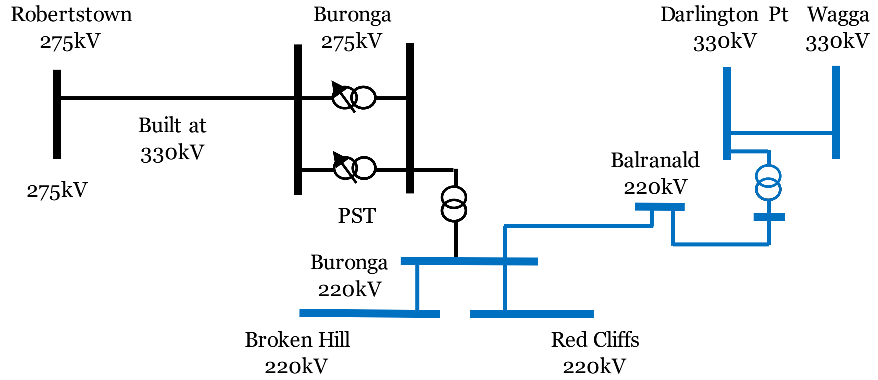
1.3.3. C.2ii Robertstown-Buronga 275 kV single circuit

Variant C.2ii phases ElectraNet's preferred option C.3i as follows:

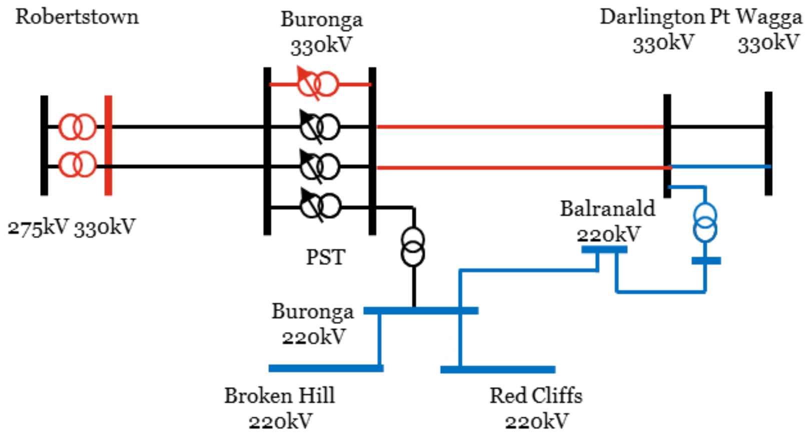
- Early works installs a double circuit from Robertstown to Red Cliffs 275 kV (built at 330 kV).
- Final work upgrades the line to 330 kV with new transformers installed at Robertstown, Buronga and Red Cliffs and completes the 330 kV upgrade by extending to Wagga

Figure 5 – Diagram of variant C.2ii

Early works



Final phase



Key

Existing line
ElectraNet PADR proposal
DEM alternative

Source: ElectraNet, SAET-RIT-T-Network-Technical-Assumptions.pdf, June 2018, Jacobs analysis

Table 6 – Variant C.2ii technical assessment – Early works

Criteria	Description
Network security	Network security maintained but transfer capacity is less than the Heywood capacity hence resulting in load shedding with battery response.
Delivery date	December 2021
Thermal limit	300 MW
Combined import limit	650 MW
System strength	Improved system strength through AC interconnection but inferior to double circuit options
Early works capex estimate	$387 million
$/MW transfer limit	$1.29/MW
Rate of change of frequency	Effectively eliminated but requires load shedding and battery response to keep the interconnector within rating.
Frequency control ancillary services	Cannot provide FCAS as there is no dynamically controlling equipment to regulate line flows. However, the improved access to the NEM could permit other NEM generators to provide inter-regional FCAS.
Inertia	Synchronism maintained with remainder of NEM effectively providing additional inertia however effectiveness is inferior to double circuit option.
Load shedding	If the combined import is less than the thermal limit, then no load shedding is required. If the combined import is at the combined import limit, then 250 MW of load shedding and battery response is required.

Source: Jacobs analysis

This 275 kV variant reduces the initial capital expenditure as it does not require 330 kV works at Robertstown in the first instance. The variant can be considered a “bare bones” option as it offers no redundancy and a reduced transfer capacity of around 300 MW (thermal limit). This limited transfer capacity is determined by both the rating of the network surrounding Buronga and the issue of MW loss to a single contingency.

It is assumed that the lines, Buronga switchyard and PSTs are built to 330 kV standard but operated at 275 kV until the final 330 kV stages to Darlington Point – Wagga are complete in final phase.

It is further assumed that 200MVAr SVC’s are located at both Buronga and Robertstown along with 330 kV-rated series compensation.

When upgrading to 330 kV, the 275/220 kV transformer at Buronga becomes “stranded” under the same circumstances as described in project variant C.2i.

Early works will have limited capability of accepting MW transfer from SA during the day due to the high level of existing, under construction and planned solar PV penetration in the region around Buronga, Red Cliffs and Balranald. This limitation is lifted on completion of final works in line with ElectraNet’s preferred option C.3i.

This project variant is taken forward for inclusion in the market modelling and net market benefit analysis.

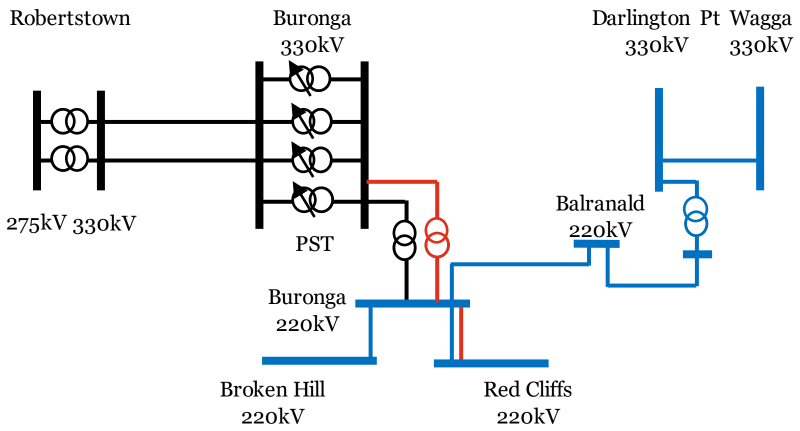
1.3.4. C.3ii Robertstown-Buronga 330 kV double circuit

Variant C.3ii phases ElectraNet's preferred option C.3i as follows:

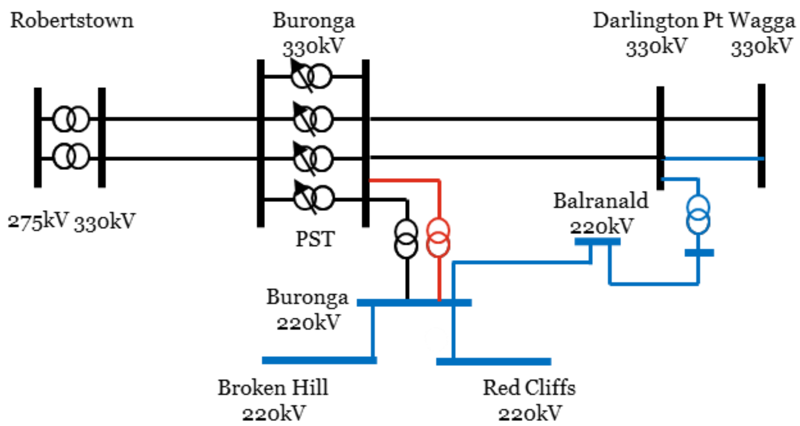
- Early works installs a double circuit from Robertstown to Red Cliffs 330 kV and duplicates 20km Buronga-Red Cliffs 220 kV line (for security).
- Final phase completes the 330 kV upgrade by extending to Wagga.

Figure 6 – Diagram of variant C.3ii

Early works



Final phase



Key

Existing line
ElectraNet PADR proposal
DEM alternative

Source: ElectraNet, SAET-RIT-T-Network-Technical-Assumptions.pdf, June 2018, Jacobs analysis

Table 7 – Variant C.3ii technical assessment – Early works

Criteria	Description
Network security	Network security maintained as transfer capacity is greater than the Heywood interconnector capacity.
Delivery date	December 2021
Thermal limit	800 MW
Combined import limit	950 MW
System strength	Improved system strength through AC interconnection
Final phase capex estimate	$603 million
$/MW transfer limit	$0.75/MW
Rate of change of frequency	Effectively eliminated.
Frequency control ancillary services	Cannot provide FCAS as there is no dynamically controlling equipment to regulate line flows. However, the improved access to the NEM could permit other NEM generators to provide inter-regional FCAS.
Inertia	Synchronism maintained with remainder of NEM effectively providing additional inertia
Load shedding	If the combined import is less than Thermal limit, then no load shedding is required. If combined import is at the combined import limit, then 150 MW of load shedding and battery response is required.

Source: Jacobs analysis

This 330 kV variant can be considered as the first phase of the proposed ultimate development of the Robertstown – Wagga development. The NSW component can be "bolted" onto Buronga with no additional SA works required. This variant provides redundancy and would allow up to 800 MW transfer capacity (thermal limit).

It is assumed that 200MVAr SVC's are located at both Buronga and Robertstown along with series compensation on both 330 kV circuits.

Early works will have limited capability of accepting MW transfer from SA during the day due to the high level of existing, under construction and planned Solar PV penetration in the region around Buronga/Red Cliffs/Balranald. At night, this restriction is removed and SA would be able to export into the NEM. This limitation is lifted on completion of final works in line with ElectraNet's preferred option C.3i.

This project variant is taken forward for inclusion in the market modelling and net market benefit analysis.

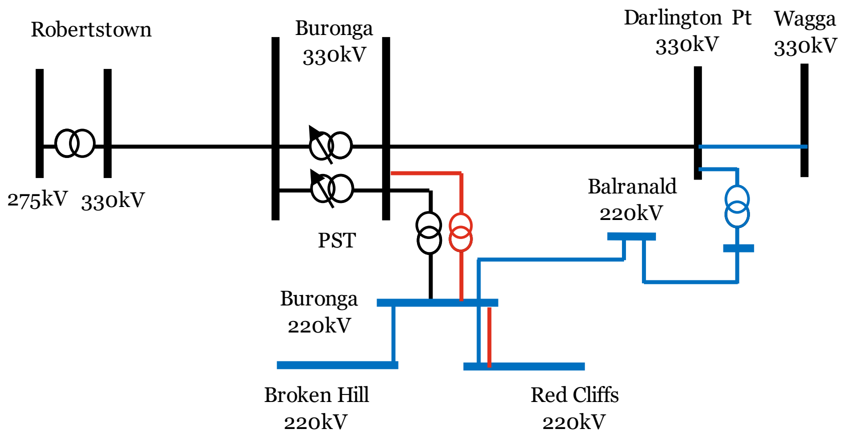
1.3.5. C.3iii Robertstown-Buronga 330 kV single circuit

Variant C.3iii phases ElectraNet's preferred option C.3i as follows:

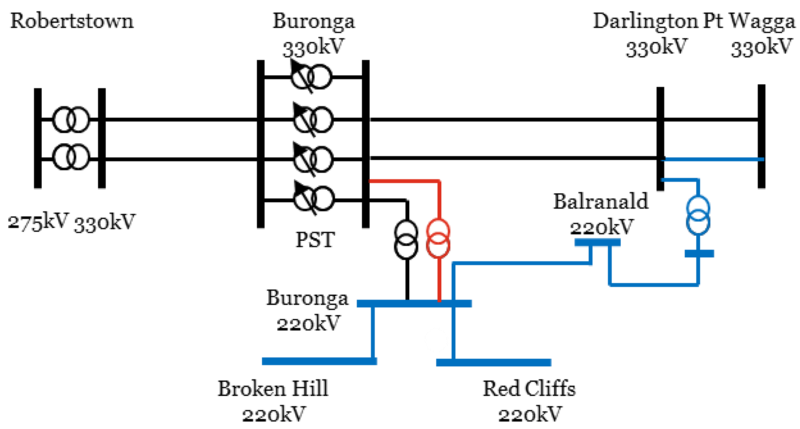
- Early works installs a single circuit from Robertstown to Red Cliffs 330 kV and duplicates 20 kilometres Buronga-Red Cliffs 220 kV line (for security).
- Final phase upgrades to a double circuit and completes the 330 kV upgrade by extending to Wagga.

Figure 7 – Diagram of variant C.3iii

Early works



Final phase



Key

Existing line

ElectraNet PADR proposal

DEM alternative

Source: ElectraNet, SAET-RIT-T-Network-Technical-Assumptions.pdf, June 2018, Jacobs analysis

Table 8 – Variant C.3iii technical assessment – Early works

Criteria	Description
Network security	Network security maintained but transfer capacity is less than the Heywood capacity hence resulting in limited load shedding or battery response.
Delivery date	December 2021
Thermal limit	300 MW
Combined import limit	850 MW
System strength	Improved system strength through AC interconnection but inferior to double circuit options.
Early works capex estimate	$852 million
$/MW transfer limit	$1.42/MW
Rate of change of frequency	Effectively eliminated but requires load shedding and battery response to keep the interconnector within rating.
Frequency control ancillary services	Cannot provide FCAS as there is no dynamically controlled equipment to regulate line flows. However, the improved access to the NEM could permit other NEM generators to provide inter-regional FCAS.
Inertia	Synchronism maintained with remainder of NEM effectively providing additional inertia however effectiveness is inferior to double circuit option.
Load shedding	If combined import is less than Thermal limit, then no load shedding required. If combined import is at the combined import limit, then 250 MW of load shedding and battery response is required.

Source: Jacobs analysis

This 330 kV variant has been considered for completeness of the options assessment. However, the variant has a relatively high cost estimate of capital expenditure due to the additional 388 kilometres of the 330 kV circuit Buronga – Darlington Point and a lower capacity resulting in a low score for the $/MW assessment criteria. The reduced redundancy also makes this option less attractive in terms of network security than the double circuit 330 kV variant (C.3ii).

It is assumed that 200MVAr SVC's are located at both Buronga and Robertstown along with series compensation on both 330 kV circuits.

Early works will have limited capability of accepting MW transfer from SA during the day due to the high level of existing, under construction and planned solar PV penetration in the region around Buronga, Red Cliffs and Balranald. At night, this restriction is removed and SA would be able to export into the NEM. This limitation is lifted on completion of final works in line with ElectraNet's preferred option C.3i.

This project variant is not taken forward in the market modelling and net market benefit analysis.

1.4. Conclusion of technical assessment

Table 9 summarises key technical benchmarks for the proposed project variants.

Table 9 – Summary outcome of DEM project variant technical assessment

Ref	Description	Early works			
		Delivery date	Thermal limit (MW)	Capex estimate $m	$/MW transfer limit
C.1i	Murraylink 2 HVDC upgrade (no staging)	Dec-2021	300	813	$2.71
C.2i	Robertstown-Buronga 275 kV double circuit	Dec-2021	600	553	$0.92
C.2ii	Robertstown-Buronga 275 kV single circuit	Dec-2021	300	387	$1.29
C.3ii	Robertstown-Buronga 330 kV double circuit	Dec-2021	800	603	$0.75
C.3iii	Robertstown-Buronga 330 kV single circuit	Dec-2021	600	852	$1.42

Source: Jacobs analysis

Based on the proposed DEM technical assessment framework and desktop review, three project variants have been proposed for further analysis:

- C.2i phased approach:
  - starting with early works Robertstown-Buronga 275 kV double circuit including additional 220 kV circuit Buronga to Red Cliffs
  - finishing with final phase 330 kV double circuit Robertstown-Buronga-Wagga
- C.2ii phased approach
  - starting with early works Robertstown-Buronga 275 kV single circuit
  - finishing with final phase 330 kV double circuit Robertstown-Buronga-Wagga
- C.3ii phased approach
  - starting with early works Robertstown-Buronga 330 kV double circuit including additional 220 kV circuit Buronga to Red Cliffs
  - finishing with final phase 330 kV double circuit Robertstown-Buronga-Wagga.

2. Capital and operating cost estimates

2.1. Capital expenditure cost assumptions

The RIT-T draft guidelines state that "costs incurred in constructing or providing the credible option" must be included.[8] ElectraNet has estimated capital costs for each project option. The PADR provides high level summaries of the methodology and assumptions which are documented in the 'SAET Basis of Estimate'.[9] Detailed breakdowns of these capital costs have not been provided.

Detailed cost estimates for DEM's project variants have been developed here on the basis of building block cost assumptions. Two key cost components include transmission line costs and substation costs.

2.1.1. Transmission line cost estimates

Table 10 summarises the transmission line cost estimates applied for DEM's project variants. A contingency factor of 10 per cent has been added to DEM's transmission line cost estimates outlined in Table 10.

Table 10 – Transmission line cost estimates per kilometre

Line	Line	Undiscounted value \$m/km	Comments
330 kV	Double circuit	\$1.198/km	Applicable to all project variants at some section of the Early works or 2 interconnector works.
330 kV	Early works first line	\$0.899/km	Note 1 - applicable to project variant C.2ii and C.3iii.
330 kV	Final phase second line	\$0.599/km	
220 kV	Second line	\$0.862/km	Note 2 - relates to the 220 kV extension between Buronga and Red Cliffs.

Source: Jacobs analysis

Note 1

First and second line cost estimates are relevant to the following project variants:

- C.2ii which proposes to install a single line on double circuit towers in early works between Robertstown and Buronga. The single circuit is operated at 275 kV in early works but is built at 330 kV.
- C.3iii which similarly proposes a single line between Robertstown and Darlington Point.

8 AER, *D18-98444 Draft Regulatory investment test for transmission application guidelines*, July 2018
9 ElectraNet, *SA Energy Transformation RIT-T Basis of Estimate,* 29 June 2018.

- Both variants are upgraded to a double circuit in final phase by stringing the second side of the towers.

A price discount is applied individually to the early works and final phase cost estimates in comparison with the 330 kV double circuit, Price discounts are applied to:

- Early works line costs since only one side is conductored
- Final phase line cost since key infrastructure has already been installed in early works.

However, a premium price offsets some of this discount in the final phase because of the impact on line operations, access and availability limitations, and the live electrical environment.

Note 2

Cost estimates for the Buronga-Red Cliffs 220 kV extension include a short line construction factor and two tension/strain towers for the river crossing.

2.1.2. Substation cost estimates

Key components of substation costs include:

- 330 kV yard at Robertstown and Buronga
- switch bays
- transformers
- static VAR compensators (SVCs)
- phase shift transformers (PST).

2.1.3. Capital cost estimate results

Refer to Table 11 for capital cost estimates of the three DEM project variants proposed for analysis.

Table 11 – Capital costs estimates

	Capex cost estimates undiscounted 2018 $m			
Item	**C.3i**	**C.2i**	**C.2ii**	**C.3ii**
Early works				
Line costs				
Robertstown-Buronga	377	377	283	377
Buronga-Darlington Point	465		-	-
Darlington Point-Wagga	122		-	-
Buronga-Red Cliffs	-	17	-	17
Subtotal line costs	**964**	**394**	**283**	**394**
Substation costs[2]				
Robertstown	133	73	46	114
Buronga	155	82	58	91
Darlington Point	114	-	-	-
Wagga	41	-	-	-
Red Cliffs	-	4	-	4
Subtotal - substation costs	**443**	**159**	**104**	**209**
Subtotal - early works costs	**1,407**	**553**	**387**	**603**
Line costs				
Robertstown-Buronga	-	-	188	-
Buronga-Darlington Point	-	465	465	465
Darlington Point-Wagga	-	146	146	146
Buronga-Red Cliffs	-	-	-	-
Subtotal line costs	**-**	**612**	**800**	**612**
Substation costs[2]				
Robertstown	-	75	104	26
Buronga	-	105	122	88
Darlington Point	-	136	136	136
Wagga	-	49	49	49
Red Cliffs	-	-	-	-
Subtotal - substation costs	**-**	**365**	**412**	**299**
Subtotal - final phase costs	**-**	**977**	**1,212**	**911**
Total costs	**1,407**[1]	**1,530**	**1,599**	**1,514**

Note: [1] The total C.3i cost estimate here reflects Jacobs' detailed analysis rather than ElectraNet's total cost estimate of $1,480m. [2] Substation costs include series compensation costs

Key

	Existing ElectraNet project option
	DEM project variant

Source: PwC and Jacobs analysis,

2.1.4. Reconciliation of capital cost estimates

For consistency and comparability of the capital cost estimates, a reconciliation has been performed between ElectraNet's high level cost estimate for its preferred option C.3i and a detailed cost estimate on the basis of the building block cost assumptions. The total C.3i cost as per ElectraNet was estimated at $1,480 million which represents a variance of five per cent compared to the Jacobs analysis. This variance is deemed reasonable to adopt and apply the same building block cost assumptions to DEM's project variants.

2.1.5. Timing of project variant early works

For the preferred project option C.3i, ElectraNet has assumed that construction costs are incurred in FY22 and FY23 (50 per cent each year).

For the DEM project variants, capital costs are also assumed to be incurred over a two year period. It is assumed that early works are completed by December 2021 (FY22) and the final phase is complete in FY23. This phasing assumption is kept constant for variants C.2i, C.2ii and C.3ii.

Detailed analysis to support the timing of these project variants has not been completed at this stage. There are diverse views on the timelines of the constructability of the project. The DEM considers that there are a number of opportunities for reducing the construction program that need to be investigated and validated. Such opportunities relate to use of multiple construction teams, early contractor involvement, and resourcing. Acceleration outcomes are also likely to come from opportunities in the approvals process. It is feasible that regulatory approvals could be in place by mid-2019 and land approvals by end 2019. This combined with minor works variations could see early energisation achieved along with a project completion date of end 2023.

2.2. Operating expenditure cost assumptions

ElectraNet has assumed annual operating costs of $1.5 million per annum (referred to as routine maintenance costs in the PADR). These estimates represent approximately 0.13 per cent of total capital costs. This level differs from the benchmark levels of two per cent sourced from other RIT-T guidance materials.[10]

While applying an alternative operating cost assumption will affect the net benefit outcome, since this analysis is of the relative impact of project variants and that those variants are generally alternative phasing of ElectraNet's options C2 and C3i, we have assumed the same operating expenditure costs to maintain comparability. The operating costs are adjusted for the additional Buronga-Red Cliffs line – the operating costs for this section of line are estimated by applying the same 0.13 per cent ratio to capital costs.

10 Grid Australia, RIT-T Cost Benefit Analysis Handbook, p. 62

3. Market modelling

Market modelling was conducted to provide preliminary estimates of the impact of the project variants on NEM cost outcomes and wholesale electricity prices.

3.1. Overview of market modelling

Market modelling was conducted using Strategist[11] for the project variants identified from Section 1. Strategist provides a multi-region probabilistic market dispatch algorithm that represents an economically efficient optimisation of each of Australia's energy markets. It incorporates representations of future demand as well as existing and future generation capacity, considering interregional market constraints, planned and unplanned maintenance schedules, temporal availability of plant, cost and efficiency of plant and fuel and other factors.

Base assumptions were derived from ElectraNet's market modelling and assumptions databook[12], and where relevant and appropriate, updated to current conditions. Refer to Appendix A for details of the logic applied in Strategist.

3.2. Modelling the impact on customers' electricity bills

The impact of the new interconnector project variants was assessed for residential and small business customers in SA and NSW. The following key assumptions are derived from ElectraNet's PADR:[13]

A representative residential customer consumes:[14]

- 5,000 kWh per annum in SA
- 4,215 kWh per annum in NSW

A representative small business customer consumes:[15]

- 10,000 kWh per annum in SA
- 10,000 kWh per annum in NSW.

The impact of the new interconnector on customers' electricity bills was assessed with reference to the energy costs (wholesale price impact).

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11 Strategist is licensed through ABB.

12 ElectraNet, 2018-07-09 SA-Energy-Transformation-Modelling-and-Assumptions-Data-Book.pdf

13 ACIL Allen, South Australia New Souths Wales Interconnector – Preliminary Analysis of Potential Impact on Electricity Prices, Report to ElectraNet 3 July 2018

14 Consistent with assumptions made by the Australian Energy Market Commission (AEMC) in its 2017 electricity residential price trends report.

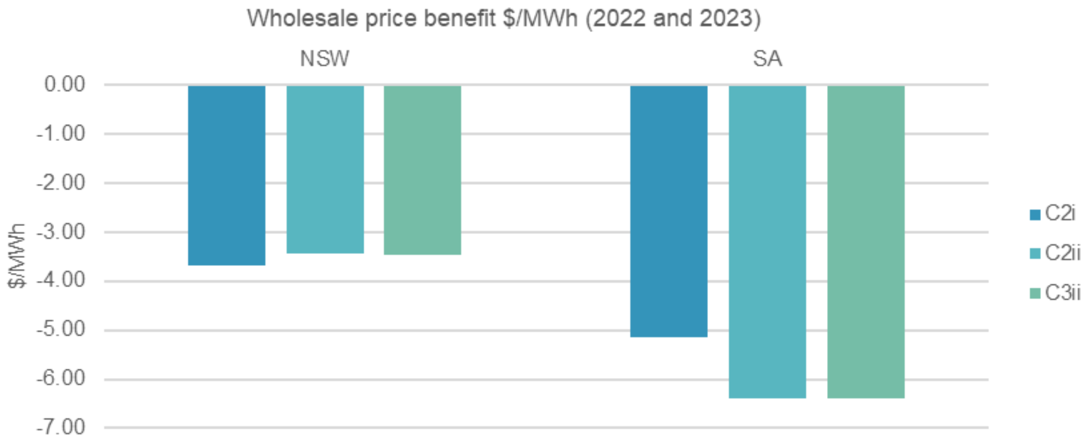
15 Consistent with the approach the Essential Services Commission of South Australia took in its 2017-17 Energy Retail Offers Comparison Report.1. The same usage assumption has been applied for NSW for ease of comparison.

3.3. Results

3.3.1. Wholesale spot price

Delivery of early works will likely have implications on wholesale prices. Reductions in wholesale prices are estimated in all cases modelled and are up to $3.70/MWh in NSW and $6.40/MWh in SA in addition to reductions under the C.3i option.

Figure 8 – Wholesale price impacts relative to Option C.3i $2018 (Central scenario)



Source: Jacobs' analysis

3.3.2. Projected customer bill impacts

These wholesale price benefits are assumed to flow through to benefit consumers through lower customer bills. We estimate that the following benefits will accrue from the staging of the interconnector works:

1. SA Residential customers - $26 to $32 power bill reduction per annum (FY22-FY23)
2. SA Business customers - $51 to $64 reduction per annum (FY22-FY23)
3. NSW Residential customers - $14 to $16 reduction per annum (FY22-FY23)
4. NSW Business customers - $34 to $37 reduction per annum (FY22-FY23).

These annual power bill reduction do not include the required increase in network costs to cover the costs of constructing and operating the new interconnector. Wholesale price benefits are estimated to more than offset the additional network charges applied to customer bills to recover transmission network costs. The greatest customer bill savings are estimated to occur for variant C.3ii with benefits to households and businesses in both NSW and SA.

4. Net present value results

4.1. Overarching assumptions and benefits

Net market benefits are calculated on the basis of outputs of previous sections and assumptions and parameters outlined in Table 12. For comparability with ElectraNet's PADR, the cost and benefit categories have been tailored to correspond to those defined by ElectraNet.

- Capital cost estimates were developed for each project variant for individual line items (these are described above in Section 2)
- Operating costs were estimated using assumptions from ElectraNet's PADR (see Section 2)
- Primary market benefits were incorporated from market modelling in the previous section (avoided fuel costs, avoided generator fixed costs, avoided generator and storage capital)
- Other market benefit estimates include avoided REZ transmission capex and demand side participation. The PADR's estimates for option C.3i were replicated given that all project variants match the former's interconnector capacity by FY23.

Additional assumptions underlying the cost benefit analysis are listed in Table 12. These are all equivalent to those in ElectraNet's PADR.

Table 12 – Overarching economic modelling assumptions

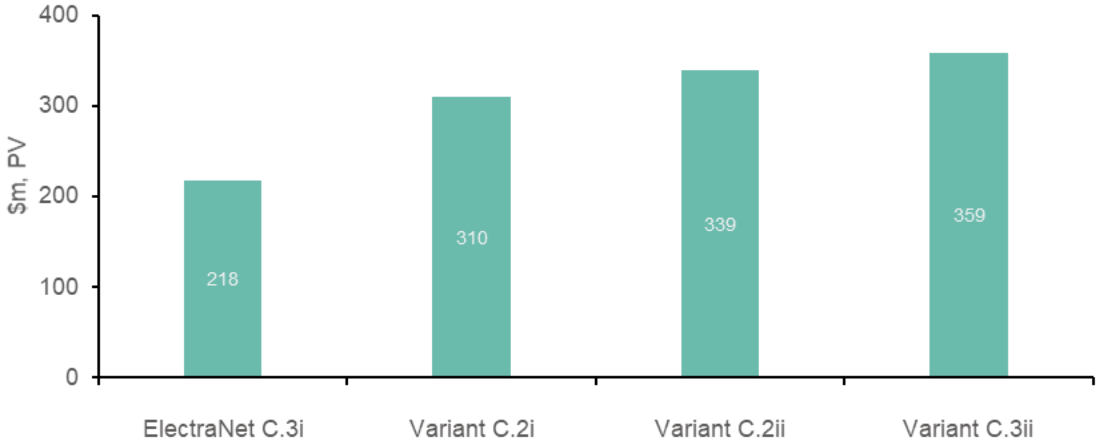
Parameter	Value	Comments
Discount rate (real, pre-tax)	6%	Benefits and costs are discounted to present values using a real discount rate.
Financial year	June year end	Cash flows are expressed in financial years ending June
Base financial year of analysis	FY18	The base year of the appraisal is 2018
First year of analysis	FY19	
Time horizon	22 years	The evaluation period has a base year of FY18 and extends 22 years from the construction start date of FY19 to FY40.
Asset lifespan	40 years	Straight-line depreciation was applied to the end of life of each asset to determine terminal values at the end of FY40.

Source: ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018, PwC analysis

4.2. Quantification of costs for each project variant

Based on the method and assumptions above, Figure 9 illustrates the present value of capital and operating costs for ElectraNet's project option C.3i and the DEM project variants in the Central scenario.

Figure 9 – Present value of costs (capital and operating) for DEM's project variants ElectraNet's preferred project option (C.3i)



Source: ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018, Jacobs and PwC analysis

On a present value basis, total capital and operating costs for the variants are estimated to be approximately 40 to 65 per cent higher than the project option C.3i. Section 2 has previously explained the key reasons for these differences include the construction costs associated with live operations during the final phase of the capital works.

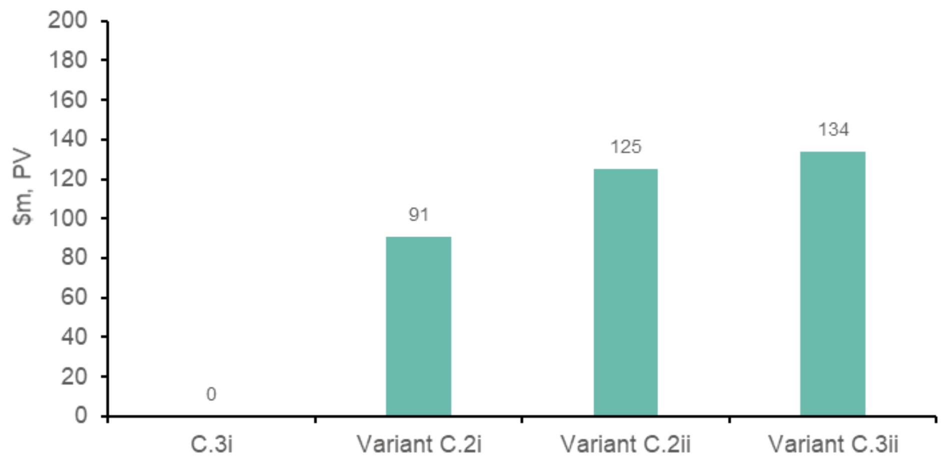
4.3. Quantification of gross market benefits for each project variant

Gross market benefits have been calculated in three steps.

Step 1 and 2 – Calculate primary market benefits
Primary market benefits include avoided fuel costs, avoided generator fixed costs, avoided generator and storage capital.

Step 1 calculates the differential between Jacobs' market modelling results for project option C.3i and the project variants. The differential calculation is illustrated in Figure 10.

Figure 10 – Differential in present value market modelling benefits between C.3i and project variants – illustration for demonstration purposes



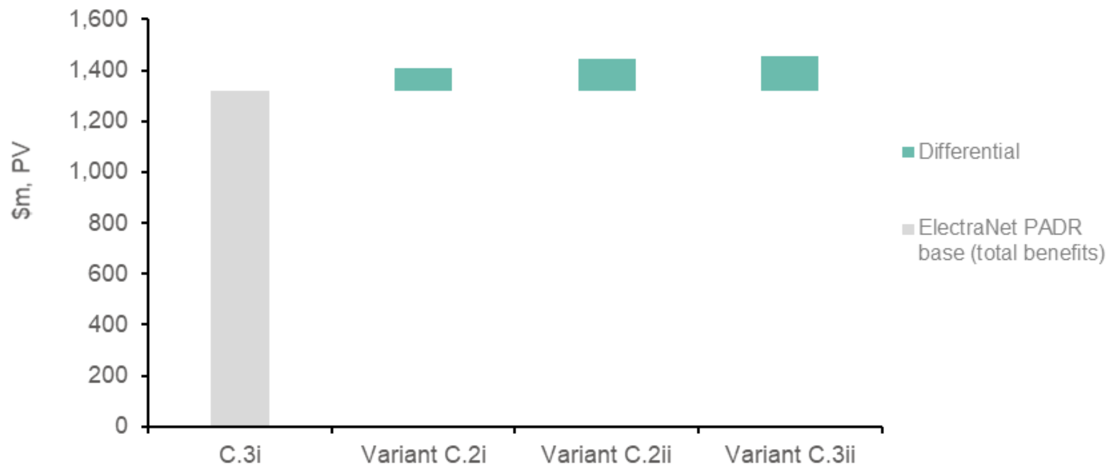
Source: ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018, Jacobs and PwC analysis

Step 2 normalises the gross market benefits and treats the gross market benefits of ElectraNet's Option C.3i, as calculated in the PADR, as the baseline for each project variant.

The delta of the market modelling results as calculated in Jacobs Section 3 are applied as an uplift or downside to ElectraNet's Option C.3i. This approach is designed to ensure consistency with the ElectraNet baseline.

Figure 11 illustrates the impact of this differential applied to the C.3i baseline.

Figure 11 – Market modelling differentials (Jacobs) applied to ElectraNet's C.3i option – illustration for demonstration purposes



Source: ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018, Jacobs and PwC analysis

Step 3 – Calculate secondary market benefits

Step 3 replicates market benefit estimates for avoided REZ transmission capex and demand side participation, as calculated in the ElectraNet PADR.

4.4. Net market benefits for each project variant

The quantified present value of the costs and benefits are collated for each project variant. The following tables show the breakdown of costs, benefits and net market benefits for ElectraNet's project option C.3i and each of DEM's project variants under four scenarios; central, low, high and weighted.

Table 13 – Net market benefits, central scenario

	Present value (discounted at 6%, 2018 $M, Central Scenario			
Item	**C.3i**	**C.2i**	**C.2ii**	**C.3ii**
Costs				
Capital costs	883	989	1,010	983
Operating costs	14	14	14	14
Total costs	**897**	**1,003**	**1,024**	**997**
Benefits				
Avoided fuel costs	1,027	1,100	1,092	1,101
Avoided generator fixed costs	208	252	267	268
Avoided REZ transmission capex	328	328	328	328
Generator and storage capex deferral	(254)	(281)	(254)	(254)
Demand side participation	12	12	12	12
Total benefits	**1,320**	**1,411**	**1,445**	**1,454**
Net present value	**423**	**407**	**421**	**457**

Key

	Existing ElectraNet project option
	DEM project variant

Source: ElectraNet, NPV model output for central scenario.xlsx, August 2018, PwC and Jacobs analysis

Under the central scenario, the NPVs of the project variants range between negative four and positive eight per cent compared to the C.3i project option.

Relative to option C.3i, all project variants are estimated to deliver higher avoided fuel costs and avoided generator fixed costs by bringing forward the period in which these benefits commence.

For project variant C.3ii, these higher benefits outweigh the 11 per cent premium in capital costs resulting from the staged approach.

Table 14 – Net market benefits, low scenario

	Present value (discounted at 6%, 2018 $M, Low Scenario			
Item	**C.3i**	**C.2i**	**C.2ii**	**C.3ii**
Costs				
Capital costs	883	989	1,010	983
Operating costs	14	14	14	14
Total costs	**897**	**1,003**	**1,024**	**997**
Benefits				
Avoided fuel costs	400	317	316	433
Avoided generator fixed costs	340	340	340	342
Avoided REZ transmission capex	328	328	328	328
Generator and storage capex deferral	285	492	492	285
Demand side participation	4	4	4	4
Total benefits	**1,357**	**1,481**	**1,481**	**1,391**
Net present value	**460**	**478**	**456**	**394**

Key

(shaded)	Existing ElectraNet project option
(unshaded)	DEM project variant

Source: ElectraNet, NPV model output for low scenario.xlsx, August 2018, PwC and Jacobs analysis

Under the low scenario, the NPV of the C2i variant is four per cent higher than the C.3i project option due to cost savings in generator and storage capex deferral which outweigh the 12 per cent premium in capital costs resulting from the phased approach.

However, the NPV of the C3ii variant is negative 14 per cent as the marginal improvement in avoided fuel costs does not compensate for the increased costs of staging.

Table 15 – Net market benefits, high scenario

	Present value (discounted at 6%, 2018 $M, High Scenario			
Item	**C.3i**	**C.2i**	**C.2ii**	**C.3ii**
Costs				
Capital costs	883	989	1,010	983
Operating costs	14	14	14	14
Total costs	**897**	**1,003**	**1,024**	**997**
Benefits				
Avoided fuel costs	2,549	2,574	2,570	2,580
Avoided generator fixed costs	305	307	306	307
Avoided REZ transmission capex	328	328	328	328
Generator and storage capex deferral	292	292	292	292
Demand side participation	(1)	(1)	(1)	(1)
Total benefits	**3,473**	**3,500**	**3,496**	**3,506**
Net present value	**2,576**	**2,497**	**2,471**	**2,509**

Key

	Existing ElectraNet project option
	DEM project variant

Source: ElectraNet, NPV model output for high scenario.xlsx, August 2018, PwC and Jacobs analysis

Under all project options and variants, the NPVs are greatest in the 'high' scenario since the assumed fuel costs are higher and therefore the avoided fuel cost benefits are larger - see Table 18 for a description of the scenarios' key assumptions.

However, in the high scenario the NPVs of the project variants are three to four percent lower than the C.3i project option.

Table 16 – Net market benefits, weighted scenario

	Present value (discounted at 6%, 2018 $M, Weighted Scenario			
Item	**C.3i**	**C.2i**	**C.2ii**	**C.3ii**
Costs				
Capital costs	883	989	1,010	983
Operating costs	14	14	14	14
Total costs	**897**	**1,003**	**1,024**	**997**
Benefits				
Avoided fuel costs	1,251	1,273	1,268	1,304
Avoided generator fixed costs	265	288	295	296
Avoided REZ transmission capex	328	328	328	328
Generator and storage capex deferral	17	56	69	17
Demand side participation	7	7	7	7
Total benefits	**1,867**	**1,951**	**1,967**	**1,951**
Net present value	**970**	**947**	**942**	**954**

Key

	Existing ElectraNet project option
	DEM project variant

Source: ElectraNet, 2018-07-06 SAET PADR Final, 29 June 2018, PwC and Jacobs analysis

Note: Consistent with ElectraNet's PADR the weighted scenario is a combination of results from the low, central and high scenarios. Low is weighted 25 per cent, central is weighted 50 per cent and high is weighted 25 percent.

Cost increases from staging are mostly but not fully offset by the early delivery of market benefits including fuel cost savings and generator and storage capex deferral.

The NPV of the variants is approximately three to four per cent lower than the C.3i project option. The project variant capital costs have a premium of 11 to 14 per cent compared to option C.3i as a result of the phased approach.

4.5. Further considerations and sensitivities

ElectraNet has assumed annual operating costs of $1.5 million per annum (referred to as routine maintenance costs in the PADR). These estimates represent approximately 0.13

per cent of total capital costs. This level differs from the benchmark levels of two per cent sourced from other RIT-T guidance materials.[16]

Should it be considered important to assess operating costs at the RIT-T guidance level then this should be applied across all variants including the ElectraNet baseline case C.3i. Given that capex costs are materially consistent across all variants assessed in this report we view the resultant operating cost estimates using RIT-T guidance assumptions to also be materially consistent and as a result the NPV analysis outlined in this report is viewed as valid.

[16] Grid Australia, RIT-T Cost Benefit Analysis Handbook, p. 62

5. Conclusion

DEM has analysed variants to ElectraNet's preferred option C.3i with an objective to energise a first phase interconnector between SA and NSW by 2021.

Key recommendations are outlined below.

Opportunities should be investigated and validated to reduce the delivery timeframes; any project acceleration will bring forward benefits and the costs of such acceleration will likely be offset by the timing and quantum of these benefits.

DEM recommends that opportunities are investigated to optimise the delivery timetable.

Acceleration outcomes are also likely to come from opportunities in the approvals process. It is feasible that regulatory approvals could be in place by mid-2019 and land approvals by the end of 2019 (with a focused prioritisation on the Robertstown-Buronga works).

An extension of the 220 kV transmission line of Buronga-Red Cliffs would enhance network security.

Two of the three proposed variants include an extension of the 220 kV transmission line between Buronga and Red Cliffs. This extension would allow additional import and export of generation via the new interconnector. It is designed to enhance network security eg in the event of various outages in NSW, including an outage of the Buronga-Red Cliffs line. Constraints on the Buronga-Red Cliffs 220 kV transmission line, as well as other transmission lines in Western Victoria, may otherwise constrain the transfer capacity of the SA-NSW interconnector. While the Buronga-Red Cliffs extension is currently considered in the Western Victoria Renewable Integration RIT-T, it aligns with the identified needs of the SAET RIT-T and would support the latter's phased delivery.

Further work is required to validate all of the assumptions including the net market benefits and to agree the regulatory approval process for the project variant.

We understand that early works variants can be considered in the current RIT-T process given the proposed variations are relatively minor and have potential to be value accretive.

Due to the constraints of time in preparing this PADR submission, this analysis is a preliminary estimate of costs and benefits. We recommend that further technical assessments and modelling are conducted to assess the veracity of the assumptions and modelling work undertaken.

APPENDICES

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Appendix A Market modelling assumptions

Base assumptions were derived from ElectraNet's market modelling and assumptions databook,[17] and where relevant and appropriate, updated to current conditions.

This approach enables comparison of options under a variety of renewable uptake conditions across the low, central and high scenarios outlined in section 4.

Table 17 outlines any differences between sources and assumptions for ElectraNet's PADR and the DEM project variant assessment.

Table 17 – Comparison of market modelling assumptions – ElectraNet and DEM

Summary	Description	ElectraNet source	Jacobs source	Comment
Effective LRET	Effective LRET, Green Power and ACT Scheme Trajectories	2018 ISP	As per current policy such that 33 TWh of renewable generation is built by 2020	Equivalent
QRET	Queensland Renewable Energy Target ~50% by 2030	2018 ISP	Not applied	Not yet legislated and may be dependent on political outcomes
VRET	Victorian Renewable Energy Target ~40% by 2025	2018 ISP	2018 ISP	While legislated, the VRET is still dependent on political outcomes. The VRET enables the commonwealth obligation of 26% emissions reduction to be met.
COP21 emissions trajectory	28% and 45% Emission Reduction Trajectories	2016 NTNDP	Finkel review was used for the 2005 NEM emissions estimate enabling 26% and 45% Emission Reduction Trajectories[18] to be derived.	A 0% emissions trajectory is applied in the low scenario, 26% applied in the central scenario and 45% applied in the high scenario. Note that the 26% target in the central scenario is effectively met by including the VRET in that scenario.
Energy	Demand projections	AEMO March 2018 EFI	AEMO March 2018 EFI	Equivalent

[17] ElectraNet, 2018-07-09 SA-Energy-Transformation-Modelling-and-Assumptions-Data-Book.pdf

[18] Finkel review uses a 2005 emissions value that is approximately 5 per cent lower than used in the ElectraNet modelling. Applied for consistency with previous work. Inclusion of VRET achieves 26 per cent emissions reduction in the central scenario without additional action. A 45 per cent emissions reduction trajectory has been applied in the high scenario.

Distributed batteries	Assumed behind-the-meter battery growth and control assumptions	2018 ISP	2018 ISP	Equivalent
DSP	Lists assumed demand side participation	2016 NTNDP	Not explicitly considered; assumed to be included in AEMO demand projections	ElectraNet note that their modelling does not make investment in DSP so this is unlikely to be a material difference.
Hydro storage	Contains information regarding hydroelectric storage inflows	2016 NTNDP	2016 NTNDP	Equivalent
Interconnector capability	Lists forward and backward interconnector capability	2016 NTNDP	2016 NTNDP	Equivalent
MRL	Minimum Reserve Level	2016 NTNDP	2016 NTNDP	Equivalent
Max capacity factors	Maximum Capacity Factors	2016 NTNDP	Jacobs	Equivalent
Installed capacity	Installed capacities for scheduled generators	2016 NTNDP, Generator Information Page December 2017	2016 NTNDP, Generator Information Page December 2017	More recent source appropriate given rapid reduction in capex for renewables
Build cost	Capital cost for new entrant generators	2016 NTNDP	2018 ISP	More recent source appropriate given rapid reduction in capex for renewables
Storage costs and properties	Capital cost for new entrant large scale batteries	2016 NTNDP, Draft 2018 ISP assumptions	2018 ISP	Jacobs approach enables retirements to respond to market conditions
Announced retirements	Committed generator retirements	2018 ISP	Output of modelling, not an assumption. Exceptions include Liddell which retires no later than 2022 and Yallourn which retires no later than 2032 due to expired mining license.	See above

Summary	Description	ElectraNet source	Jacobs source	Comment
Retirement	Generator end of technical life and retirement costs	2018 ISP	See above	See above
Refurbishment	Generator refurbishment costs, dates and supporting parameters	2018 ISP	2018 Jacobs	
WACC	Weighted cost of capital for new entrant generators	2018 ISP	Jacobs	More up to date.
Coal cost	Coal cost	2016 NTNDP, submissions	2018 ISP	More up to date.
Gas cost	Gas cost	2017 GSOO, ElectraNet, EnergyQuest	2018 ISP	More up to date.
Heat rates	Heat rates	2016 NTNDP	Jacobs	
FOM	Fixed operating and maintenance cost	2016 NTNDP	Jacobs	.
VOM	Variable operating and maintenance cost	2016 NTNDP, ElectraNet	2018 ISP	More up to date.
Emissions rate	Emissions Rate	2016 NTNDP	Jacobs	Equivalent
Auxiliaries	Generator Auxiliary	2016 NTNDP	Jacobs	
Min up and down times	Minimum operating and down times for coal plant	ElectraNet	N/A	

Source: Jacobs analysis

Scenarios

Three scenarios were considered in line with ElectraNet's market modelling report. These scenarios are designed to reflect a sufficiently broad range of potential outcomes across the key uncertainties that might affect future market benefits of the investment options being considered. The central scenario is provided the highest weighting in the cost benefit analysis, at 50 per cent compared to 25 per cent each for the low and high scenarios.

Table 18 outlines key differences in assumptions for each scenario.

Table 18 – DEM market modelling assumptions – Low central and high

	Low – No policy	Central - 26% emissions reduction target	High – 45% emissions reduction target
Effective LRET	As legislated (33 GWh renewable generation across Australia by 2020).		
QRET	Not applied		
VRET	VRET proceeds: 25% renewable energy gen by 2020, 40% renewable generation by 2025		
Coal cost	AEMO 2018 ISP Coal Price ($/GJ)		
COP21 emissions trajectory	No emissions reduction targets	26% emissions reduction by 2030; 0% by 2070	45% emissions reduction by 2030; 0% by 2060
Energy demand	AEMO March 2018 EFI - Weak	AEMO March 2018 EFI - Neutral	AEMO March 2018 EFI - Strong
Distributed batteries	AEMO March 2018 EFI - Weak	AEMO March 2018 EFI - Neutral	AEMO March 2018 EFI - Strong
Renewable and storage build cost	ISP 2018 - 15%	ISP 2018	ISP 2018 + 15%
Gas cost	AEMO 2018 ISP Weak Gas Prices ($/GJ)	AEMO 2018 ISP Neutral Gas Prices ($/GJ)	AEMO 2018 ISP Strong Gas Prices ($/GJ)

Source: Jacobs analysis

Primarily for consistency with the modelling undertaken by ElectraNet, a 26 per cent emissions reduction target by 2030 is assumed in the central scenario. This assumption does not suggest that a National Energy Guarantee will be resurrected given its recent demise. Rather, it recognises that the international emissions obligations for 26 per cent emissions reduction in Australia relative to 2005 levels still exists.

Furthermore, if the reduction target were retained and we are to assume that either of the Queensland or Victorian state policies were to exist, the 26 per cent emissions reduction target would be likely met without further action. The scenario is therefore still sensible in the current policy environment.

Another key feature of the scenarios is that demand, including the impact of distributed batteries and solar rooftop PV, is based on AEMO's weak, neutral and strong scenarios. These scenarios have been developed by AEMO to represent change in population and economic growth, as well as uptake of technology including rooftop PV, energy efficiency and electric vehicles.

The weak scenario represents the hesitant consumer in a weak economy with slow population growth; the neutral scenario represents the neutral consumer in a neutral economy with neutral population growth and the strong scenario represents the confident consumer in a strong economy with high population growth. The different scenarios also present environments in which differing degrees of renewable energy uptake will occur.

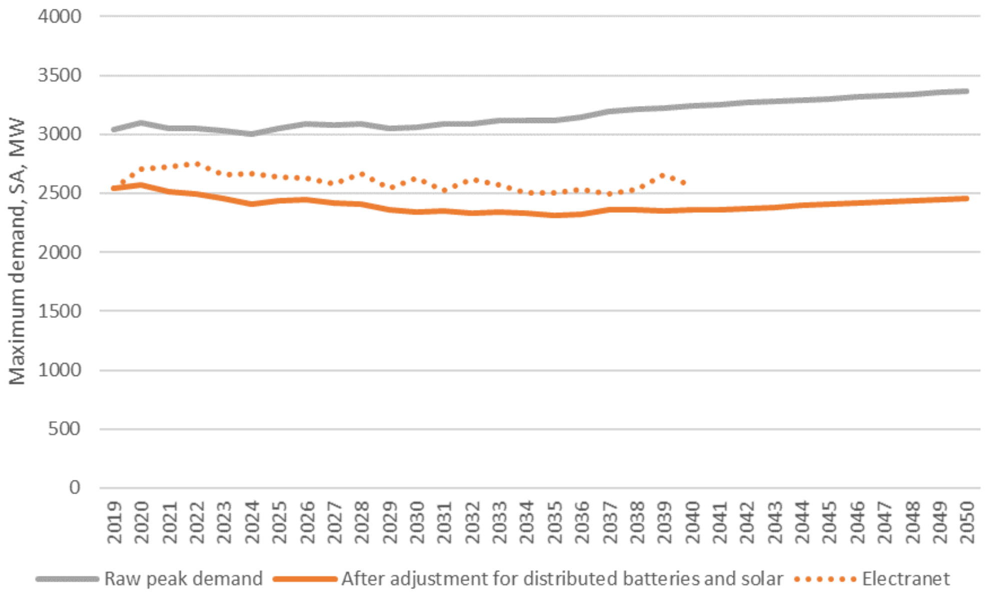
Demand

Market models used in this study are based on the peak demands and energy demand forecasts available in the March 2018 Electricity Forecasts Insights report published by AEMO.

Energy and peak demand forecasts are applied to historical half-hourly demand profiles based on typical demands seen between 2014 and 2017, adjusted for rooftop PV generation. This adjustment ensures that we represent load patterns in the wholesale market that adapt to the presence of increasing levels of rooftop solar and storage generation in the market.

As shown in Figure 12, the presence of behind the meter storage and generation has a significant impact on demand requiring delivery of centralised generation. Equivalent modelling performed by ElectraNet results in higher peak demand values, likely due to differences in profile assumptions or software. The differences will reduce the amount of centralised peaking generation required to meet demand and possibly reduce prices in the Jacobs work. This could lead to lower investment in dispatchable generation and/or a greater likelihood of retirement of plant compared to the ElectraNet work. Nevertheless, this is unlikely to make a material difference in a comparison of interconnector options over a comparatively short time frame.

Figure 12 – Comparison of sent out 50 PoE demand in SA before and after adjustment for distributed generation and storage, AEMO neutral scenario



Source: AEMO March 2018 EFI, Jacobs' analysis

Some embedded generation, such as small-scale cogeneration is not included in the Strategist model, and the native load forecasts are adjusted accordingly.

The use of the 50 per cent PoE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch. The modelling is based on system normal conditions and is not intended to represent extreme weather conditions.

The load is modelled hourly and therefore the peak is applied as an hourly load in Strategist rather than half-hourly as occurs in the market.

The impact of the various state-based energy efficiency schemes on the electricity market is to lower the total demand seen by the grid and is already incorporated in AEMO demand projections. This in turn has a flow-on impact on prices, as lower demand leads to increased competition from suppliers and places downward pressure on prices.

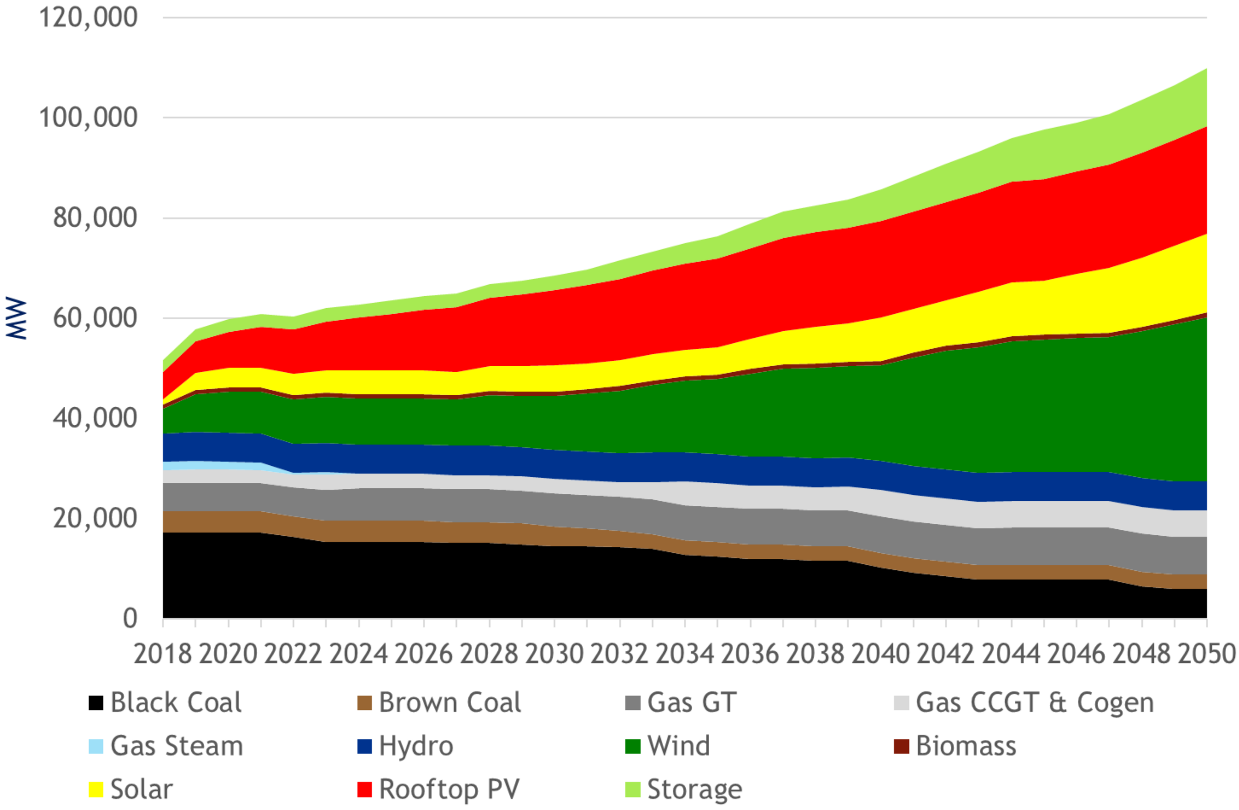
Supply

Each of the scenarios incorporates some level of renewable energy generation as a result of market trends in combination with the following policies.

- National Large Scale Renewable Energy Target (LRET), as currently legislated, 33 TWh renewable generation Australia wide by 2020
- Queensland Renewable Energy Target (QRET) – 400 MW renewable reverse auction and 100 MW of battery storage capacity by 2020.
- Victorian Renewable Energy Target (VRET) – 650 MW renewable energy capacity by 2020 and 40 per cent renewable generation by 2025.

Figure 13 displays the required market changes that would be anticipated under a central scenario, assuming some retirement of existing plant occurs due to emissions reduction policies and/or low cost renewable generation entering the market.

Figure 13 – NEM installed capacity, central scenario (Option C.3i)

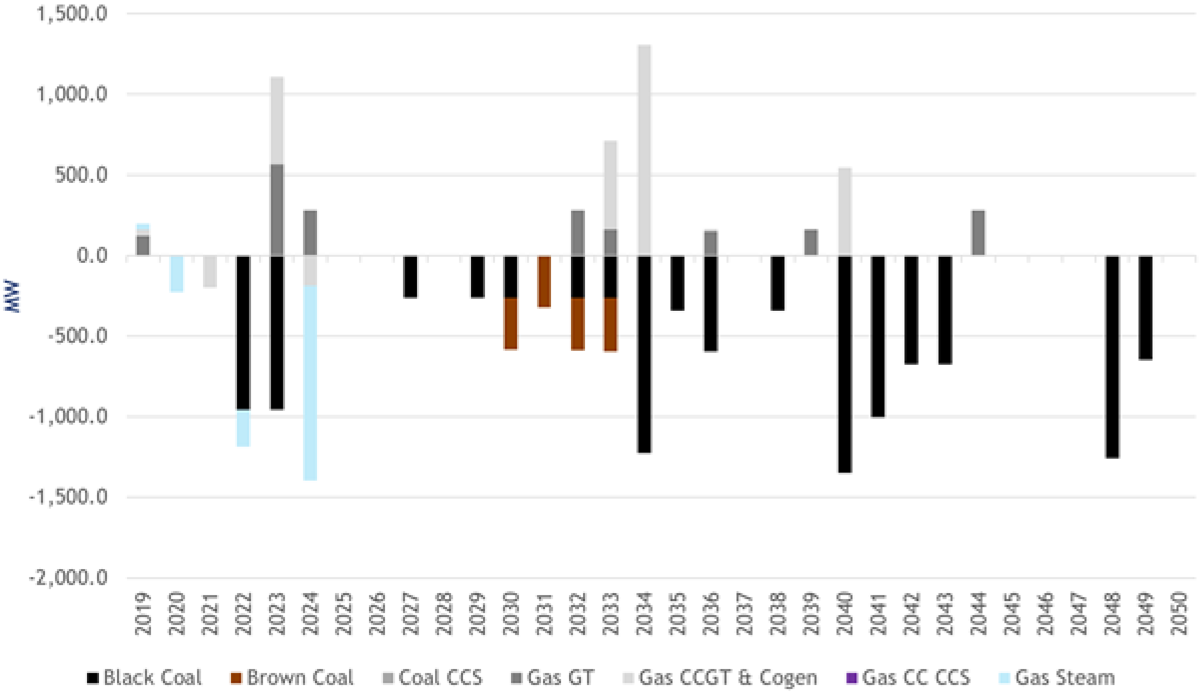


Source: Jacobs analysis

In addition to some new gas-fired capacity in the early 2020s to support Liddell retirement, the ongoing shift from a system made up of predominantly coal-fired capacity to a largely variable renewable dominated one requires investment in dispatchable generation technologies. These new entrants are predominantly made up of fast response storage capacity (battery and small pumped hydro systems) from the late 2020s, with the rate of expansion of battery technologies in particular increasing from the mid-2030s onwards as their costs decline.

Figure 14 displays changes in thermal capacity for the Central scenario. Generator retirements have been determined on an economic basis as an output of the market modelling, except for announced retirements and closures (such as Liddell, Torrens A, and Yallourn). For consistency with the ElectraNet modelling, retirement of Torrens B was assumed to occur when any new interconnector was brought in.

Figure 14 – Change in thermal capacity, base EIS scenario



Source: Jacobs analysis

Emissions outcomes

Least emissions present in the Low scenario primarily as a result of low demand in combination with a VRET. This combination makes this scenario nearly comparable with the high scenario which is based on a 45 per cent emissions reduction target in combination with high demand. The highest emissions outcomes occur under the central scenario because this scenario utilises central demand in combination with a 26 per cent emissions reduction target which includes the VRET policy[19].

Under the various scenarios, there is generally little difference in emissions across the options assessed; however, it is apparent that the emissions under Options C.3i and C.3ii are less than those in C.2i and C.2ii. It is likely that this occurs because of better utilisation of renewable generation across the market.

Aggregated storage

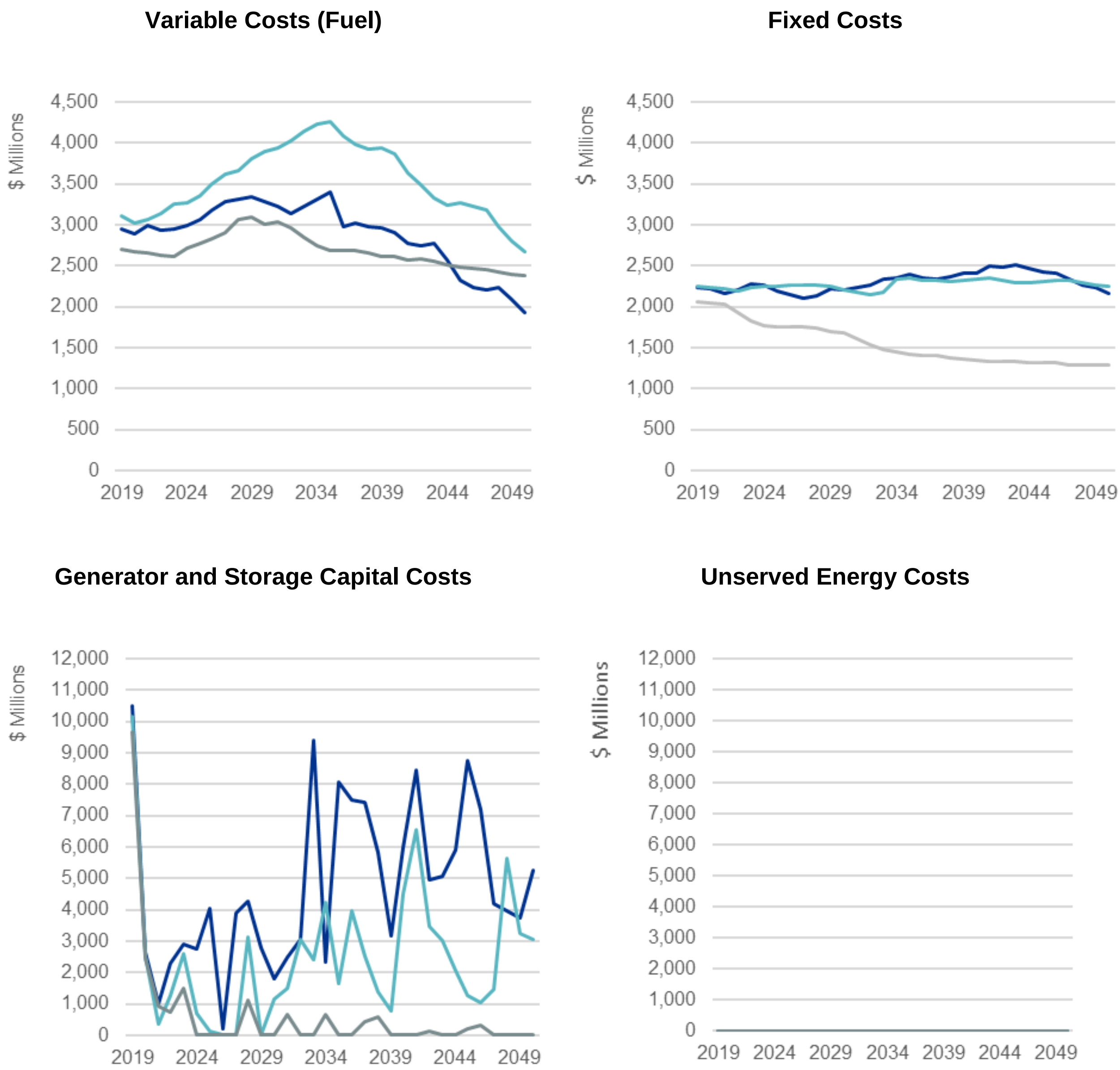
The market modelling has used the residential aggregated battery uptake assumptions and distributed generation assumptions from the Neutral 45 per cent growth scenario in AEMO's 2018 ISP. Aggregated storage is treated like a large scale battery with its use optimised in the model for maximised revenue returns in respect of the market as a whole.

NEM cost outcomes

Figure 15 and Figure 16 present the cost outcomes for Option C.3i for the Base, Low and High scenarios for the NEM and for South Australia. These charts present the scale of development costs impacting the generation sector, as anticipated by the market modelling under the three scenarios. Because the options presented only really impact the years prior to 2026 however, the data in this section will focus on this period.

[19] On 10 September 2018, the Victorian government announced an extension to the VRET policy which was not considered in this work.

Figure 15 – NEM cost outcomes $2018 (Option C.3i)

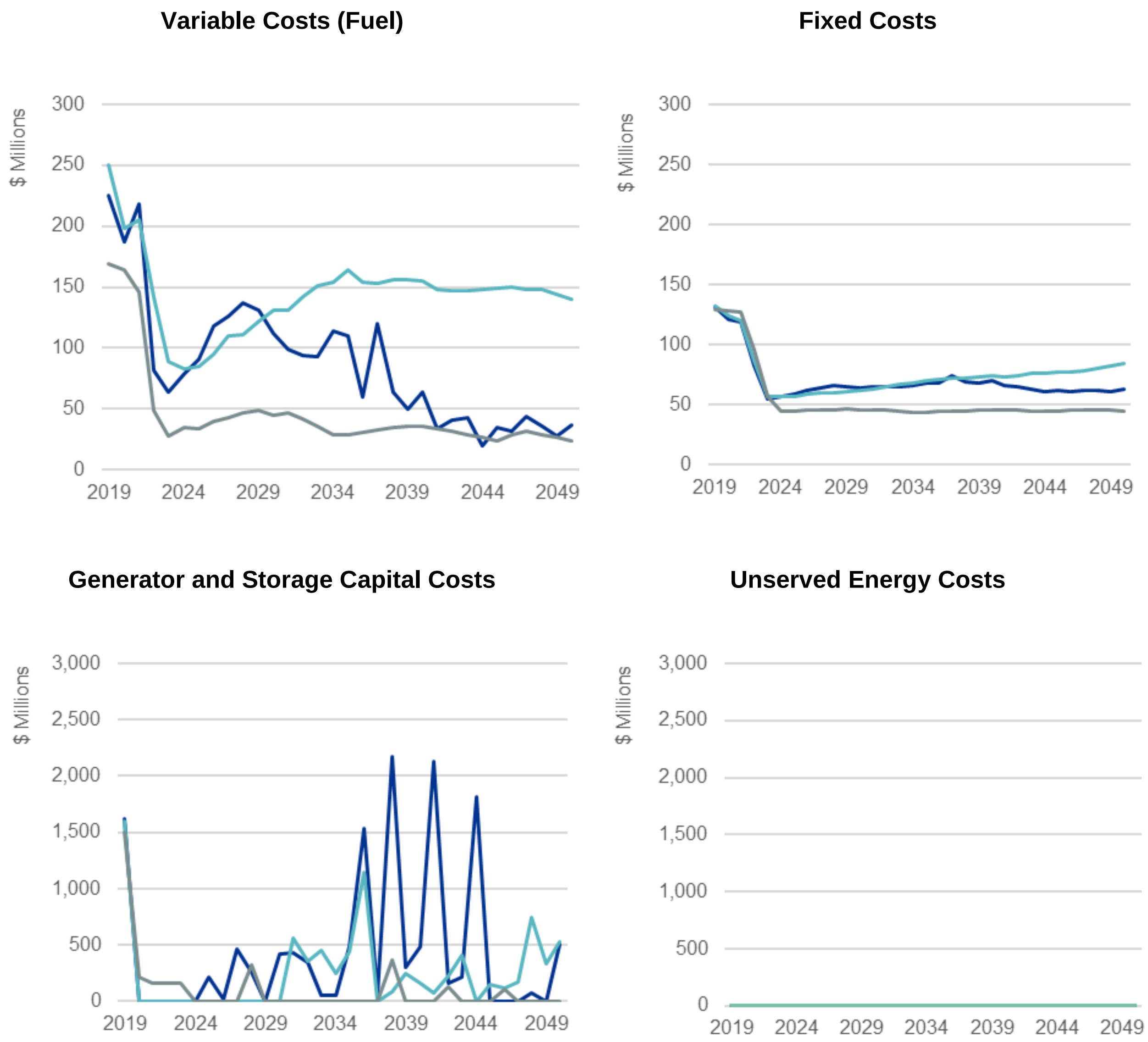


Key

High scenario   Central scenario   Low scenario

Source: Jacobs analysis

Figure 16: South Australia cost outcomes $2018 (Option C.3i)



Key

High scenario | Central scenario | Low scenario

Source: Jacobs analysis

Build limits

Jacobs' modelling does not impose build limits. Rather, the modellers check that any large scale new plant brought in is profitable relative to assumed technology costs. Overbuild is prevented with this approach as excessive levels of solar or wind would cause significant drops in price during the middle of the day which would lead to unprofitable plant. Curtailment of plant is also reviewed.

Notional interconnector capabilities

Assumptions on interconnect limits are shown in the table below. The proposed interconnector would supplement the existing Heywood interconnector with a capacity of 600 MW.

The Strategist representation retains a Snowy zone to better represent the impact of intra-regional constraints on each side of the Victoria/NSW border. The limits shown are based on the maximum recorded inter-regional capabilities. The Victorian export limit to Snowy/NSW is sometimes up to 1300 MW. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong.

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore, we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO 1 June 2018 Report “Regions and Marginal Loss Factors: FY 2018-19”.

Intra-regional losses are applied as detailed in the AEMO 1 June 2018 Report “Regions and Marginal Loss Factors: FY 2018-19”. The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

Table 19 – Interconnector capacity limits (additional to Heywood 600 MW capacity)

From	To	Capacity	Summer
Victoria	Tasmania	480 MW	
Tasmania	Victoria	600 MW	
Victoria	South Australia	600 MW	
South Australia	Victoria	600 MW	
South Australia	Red Cliffs	135 MW	
Red Cliffs	South Australia	220 MW	
Victoria	Snowy	1,300 MW	
Snowy	Victoria	1,900 MW	
Snowy	NSW	3,559 MW	3,117 MW
NSW	Snowy	1,150 MW	
NSW	South Queensland (Terranora link)	120 MW	
South Queensland	NSW (Terranora link)	180 MW	120 MW
NSW	Tarong	589 MW	
Tarong	NSW	1,078 MW	

Source: Jacobs analysis

Capacity and loss factors for the SA-NSW link are detailed as per the table below.

Table 20 – Capacity and loss factors in the NEM

Project variant	**C.3i**	**C.2i**	**C.2ii**	**C.3ii**
*Early works capacity Dec-2021 to Jun-2024**				
SA to NSW (MW)	800	600	400	800
SA to NSW losses (%)	4.9%	3.7%	2.5%	4.9%
NSW to SA (MW)	350	250	250	350
NSW to SA losses (%)	2.2%	3.1%	3.1%	2.2%
Final phase capacity Jul-2024 onwards				
SA to NSW (MW)	800	800	800	800
SA to NSW losses (%)	4.9%	4.9%	4.9%	4.9%
NSW to SA (MW)	700	700	700	700
NSW to SA losses (%)	4.3%	4.3%	4.3%	4.3%

Note: *Construction of the interconnector for project option C.3i is assumed to be complete in July 2023, financial year 2024. Construction of final phase works for project variants is assumed to be complete 12 months later in July 2024, financial year 2025. The capacity values exclude the transfer limits of the existing Heywood interconnector.

Key

(grey)	Existing ElectraNet project option
(white)	DEM project variant

Source: Jacobs analysis

Government of
South Australia