Victoria to New South Wales Interconnector Upgrade

February 2020

Project Assessment Conclusions Report

Important notice

PURPOSE

AEMO and TransGrid have prepared this Project Assessment Conclusions Report to meet the requirements of clause 5.16.4(t) – (v) of the National Electricity Rules.

DISCLAIMER

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Note that equipment locations identified in this document are indicative only. The actual locations will be determined as required during the detailed design and route assessment phase, after conclusion of the RIT-T process.

VERSION CONTROL

Version	Release date	Changes
1	February 2020	First release

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Executive summary

The energy landscape across the National Electricity Market (NEM) is changing rapidly. Strong investor interest in renewable generation continues to shift the geography and technical characteristics of supply, while it is anticipated that an ageing fleet of existing conventional generators will progressively withdraw from the market over the coming decades. Furthermore, consumer behaviour is evolving and the increasing penetration of distributed energy resources (DER) is changing the nature of 'demand' while also providing new opportunities to address Australia's energy transition.

This energy transition is already having a dramatic impact on the utilisation of the existing power system. It is, for instance, increasing network congestion in some areas, while also increasing the system's reliance on interconnection between regions. Well-targeted and timely investment in the transmission network is required to keep pace with these changes and provide consumers with the most cost-effective energy outcomes.

AEMO's Integrated System Plan (ISP) sets out an optimised national pathway for development of the power system that would maximise the value from new and existing resources across the NEM, while delivering energy reliability at the lowest cost to consumers. The 2018 ISP identified that immediate action was required to increase the transfer capability between Victoria and New South Wales, and designated this as a 'Group 1' project. The Draft 2020 ISP re-confirmed this need.

Transfer between these two states is currently restricted by thermal, voltage stability, and transient stability limitations. Without investment, these limitations will reduce access to lower-cost generation sources in the southern states, resulting in an increased economic cost of generating electricity across the NEM, and increasing the requirement for new generation investment to maintain adequate supplies.

In mid-2018, AEMO and TransGrid jointly initiated a Regulatory Investment Test for Transmission (RIT-T) to assess network and non-network options to increase the capacity to transfer electricity from Victoria to New South Wales. In November 2018, AEMO and TransGrid published a Project Specification Consultation Report (PSCR), which identified the need for and benefit of additional export capability from Victoria to New South Wales.

In August 2019, AEMO and TransGrid published a Project Assessment Draft Report (PADR), which identified, and sought feedback on, the proposed preferred option which was identified as delivering the highest net economic benefits to all those who produce, consume, and transport electricity in the market (referred to as 'net market benefits'). The PADR received six stakeholder submissions (discussed in Section 4). Following extensive stakeholder consultation and analysis, AEMO and TransGrid have produced this third and final report of the RIT-T process, the Project Assessment Conclusions Report (PACR)[1]. The PACR reconfirms the nature of the identified need, summarises the technical and economic assessment of the credible options, and justifies selection of the preferred option.

The preferred option

The preferred option identified in this PACR (as shown in Figure 1) is to implement the following augmentations by 2022-23:

- Install a second 500/330 kilovolt (kV) transformer at South Morang Terminal Station.
- Re-tension the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors[2]), to allow operation at thermal rating.
- Install modular power flow controllers on the 330 kV Upper Tumut – Canberra and Upper Tumut – Yass lines to balance power flows and increase transfer capability.

[1] As specified by Clause 5.16.4(t) – (y) of the National Electricity Rules, at https://www.aemc.gov.au/sites/default/files/2019-05/NER%20-%20v122.pdf.

[2] The capacitors will be replaced with higher rated capacitors to align with the new line ratings.

Together, these augmentations satisfy the regulatory investment test for transmission.

The preferred option will increase export capability from Victoria to New South Wales by approximately 170 megawatts (MW) during peak demand conditions in New South Wales and has a cost of approximately $87 million (in present value terms). This option yields the highest net market benefits under all of the future scenarios and sensitivities assessed.

The RIT-T analysis identifies that this option will deliver a net present economic benefit of approximately $268 million, by:

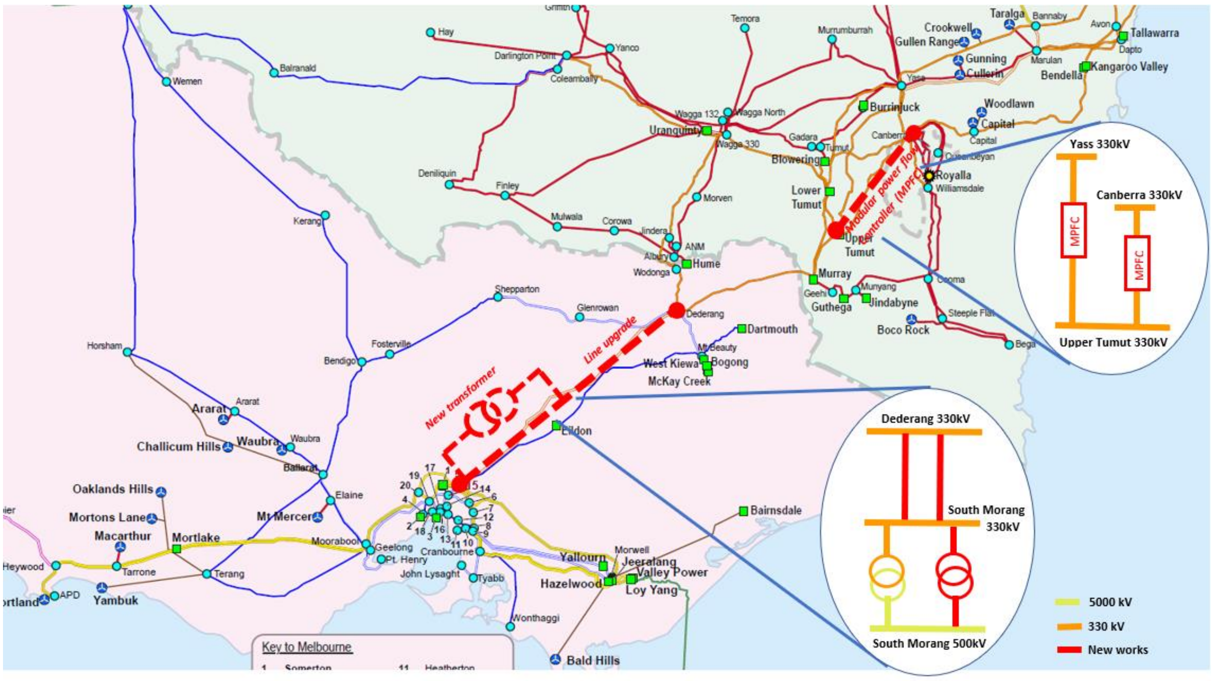
- Reducing dispatch costs, through more efficient dispatch of generation in Victoria and New South Wales.
- Reducing capital costs associated with new generation build in New South Wales.

The RIT-T analysis took into consideration the status of other RIT-Ts in progress at the time of PADR and PACR analysis and confirmed that the preferred option remains justified. The preferred option is consistent with the project identified as a Group 1 priority project in AEMO's Draft 2020 ISP.

The RIT-T analysis identifies that the preferred option generates sufficient market benefits to recover the project cost within a short time frame and is therefore not subject to future uncertainties.

The preferred option is shown in Figure 1 below.

Figure 1 Preferred option (Option 2 from PADR)



Joint RIT-T approach

AEMO and TransGrid are jointly undertaking this RIT-T to assess the technical and economic viability of increasing the transfer capacity between Victoria and New South Wales, aimed at reducing the market costs across the NEM.

This PACR has been jointly prepared by both parties in accordance with the requirements of the RIT-T process set out in the National Electricity Rules (NER) clause 5.16. The PACR is the third and final stage of the RIT-T process.

The identified need

The identified need for investment is to realise net market benefits by increasing the power transfer capability from Victoria to New South Wales. Alleviating current and projected limitations on this transfer corridor will reduce market costs, through more efficient sharing of generation resources between states, and greater access to diverse supply sources.

Credible options included in the assessment

A range of credible options were considered to increase the Victoria to New South Wales export capability. The credible options are consistent with those proposed in the PADR and are summarised in Table 1 below.

Table 1 Credible options that were tested in detail

Option	Description
Option 1	**Base option** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors) to allow operation at thermal rating. • 330 kV Upper Tumut - Canberra line upgrade.
Option 2 (Preferred option)	**Base option with modular power flow controllers** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors) to allow operation at thermal rating. • Install modular power flow controllers on both 330 kV Upper Tumut – Canberra and 330 kV Upper Tumut – Yass lines.
Option 3	**Additional higher capacity upgrades in New South Wales** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors) to allow operation at thermal rating. • Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales[A].
Option 4	**Additional higher capacity upgrades in New South Wales and Victoria** • Two new 500/330 kV transformers at South Morang Terminal Station. • New 330 kV South Morang – Dederang line • Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales[A].

A. At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network.

Scenarios and sensitivities analysed

The RIT-T requires a cost-benefit analysis that considers reasonable scenarios of future supply and demand under conditions where each credible option is implemented, and compared against conditions where no option is implemented.

A reasonable scenario represents a set of variables or parameters that are not expected to change across each of the credible options and the base case. They are intended to reflect a wide range of variations to the variables that may materially affect the relative benefits of the RIT-T credible options.

This RIT-T considers three reasonable future scenarios, based on equivalent scenarios in the 2019 Planning and Forecasting Consultation Paper[3]:

1. **Neutral** – a future where modest economic and population growth is experienced, and existing policies are delivered. Consequently, grid demand is relatively static, and change in the large-scale generation mix is largely driven by the timing of coal-fired generation retirements.
2. **Slow change** – a future where Australia's economic and population growth is weaker, the life of existing power stations could be extended, households and commercial businesses install rooftop photovoltaic (PV) systems to help reduce energy costs, and the transition towards zero emission vehicles is slower, as people have less disposable income and are buying new vehicles less often. Consequently, grid demand is in decline and the change in large-scale generation mix over time is less pronounced.
3. **Fast change** – a future where Australia's economy is booming, population growth is strong, and emission reduction targets are aggressive, leading to rapid decarbonisation of both the stationary energy sector and the transport sector. Consequently, growth in grid demand is relatively strong and there is a material change in the large-scale generation mix over time.

Additional sensitivity analysis was carried out by varying the assumed option cost, discount rate, and scenario weightings.

Market benefits

The RIT-T assessment involved detailed market modelling using a capacity outlook model and a market dispatch model. The results of the assessment highlight that the key categories of market benefit for this RIT-T are:

- Changes in fuel and operating costs arising from the offset of more expensive New South Wales generation with cheaper Victorian generation; and
- Changes in generation investment costs, as there is a decreased need to build new generation in New South Wales.

Table 2 below summarises the weighted net market benefit in net present value (NPV) terms[4] for each credible option. The net market benefit for each option reflects the weighted net market benefit across the three reasonable scenarios considered.

Table 2 Weighted net market benefit (NPV terms)

Option	Option Cost ($M) – NPV	Gross market benefit ($M) – NPV	Weighted net market benefit ($M) – NPV
Option 1 – Base option	99	356	257
Preferred option Option 2 – Base option with modular power flow controllers	87	355	268
Option 3 – Additional higher capacity upgrades in New South Wales	628	750	123
Option 4 – Additional higher capacity upgrades in New South Wales and Victoria	947	827	-120

[3] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Planning-and-Forecasting-Consultation-Paper.pdf.

[4] Net Present Value (NPV) is the value of all future cash flows (both positive and negative) over the outlook period when discounted to the present. NPV analysis is a form of valuation used extensively across finance and accounting to determine the value of a long-term investment.

The preferred option will increase export capability from Victoria to New South Wales by approximately 170 MW during peak demand conditions in New South Wales, and has a cost of approximately $87 million (in present value terms). This option yields the highest net market benefits under all the future scenarios and sensitivities assessed.

Next steps

AEMO and TransGrid will finalise the optimal pathway to implementing the preferred option by 2022-23. Both parties are committed to keeping stakeholders informed of progress and will provide updates during the implementation stages on AEMO's and TransGrid's websites[5].

[5] Refer to https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission and https://www.transgrid.com.au/what-we-do/projects/current-projects/Victoria%20to%20NSW%20Interconnector.

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1. Introduction

1.1 Overview

Under the National Electricity Law, Australian Energy Market Operator Limited (AEMO) is responsible for planning and authorising augmentation on the Victorian electricity transmission Declared Shared Network (DSN). NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust (trading as TransGrid) is the Transmission Network Service Provider (TNSP) in New South Wales, responsible for planning and augmenting the New South Wales electricity transmission network.

This Project Assessment Conclusions Report (PACR) has been prepared by AEMO and TransGrid in accordance with the requirements of the National Electricity Rules (NER) clause 5.16[6] for a Regulatory Investment Test for Transmission (RIT-T)[7].

The purpose of a RIT-T is to identify the credible option for meeting an identified need that maximises net economic benefit for all those who produce, consume and transport electricity in the market (referred to as 'net market benefits').

The RIT-T process involves the publication of three reports. For this RIT-T:

- The Project Specification Consultation Report (PSCR), which sought feedback on the identified need and proposed credible options to address the need, was published in November 2018[8].
- The Project Assessment Draft Report (PADR), which identified and sought feedback on the preferred option which delivers the highest net market benefit and other issues, was published in August 2019[9].
- This Project Assessment Conclusions Report (PACR) makes a conclusion on the preferred option, and, amongst other things, provides a summary of the submissions received on the PADR.

1.2 Stakeholder consultation

AEMO and TransGrid carried out stakeholder consultation throughout the RIT-T process, with the objectives of:

- Ensuring the robustness of the RIT-T findings.
- Validating the study assumptions.
- Communicating the process and identified need driving the RIT-T, as well as describing the credible options and assessments considered in the PADR.

This PACR stage assessment considered PADR submissions and other feedback from stakeholders. See Section 4 for information on submissions received and AEMO and TransGrid's responses.

1.3 Further enquiries

AEMO and TransGrid are committed to keeping stakeholders informed on the progress of this RIT-T project and will provide updates on the AEMO's and TransGrid's websites[10].

For further information, please e-mail Planning@aemo.com.au.

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[6] At https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current.

[7] Refer to Appendix A1 for a list of PACR requirements.

[8] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PSCR.pdf.

[9] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PADR.pdf.

[10] Refer to https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission and https://www.transgrid.com.au/what-we-do/projects/current-projects/Victoria%20to%20NSW%20Interconnector.

2. Identified need

2.1 Description of the identified need

The identified need for this RIT-T remains consistent with that described in Chapter 2 of the PADR[11]. Investment is required to increase the transfer capability from Victoria to New South Wales to capture positive net market benefits, that is, an increase in the sum of consumer and producer surplus, through more efficient sharing of generation resources between states.

Import into Victoria has also been considered but has not been included as part of the identified need. This is because the short- and medium-term need for additional imports is being addressed through a number of operational and planning initiatives, as discussed in Section 2.3 below. In the longer term, generator retirements also pose a risk to the supply-demand balance and a separate RIT-T (VNI West) is currently in progress[12] to identify the preferred option to increase the transfer capability between Victoria and New South Wales in both directions.

2.2 Drivers for augmentation

The key driver for this RIT-T is to allow for more efficient sharing of lower-cost generation resources between states. This predominantly results in significant fuel cost savings as well as the following benefits:

- Reduced fixed and variable generator operating and maintenance costs.
- Reduced capital costs associated with new generation build.
- Reduced voluntary load curtailment and involuntary load shedding by improving reliability, particularly due to the New South Wales augmentation.

2.2.1 Difference between historical and forecast constraint outcomes

This section discusses the reasons for differences between the forecast constraint outcomes presented through this RIT-T and the historical constraint outcomes available on the AEMO website.

Market impact

Historical information on the market impact of constraints, including the thermal and stability constraints being addressed through this RIT-T, can be found on the AEMO website[13]. The published information represents the market impact (calculated using generator bid prices) of relieving a constraint by 1 MW. The forecast market benefits presented in Section 6.3.2 predominantly represent the difference in dispatch costs (underlying generator fuel and operational costs) of increased VNI transfer. As such, the historical market impact information on the AEMO website does not give a fair indication of market benefits associated with relieving constraints.

[11] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

[12] See https://www.aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission.

[13] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams.

Constraint binding hours

Historical information on constraint binding hours, including the thermal and stability constraints being addressed through this RIT-T, can be found on the AEMO website[14]. This is also presented in Section 2.1.2 of the PADR and represents the constraint binding hours based on the network at the time.

The network is changing with additional generator connections in Victoria and southern New South Wales, augmentations in western Victoria, and the retirement of Liddell Power Station resulting in the loss of approximately 1,700 MW of firm capacity in New South Wales. These changes are forecast to increase utilisation of the Victoria to New South Wales pathway, resulting in an increase in the binding hours of the associated constraints as presented in Section 2.1.3 of the PADR.

2.3 Imports into Victoria

As part of this RIT-T, AEMO and TransGrid considered import requirements from New South Wales to Victoria. The supply-demand balance remains tight in Victoria, with Reliability and Emergency Reserve Trader (RERT) activated to maintain system security in January 2019, December 2019, and January 2020[15]. These events related to bushfires, extreme weather conditions, and unplanned generator outages in Victoria.

The 2019 Electricity Statement of Opportunities (ESOO)[16] identified a risk of supply-demand shortfalls which may lead to reliability standard breaches in Victoria in the short term if unplanned generator outages were to occur during extreme heat conditions.

An increase in New South Wales to Victoria import capability would enable better utilisation of spare reserves from neighbouring regions to manage this risk. However, the scale of net market and reliability benefits that can be counted in a RIT-T process is comparatively small. AEMO and TransGrid are therefore undertaking a number of cost-effective operational and planning initiatives to improve import capability into Victoria, which include:

- Installation of a 100 megavolt amperes reactive (MVAr) cap at Wagga Wagga to improve the voltage stability limitation[17].
- A Network Capability Incentive Project Action Plan (NCIPAP) project to install modular power flow controller on the Jindera – Wodonga line to improve thermal limitations.
- A review of stability constraints to improve the voltage stability limitation.
- Use of short-term line ratings and post-contingent load shedding to improve thermal limitations.

These initiatives will help manage the risks posed by bushfires, extreme weather conditions, and unplanned generator outages in Victoria. The operational initiatives are low-cost with short lead times, and will help manage risks in the short to medium term until longer-term planning solutions are identified.

In the longer term, generator retirements also pose a risk to the supply-demand balance in Victoria. AEMO and TransGrid have jointly initiated the Victoria to New South Wales Interconnector West (VNI West) RIT-T[18] to assess the technical and economic viability of increasing bi-directional interconnector capacity between New South Wales and Victoria, to address interconnector limitations and realise market benefits in the long-term interests of Australian energy consumers.

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[14] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams.

[15] At https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

[16] At https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/2019-Electricity-Statement-of-Opportunities.pdf.

[17] Imports from New South Wales to Victoria are limited by a voltage stability limitation which prevents voltage collapse in Southern New South Wales for the loss of Basslink or a large generator in Victoria.

[18] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

2.4 New information since the PADR

2.4.1 Updated demand forecasts

Each year, AEMO assesses future planning and forecasting requirements under a range of credible scenarios over a period sufficiently long to support stakeholders' decision-making in the short, medium and long term. AEMO has produced an updated set of demand forecasts for the five scenarios developed in consultation with industry and consumer groups for use in AEMO's 2019-20 forecasting and planning publications, including the Integrated System Plan (ISP) [19]. These five scenarios, referred to here as the "ISP scenarios", provide a wide range of possible industry outcomes differing with respect to the growth in grid-scale renewable generation resources, the uptake of distributed energy resources, and decarbonisation policies.

Section 5.2.4 discusses the differences between the three PADR scenarios and the new ISP scenarios. While the overall range of outcomes for the energy industry, in terms of decentralisation and decarbonisation, is greater in the long term under the five ISP scenarios than the three PADR scenarios, the range of outcomes in the short to medium term is similar.

As the preferred option in this RIT-T has a payback period within a short time frame and is therefore not subject to future uncertainties, it is considered that the PADR scenarios include a suitably wide range of reasonable scenarios for this RIT-T assessment. The PACR therefore continues to use the PADR Neutral, Slow Change, and Fast Change scenarios.

AEMO produced annual consumption and maximum demand forecasts for the Central, Step Change, and Slow Change scenarios for use in the 2019 ESOO analysis[20]. Forecasts for the Fast Change and High DER scenarios were also prepared for use in the 2020 ISP[21].

Generally, these annual consumption and maximum demand forecasts are lower than the 2018 ESOO forecasts. This downward revision is predominantly due to greater expectations for energy efficiency contributions, and observed changes in the relationship between gross state product (GSP) and business consumption, driven by the changing structure of the economy.

The impact of the updated demand forecasts is discussed in Section 5.2.7.

2.4.2 Status of other RIT-T projects

The PADR analysis concluded that the stability limitations associated with Victoria to New South Wales exports will be improved by the preferred option of this RIT-T as well as preferred options proposed in other RIT-Ts. In particular, the South Morang transformer component of this RIT-T and Western Victoria Transmission Network Project and Project EnergyConnect RIT-T preferred options will achieve a 170 MW increase in the stability limitations.

Western Victoria Transmission Network Project and EnergyConnect RIT-Ts

Since the publication of the PADR, the Western Victoria Transmission Network Project has become committed and has moved into the implementation phase. The EnergyConnect project has completed the final stage of the RIT-T process and received Australian Energy Regulator (AER) approval[22]. The RIT-T modelling confirmed that the VNI RIT-T preferred option would be required along with both Western Victoria Transmission Network Project and EnergyConnect RIT-Ts. Without EnergyConnect, New South Wales would be more reliant on import from Victoria and higher-cost generation within New South Wales, increasing the benefits of the preferred option in this RIT-T.

[19] More information at https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-20-Forecasting-and-Planning-Scenarios-Inputs-and-Assumptions-Report.pdf .

[20] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[21] Forecasts for all scenarios are available on AEMO's forecasting data portal: http://forecasting.aemo.com.au/

[22] The Australian Energy Regulator (AER) has completed the formal process as required under NER 5.16.6 to determine if investment identified through the EnergyConnect project satisfies the requirements of the RIT-T. See https://www.aer.gov.au/news-release/aer-approves-south-australia-–-nsw-interconnector-regulatory-investment-test.

Given the advanced stages of these RIT-Ts, this PACR does not propose any additional investment to address the stability limitations to achieve the 170 MW increase. AEMO will continue to monitor the implementation of these projects and re-assess the stability limitations in light of any changes.

Victorian Reactive Power Support RIT-T

The PADR noted that dynamic reactive equipment delivered through the Victorian Reactive Power Support RIT-T[23] would further improve the stability limitations above what is included in this RIT-T assessment. The Victorian Reactive Power Support RIT-T PACR has since been published, and the preferred option does not include dynamic reactive support equipment and therefore will not impact this RIT-T assessment.

Reinforcing the New South Wales Southern Shared Network RIT-T

TransGrid is progressing the 'Reinforcing the New South Wales Southern Shared Network' (HumeLink) RIT-T[24]. The HumeLink RIT-T is assessing investments that can reinforce the New South Wales Southern Shared Network to increase transfer capacity between the Snowy Mountains, southern New South Wales, and the major load centres of Sydney, Newcastle, and Wollongong. The preferred option of the HumeLink RIT-T would also increase the stability limit beyond the 170 MW increase, as detailed in Section 5.4.4. TransGrid published the PADR in January 2020.

For this RIT-T's PADR assessment, a new 500 kV line between Tumut and Bannaby was modelled from 1 July 2026. This proposed investment increases the stability limitations by 50 MW over and above the 170 MW increase, and allows Snowy 2.0 generation greater access to New South Wales demand. The new 500 kV line reduces the reliability benefits of the preferred option from 1 July 2026 (refer to Section 6.3.2) as it reduces the reliance on generation from Victoria. If the new 500 kV line is delayed, or does not proceed, then it would be expected that the reliability benefits of the preferred option would not decrease to the same extent, increasing the net market benefits of the preferred option.

Expanding New South Wales to Queensland Transmission Transfer Capacity RIT-T

TransGrid and Powerlink's Expanding New South Wales to Queensland Transmission Transfer Capacity RIT-T PACR[25] identified that their preferred option would allow Queensland generation to export to New South Wales, reducing the need for new investment in generation in New South Wales and decreasing fuel costs. This RIT-T's PACR assessment modelled an increase in Queensland to New South Wales transfer capacity equivalent to that proposed by TransGrid and Powerlink from 1 July 2022. Without this expansion, New South Wales would be more reliant on import from Victoria and higher-cost generation within New South Wales, increasing the benefits of the preferred option in this RIT-T.

Marinus RIT-T

TasNetworks' Project Marinus (Marinus Link) RIT-T[26] is assessing the market benefits of additional interconnection between Tasmania and Victoria. A PADR was published in December 2019. Marinus Link was not modelled in this RIT-T assessment because its timing in the 2018 ISP was outside this RIT-T's modelling period. However, since the proposed Marinus Link would enable additional renewable generation and storage capability to be exported from Tasmania to Victoria, and the preferred option under this RIT-T increases the export capability between Victoria to New South Wales, it is expected that Marinus Link would have a positive impact on the net market benefits of the preferred option.

Refer to Section 5.2.1 for the details of the transmission investments included in this RIT-T assessment.

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[23] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Reactive-Power-Support-RITT.

[24] At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network.

[25] At https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity.

[26] At https://www.marinuslink.com.au/rit-t-process/.

Victoria to New South Wales Interconnector West (VNI West) RIT-T

AEMO and TransGrid have jointly initiated the Victoria to New South Wales Interconnector West (VNI West) RIT-T[27] to assess the technical and economic viability of increasing bi-directional interconnector capacity between New South Wales and Victoria to address interconnector limitations in the long term. A PSCR was published in December 2019. VNI West was not modelled in this RIT-T assessment because its timing in the 2018 ISP was outside this RIT-T's modelling period. The 2020 Draft ISP identified that the investments proposed under both this RIT-T and the VNI West RIT-T are critical to address cost, security, and reliability issues and hence both form part of the optimal development path for the NEM.

2.4.3 Generator retirements and connections

The PADR analysis assumed retirement of Liddell Power Station in 2022. However, AGL has since advised[28] that the retirement will be staged, with the first of the four units being retired in 2022, and the reminder of the units being retired in 2023, supporting system reliability throughout the 2022-23 summer months. This is expected to reduce the first year of reliability benefits in year 2022-23 (refer Section 6.3.2), but does not change the preferred option or the ranking of the options.

The PADR analysis assumed retirement of Yallourn Power Station in 2032. EnergyAustralia has advised[29] of a staged retirement of the four Yallourn Power Station units from 2029 to 2032. This is expected to reduce the RIT-T benefits but does not change the preferred option or the ranking of the options. The payback period for the preferred option is six years, as noted in Section 6.3.2, as such any early retirement would need to occur before 2028 to have any impact on the preferred option.

The PADR analysis considered committed generation projects as detailed in the January 2019 release on AEMO's Generation Information web page[30]. AEMO has subsequently updated the Generation Information page with a November 2019 release. A comparison of the committed projects between the January 2019 and November 2019 releases shows an increase in the level of committed generation in Victoria compared to New South Wales/Queensland:

- Victoria has one new committed solar farm project (85 MW capacity).
- New South Wales has two new committed solar farm projects (70 MW and 30 MW capacity), as well as Snowy 2.0 which was included in the PADR analysis.
- In Queensland, a solar farm project which was committed in the January 2019 release has been recategorized as uncommitted in the November 2019 release (53 MW capacity).

Overall, the change in the level of committed generation capacity in Victoria (85 MW) is higher than in New South Wales/Queensland (47 MW). This change would likely have a positive impact on the net market benefits of the preferred option.

[27] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

[28] See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa.

[29] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Refer to 'Generating Unit Expected Closure Year – 08 November 2019' spreadsheet.

[30] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. AEMO"s commitment criteria are listed under the background information tab on each update spreadsheet.

3. Credible options included in the RIT-T analysis

3.1 Credible options assessed

The PADR assessed a range of credible options (in Table 3 below) and found that Option 2 delivers the greatest weighted net market benefits. Refer to Sections 3.1 and 3.2 of the PADR[31] for detail on each of the credible options. The PACR has taken into consideration new information since the PADR (refer Section 2.4) including the status of other RIT-T projects and reconfirms Option 2 as the preferred option.

Table 3 Credible options tested in detail through the RIT-T analysis

Option	Description
Option 1	**Base option** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors) to allow operation at thermal rating. • 330 kV Upper Tumut – Canberra line upgrade.
Preferred option Option 2	**Base option with modular power flow controllers** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors) to allow operation at thermal rating. • Install modular power flow controllers on both 330 kV Upper Tumut – Canberra and 330 kV Upper Tumut – Yass lines.
Option 3	**Additional higher capacity upgrades in New South Wales** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors) to allow operation at thermal rating. • Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern NSW[C].
Option 4	**Additional higher capacity upgrades in New South Wales and Victoria** • Two new 500/330 kV transformers at South Morang Terminal Station. • New 330 kV South Morang – Dederang line. • Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern NSW[C].

The PACR analysis used updated cost estimates for the transformer component in Victoria as additional investigations identified site restrictions at South Morang Terminal Station in Victoria. Additional works (civil works and electrical workarounds) are required to allow installation of the second 500/330 kV

[31] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

transformer, which has resulted in the capital cost of the transformer component increasing by approximately $4 million since the PADR analysis.

The PACR analysis also incorporated updated cost estimates for works in New South Wales. The increase in cost of the New South Wales works associated with the preferred option is based on recent negotiations with the modular power flow controller vendor, and includes additional protection system upgrades to ensure reliability is maintained under fault conditions. This has resulted in the capital cost of New South Wales works increasing by approximately $20 million since the PADR analysis.

The increase in cost of New South Wales works for Options 1, 3, and 4 is based on further scoping assessment which has provided greater information on site specific environmental conditions (such as design and construction requirements due to ice loadings, bushfires risk, outages, and access to construction locations) and work methodology (such as required work practices on overhead earth wire installation, and clearing requirements in bushfire-affected areas).

3.1.1 Preferred option (Option 2): Base option with modular power flow controllers

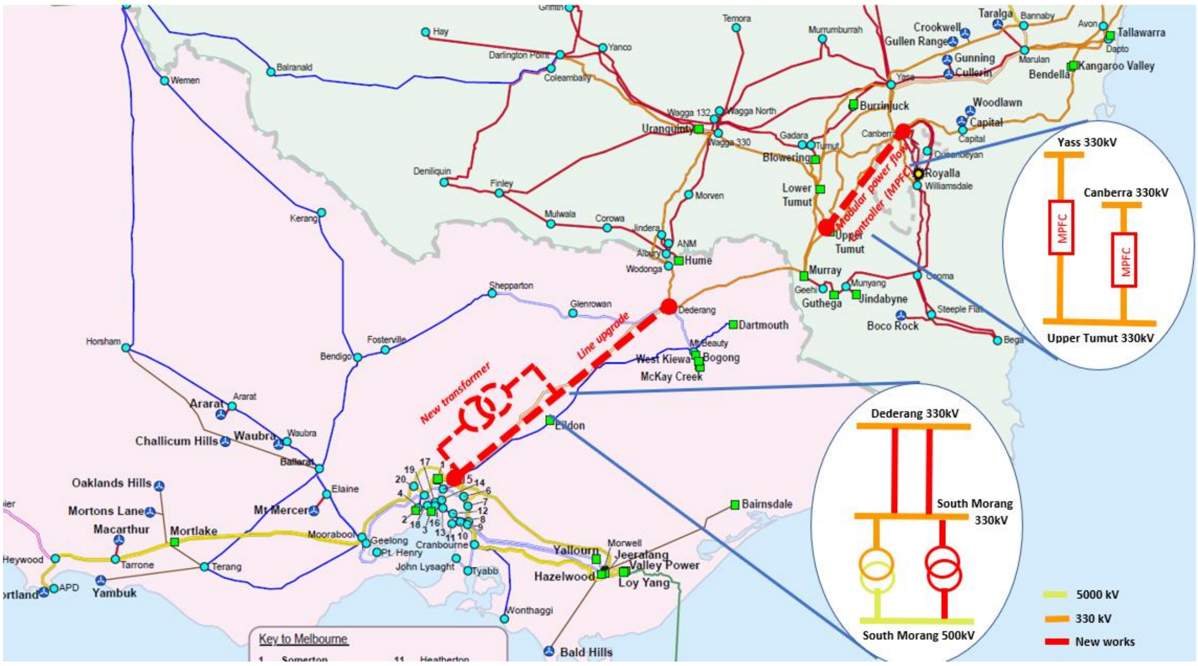
Option 2 consists of a new transformer and line upgrade in Victoria and modular power flow controllers in New South Wales. Table 4 below provides a summary of the augmentations comprising this option.

Table 4 Option 2 – Base option with modular power flow controllers

Option	Description	Estimated capital cost, $ million (2019-20)	Estimated lead time (months) [A]
2	Installation of a new 1,000 MVA 500/330 kV transformer at South Morang Terminal Station.	43	24
	Re-tensioning the South Morang – Dederang 330 kV lines and associated works (including replacing of series capacitors) to allow the line to run to its 82 C thermal ratings.	21	21
	Installation of modular power flow controllers on the 330 kV Upper Tumut – Canberra line and 330 kV Upper Tumut – Yass line to increase the transfer capacity on Lower Tumut / Upper Tumut – Canberra/Yass cut-set by 170 MW to 220 MW.	41	24
Total		**105**	**-**

A. AEMO and TransGrid will refine the lead times to maximise efficiency, allowing for the delivery of preferred option within optimal lead times.

Figure 2 Option 2 – Base option with modular power flow controllers



Modular Power Flow Controller (MPFC) – technical assessment

Investigations were conducted into the technical feasibility of modular power flow controllers (MPFC) on the 330 kV Upper Tumut – Canberra and 330 kV Upper Tumut – Yass lines. The MPFC can be used to effectively increase or decrease the reactance of a given circuit through lagging or leading constant voltage injection. It enables the real-time control of power flow within the Upper Tumut/Lower Tumut – Yass/Canberra cut-set by increasing or decreasing the transmission line reactance, either pulling more current into the least loaded Upper Tumut – Yass line (capacitive mode) or pushing the current away from the mostly loaded Upper Tumut – Canberra line (inductive mode) onto parallel underutilised lines, depending on the contingency and overloaded line(s) in the cut-set.

Since the publication of VNI PADR, further technical assessments have been conducted to confirm the technical feasibility of the modular power flow controller:

- **Dynamic Assessment** – RMS (root mean square) dynamic simulations were undertaken to assess the impact of the MPFC devices on Victoria – New South Wales Interconnector transient stability. The assessment was based on a selection of eight NEM system snapshots with a wide range of demand levels, and generation profiles. The study confirms that MPFC will not have any material adverse impact on the Victoria – New South Wales interconnector transient stability limits.
- **Control Interaction and Sub Synchronous Torsional Interaction Assessment** – simulation studies were undertaken to investigate potential Control Interaction (CI) issues and thermal generator shaft torsional interaction issues (SSTI) due to the addition of the proposed MPFC on the 330 kV Upper Tumut – Canberra and 330 kV Upper Tumut – Yass lines. These assessments reveal that the MPFC devices do not lead to unstable interactions (Control Interactions) with other dynamic devices in the power system, and that SSTI risks due to the addition of MPFC devices are minimal.
- **Control Interactions (CI)** – the coordinated operation of the MPFC device(s) with other dynamic devices (including power electronic inverter-based wind and solar plants) in the vicinity of the line ends were established using EMT (Electro Magnetic Transient) simulations.
- **Sub Synchronous Torsional Interactions (SSTI)** – screening level damping analysis and another industry accepted screening technique ("Unit Interaction Factor (UIF)") were used to identify potential SSTI issues with Gas Turbine generators in the southern subsystem.

On the basis of these studies, AEMO and TransGrid are satisfied that the MPFC solution is technically feasible.

4. Submissions to the Project Assessment Draft Report

The VNI RIT-T PADR was published in August 2019, and stakeholder submissions closed on 11 October 2019. Six submissions were received, which AEMO and TransGrid have considered when undertaking the PACR assessment and preparing this report.

4.1 Consultation on the VNI RIT-T

AEMO and TransGrid consulted on the PSCR[32] which was published on 15 November 2018. During the consultation period, which closed on 15 February 2019, 10 submissions were received. AEMO's and TransGrid's responses to the PSCR submissions were published in the VNI RIT-T PADR which was published on 30 August 2019.

During the consultation period for the PADR, which closed on 11 October 2019, six submissions were received. AEMO and TransGrid have had one-on-one meetings with each of the six respondents. The matters raised in these submissions, as well as AEMO's and TransGrid's responses, are summarised in Table 5 below.

The individual VNI RIT-T PSCR and PADR submissions are published on AEMO's website[33].

4.2 PADR submissions

The VNI RIT-T PADR received six submissions from the following stakeholders:

- PIAC (Public Interest Advocacy Centre).
- Major Energy Users Inc (MEU).
- MEA Group (Meridian Energy Australia and Powershop).
- Snowy Hydro.
- AusNet Services.
- Smart Wires.

Table 5 Summary of matters raised in the PADR submissions and responses

Matters raised in submissions by general topic	AEMO and TransGrid response
Majority of respondents expressed support for the preferred option.	• The preferred option (Option 2) delivers the greatest net market benefits across the NEM and fully considers all associated costs and benefits of the option. • The preferred option will deliver some reliability benefits however the benefits are predominantly driven by fuel cost savings and capital deferral benefits.

[32] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

[33] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

Matters raised in submissions by general topic	AEMO and TransGrid response
Several recommended expanding the scope to include Victorian imports	• Acknowledge the need for additional import capability noting the January 2019, December 2019 and January 2020 RERT[34] events which were the result of bushfires, extreme heat conditions and unplanned generator outages. • AEMO and TransGrid are undertaking a number of operational and planning initiatives to improve import capability into Victoria as discussed in Section 2.3. The initiatives will help manage the risk and minimise any impact of the issues that resulted in the activation of RERT in Victoria.. • The operational initiatives are low cost and have short lead times and will help manage risks in the short to medium term until longer term planning solutions are identified[35].
Several raised questions on the balance between those who pay and those who benefit from the RIT-T outcomes	• The transmission charging framework is set out in the NER. AEMO and TransGrid note that the AEMC has been considering refinements to the inter-regional transmission use of service (IR-TUOS) charges as part of their review into the co-ordination of generation and transmission. The appropriateness of the current IR-TUOS arrangements is an issue that is separate to this RIT-T, and modifications to the arrangements are not precluded by the outcome of this RIT-T.
One proposed an alternative 220 kV option between Bendigo-Shepparton-Dederang.	• This option was tested as a potential alternate option to the Victorian works (i.e. installing a new South Morang transformer and uprating South Morang-Dederang lines). Refer to Appendix A2 for detail. • This option is more expensive than the preferred option. This option is approximately $300 million and the Victorian component of the preferred option is approximately $64 million. • Studies identified that this option would not be effective in allowing the transfer of lower cost Victorian generation to New South Wales to deliver fuel cost benefits. • As this option is more expensive, has a longer lead time[36], and does not relieve the constraints limiting high exports from Victoria to New South Wales, it was not assessed further. • This alternative option does not mitigate the need for the Western Victoria Transmission Network Project, which supports generator connections and relieves congestion around Bulgana, Ballarat and Sydenham. This is because the alternative option proposes augmentation in a different location between Bendigo and Shepparton. • As noted in the VNI West RIT-T PSCR[37] there is currently over 8 GW of renewable generation and storage operational or proposed to connect in northern and western Victoria. The VNI West RIT-T will assess the market benefits of this new interconnection taking into account the ability of the alternative credible options to enable this proposed generation to access demand centres.
One questioned the alignment and independence of the RIT-T assessment from the Integrated System Plan (ISP)	• While the modelling inputs and assumptions used in this RIT-T are consistent with those used in the ISP and ESOO, the power system and market modelling assessment studies that underpin selection of a preferred option have been conducted independently of those activities.
One requested further transparency on how the other RIT-Ts would resolve stability issues	• The Western Victoria Transmission Network Project has completed the RIT-T process is and has moved into the implementation phase. Project Energy Connect has completed the final stage of the RIT-T process and received AER approval. Both projects will improve the stability limits between Victoria and New South Wales. • Section 5.4.4 of this report includes additional detail on the stability studies that were conducted to confirm the other RIT-T preferred options would address the stability limitations.

[34] At https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

[35] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/VNI-West-RIT-T.

[36] Lead times associated with planning approvals for new line builds can be significant.

[37] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

5. Methodology and assumptions

The modelling carried out in this RIT-T, consistent with the approach specified in the RIT-T application guidelines, includes:

- Detailed power flow studies to quantify the network impact of credible options, and
- Subsequent market modelling to assess the net economic benefits of the options under a least-cost national development pathway.

The methodology and assumptions used for the PADR also apply for this report, as additional market modelling has not been undertaken as part of the PACR stage. This is because there have not been sufficient changes since the PADR to necessitate the need to undertake additional modelling. The key changes and their impacts are discussed in Section 2.4 and below.

5.1 Overview

The assessments in this RIT-T are based on the AER's RIT-T application guidelines published in December 2018[38].

The assumptions used in the PADR assessment were based on AEMO's 2019 Planning and Forecasting Consultation Paper[39] and input workbook, provided as Attachment A: Input assumptions on AEMO's website[40] and summarised in Appendix A of the PADR.

Following stakeholder consultation, AEMO published the finalised scenarios and input assumptions to be used in AEMO's 2019-20 Planning and Forecasting publications in August 2019. The key changes and their impacts are discussed below.

The market modelled methodology used is consistent with AEMO's 2018 ISP approach, and further details are available in Section 5.3, and in AEMO's Market Modelling Methodologies paper[41].

This chapter describes the key assumptions and methodologies applied in this RIT-T.

5.2 Assumptions

5.2.1 Transmission development

Transmission development, including augmenting existing interconnectors and building new interconnectors, was based on the modelled outcome identified in the 2018 ISP, and associated RIT-T processes where available. The current status of these RIT-T processes is discussed in Section 2.4.2.

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

[39] At https://www.aemo.com.au/Stakeholder-Consultation/Consultations/2019-Planning-and-Forecasting-Consultation.

[40] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

[41]AEMO, July 2018, at www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Market-Modelling-Methodology-Paper.pdf.

The timing and notional capacities of these interconnector developments are shown in Table 6 below. Note that the modelling for this RIT-T used constraint equations to represent network capability, as described in Section 5.4.1.

In addition to these interconnector developments, the 2018 ISP showed that a new link from Tumut to Bannaby, referred to as HumeLink as part of TransGrid's Reinforcing the New South Wales Southern Shared Network RIT-T (and called 'SnowyLink North' in the 2018 ISP), would provide benefits in the mid-2020s, supporting the development of the Snowy 2.0 project. This link was included as an anticipated project from 1 July 2026 to align with the timing for Snowy 2.0 in the Neutral and Fast change scenarios.

This RIT-T also assumed that the Western Victoria Transmission Network Project, an upgrade between Sydenham to Ballarat to Bulgana, was in place by 2025 across all scenarios.

Table 6 Interconnector developments assumed in this PACR

Interconnector	Timing	Capacity, MW, forward direction	Capacity, MW, reverse direction
NSW–QLD[A]	2022-23	770 (increase of 460)	1,215 (increase of 190)
NSW–QLD[B]	2023-24	770 (increase of 460)	1,593 (increase of 568)
EnergyConnect (SA–NSW)[C]	2022-23	750	750

A. For details see RIT-T at https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity.
B. It is noted that this ISP "Group 2 – medium term NSW to QLD upgrade", while assumed in the RIT-T modelling, is no longer part of the QNI RIT-T scope. This change has not been modelled in this PACR as it would only increase the benefits for this VNI RIT-T. This is because the medium term NSW to QLD upgrade would have provided additional support from QLD to NSW, without it, the support from Vic is more valuable as it would be utilised more to compensate.
C. For details see RIT-T at https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf.

The above transmission developments tend to decrease the benefits[42] of the preferred options assessed in this RIT-T, by:

- Relieving stability constraints limiting Victoria to New South Wales export (refer to Section 2.2.2 for detail) allowing for greater imports into New South Wales, hence less reliance on additional import from Victoria.
- Providing additional capacity into New South Wales via South Australia and Queensland, hence less reliance on import from Victoria.
- Providing additional capacity into Sydney via Tumut, hence less reliance on import from Victoria.

This RIT-T has not included a scenario without the above transmission developments as the RIT-T benefits under such scenarios would only increase further confirming the robustness of the preferred option.

5.2.2 Analysis period

The RIT-T analysis has been undertaken over the period from 2021-22 to 2033-34.

To capture the overall market benefits of a credible option with asset life or assumed network support arrangements extending past 2033-34, the market dispatch benefits calculated for the final year of the modelling period have been assumed to be indicative of the annual market dispatch benefit that would continue to arise under that credible option in the future. As such, this approach of using the final year is conservative and demonstrates the robustness of the preferred option as the market benefits are lower in the final year, compared to previous years (refer to Section 6.3.2 for detail).

Terminal values[43] have been used to capture the remaining asset life[44] of the credible options and other investments in the market (generation plant).

[42] This decrease is reflected in the market benefits assessment presented in Chapter 6.

[43] The value of an asset at the end of the modelled horizon.

[44] Based on ISP assumptions for various asset types.

5.2.3 Discount rate

The RIT-T requires the base discount rate used in the net present value (NPV) analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

A base discount rate of 5.9% (real, pre-tax) has been used in the NPV analysis. This discount rate is consistent with the commercial discount rate calculated in the Energy Networks Australia (ENA) RIT-T Economic Assessment Handbook[45]. This calculation assumes that a private investment in the electricity sector has a return on equity, and a debt gearing ratio, equal to an average firm on the Australian Stock Exchange as of 15 March 2019.

The cost-benefit assessment has included sensitivity testing with a lower bound discount rate equal to the regulated weighted average cost of capital (WACC) of 2.85% based on the AER's most recent transmission determination[46], and a higher bound discount rate of 8.95% (that is, a symmetrical adjustment upwards).

5.2.4 Reasonable scenarios

Clause 5.16.1(c)(1) of the NER requires that the RIT-T is based on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand if each credible option were implemented, compared to the situation where no option is implemented. A reasonable scenario represents a set of variables or parameters that are not expected to change across each of the credible options or the base case.

The PADR analysis included three reasonable scenarios as described in AEMO's 2019 Planning and Forecasting Consultation Paper[47]:

- **Neutral** – a future where modest economic and population growth is experienced, and existing policies are delivered. Consequently, grid demand is relatively static, and change in the large-scale generation mix is largely driven by the timing of coal-fired generation retirements.
- **Slow Change** – a future where Australia's economic and population growth is weaker, the life of existing power stations could be extended, households and commercial businesses install rooftop photovoltaic (PV) systems to help reduce energy costs, and the transition towards zero emission vehicles is slower, as people have less disposable income and are buying new vehicles less often. Consequently, grid demand is in decline and the change in large-scale generation mix over time is less pronounced.
- **Fast Change** – a future where Australia's economy is booming, population growth is strong, and emission reduction targets are aggressive, leading to rapid decarbonisation of both the stationary energy sector and the transport sector. Consequently, growth in grid demand is relatively strong and there is a material change in the large-scale generation mix over time.

Following stakeholder consultation, AEMO developed the following five ISP scenarios:

- Central scenario – reflects the transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current federal and state government policies.
- Slow Change scenario – reflects a general slow-down of the energy transition. It is characterised by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction.
- Step Change scenario – reflects strong action on climate change that leads to a step change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster technological improvements, accelerated exit of existing generators, and greater electrification of the transport sector, with increased infrastructure developments, energy digitalisation, and consumer-led innovation.

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[45] At https://www.energynetworks.com.au/rit-t-economic-assessment-handbook.

[46] At https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24.

[47] At https://www.aemo.com.au/Stakeholder-Consultation/Consultations/2019-Planning-and-Forecasting-Consultation.

- High Distributed Energy Resources (DER) scenario – reflects a more rapid consumer-led transformation of the energy sector, relative to the Central scenario. It represents a highly digital world where technology companies increase the pace of innovation in easy-to-use, highly interactive, engaging technologies. This scenario includes reduced costs and increased adoption of DER, with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.
- Fast Change scenario – reflects a rapid technology-led transition, particularly at grid scale, where advancements in large-scale technology improvements and targeted policy support reduce the economic barriers of the energy transition. This includes coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated exit of existing generators, and integration of transport into the energy sector.

Comparing the ISP scenarios to the PADR scenarios:

- The Central scenario is analogous to the PADR Neutral scenario, reflecting current government policies and best estimates of all key drivers.
- The Slow Change scenario, with weak economic and population growth, has lower consumer interest in directing change resulting in lower uptake of rooftop PV compared to the PADR Slow Change scenario.
- The Fast Change scenario has a more moderate economic and population growth (in line with the Central scenario) compared with the strong growth underpinning the PADR Fast Change scenario. Like the PADR Fast Change scenario, technology innovations lead to cost reductions across large and small technologies, leading to material change in the large-scale generation mix over time.

The High DER and Step Change scenarios are in addition to those included in the PADR. In comparison with the Central scenario:

- The High DER scenario has significantly greater decentralisation through higher DER compared with the Central scenario.
- The Step Change scenario has higher economic and population growth, more aggressive decarbonisation goals, higher technology innovation and DER uptake, and greater electric vehicle uptake.

While the overall range of outcomes for the energy industry, in terms of decentralisation and decarbonisation, is greater in the long term under the five ISP scenarios than the three PADR scenarios, the range of outcomes in the short to medium term are similar.

As the preferred option in this RIT-T has a payback period in the order of six years, it is considered that the PADR scenarios include a suitable wide range of reasonable scenarios for this RIT-T assessment. The PACR therefore continue to use the PADR scenarios.

The rest of this chapter discusses the key input assumptions in the scenarios in more detail.

5.2.5 Policy settings

The following market and policy settings were applied in the PADR as modelling constraints:

- Emissions trajectories – reduce emissions to 26% on 2005 levels by 2030[48] in the Neutral and Slow Change scenarios, and reduce emissions to 52% on 2005 levels by 2030[49] in the Fast Change scenario.
- Victorian Renewable Energy Target (VRET) – 25% renewables by 2020, 40% by 2025, and 50% by 2030[50].

[48] Based on the existing Federal emissions reduction policy to reduce Australia's emissions by 26% by 2030 economy- wide, with a commensurate degree of decarbonisation to be required form the electricity sector.

[49] Emission constraint consistent with the Low Emissions Technology Roadmap developed with the CSIRO, at https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/.

[50] Details at https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

- Queensland Renewable Energy Target (QRET) – 50% renewables by 2030[51].

The policy settings that have changed under the ISP scenarios include:

- Emissions trajectories – all five ISP scenarios have been modelled with a 26% reduction in emissions by 2030 constraint as per the PADR scenarios. In addition, the Fast Change and Step Change scenarios have NEM carbon budgets applied to constrain emissions to a specified volume between 2020 and 2050. For the Fast Change scenario, this translates to a similar 2050 emission target as that applied in the PADR Fast Change scenario. The Step Change scenario has a higher level of emissions reductions by 2050 than any of the PADR scenarios, however this impact of this will be outside the payback period.
- VRET – the 25% renewables by 2020 and 40% by 2025 targets were applied to all ISP scenarios and the 50% by 2030 was applied in the Central, High DER, and Step Change scenarios only. However, the increase in the VRET target to 50% by 2020 was passed into legislation on 30 October 2019[52], aligning with the assumptions applied in the PADR scenarios (of 25% by 2020, 40% by 2025 and 50% by 2030).
- QRET – the 50% renewables by 2030 target was applied in the ISP Central, High DER, and Step Change scenarios only. The PADR modelled the QRET target in all reasonable scenarios, however, removing this target would be expected to have a positive impact on the net market benefits of the preferred option by reducing a competition source of low cost supply.

A number of policies exist across NEM jurisdictions to support uptake of DER. These include:

- South Australia – Home Battery Scheme[53].
- Victoria – Solar Homes Package[54].
- New South Wales – Clean Energy Initiatives[55].
- Queensland – Solar battery rebates[56].

AEMO incorporated each of these schemes in the DER uptake and behavioural analysis performed within the 2019 demand forecasts.

5.2.6 Weightings applied to each scenario

Three separate weightings have been applied to the reasonable scenarios, to test if different weightings have an impact on the preferred option. However, as the net market benefits of the preferred option are positive, and the rankings of the credible options are the same in all scenarios, the preferred option is not sensitive to the scenario weightings.

Table 7 Scenario weightings

Scenario weightings	Neutral	Slow change	Fast change
Set A – Base	50%	25%	25%
Set B – Slow	25%	50%	25%
Set C – Fast	25%	25%	50%

[51] Details at https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland.

[52] Details at https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[53] Details at https://homebatteryscheme.sa.gov.au/.

[54] Details at https://www.solar.vic.gov.au/.

[55] Details at https://energy.nsw.gov.au/renewables/clean-energy-initiatives.

[56] Details at https://www.qld.gov.au/community/cost-of-living-support/concessions/energy-concessions/solar-battery-rebate.

5.2.7 Energy consumption

This RIT-T applied the energy consumption and demand forecasts from the 2018 ESOO[57].

As discussed in Section 2.4.1, AEMO has since prepared updated demand forecasts for the 2020 ISP for the five ISP scenarios.

The market benefits of the preferred option in this RIT-T are sensitive to the:

- Maximum demand in New South Wales, particularly in the years prior to the commissioning Snowy 2.0 and associated transmission investment.
- Annual consumption in Victoria with benefits increasing as consumption decreases, due to additional spare low-cost generation capacity being available to export to New South Wales.

Figure 3 shows the New South Wales summer 50% probability of exceedance (POE) maximum demand forecasts used in the PADR assessment (dashed lines) compared to forecasts under the Draft 2020 ISP scenarios. The maximum demand forecasts for all ISP scenarios are higher than the PADR scenarios until around 2024-25, and generally between the PADR Neutral and Slow Change scenarios from 2025-26 onwards.

Figure 3 Comparison of 50% POE summer maximum demand forecasts for New South Wales

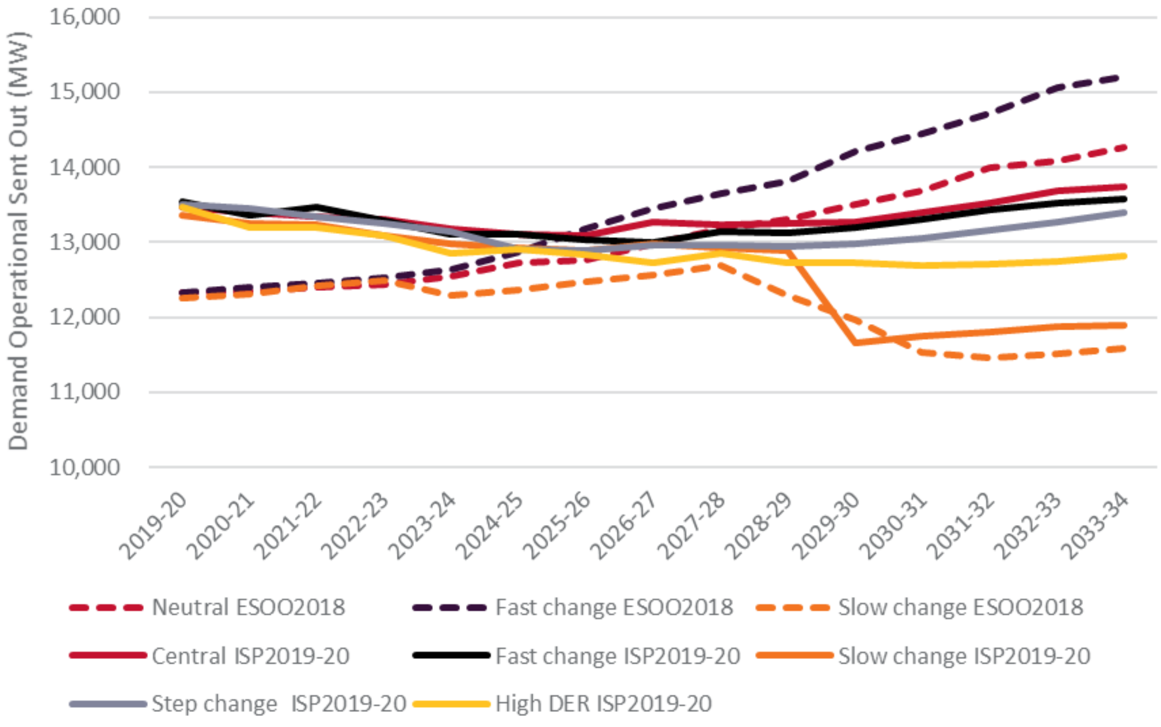
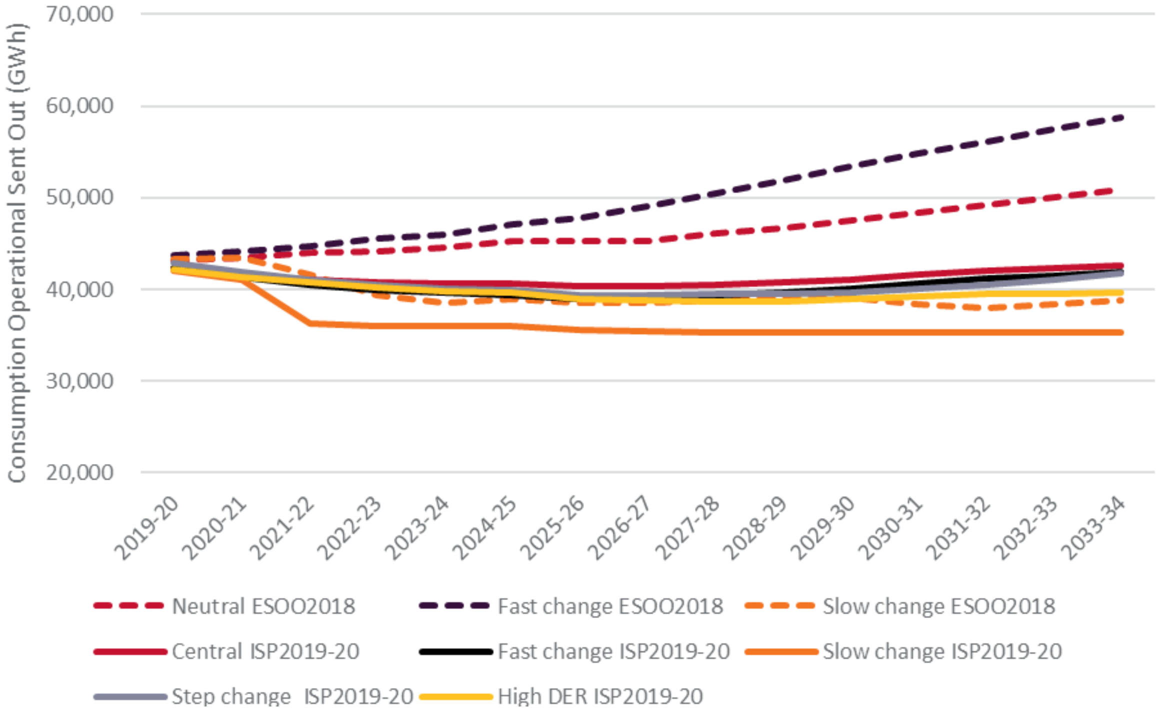


Figure 4 shows the Victoria annual consumption forecasts used in the PADR assessment (dashed lines), compared to the forecasts under the draft 2020 ISP scenarios. Forecast growth in annual consumption is lower across all scenarios across the forecast horizon in the updated forecasts.

AEMO and TransGrid consider that the combined impact of these updated forecasts would have a minimal impact on the market benefits of the preferred option.

[57] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

Figure 4 Comparison of annual consumption forecasts for Victoria



Both 10% and 50% POE demand projections were used for this RIT-T assessment, with a weighting of 30% and 70%, respectively. The 10% POE projections reflect an expectation of more extreme maximum demand conditions driven by variations in weather conditions, and the 50% POE projections reflect an expectation of typical maximum demand conditions.

In response to stakeholder feedback, AEMO and TransGrid have included a sensitivity including only the 50% POE projections. As shown in Table 16 (in Section 6.3.3), the net market benefits of the preferred option remain positive and the ranking of options is unchanged when using only 50% POE projections.

5.2.8 Reference years

Time-sequential traces are used in the market modelling to represent consumption patterns, wind and solar generation output, and temperature-sensitive transmission line thermal ratings ('dynamic ratings'). These traces reflect the historical patterns observed in previous financial years, or 'reference years'. A consistent methodology is used to develop these reference years traces to ensure that weather patterns affecting energy consumption also affect available renewable energy generation and line ratings.

This RIT-T used the 2013-14 reference year for the 10% POE demand projection modelling runs, and the 2014-15 reference year for the 50% POE demand projections modelling runs. These reference years were selected based on load conditions seen in those years, where the 2013-14 year represented peaky demand conditions and the 2014-15 year represented more moderate demand conditions, representing demand conditions expected in a 10% POE and 50% POE year respectively.

5.2.9 Value of customer reliability

The value of customer reliability (VCR) represents a customer's willingness to pay for the reliable supply of electricity[58], and was used in this RIT-T to value any reductions in unserved energy. The AER released its final report on its VCR review in December 2019[59].

[58] For more, see https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability-vcr.

[59] At https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

The cost-benefit assessment in this RIT-T has been updated using the state VCR values from this report, as set out in Table 8.

Table 8 VCR $/MWh (2019-20)

	NSW+ACT	VIC	QLD	SA	TAS
VCR (including direct connect)	42,120	41,210	40,030	43,230	32,160

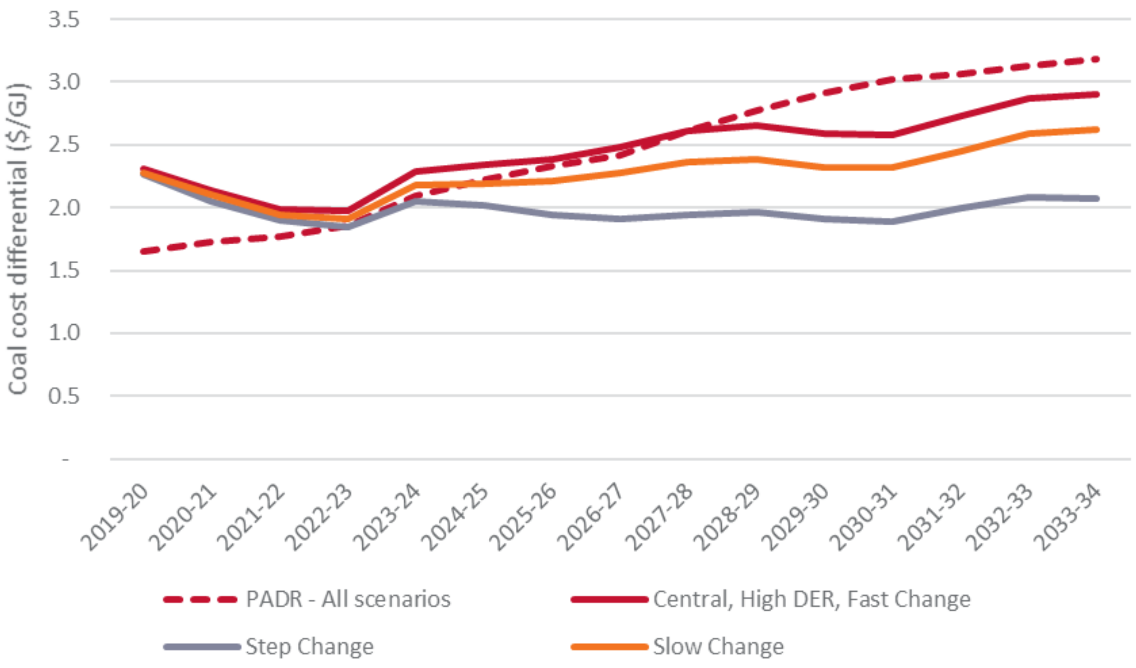
5.2.10 Fuel prices

The primary benefits of the preferred option arise from reducing dispatch costs through more efficient dispatch of generation, with lower cost generation in Victoria displacing higher cost generation in New South Wales.

The PADR assessment used the fuel prices from the 2019 Planning and Forecasting Consultation. Gas prices were developed by AEMO in collaboration with consultant Core Energy & Resources Pty Limited (CORE)[60]. Coal cost projections were based on the 2016 Wood Mackenzie Coal Cost report[61] for existing generators, and the Resources and Energy Quarterly (June 2018) report[62] for new entrant technology.

Since the PADR, AEMO has updated the coal cost projections for existing generators and new entrant technology based on the 2019 Wood Mackenzie coal cost projections[63]. Figure 5 shows the difference between the average cost of coal at existing New South Wales black coal generators and the average cost of coal at existing Victoria brown coal generators used in the PADR versus the updated projections.

Figure 5 Coal cost differential projections (New South Wales black coal minus Victorian brown coal)



[60] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE_Delivered-Wholesale-Gas-Price-Outlook_16-January-2019.pdf.

[61] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/AEMO_Coal-cost-projections_approach_20160512.pdf.

[62] At https://www.industry.gov.au/data-and-publications/resources-and-energy-quarterly-all/resources-and-energy-quarterly-june-2018.

[63] Report at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/WoodMackenzie_AEMO_Coal_cost_projections_Approach_20190711.pdf, Databook at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/WoodMackenzie_AEMO_Delivered_cost_of_coal_20190711.xlsx.

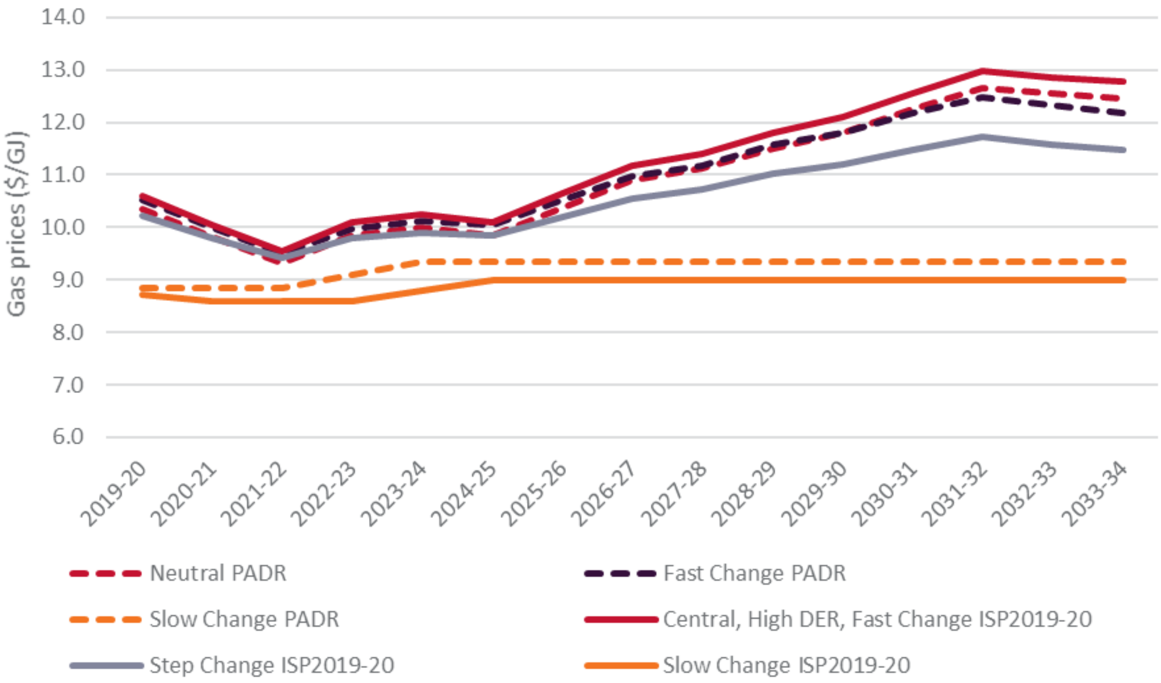
This shows that from around 2023, the PADR projections had a higher coal price differential between New South Wales black coal and Victoria brown coal than in the updated projections. The updated differential is the lowest in the Step Change scenario because under this scenario an increase in renewables drives a rapid decline for coal, resulting in a lower price of thermal coal impacting stations with coal supplied on an export parity basis.

These updated coal price projections will reduce the net market benefits of the preferred option, and a sensitivity study has been included using the Step Change scenario coal price projections as shown in Section 6.3.3. Using the Step Change coal price projections, and keeping all other inputs fixed as per the PADR Neutral scenario, reduces the net market benefits over the asset lifetime by around 19%, but does not reduce the payback period of the preferred option.

Since the PADR, gas price projections have also been updated using Core Energy's 2019 wholesale gas price outlook report[64]. To indicate the changes, Figure 6 shows the average gas price projections for existing New South Wales gas-powered generators (GPG) as used in the PADR scenarios, compared with the updated projections across the ISP scenarios.

Generally, the new projections are slightly higher than the PADR projections in the Neutral/Central scenario and slightly lower in the other scenarios. The impact of the updated fuel price projections has been assessed as a sensitivity, as shown in Section 0. The net market benefits reduce by around 7-17%, depending on the scenario, with the updated fuel price projections, but the payback period remains unchanged.

Figure 6 Gas price projections – average across existing New South Wales gas powered generators



5.2.11 Technology costs

As detailed in AEMO's Planning and Forecasting Consultation Paper, AEMO engaged GHD and CSIRO to review and update new entrant costs and technical parameters across a range of generation and storage technologies. GHD provided AEMO with current technology costs and performance data for a range of

[64] Report at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE_Delivered-Wholesale-Gas-Price-Outlook_16-January-2019.pdf, Data book at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE-Eastern-Australia-Gas-Price-Projections-Databook_16-January-2019.xlsx.

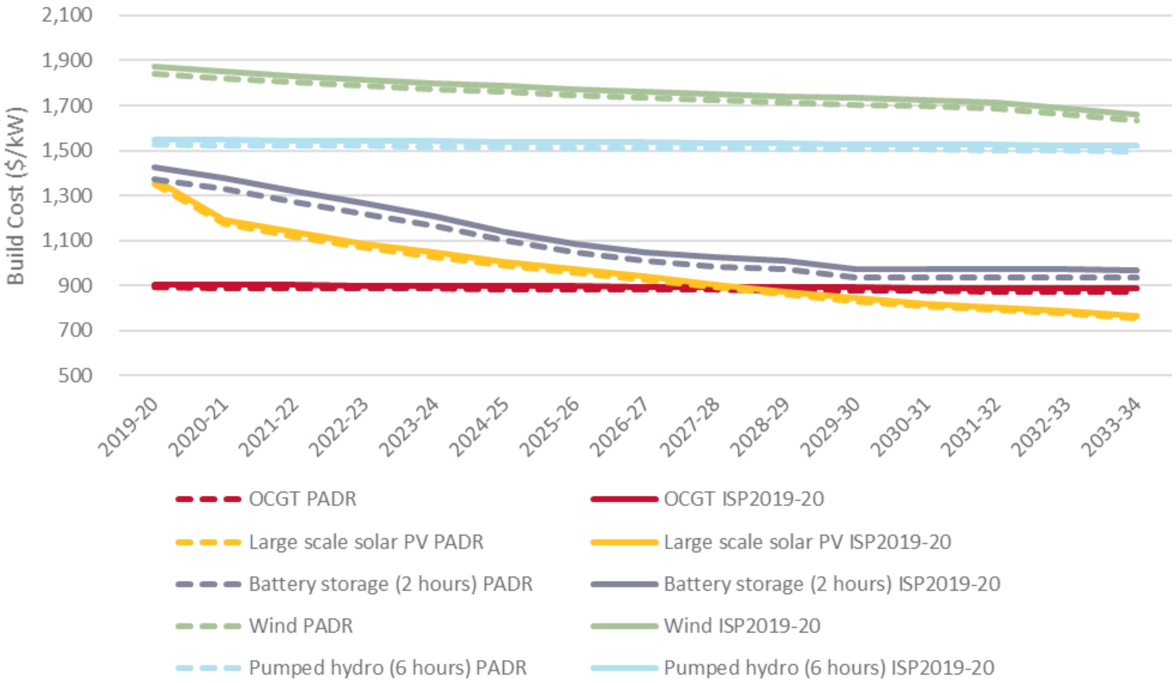
candidate technology options[65]. CSIRO produced cost projections from GHD's current technology costs using their Global and Local Learning Model (GALLM).

CSIRO's GALLM build costs projects are a function of global and local technology deployment. As the global technology deployment depends on the global climate policy, CSIRO GALLM build cost projections are given for two scenarios, termed '4-degrees' and '2-degrees'[66]. The PADR assessment applied the February 2019 '4-degree' build cost projections for the Neutral and Slow Change scenario, and the '2-degree' build cost projections for the Fast Change scenario.

The build cost assumptions were by CSIRO, updated in August 2019[67], and for the ISP studies AEMO is generally applying the '4-degree' build cost projections to the Slow Change, Central and High DER scenarios and the '2-degree' build cost projections to the Fast Change and Step Change scenarios[68].

Figure 7 shows the build cost projections for selected technologies for construction in Melbourne for the 4-degrees scenario used in the PADR (dashed lines) compared with the updated projections. As can be seen, the changes are relatively minor, and AEMO and TransGrid consider that the changes would have a minimal impact on the market benefits assessment.

Figure 7 Build cost projection for selected technologies for 4-degree scenario ($/kW)



5.2.12 Generation expansion

Generation expansion (including the development of new generation and storage) and the closure of existing generation was obtained from the capacity outlook model described in Section 5.3.1 for each reasonable scenario.

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[65] At http://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.

[66] The CSIRO scenario names describe the global climate policy goal. For example, the 2-degree scenario represents a pathway that would be consistent with limiting temperature increase to less than 2 ^{0}C.

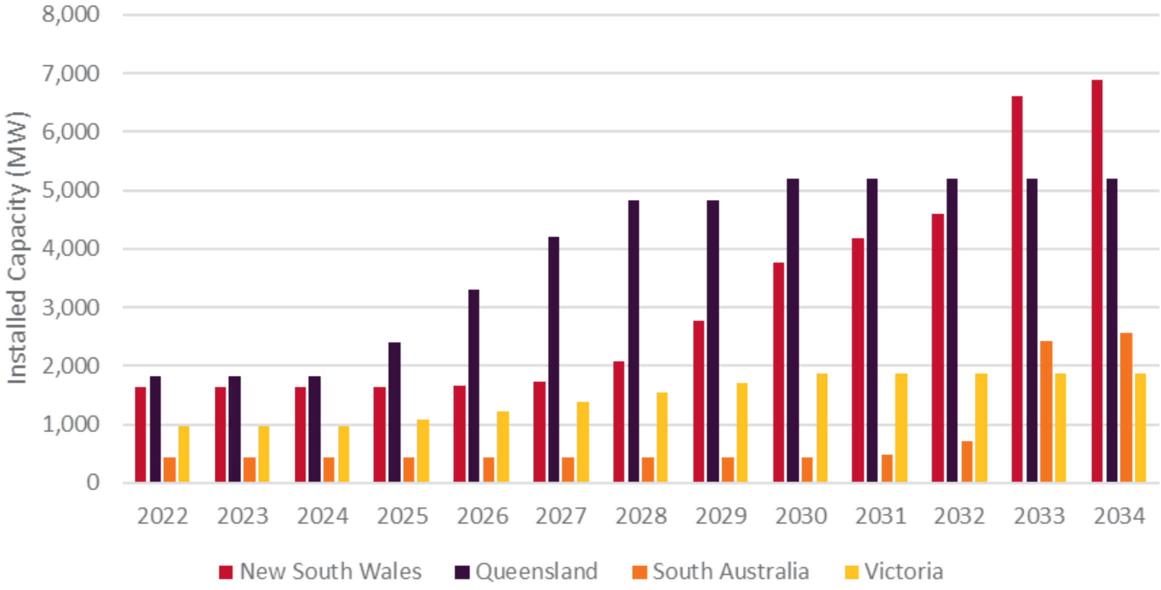
[67] At https://publications.csiro.au/rpr/download?pid=csiro:EP189502&dsid=DS1.

[68] The ISP scenarios will bring forward or delay some technology cost improvements in some scenarios as detailed in the 2019 Forecasting and Planning Scenarios, Inputs and Assumptions Report, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

For the PADR assessment, committed generation projects were taken from the January 2019 Generation Information update[69]. The VRET projects[70] (listed in the 2019 Forecasting and Planning – Input and Assumptions workbook[71]) and the Snowy 2.0 project were assumed to be committed in all reasonable scenarios.

Section 2.4.3 discusses the changes to committed generation in the November 2019 Generation Information update. These changes are relatively minor, with additional utility solar generation committed in Victoria (85 MW) and in New South Wales and Queensland (total of 47 MW), compared to the PADR assessment. To put this into perspective, Figure 8 shows the modelled installed capacity of utility solar generation in the Neutral scenario for the 'do nothing' case.

Figure 8 Utility solar generation expansion – Neutral scenario, 'do nothing' case



Announced and end-of-technical life retirements were applied as outlined in the 2019 Forecasting and Planning – Input and Assumptions workbook. End-of-life retirement timings are determined according to equipment age, and units may be retired earlier in the capacity outlook model if this is determined as a least-cost outcome to the overall market.

As discussed in Section 2.4.3, the announced retirement for a number of coal generators have changed since the PADR assessment.

0 presents the coal retirement dates for coal generators up to the end of the modelling period from the January 2019 Generation Information update (as used in the PADR assessment) compared with the November 2019 Generation Information update.

[69] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[70] VRET projects refers to VRET Stage 1 auction winners. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-auction-scheme.

[71] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

Table 9 Coal generator retirement dates

Generator Name	Region	Capacity (MW)	January 2019 Update	November 2019 Update
Liddell 1-3	NSW	1,500	2022	2023
Liddell 4	NSW	500	2022	2022
Vales Point B	NSW	1,320	2028	2029
Eraring	NSW	2,880	2034	2031
Gladstone	QLD	1,680	2029	2029
Yallourn 1	VIC	350	2032	2029
Yallourn 2	VIC	350	2032	2030
Yallourn 3	VIC	375	2032	2031
Yallourn 4	VIC	375	2032	2032

In addition to the retirements listed above, the capacity outlook model retired a number of coal generators in the Fast Change and Slow Change scenarios. As noted, these retirements, shown in Table 10, are based on a least-cost outcome to the overall market not on a profitability assessment of the individual generators. The additional generators retired were the same for the 'do nothing' case and across all credible options.

Table 10 Additional coal retirements – 'do nothing' and all credible options

Scenario	Region	Capacity (MW)	Retirement Year
Fast Change	QLD	730	2026
Fast Change	VIC	1,090	2027
Slow Change	QLD	1,460	2026

The detailed outputs of the capacity outlook model were published as PADR Attachment B: Market modelling results[72].

5.3 Market modelling methodology

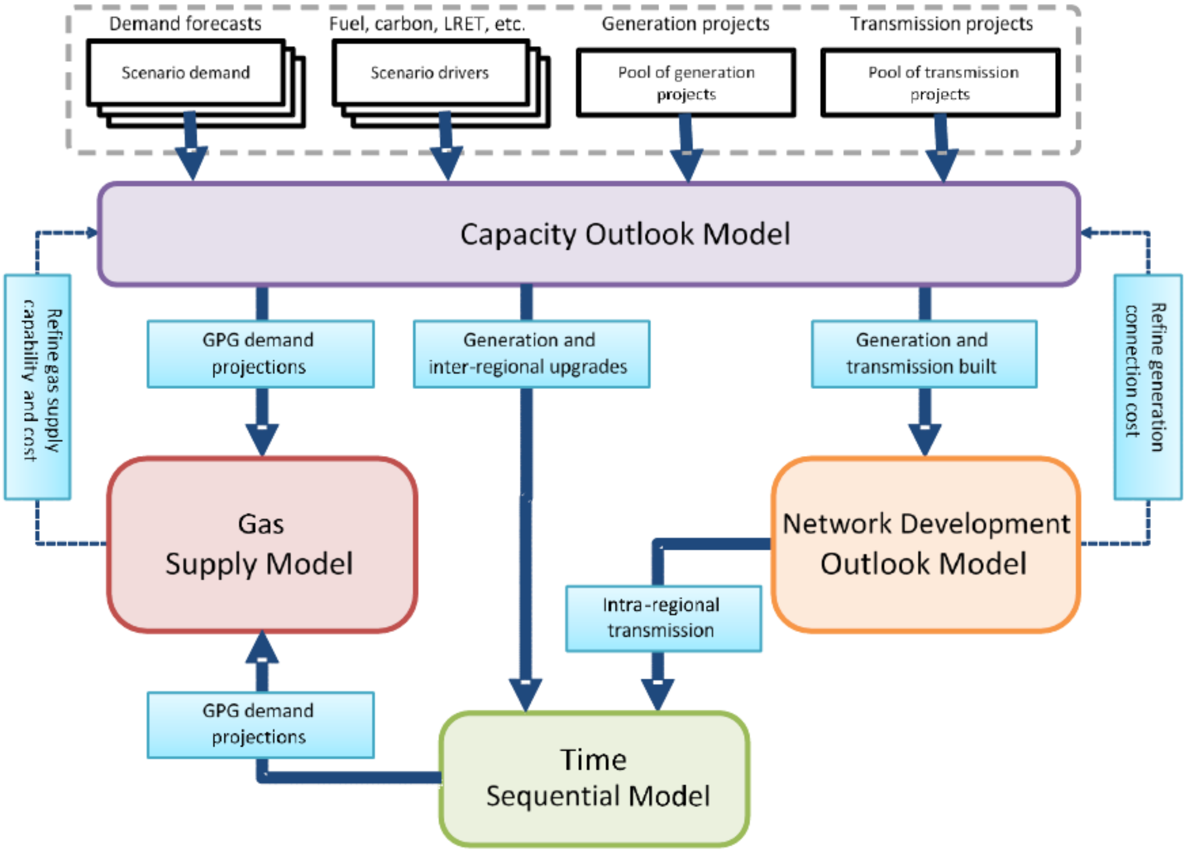
AEMO used market dispatch modelling to estimate the market benefits associated with the credible options.

This estimation was done by comparing the 'state of the world' in the base case (or 'do nothing' case) with the 'state of the world' with each of the credible options in place. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity, and timing of future generation, storage, and transmission investment, as well as the market dispatch outcomes over the modelling period.

AEMO maintains four mutually-interacting planning models, shown in Figure 9.

[72] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Attachment-B-Market-modelling-results.xlsx.

Figure 9 Market modelling process



These models incorporate the assumptions about future development described by the scenarios and simulate the operation of energy networks to determine a reasonable view as to how those networks may develop under different demand, technology, policy, and environmental conditions.

This RIT-T primarily uses two of these market models to deliver its key outputs:

- **Capacity outlook model** – determines the most cost-efficient long-term trajectory of generator and transmission investments and retirements to maintain power system reliability. Two variants exist:
  - **Long Term Integrated model (IM)** – co-optimised model which considers interdependencies between gas and electricity markets to determine optimal thermal generation investments, retirements, transmission and pipeline investment plans, over the longest time horizon (25 years or beyond).
  - **Detailed Long Term (DLT) model** – optimisation model of the electricity system in isolation to the gas market, optimising new generation investments and sub-regional transmission developments, using inter-regional transmission and other long-lived thermal generation development decisions produced by the IM capacity outlook model. The DLT model is a more granular capacity outlook approach that provides chronological, detailed representations of the long term via a multi-step solve, thus with reduced foresight relative to the IM.
- **Time-sequential model** – carries out an hourly simulation of generation dispatch and regional demand while considering various power system limitations, generator forced outages, variable generation availability, and bidding models. This model validates insights on power system reliability, available generation reserves, emerging network limitations, and other operational concerns. Depending on the study this model is used for, the generation and transmission outlook from the capacity outlook model may be incorporated.

The Network Development Outlook Model in Figure 9 is a PSS/e[73] model used to examine the engineering parameters of the identified need and the credible options.

The Gas Supply Model is used primarily in the Gas Statement of Opportunities (GSOO) and was not used in the RIT-T studies.

5.3.1 Capacity outlook model

A 'least-cost' market development modelling was undertaken, according to the RIT-T application guidelines. The least-cost model is orientated towards minimising the cost of serving load (or allowing load to remain unserved if that is least-cost) while meeting minimum reserve levels and policy settings. The model can select between different generation and storage types, based on resource availability and transmission network capacity. The least-cost market development model used was the PLEXOS® long-term optimisation model.

The DLT model discussed above was used to develop a generation and storage expansion plan for each reasonable scenario with and without the credible options in place.

Following this, time-sequential modelling (described in the next section) was applied to assess the differences in market benefits for each credible option.

5.3.2 Time-sequential model

The time-sequential modelling aims to dispatch the least-cost generation to meet customer demand, mandatory service standards, and the various carbon abatement targets that have been assumed, while remaining within the technical parameters of the electricity transmission network.

Detailed market modelling was undertaken with the PLEXOS® short-term dispatch model.

Model inputs

- Generation and interconnector expansion plans were obtained from the Capacity outlook model described in Section 5.3.1.
- Transmission network parameters that were included in the modelling are described in Section 5.4.
- Generation, storage, and demand side resource input assumptions are described in Appendix A1 of the PADR.

Model outputs

This model produces an hourly pricing and dispatch solution for generation, storage, and demand side resources, which is used to calculate operational benefits (reduction in fuel and variable operation and maintenance costs).

5.4 Transmission network parameters

Constraint equations and dynamic rating traces are two key inputs to the time-sequential model.

5.4.1 Constraint equations

Constraint equations are a mathematical representation of transmission network parameters AEMO uses to manage power system limitations, generation dispatch, and frequency control ancillary services (FCAS) requirements.

[73] Description of software at https://www.siemens.com/global/en/home/products/energy/services/transmission-distribution-smart-grid/consulting-and-planning/pss-software/pss-e.html.

The constraint equations for network limitations were obtained from the 2018 ISP[74] and updated for each credible option described in Section 3.1 under system normal and contingency [(N-0)[75] and (N-1)[76]] conditions for all transmission lines with a voltage level of 220 kV and above. Constraint equations were validated against different demand, interconnector, and generation dispatch scenarios.

In general, the following types of constraints were considered:

- **Thermal** – for managing the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency[77].
- **Voltage stability** – for managing transmission voltages and reactive power margin so that they remain at acceptable levels after a credible contingency.
- **Transient stability** – for managing network flows to ensure the continued synchronism of all generators on the power system following a credible contingency.
- **Oscillatory stability** – for managing network flows to ensure the damping of power system oscillations is adequate under system normal and following a credible contingency.
- **Rate of change of frequency (RoCoF) constraints** – for managing the rate of change of frequency following a credible contingency.

Refer to AEMO's Constraint Formulation Guidelines[78] for more information on constraint equations. FCAS constraints were not modelled in this RIT-T, since they are not expected to materially impact market benefits (refer to Section 6.1 for further details).

5.4.2 Dynamic ratings traces

Dynamic transmission line ratings were modelled for critical transmission lines in Victoria, using thermal rating traces, which were developed using reference year ambient temperature traces. Some transmission lines are limited by substation equipment, or their protection settings.

AEMO used 15-minute short-term ratings for contingency constraint equations.

5.4.3 Thermal limits assessment

Studies were conducted to identify the impact of each credible option (see Section 3.2 for detail) on the Victoria to New South Wales interconnector transfer capacity. The studies were conducted on a single snapshot representing high export from Victoria to New South Wales. As such, the transfer capacities presented in this section serve to give an indication of the notional differences between the options, noting that transfer capacities can vary based on a number of factors including temperature and operating conditions.

It should be noted that the overall Victoria to New South Wales transfer capability can be limited by thermal or stability limitations (see Section 5.4.4 for detail) and the specific limitation at any point in time will depend on operational conditions.

The VNI RIT-T relieves one of the two critical thermal limitations for imports into Victoria. The South Morang – Dederang line constraint is relieved in both directions (for imports and exports) through the line re-tensioning works under the preferred option (Option 2). The Murray – Dederang constraint would become the critical thermal limitation for imports into Victoria, and its impact on the import limit would vary based on operating conditions.

[74] 2018 ISP modelling database, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database.

[75] Steady state operating condition with the power system in a secure operating state.

[76] The unexpected disconnection of one operating generating unit, or the unexpected disconnection of one major item of transmission plant (such as transmission line, transformer, or reactive plant).

[77] Based on ISP assumptions for various asset types.

[78] See http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint_Formulation_Guidelines_v10_1.pdf.

Table 11 Improvement to Victoria to New South Wales interconnector export limit (thermal)

Option	Description	Indicative impact on transfer capacity (MW)
Option 1	Base option	+170
Preferred option – Option 2	Base option with modular power flow controllers	+170
Option 3	Additional higher capacity upgrades in New South Wales	+300
Option 4	Additional higher capacity upgrades in New South Wales and Victoria	+500

5.4.4 Stability limits assessment

Studies were conducted to assess the impact of future network augmentations on the Victoria to New South Wales transient and voltage stability export limits, under periods of high Victoria to New South Wales export. Multiple high export snapshots representing a variety of different network operating conditions were used for the studies. The studies were carried out using PSS/E dynamic simulations.

In general, the following steps were taken:

- The study cases were modified to represent a scenario with no network augmentations, and each network augmentation.
- Victoria to New South Wales export was progressively increased in the study cases, to find the limit where the cases became unstable, based on the criteria described in the next sections.
- The maximum stable transfer limit was recorded for:
  - Scenario with no network augmentations.
  - Scenario with second South Morang transformer.
  - Scenario with addition of Project EnergyConnect preferred option and Western Victoria Transmission Network Project.
  - Scenario with addition of HumeLink.

Transient stability limit

A study case is considered unstable if one of the following criteria is met:

- There are more than four machines, with an individual maximum rotor angle swing deviation greater than 160^0.
- Rotor angle deviation spread between any two machines in the network is greater than 360^0.
- Out-of-step conditions are detected.

Voltage stability limit

NER S5.1.8 states that the reactive power margin (expressed as a capacitive reactive power (in MVAr) must not be less than one percent of the maximum fault level (in MVA) at any connection point.

A study case is considered stable if the following criteria are met:

- The minimum reactive power margin at every monitored bus is maintained.
- The pre-contingent and post-contingent minimum voltage at every monitored bus is within operating limits.

Improvement on interconnector export stability limit

Table 12 shows the improvement in Victoria to New South Wales export limit that has been assumed in market modelling, reflecting network augmentations under the current RIT-T, and based on the assessment described above.

Table 12 Improvement to Victoria to New South Wales interconnector export limit (stability)

Augmentation	Impact on transient stability[A] (MW)	Impact on voltage stability[B] (MW)
Second South Morang transformer	+40	+6
Second South Morang transformer + Project EnergyConnect + Western Victoria Transmission Network Project	+170	+122
Second South Morang transformer + Project EnergyConnect + Western Victoria Transmission Network Project+ HumeLink	+220	+284

A. Prevent transient instability for a fault and trip of the Hazelwood to South Morang 500 kV transmission line.
B. Avoid voltage collapse around Murray for loss of APD potlines during light load conditions.

Stability limit study results

This section presents the results from the studies that were conducted to assess the impact of network augmentations on system stability. The augmentations that were specifically considered were the transformer component of this RIT-T and the preferred options of both the Western Victoria Renewable Integration and Project EnergyConnect RIT-Ts.

Figure 10 below shows the impact of the network augmentations on transient stability. The solid lines show that without the network augmentations, under fault conditions the rotor angles of generating units at Station A and B deviate by greater than 160^0 leading to transient instability. The dotted lines show that with the network augmentations, the generating units at Stations A and B experience improved damping to recover from fault conditions and return to pre fault rotor angle positions.

Figure 10 Impact of network augmentations on transient stability

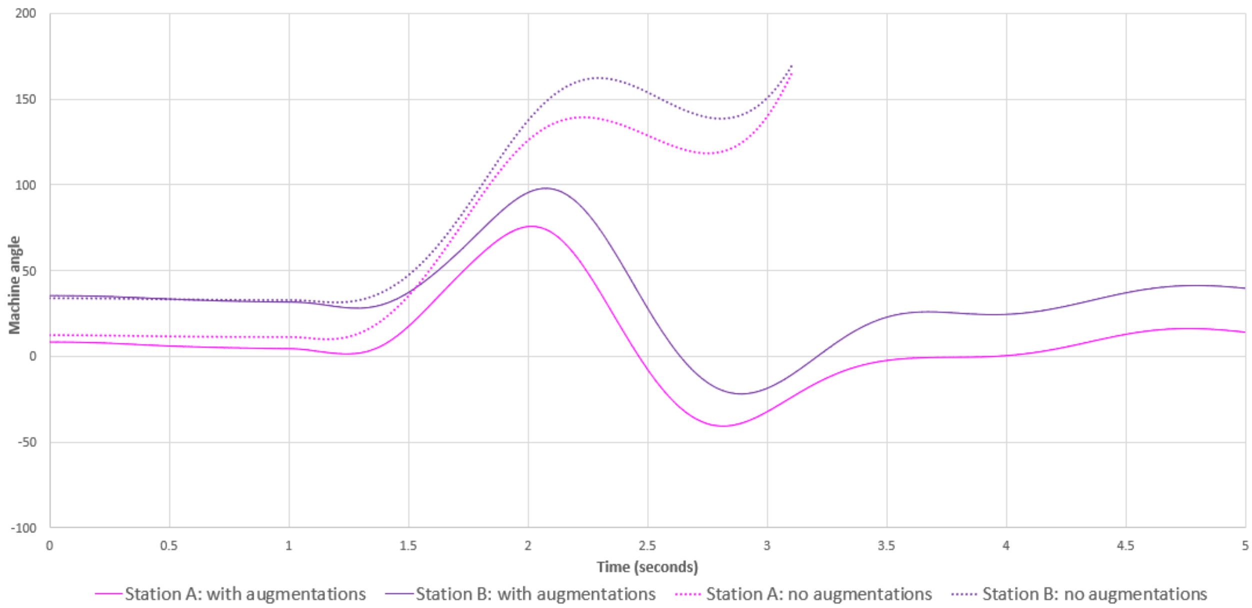
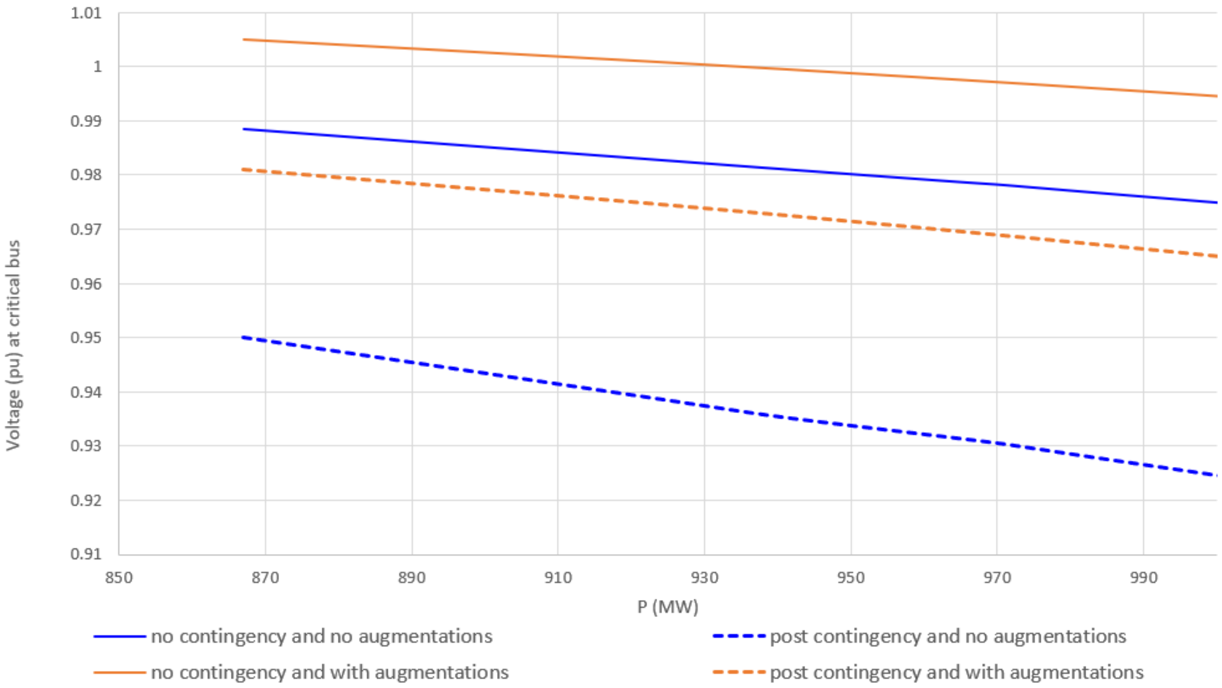


Figure 11 below shows the impact of the network augmentations on voltage stability. The solid lines show that under steady state conditions, the network augmentations improve the voltage profile at the critical bus under a range of transfer levels. The dotted lines show that the network augmentations also improve the voltage profile at the critical bus under fault conditions thereby improving voltage stability.

Figure 11 Impact of network augmentations on voltage stability



5.5 Cost estimate methodology

Costs for the different types of credible options were estimated in several ways:

1. Network options in Victoria – costs were developed by AusNet Services.
2. Network options in New South Wales – costs were developed by TransGrid.
3. Non-network options – costs were provided by vendors.

The costs for each option was varied by ±30% as a worst case scenario, to test the robustness of the market benefits. Operational cost was assumed to be 2% of the capital cost.

The cost of each option includes the following components:

- Project management.
- Contracts (sub-contracting).
- Administration and overheads.
- Equipment and services procurement.
- Installation.
- All station upgrade works, including:
  - Plant and equipment.
  - Civils.
  - Internal labour.

Estimated/typical lead times for components have been sourced in the same way as costs.

5.5.1 Cost estimate of outages

An assessment of the duration and costs of the outages required to implement the credible options is shown in Table 13.

The outage costs were assessed using market modelling, comparing the market costs in the 'do nothing' case with the market costs in a case with a network configuration matching that which would be required during the outage period.

This outage cost represents the fuel costs to the market from losing access to cheaper generation sources, requiring replacement with more expensive generation.

Table 13 Outage cost for credible options

Outage	Outage duration	Outage cost, $ million
330 kV South Morang – Dederang line upgrade	56 days[A]	1.3
330 kV Upper Tumut – Canberra line upgrade	6 months	4.6
Installation of modular power flow controllers on 330 kV Upper Tumut – Canberra and 330 kV Lower Tumut – Canberra line	50 days	1.4

A. For both lines (34 and 22 days for lines 1 and 2 respectively).

The outage cost modelling considered various generator outage patterns as well as the impact of the line outage on other lines.

6. Market benefits

The primary sources of market benefits are fuel cost savings associated with access to lower-cost generation in the southern states, and capital cost savings associated with deferred or avoided investment in additional generation capacity.

6.1 Classes of market benefits not expected to be material

PADR Section 6.1 identified classes of market benefits that were not expected to be material to this RIT-T.

A class of market benefit is considered immaterial if either:

- The class is likely not to affect materially the assessment outcome of the credible options for this RIT-T, or
- The estimated cost of undertaking the analysis to quantify market benefits of the class is likely to be disproportionate to the scale, size, and potential benefits of each credible option being considered.

The classes of market benefits that are still considered immaterial are:

- Changes in ancillary services costs – there is no expected change to the costs of FCAS, Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) because of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.
- Competition benefits – it is likely that increasing the ability for resource sharing between states would increase competition and therefore provide a competition benefit, and that the larger options (Option 3 and 4) would provide a larger competition benefit than the smaller options (Option 1 and 2). However, AEMO and TransGrid consider that the competition benefits under Option 3 and 4 would not be of the scale to change the rankings of the credible options. The main difference between Option 3 and the preferred option (Option 2) is the bring-forward of the HumeLink component by two years. Competition benefits would need to be in the order of $100 million over that two-year period to change the rankings of the credible options. Option 4 includes an additional line between South Morang and Dederang, along with the two-year bring forward of HumeLink, and this option would require at least $350 million in competition benefits to change the rankings of the credible options and is not considered to be achievable.
- Option value – for this RIT-T, estimating any option value benefit over and above that already captured via the scenario analysis in this RIT-T and the 2018 ISP analysis would require a disproportionate level of investigation having regard to the cost of the analysis and the potential benefits. As such, additional option value market benefit estimates are not proposed as part of this RIT-T assessment.
- Negative of any penalty for not meeting the renewable energy target – the Federal Large-scale Renewable Energy Target (LRET), VRET, QRET, and 2030 climate change target were met in all scenarios, with and without the credible options in place. Therefore, this class of market benefit is not material to this RIT-T analysis.
- Changes in network losses – the PADR market modelling captures changes in inter-regional network losses due to changing dispatch patterns enabled by the credible options as part of the overall change to fuel consumption. Changes in intra-regional network losses due to the credible options have been captured in the constraint equations, as the equations were updated to reflect the impact of the options. As such, no separate category of changes in network losses is included in this RIT-T analysis.

AEMO did not receive any PADR submissions on the materiality of the market benefits listed above, and therefore has continued to exclude them in this PACR assessment.

6.2 Quantification of classes of material market benefit for each credible option

The classes of market benefits/costs that are material in the case of this RIT-T are:

- Changes in fuel consumption arising through different patterns of generation dispatch.
- Changes in cost to parties other than the TNSPs, due to:
  - Differences in the timing of the installation of new plant.
  - Differences in capital costs of different plant.
  - Differences in the operating and maintenance costs of different plant.
- Differences in the timing of transmission investment.
- Reduced voluntary load curtailment and involuntary load shedding.

The next sections further describe the main market benefits of each credible option.

All classes of market benefits are calculated for the entire NEM and will therefore capture benefits arising in other regions, as well as Victoria and New South Wales.

6.2.1 Changes in fuel consumption

Changes in generation costs, where generation costs include fuel consumption cost, variable operation and maintenance (O&M) cost, and any emissions costs, are the primary source of market benefits in this RIT-T. These arise because the credible options promote more efficient sharing of generation resources between regions, enabling better utilisation of low-cost fuel sources, in particular renewable and brown coal generation in Victoria displacing black coal and gas generation in New South Wales and Queensland.

The market modelling for this RIT-T calculated the difference in total generation costs between the 'do nothing' base case and cases with each of the credible options in place. If cases with the credible option in place have a lower total generation cost than the 'do nothing' case, then the market benefit is positive.

The PLEXOS® model used for the market modelling is optimised to always identify the least-cost generation dispatch.

6.2.2 Changes in costs for other parties

Changes in costs for other parties are also a source of market benefits in this RIT-T. 'Other parties' in the context of this analysis refers mainly to costs incurred by market participants[79]. Market benefits arise due to better utilisation of existing plant, as the credible options allow for more efficient sharing of generation resources between regions.

The market modelling for this PADR developed a least-cost generation expansion required to meet customer demand under various scenarios, using the Capacity outlook model described in Section 5.3.1. The modelling showed that the credible options tended to result in a lower-cost generation expansion plan, due to:

- Deferral of new generation capacity built.
- Reducing the total megawatt capacity of new generation built.

The difference between capital costs under the 'do nothing' base case and the credible option cases represents the market benefits of the preferred option. Refer to Section 6.3.2 below for further information on the capital cost savings identified for the preferred option.

6.2.3 Differences in the timing of transmission investment

AEMO's 2018 ISP identified that transmission augmentation from Tumut to Bannaby (HumeLink) would provide system benefits once the Snowy 2.0 project is committed. Options 3 and 4 considered the benefits of

[79] Parties other than AEMO in its capacity as one of the Victorian TNSPs and TransGrid as New South Wales TNSP.

reducing the future cost of HumeLink, compared to the other credible options, in meeting the identified need of this RIT-T.

This RIT-T does not preclude, or have any material impact on, known transmission network replacement projects in Victoria or New South Wales.

6.2.4 Reduced voluntary load curtailment and involuntary load shedding

Increasing transfer capacity between regions can improve the availability of supply at times of high demand if one of the regions has spare capacity. The market modelling for this RIT-T calculated the difference in voluntary load curtailment and involuntary load shedding between the 'do nothing' base case and cases with each of the credible options in place.

6.3 Net market benefit assessment

6.3.1 The 'do nothing' base case

The 'do nothing' base case is defined in the RIT-T and the application guidelines as the case where the RIT-T proponent does not implement an option to meet the identified need.

For the purposes of the net market benefits assessment, the market costs associated with each augmented case (credible option) are compared against the market cost in the base case to calculate a gross market benefit. This is subsequently compared against the cost of the credible option to determine and rank the net market benefits.

The same process is applied across each scenario and the results are weighted to provide an overall net market benefit result and option ranking.

6.3.2 Net market benefits

Table 14 presents the net market benefits for each major credible option, under each reasonable scenario. The results presented in this chapter show the outcomes assuming the base scenario weighting.

Refer to Attachment C: Market benefits calculation on AEMO's website[80] for the gross and net market benefits under each assessed scenario.

Table 14 Net market benefits for each credible option and reasonable scenario

Option	Capital cost, $ million (2019-20)	Costs NPV $ million	Neutral, $ million (NPV)	Fast change, $ million (NPV)	Slow change, $ million (NPV)	Weighted Net benefit, $ million (NPV)
Scenario weighting			50%	25%	25%	
Option 1 – Base option	116	99	238	197	355	257
Preferred option **Option 2 – Base option with modular power flow controllers**	105	87	249	209	367	268
Option 3 – Additional higher capacity upgrades in NSW	859	628	230	191	-161	123
Option 4 – Additional higher capacity upgrades in NSW and Victoria	1,296	947	-21	-22	-415	-120

[80] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

Option 2 (preferred option) – Base option with modular power flow controllers

This option has been selected to be the preferred option as it has the highest net market benefits of all credible options.

Figure 12 shows the breakdown of the gross market benefits for this option under the Neutral scenario. The analysis identifies that the preferred option generates sufficient market benefits to recover project cost within six years of being commissioned.

Figure 12 Option 2 gross and net market benefits under the Neutral scenario

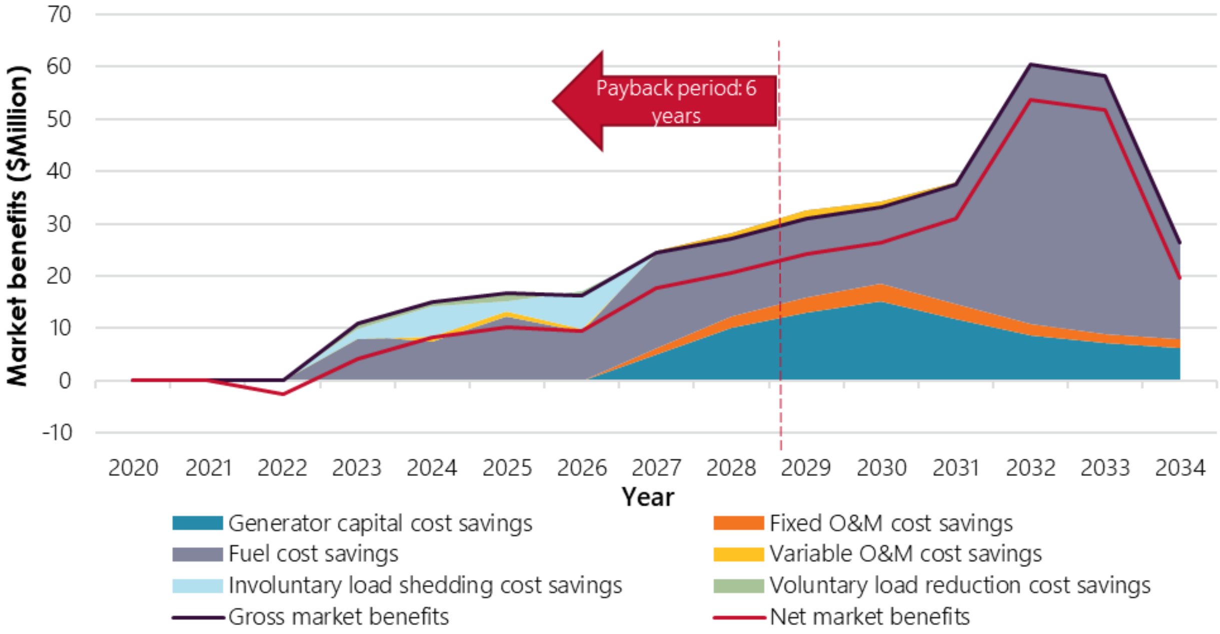


Figure 13 shows the changes in generation development for this option under the Neutral scenario. The preferred option leads to less new generation build (mostly solar, pumped hydro and some wind) in the northern states which aligns with the generator capital cost savings presented in Figure 12 above.

Figure 13 Option 2 changes in generation development under the Neutral scenario

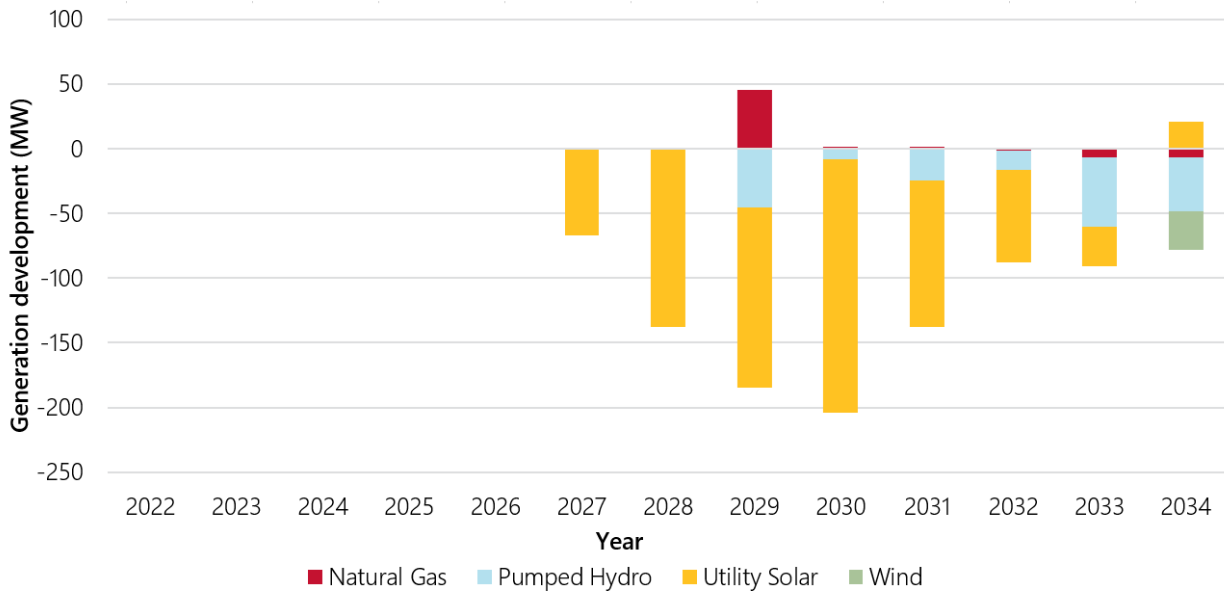
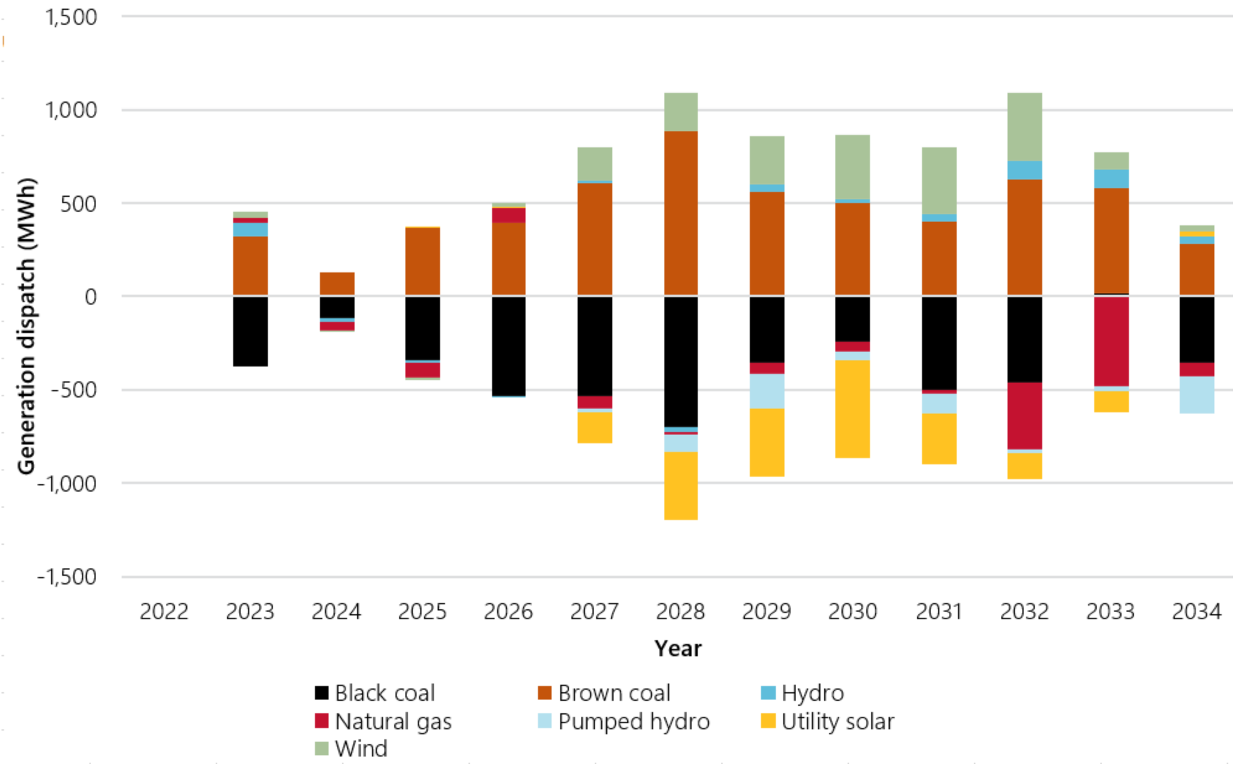


Figure 14 shows the changes in generation dispatch for this option under the Neutral scenario. This aligns with the fuel cost savings presented in Figure 12 above. The preferred option results in the displacement of black coal generation which is predominantly displaced by brown coal generation. It is also noted that natural gas powered generators are running more in later years to compensate for coal retirements (for example, Vales Point in 2029 and Gladstone in 2030). The preferred option also displaces the natural gas generation with cheaper brown coal generation. Finally, the reduction in utility solar generation is due to the changes in generation development as presented in Figure 13 above.

Figure 14 Option 2 changes in generation dispatch under the Neutral scenario



Figures 15 to 17 show the average increase in VNI exports from Victoria to New South Wales due to the preferred option under the Neutral scenario over three years representing a spread over the modelling horizon.

The figures show the average hourly increase in VNI export and the average hourly operational demand profile for the corresponding year. They demonstrate that the increase in exports is greatest when Victorian demand is lower as Victoria has higher levels of excess generation under this scenario. Conversely, the increase in exports is lower when Victorian demand is higher as Victoria has lower levels of excess generation under this scenario.

Figure 15 Changes in VNI exports with and without Option 2 (Neutral scenario) – 2023

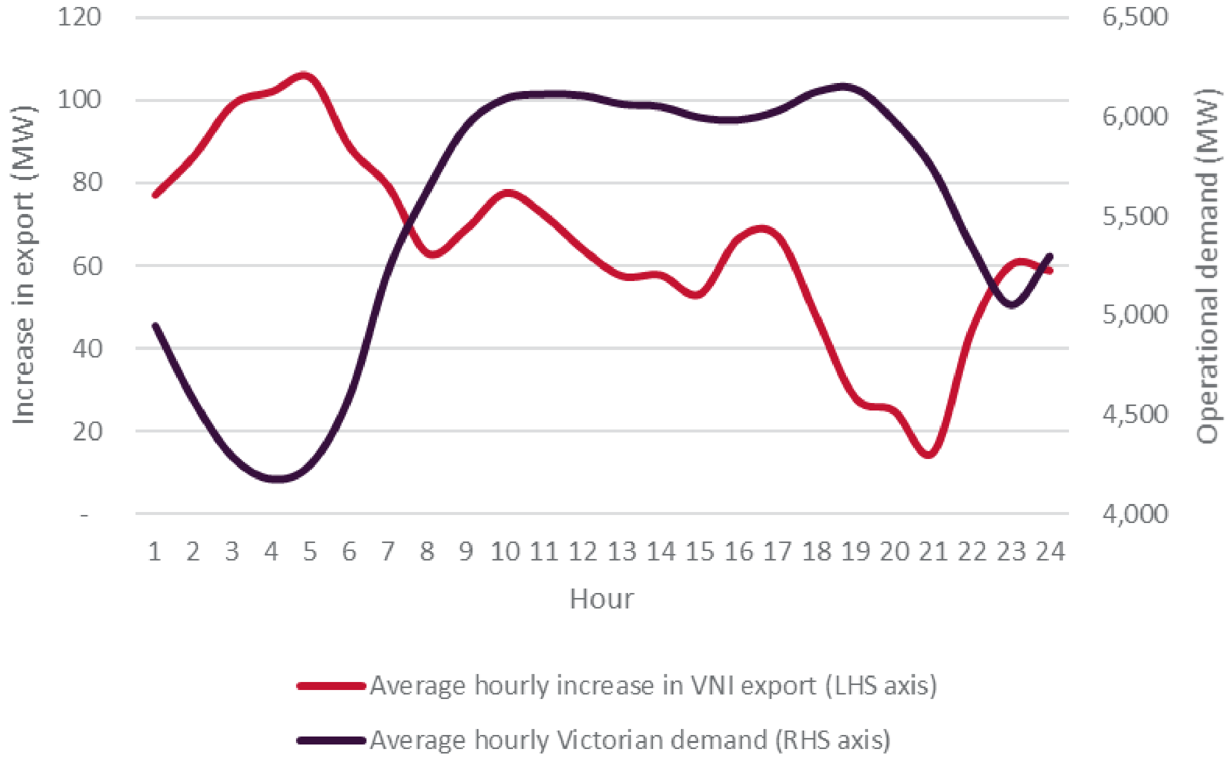


Figure 16 Changes in VNI exports with and without Option 2 (Neutral scenario) – 2028

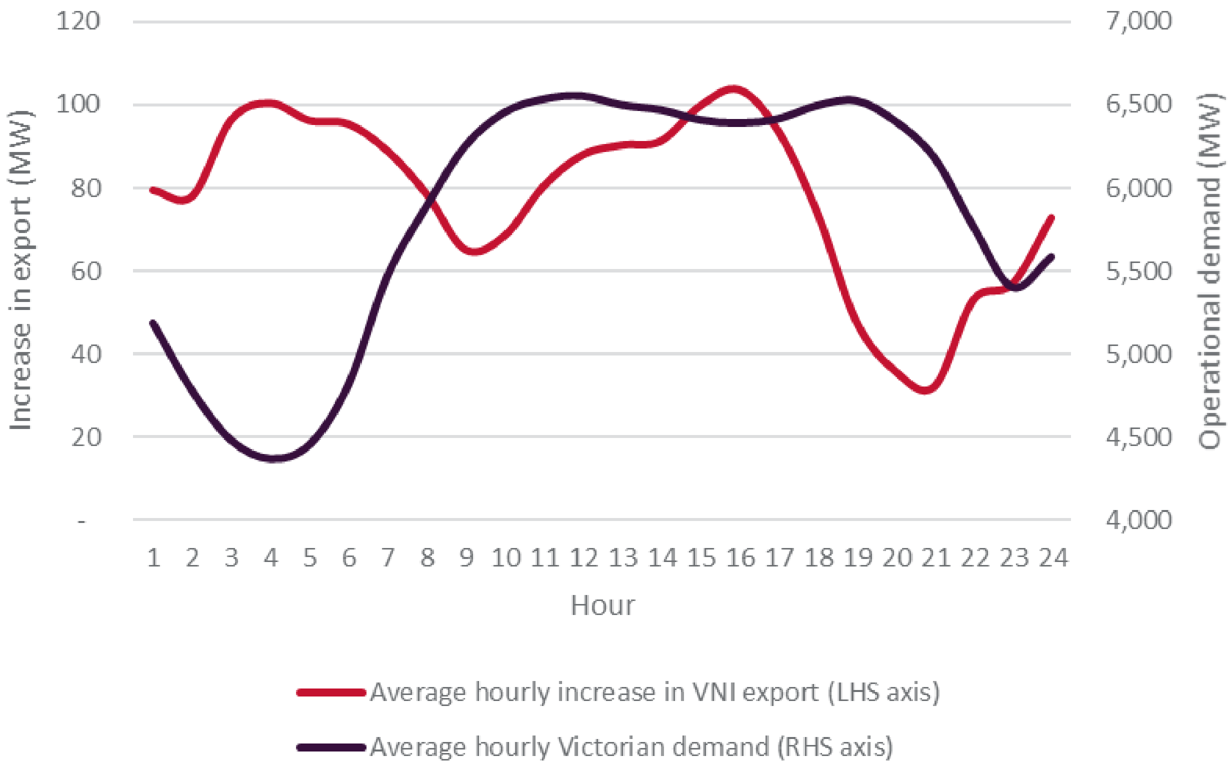
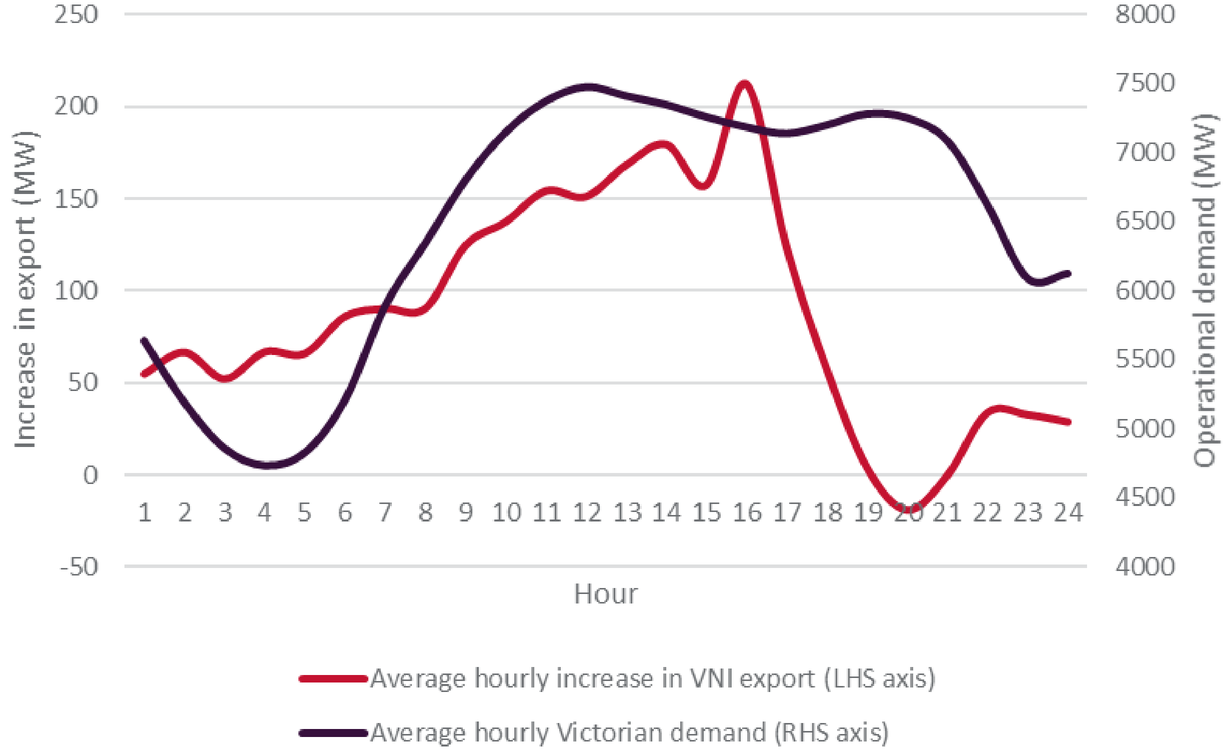


Figure 17 Changes in VNI exports with and without Option 2 (Neutral scenario) – 2033



6.3.3 Sensitivity studies

The preferred option is Option 2, with a gross market benefit of $355 million and a net market benefit of $268 million.

Sensitivity analysis was carried out to test the robustness of the choice of preferred option and to determine if any factors that would change the order of the credible options assessed:

- **Change in scenario weightings** – scenario weightings were changed as described in Table 7 (in Section 5.2.6). The ranking of the preferred option does not change, and weighted net market benefits remain positive.
- **Change in cost** – costs were changed by ±30%. The ranking of the preferred option does not change, and average weighted net market benefits remain positive.
- **Change in discount rate** – the discount rate was increased to 8.6% and decreased to 3.2%. Option 2 remains the preferred option and the net market benefits remain positive for discount rates as low as 1% and as high as 20%.

As shown in Table 15, Option 2 remains preferred under all sensitivities.

Table 15 Sensitivity results – net market benefits NPV ($ million)

	Base	High discount rate	Low discount rate	High cost	Low cost	Slow weighting	Fast weighting
Option 1	257	134	510	229	285	286	247
Option 2 (preferred option)	268	145	523	244	294	298	258
Option 3	123	7	370	47	198	25	113
Option 4	-120	-224	169	-291	52	-218	-120

In response to stakeholder feedback regarding potential overstating of demand forecasts (in particular the 10% POE demand forecasts), net market benefits have been calculated with a 100% and 0% weighting given to 50% POE and 10% POE demand forecasts respectively. Table 16 shows the net market benefits of the credible options across the base assumptions and with the discount rate, cost, and scenario weighting variations using the 100% weighting on 50% POE demand forecasts.

Option 2 remains preferred and has positive net market benefits across all sensitivities. Under the base discount rate, capital cost and scenario weighting assumptions the net market benefits of the preferred option decrease by $66 million due to the reduction of reliability benefits which mainly accrue under the 10% POE forecasts. Additionally, the payback period increases by one year to seven years.

Table 16 50% POE demand only sensitivity results – net market benefits NPV ($ million)

	Base	High discount rate	Low discount rate	High cost	Low cost	Slow weighting	Fast weighting
Option 1	191	93	395	163	219	237	165
Option 2 (preferred option)	202	104	408	178	228	248	176
Option 3	61	-32	259	-15	136	-23	32
Option 4	-180	-260	59	-352	-9	-267	-202

As discussed in Section 6.3.2, the primary benefits of the preferred option arise from reducing dispatch costs through more efficient dispatch of generation, with lower cost generation in Victoria displacing higher cost generation in New South Wales. Compared to the fuel price projections used in the PADR, the updated ISP fuel price projections have a reduced difference in the forecast price of black coal in New South Wales and brown coal in Victoria. Gas price projections have increased relative to the PADR projections under some scenarios and reduced in other scenarios.

The impact of the updated ISP fuel price projections on the net market benefits of the preferred option is shown in Table 17. For this assessment, the ISP Step Change fuel price projections have been used for the Fast Change scenario (instead of the ISP Fast change projections), because the differences in the projections are more extreme under the ISP Step Change scenario. The net market benefits decrease across all scenarios, mainly due to the narrowing of the price differential between the forecast prices of black coal and brown coal. However, the payback period remains unchanged at six years, across all scenarios, because the reduction in dispatch cost benefits is more pronounced at the later end of the modelling period.

Table 17 Fuel price impact – Option 2 – net market benefits NPV ($ million)

	Neutral	Fast change	Slow Change	Weighted benefit
PADR fuel prices	249	209	367	268
ISP fuel prices	231	176	306	236
Reduction in net benefits	19	32	61	33

The reduced differential between the forecast price of black coal in New South Wales and brown coal in Victoria is most pronounced in the ISP Step Change scenario. To isolate the impact of this key factor, a sensitivity using the Step Change coal price projections has been undertaken, with all other inputs remaining the same as the PADR Neutral scenario. The change in net market benefits is shown in Table 18.

The net market benefits decrease by $47 million, however the payback period for the option remains unchanged at six years because the reduction in dispatch cost benefits is more pronounced at the later end of the modelling period.

Table 18 Step change coal price impact – Option 2 – net market benefits NPV ($ million)

	Neutral	Neutral with Step Change coal prices	Reduction in net benefits
Option 2 (preferred option)	249	202	47

6.3.4 Timing of preferred option

As shown in Figure 11, the net market benefits under Option 2 become positive from 2022-23 onwards.

The payback period for Option 2 is six years, meaning the market benefits delivered through the option will exceed its cost after six years. Accordingly, the preferred option is not exposed to longer-term uncertainty.

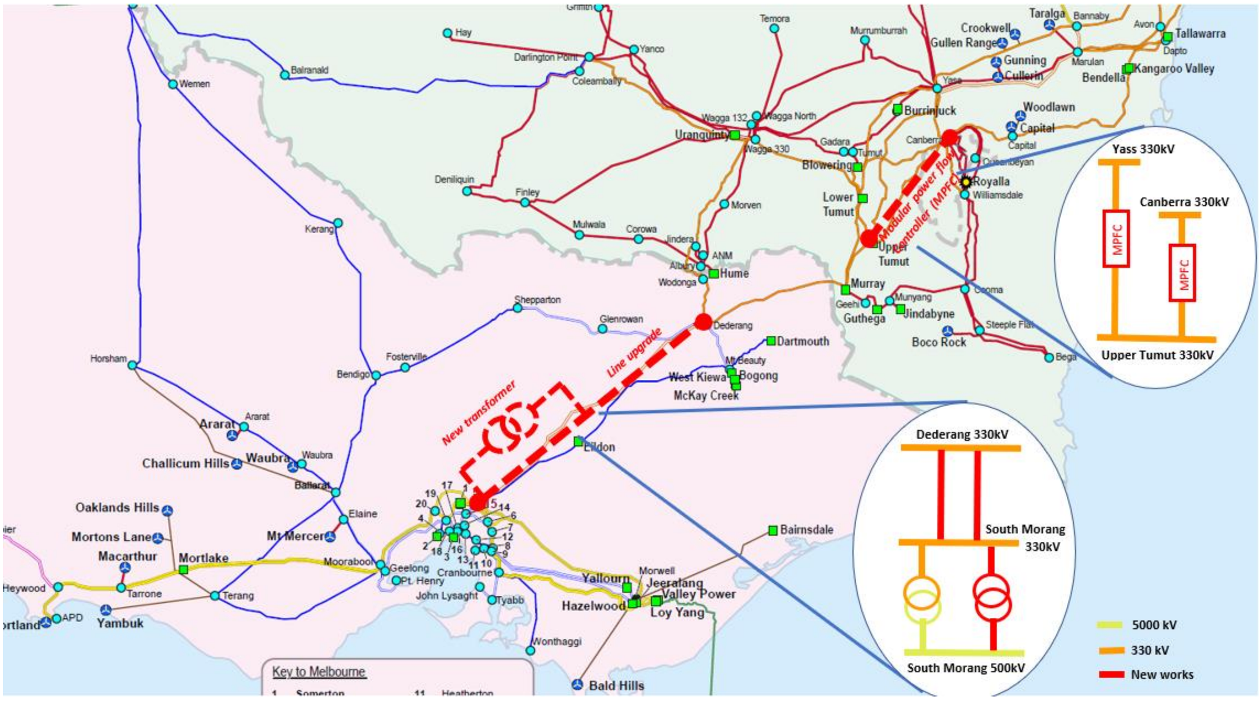
7. Conclusion

The preferred option is to implement the following augmentations with an optimal timing for delivery by 2022-23:

- Install a second 500/330 kV transformer at South Morang Terminal Station.
- Re-tension the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors[81]) to allow operation at thermal rating.
- Install modular power flow controllers on the 330 kV Upper Tumut – Canberra and Upper Tumut – Yass lines to balance power flows and increase the transfer capability.

This option returns the highest net market benefits under all assessed scenarios and all sensitivities.

Figure 18 Preferred option (Option 2)



7.1 Preferred option

The NER require that the preferred option identified in a RIT-T must be the investment option that meets the identified need, while maximising the present value of net economic market benefits to all those who produce, consume, and transport electricity in the market.

The RIT-T analysis (discussed in Chapter 6) indicates that Option 2 as shown in Figure 18 above delivers the highest net market benefits when weighted across all reasonable scenarios, and also under all sensitivities considered.

The preferred option has a cost of approximately $87 million (in present value terms), and yields the highest net market benefits when weighted across all reasonable scenarios considered.

[81] The capacitors will be replaced with higher rated capacitors to align with the new line ratings.

The PACR identifies that investing in this option will deliver a net present economic benefit of approximately $268 million, by:

- Reducing dispatch costs, through more efficient dispatch of generation in Victoria and New South Wales, and
- Reducing capital costs associated with new generation build in New South Wales.

Together, the above listed augmentations constitute the preferred option and satisfy the regulatory investment test for transmission.

7.2 Project implementation

The delivery of the preferred option will include the following high-level activities as required in relation to each of the augmentations comprising the preferred option:

- Procurement.
- Planning, environmental, cultural and other approvals.
- Stakeholder and community engagement.
- Detailed technical design, including assessment of land as required.
- Construction, testing[82], and commissioning.
- Long-term operation and maintenance.

AEMO, in relation to the Victorian augmentations forming part of the preferred option, and TransGrid, in relation to the New South Wales augmentations forming the remainder of the preferred option, will each undertake the processes set out in the National Electricity Law and the NER to seek to procure the contestable and non-contestable elements of the Project comprising the preferred option.

Figure 19 below presents the high-level indicative project timeline applying to each of the augmentations comprising the preferred option, including construction and commissioning timeframes.

Figure 19 Indicative project timeline for the proposed preferred option

[82] Includes both equipment testing and inter-regional testing to allow operation at higher VNI capacity.

The indicative project timeline for the preferred option is aimed to be completed by 2022-23, in advance of the Liddell Power Station closure in 2023. The actual project timetables will depend on the approval and procurement process of each TNSP, but for these purposes is assumed to be consistent with enabling the proposed commissioning date to be achieved within optimal lead times.

AEMO and TransGrid are committed to implementing the most economically efficient solution for consumers and are committed to keeping stakeholders informed of progress following the conclusion of the RIT-T process and will provide project updates during the implementation stages.

A1. Compliance with NER

This PACR provides all the information specified in NER 5.16.4, and as outlined in the table below:

Table 19 Information provided in this PACR, as required by NER 5.16.4 (version 132)

Description	Report section
A description of each credible option assessed.	3
A summary of, and commentary on, the submissions to the project assessment draft report.	4
A quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option.	5.4, 6.2, 3.1, 3.2
A detailed description of the methodologies used in quantifying each class of material market benefit and cost.	5
Reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material.	6.1
The identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions).	6
The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results.	6.3
The identification of the preferred option, with: • Details of the technical characteristics; • The estimated construction timetable and commissioning date; • If the preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and • A statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	6.3.4, 6.3.5, 3.4, 7.1, 7.2 (As stated in the PADR, TransGrid and AEMO have agreed that an augmentation technical report is not required.)

A2. Alternative option assessment

Export capability from Victoria to New South Wales is frequently limited by thermal limitations on the 500/330 kV South Morang F2 transformer and the 330 kV South Morang – Dederang lines. These limitations constrain generation within Victoria preventing high exports from Victoria to New South Wales[83].

The transformer and 330 kV South Morang – Dederang lines are in series and both play a similar role in limiting the transfer capacity from Victoria to New South Wales. As such, any upgrade to the transformer would need to be complimented by an upgrade of the 330 kV South Morang – Dederang lines to realise an increase in the export capability, and vice versa. The preferred option of this RIT-T address both of these thermal limitations[84] at a cost of approximately $64 million.

An alternative option was proposed through the PADR submissions which would include building a new line between Bendigo – Shepparton – Glenrowan – Dederang terminal stations. This option would consist of approximately 270 km of new 220 kV transmission line build at a cost of approximately $300 million. This alternative option is significantly more expensive and would have a longer lead time[85] than the Victorian component of the preferred option. As such, the alternative option would need to deliver significantly greater benefits than the preferred option to justify the higher cost.

The identified need considered by this RIT-T is to alleviate current and project limitations on power transfer capacity from Victoria to New South Wales. The analysis undertaken for this RIT-T the preferred option generates market benefits from implementation, and that these market benefits exceed the total cost of the augmentation within 6 years, showing the value of relieving the current limitations discussed below.

PSS/E studies were conducted to investigate the effectiveness of the alternative option at increasing export capability from Victoria to NSW (refer to Section 2.1 for detail on the identified need). Studies were conducted on a system snapshot updated with committed generator projects, reflecting high export from Victoria to New South Wales[86]. The results from the study are summarised in · below, and the key findings are as follows:

- The alternative option does not increase Victoria to New South Wales export capability because it does not reduce loading on the critical elements[87] which limit transfers between the states. As the preferred option improves the capacity of these critical elements, this increases the export capability from Victoria to New South Wales.
- The study did not identify a need to increase the 220 kV transmission line capacity between Bendigo, Shepparton, and Dederang because those lines are lightly loaded under export conditions. Since power does not tend to flow from Bendigo through to New South Wales under these conditions, this corridor has ample additional capacity, hence does not limit Victoria to New South Wales exports.
- The RIT-T preferred option maximises fuel cost benefits as it provides flexibility to export brown coal generation from the Latrobe Valley and renewable generation from Western Victoria. Conversely, the

[83] See section 2, VNI Upgrade RIT-T- PADR, August 2019: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PADR.pdf.

[84] Installation of a second 500/330 kV South Morang transformer and retensioning the 330 kV South Morang – Dederang lines.

[85] Lead times associated with planning approvals for new line builds can be significant.

[86] Studies assumed hydro generation (AGL and Snowy) output of approximately 20% of capacity, Latrobe Valley generation output of approximately 90% of capacity, and Western Vic renewable generation output of approximately 55% of capacity.

[87] 500/330 kV South Morang transformer and 330kV Dederang – South Morang lines.

alternative option does not provide the flexibility to export brown coal generation and hence would not deliver the same fuel cost benefits.

Table 20 % loading under steady state with different options

	% loading under steady state (all elements in service)				
	220 kV Bendigo – Fosterville line	220 kV Fosterville – Shepparton line	220 kV Shepparton – Dederang line[A]	500/330 kV South Morang Transformer	330 kV Dederang – South Morang line
Existing network	17%	14%	12%	101%	50% (each)
Alternative option 1B	10% (each)	9% (each)	11%	101%	50% (each)
Alternative option 2C	9% (each)	8% (each)	9% (each)	101%	50% (each)
RIT-T Preferred option	13%	10%	13%	63% (each)	35% (each)

A. Direction of flow is from Dederang into Shepparton as the load at Shepparton is supplied from both Bendigo and Dederang.
B. New line between Bendigo and Shepparton.
C. New line between Bendigo, Shepparton, and Dederang.