Victorian Reactive Power Support

December 2019

Regulatory Investment Test for Transmission
Project Assessment Conclusions Report

Important notice

PURPOSE

AEMO has prepared this Project Assessment Conclusions Report to meet the consultation requirements of clause 5.16.4 of the National Electricity Rules.

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VERSION CONTROL

Version	Release date	Changes
1	18/12/2019	Initial release

Executive summary

The energy landscape in Victoria is undergoing unprecedented change. The withdrawal of conventional supply sources and increased penetration of inverter-based renewable generation is changing the technical characteristics of the power system. Furthermore, the increasing penetration of distributed energy resources (DER), continued growth of rooftop solar photovoltaic (PV) installations, and energy efficiencies are driving reductions in operational demand during light load conditions. This transformation is presenting a number of operational challenges on the power system.

One of the key challenges in operating the Victorian power system today is managing high voltages on the transmission network during minimum demand periods. High voltages are currently being managed by short-term operational measures, such as network reconfiguration and direct intervention, which have become increasingly necessary to maintain voltages during minimum demand periods. The frequency and severity of these interventions has increased, and operators are reaching the limit of available real-time options. Continued reliance on generator directions or increasingly onerous network reconfiguration will result in higher market costs, reduced system resilience, and higher system security risks.

The 2018 National Transmission Network Development Plan (NTNDP)[1] identified an immediate Network Support and Control Ancillary Service (NSCAS) gap for voltage control in Victoria. AEMO entered into a contractual arrangement for Non-Market Ancillary Services (NMAS) to meet the ongoing NSCAS gap for voltage control while a more efficient long-term solution is progressed.

In May 2018, AEMO initiated a Regulatory Investment Test for Transmission (RIT-T) to assess the technical and economic benefits of delivering additional reactive power support in Victoria, and published a Project Specification Consultation Report (PSCR)[2] identifying a need for additional reactive support to maintain voltages within operational and design limits during minimum demand periods. In June 2019, AEMO published a Project Assessment Draft Report (PADR)[3], which identified and sought feedback on the proposed preferred option which was identified as delivering the highest net market benefit. AEMO received four stakeholder submissions on this PADR (discussed in Section 4).

After extensive analysis and stakeholder consultation, AEMO has produced this third and final report of the RIT-T process, the Project Assessment Conclusions Report (PACR)[4]. The report reconfirms the nature of the identified need, summarises AEMO's technical and economic assessment of the credible options, and justifies selection of the preferred option.

In August 2019, the Australian Energy Regulator (AER) approved the installation of a 100 megavolt amperes reactive (MVAr) 220 kilovolt (kV) reactor at Keilor Terminal Station by 2021 as part of a Network Capability Incentive Parameter Action Plan (NCIPAP) project by AusNet Services. As a result, this PACR has considered the first 100 MVAr 220 kV reactor at Keilor Terminal Station proposed in the PADR as a committed project.

As part of the PACR analysis, AEMO re-assessed the credible options (as described in Section 3.2), taking account of new information available since the publication of the PADR in June 2019, including changes to the minimum demand forecasts published in the 2019 Electricity Statement of Opportunities (ESOO)[5] and the results of AEMO's more detailed assessment of viable system strength combinations in Victoria[6].

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[1] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

[2] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[3] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/Victorian-Reactive-Power-Support-PADR.pdf.

[4] 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.

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

[6] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

This analysis reduced the size of the identified need, and resulted in a preferred option to install an additional 300 MVAr of shunt reactors (in addition to AusNet Services' 100 MVAr Keilor NCIPAP reactor). This was Option 1B in the PADR, and is a change from the original preferred option, which proposed the installation of 500 MVAr of reactive power support in the form of shunt reactors and a synchronous condenser.

The preferred option

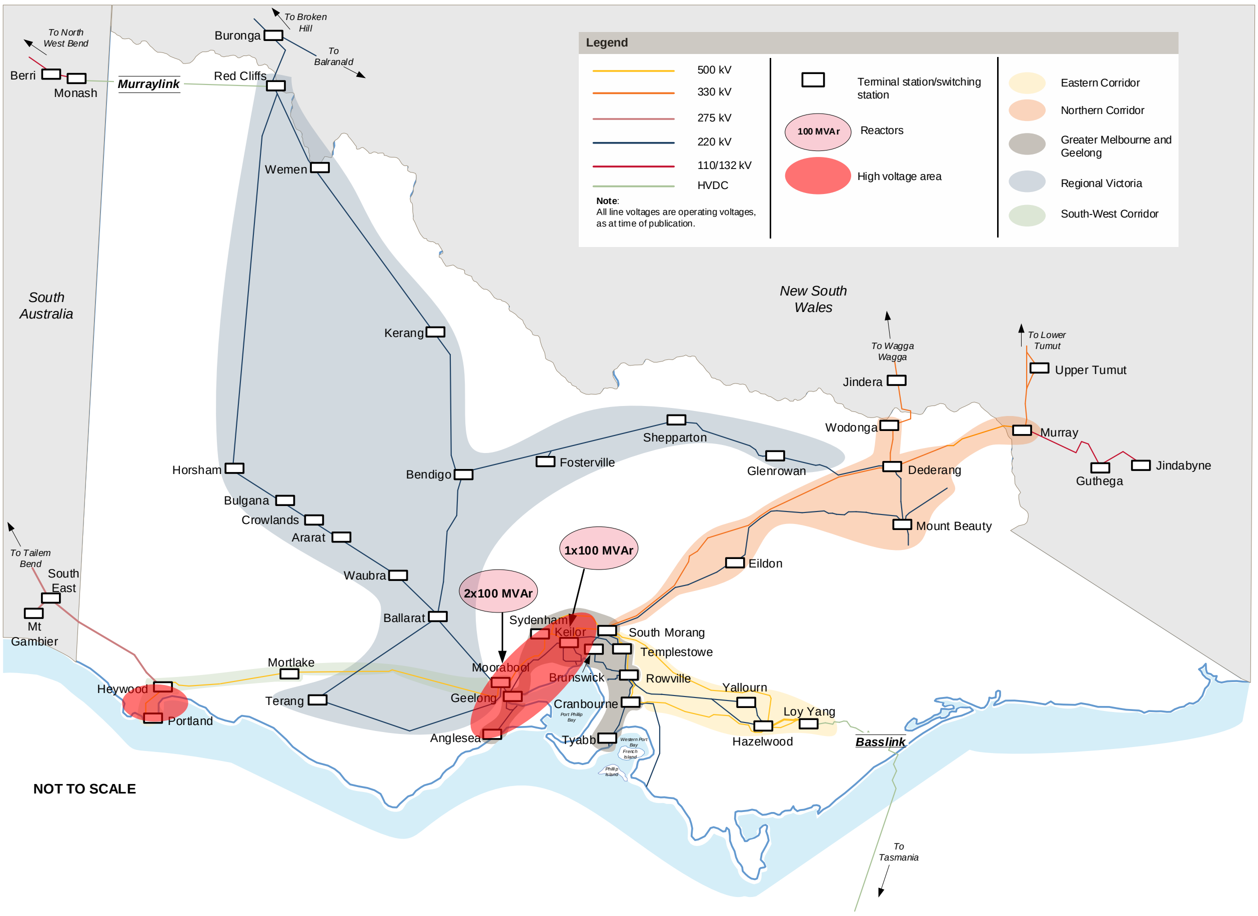
The preferred option identified in this PACR (and shown in Figure 1) will ensure transmission system voltages can be maintained within operational limits during minimum demand periods in Victoria. It includes the following major components:

- One additional 220 kV 100 MVAr shunt reactor at Keilor Terminal Station in 2022[7].
- Two additional 220 kV 100 MVAr shunt reactors at Moorabool Terminal Station in 2023 and 2025.

The preferred option has a cost of approximately $16.5 million (in present value terms), and yields the highest net market benefits when weighted across reasonable scenarios.

The PACR analysis identifies that investing in this option will deliver a net present economic benefit of approximately $92.8 million, by reducing market costs associated with dispatching generators that are normally offline during light load periods to maintain voltages within operational and design limits.

Figure 1 Preferred option of three 100 MVAr reactors



[7] AusNet Services' NCIPAP project to install a 100 MVAr 220 kV reactor at Keilor Terminal Station in 2021 is considered committed in the PACR analysis base scenario, as noted on the previous page. The 220 kV 100 MVAr shunt reactor at Keilor Terminal Station in the preferred option is additional to this.

The identified need

During periods of low demand, reactive power is produced by transmission equipment that increases transmission system voltages. Excessive levels of reactive power can cause over-voltages that damage equipment, and jeopardise the security of the transmission system.

AEMO's 2019 ESOO minimum demand forecasts[8] project that operational minimum demand may fall by as much as 975 megawatts (MW), or 32%, over the next 10 years. This forecast change is primarily driven by projections of increasing rooftop PV installations and energy efficiency improvements. This is increasing the need for absorbing reactive power capability to suppress high voltages on the network and will exacerbate issues now being observed in Victoria.

Coupled with the decline in minimum demand, the withdrawal of conventional generation in Victoria and increased penetration of large-scale renewable generation is reducing the amount of reactive power support capability in Victoria.

The identified need for investment in additional reactive support is to maintain transmission system voltages in Victoria within operational and equipment design limits during minimum demand periods, and to realise market benefits through reduced reliability risk and market intervention costs.

Credible options

AEMO considered a range of credible network options with the capability to manage high voltages on the Victorian transmission network during low demand periods (presented in Table 1).

All credible network options involved the installation of reactive power devices, such as reactors, Static VAr Compensators (SVCs), and synchronous condensers. These components are relatively modular, and therefore credible options were formed from assets across a combination of location, voltage level, technology, capacity, and connection arrangements.

Performing detailed network and economic studies against all possible permutations of these parameters would be impractical, and AEMO refined these combinations based on technical feasibility, relative effectiveness, investment cost, and local site restrictions.

Table 1 Credible network options tested in detail through the PACR analysis

Option	Description	Estimated capital cost ($M)
1.0[A]	1 x 220 kV 100 MVAr shunt reactor at Keilor	6.5
1A	1 x 220 kV 100 MVAr shunt reactor at Keilor 1 x 220 kV 100 MVAr shunt reactor at Moorabool	13.3
1B	1 x 220 kV 100 MVAr shunt reactor at Keilor 2 x 220 kV 100 MVAr shunt reactor at Moorabool	20.8
1C	1 x 220 kV 100 MVAr shunt reactor at Keilor 3 x 220 kV 100 MVAr shunt reactor at Moorabool	28.3
1D	1 x 220 kV 100 MVAr shunt reactor at Keilor 4 x 220 kV 100 MVAr shunt reactor at Moorabool	35.7
2	1 x 220 kV 100 MVAr shunt reactor at Keilor 2 x 220 kV 100 MVAr shunt reactor at Moorabool 1 X 330 kV +200/-100 MVAr synchronous condenser at South Morang	90.7

A. New option added under Option 1 to test the benefits of installing a single 100 MVAr reactor.

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

Key changes since the PADR

Changes from the PADR assessment, due to updated information, are:

- Demand forecast – since publishing the PADR, AEMO has published an updated set of minimum demand forecasts in the 2019 ESOO for the National Electricity Market (NEM). Although the new forecast shows a strong downward trend, it does not decline to the same extent, or as rapidly, as was projected in the previous forecasts used for PADR analysis. This change has reduced the scale of the absorbing reactive power support needed through this RIT-T.
- System strength – static reactors and dynamic plant (such as the proposed synchronous condenser in Option 2) can provide the required reactive power support. Synchronous condensers are more expensive than shunt reactors, but provide additional services such as increasing system strength and improving transient and voltage stability. These additional services can be included as benefits if there is a need for them in the network. In October 2019, AEMO published requirements for system strength in Victoria[9] which included an extra set of synchronous generator combinations which satisfy minimum system strength requirements in the state. The increased set of generator combinations are less onerous than those assumed in the PADR, therefore reducing the need for directions in this PACR assessment. Refer to Section 2.3.4 for further details.
- NCIPAP reactor – the AER's approval for AusNet Services to install a 100 MVAr reactor at Keilor has reduced the need for absorbing reactive support in Victoria by 100 MVAr, and reduced the size of the preferred option accordingly.
- Ongoing need for NMAS – the 2018 NTNDP identified an immediate NSCAS gap for voltage control in Victoria under low demand conditions. To address this gap, AEMO procured NMAS services to meet the immediate ongoing NSCAS gap for voltage control in Victoria until a long-term solution is delivered through this RIT-T. This contract is typically invoked during minimum demand conditions to suppress high voltages in Victoria, with each activation lasting for approximately six hours. This is in addition to de-energising a single 500 kV transmission line in Victoria.
- Trends in requirements for operator action – the frequency and severity of voltage control interventions has increased more rapidly than previously anticipated. As at 1 December, AEMO switched out 500 kV transmission lines on 57 separate occasions in 2019, for a total duration of 835 hours. By comparison, for the same duration in 2018, lines were switched out on 42 occasions for 314 hours.

Scenarios and sensitivities analysed

The RIT-T requires 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 or the base case.

This RIT-T analysis included the three scenarios considered in AEMO's 2019 ESOO – the Central, Step Change, and Slow Change scenarios[10].

Sensitivity studies were undertaken by including two additional scenarios (referred to as 'ISP scenarios'[11] in this report) – the Fast Change and High DER scenarios – and by varying the assumed option cost, discount rate, and scenario weightings.

It should be noted that the Central scenario is not necessarily considered the most likely future scenario; it represents the scenario with current policy settings and technology trajectories. However, as the Central scenario has the highest minimum demand forecasts of the five scenarios studied, a conservative approach

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[9] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

[10] Scenarios and sensitivities are outlined in AEMO, 2019 *Forecasting and Planning Scenarios, Inputs and Assumptions*, August 2019, at https://www.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.

[11] Prepared for the 2019-20 Integrated System Plan (ISP).

has been adopted in assigning the base weightings of 50% for Central, 25% for Step Change and 25% for Slow Change scenarios.

Market benefits

The primary source of market benefits quantified in this RIT-T relates to fuel and operating cost savings associated with avoided market intervention, avoided reliance on non-market ancillary services, and increased Victoria to New South Wales export stability limits[12].

Table 2 compares the weighted net market benefits (net present value [NPV]) across all credible options considered across the base weighted scenario. This shows that all credible options provide positive weighted net market benefits, with Option 1B providing the highest net market benefits of $92.8 million in the base weighting scenario.

Table 2 Weighted net market benefits NPV ($M)

Option	1.0	1A	1B (preferred option)	1C	1D	2
NPV ($M)	51.2	78.6	92.8	90.5	85.1	60.5

Although Option 1B does not have the highest net benefits under all scenarios and sensitivities, it does have positive net benefits under all scenarios and sensitivities assessed. Option 1B also has higher net benefits across most scenarios and sensitivities than the options with less reactive support (Options 1.0 and 1A).

Staging of the preferred option (discussed in Section 6.3.5), enables AEMO to revert to Option 1A, or even Option 1.0, if supply or demand assumptions deviate significantly from those considered in the RIT-T scenarios. AEMO will continue to monitor prevailing market conditions and demand forecasts following conclusion of the RIT-T; adjusting course where appropriate.

[12] The increase in Victoria to New South Wales export stability limits is a benefit in Option 2 only, due to the synchronous condenser in this option.

Contents

Tables

Figures

1. Introduction

The Regulatory Investment Test for Transmission (RIT-T) is an economic cost-benefit test used to assess and rank different options that address an identified need. This Project Assessment Conclusions Report (PACR) represents the third and final stage of the consultation process in relation to the Victorian Reactive Power Support RIT-T.

1.1 Overview

This PACR has been prepared by the Australian Energy Market Operator Limited (AEMO) in accordance with the requirements of the National Electricity Rules (NER) clause 5.16[13] for a RIT-T[14].

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 markets. 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 May 2018[15].
- 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 June 2019[16].
- This PACR makes a conclusion on the preferred option, and provides a summary of the submissions received on the PADR.

1.2 Stakeholder consultation

AEMO 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 took into account the PADR submissions and other feedback received from stakeholders. See Section 4 for information on the submissions received, and AEMO's responses.

1.3 Further enquiries

AEMO is committed to keeping stakeholders informed of the progress of Victorian Reactive Power Support Project following the conclusion of the RIT-T process. AEMO will provide further updates in the coming months, including project announcements on AEMO's website.

For further details, please e-mail planning@aemo.com.au.

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

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

[15] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[16] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/Victorian-Reactive-Power-Support-PADR.pdf.

2. Identified need

The identified need for investment is to maintain voltages within operational and design limits in the south-west transmission corridor around Geelong, Keilor, Moorabool, and Portland – particularly during low demand periods. This will:

- Address the ongoing Network Support and Control Ancillary Service (NSCAS) gap.
- Ensure the power system remains in a satisfactory and secure operating state.
- Maximise net market benefits through reduced costs of market intervention and non-market ancillary services.

2.1 Description of the identified need

The identified need, as described in Chapter 2 of the PADR[17], is for investment in additional reactive support in Victoria to maintain transmission system voltages within operational and equipment design limits during minimum demand periods, and to realise market benefits through reduced reliability risk and market intervention costs.

A key driver for this RIT-T is the continued decline in minimum demand and reactive power consumption of load during minimum demand periods in Victoria. Over the last five years, minimum operational demand[18] in Victoria has declined rapidly, with minimum demand reducing by 430 megawatts (MW), or 12%. AEMO's latest demand forecasts project that minimum operational demand may fall by as much as 975 MW (32%) over the next 10 years[19].

This forecast change is primarily driven by the continued projection of increasing rooftop photovoltaic (PV) installations across the state and energy efficiency improvements.

The projected reduction in minimum demand will only exacerbate the high post-contingent voltages observed in the south-west transmission corridor, including Geelong, Keilor, Moorabool, and Portland Terminal Stations (shown in Figure 2).

Currently, during low demand conditions in Victoria, if no operator intervention action is taken, the post-contingent steady state voltage at these terminal stations could exceed equipment design limits. Table 3 presents the voltage limits and post-contingent voltages at Geelong, Keilor, Moorabool, and Portland considering no operator intervention[20].

The most critical contingencies for voltage management at low demand times are:

- Trip of the Heywood–Tarrone–Alcoa Portland (APD) line, which also results in a trip of the load at APD (both potlines) and the 500 kilovolt (kV) line reactor.
- Trip of the Heywood–Mortlake–APD line, which also results in a trip of the load at APD (both potlines) and the 500 kV line reactor.
- Tripping of a large generator in the Latrobe Valley, which results in the loss of reactive power support from that generator and reduced flows on the 500 kV network.

[17] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/Victorian-Reactive-Power-Support-PADR.pdf.

[18] Operational demand is demand from the grid, supplied to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator).

[19] See 2019 Electricity Statement of Opportunities (ESOO) forecasts at http://forecasting.aemo.com.au/.

[20] Snapshot based on 22 April 2019 at 08:00.

Figure 2 Area of high voltages that are being addressed

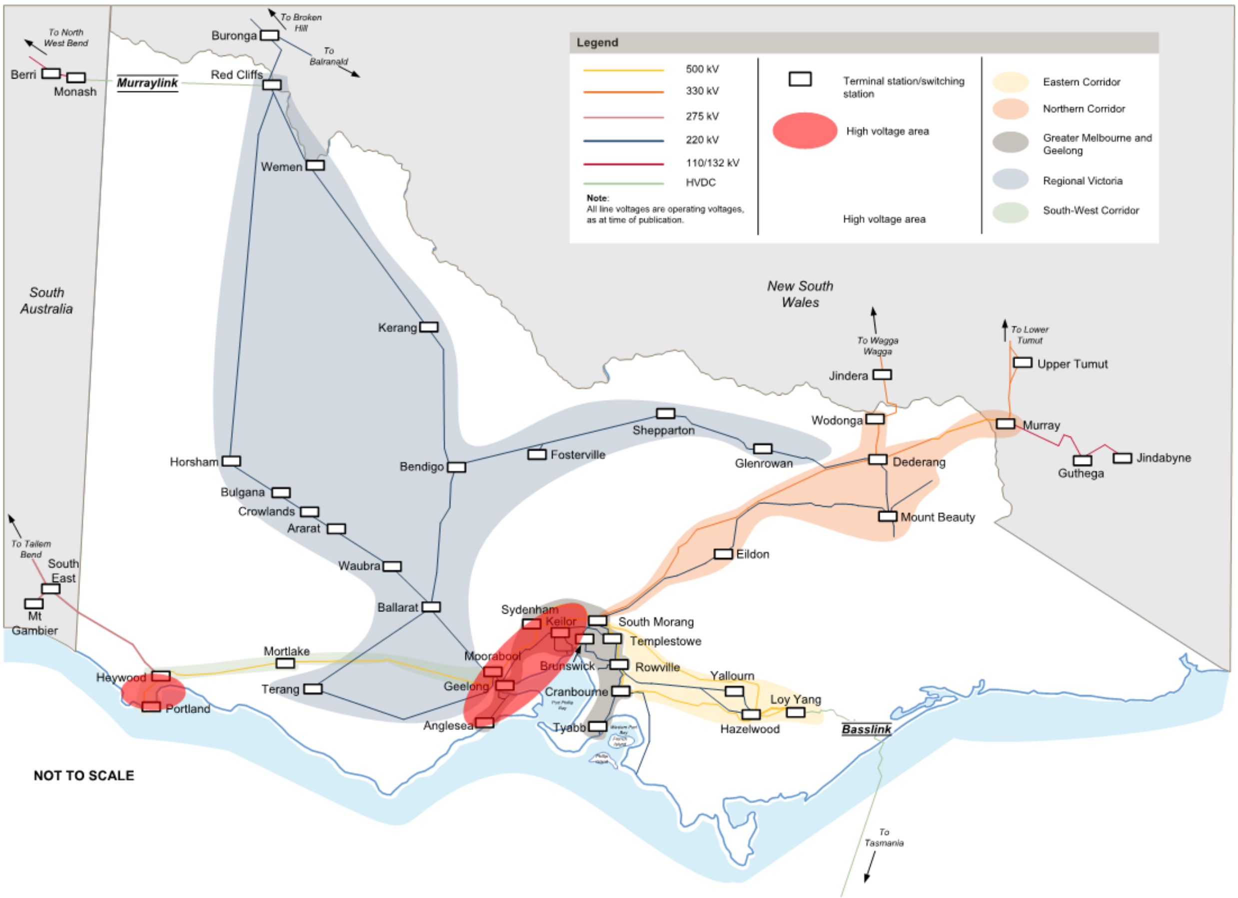

Table 3 Post contingent voltages without operator interventions

Station	Voltage limit (maximum) (kV)	Post contingent voltage without operator intervention (kV)
Geelong	230	233
Keilor	525	536
Moorabool	525[A]	541
Portland	525	536

A. Moorabool post contingent maximum allowable voltage level can go up to 550 kV, but this will create high voltages at Keilor.

2.2 Drivers for augmentation

Lightly loaded transmission lines produce reactive power, and AEMO has used the de-energisation (removal from service) of long, high-voltage lines as a short-term operational measure to manage high transmission system voltages. This approach is used only after standard voltage control practices have been exhausted (such as utilising the reactive capabilities of online generation, changing transformer taps, and switching of reactive devices including reactors and capacitors).

Switching of high-voltage lines reduces the reliability of the transmission system and is only used as a short-term operational measure by operators when there is no risk to system security.

In some cases, AEMO may also intervene directly in the market to bring units online to utilise their reactive power capability. In November 2018, AEMO was required to concurrently de-energise three 500 kV lines in the Victoria network and direct generation online to supress high voltage.

NSCAS is a non-market ancillary service that may be procured by AEMO or Transmission Network Service Providers (TNSPs) to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network. Each year, AEMO's National Transmission Network Development Plan (NTNDP) assesses all NEM regions and identifies gaps that should be resolved by an NSCAS arrangement[21]. The 2018 NTNDP[22] identified an immediate NSCAS gap for voltage control in Victoria under low demand conditions.

To address this gap, AEMO entered into a Non Market Ancillary Service (NMAS) agreement with a service provider to meet the immediate ongoing NSCAS gap in Victoria until such time as a long-term solution is delivered by this RIT-T. Between March and November 2019 inclusive, this contract was invoked on 18 occasions to supress high voltages in Victoria, with each activation lasting for approximately six hours. This contract has typically been activated overnight, where demands are often lowest, and is addition to de-energising a single 500 kV transmission line in Victoria.

The frequency, duration, and market cost of these NMAS activations further support the urgency and potential benefits associated with additional reactive support in Victoria.

As noted in the PADR, the frequency and severity of these interventions are continuing to increase, and operators are running out of real-time options to manage high voltages. Continued reliance on generator directions via the activation of a NMAS contract or increasingly onerous network reconfiguration (line switching) is costly, reduces system resilience, and increases system security risks, and is not an effective long-term solution.

While the identified need for investment remains largely the same as described in the PADR, new information has become available since the PADR was published in June 2019, as outlined in Section 2.3. As part of the PACR analysis, AEMO re-assessed the credible options (as described in Section 3.2), taking account of this new information – in particular, changes to the minimum demand forecasts published in the 2019 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM), and the results of AEMO's more detailed assessment of viable system strength combinations in Victoria.

2.3 New information since the PADR

2.3.1 Updated minimum 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. Since publication of the PADR, AEMO has produced an updated set of minimum demand forecasts as part of the 2019 ESOO[23] for the NEM. The assessment in this PACR has used these updated demand forecasts.

The 2019 ESOO considered three scenarios – Central, Slow Change, and Step Change. These are a subset of 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), as published in the 2019 Forecasting and Planning Scenarios, Inputs and Assumptions report[24].

These five scenarios provide a suitably 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.

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[21] AEMO will publish a standalone NSCAS report in 2019, and not a NTNDP.

[22] AEMO. 2018 NTNDP, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

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

[24] 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.

The five scenarios are:

- **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.
- **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.

Table 4 shows the minimum operational demand forecasts under the three scenarios considered in the 2019 ESOO, including actuals for the preceding six years.

Minimum demands are expected to reduce significantly in Victoria over the next 10 years. Under the Central 90% probability of exceedance (POE)[25] scenario, minimum demand is projected to fall from approximately 2,864 MW in 2019-20 to 2099 MW in 2029-30.

This reduction is primarily driven by projected increases in rooftop PV installation, with an increase in PV installation of 659 MW forecast during the same 10-year period (Table 5).

Table 4 Minimum demand forecast – operational demand 90% POE, 2013-14 to 2029-30 (MW)

Year	Actuals	Central	Slow Change	Step Change
2013-14	3,483			
2014-15	3,171			
2015-16	3,266			
2016-17	2,894			
2017-18	2,950			
2018-19	3,053			
2019-20		2,864	2,859	2,879

[25] POE means the statistical likelihood a forecast will be met or exceeded. For a 90% POE minimum demand forecast, the minimum is expected to be lower than the forecast one year in 10.

Year	Actuals	Central	Slow Change	Step Change
2020-21		2,603	2,674	2,456
2021-22		2,445	2,121	2,093
2022-23		2,308	2,063	1,682
2023-24		2,249	2,050	1,373
2024-25		2,229	2,054	1,091
2025-26		2,161	1,987	819
2026-27		2,139	1,966	727
2027-28		2,120	1,923	662
2028-29		2,077	1,885	481
2029-30		2,099	1,874	334

Table 5 Rooftop PV forecast, 2019-20 to 2029-30 (MW)

Year	Central	Slow Change	Step Change
2019-20	1,253	1,202	1,297
2020-21	1,428	1,246	1,645
2021-22	1,560	1,312	2,066
2022-23	1,656	1,320	2,481
2023-24	1,763	1,357	2,756
2024-25	1,852	1,391	3,131
2025-26	1,802	1,379	3,367
2026-27	1,840	1,422	3,531
2027-28	1,859	1,424	3,638
2028-29	1,915	1,443	3,875
2029-30	1,912	1,472	4,082

While these forecasts show a strong downward trend, they do not decline to the same extent, or as rapidly, as projected in the 2018 ESOO[26], which was used for PADR analysis, as shown in Figure 3.

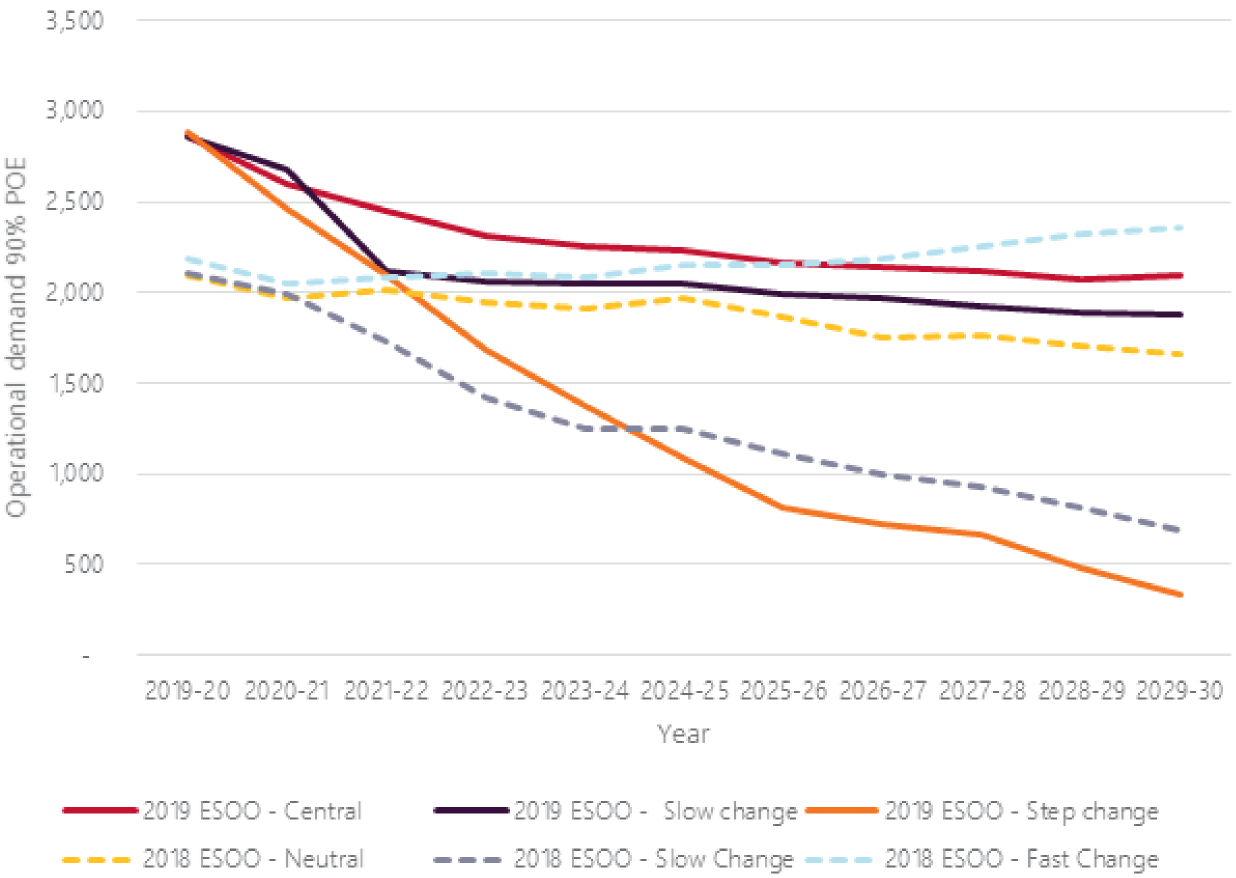
In particular, the 2029-30 minimum demand forecast in the Central scenario is 438 MW higher than that in the PADR Neutral scenario. While this does not reduce the urgency of the identified need, it has reduced the scale of absorbing reactive power required (which in the PADR was expected to be up to 500 megavolt amperes reactive [MVAr]).

[26] Except in the Step Change scenario, in which the minimum demand is lower than all scenarios.

The main reasons for the change in the Victorian minimum demand forecast from the 2018 ESOO to the 2019 ESOO are:

- Lower than forecast PV uptake over the last 12 months.
- Forecast in future growth in PV uptake is expected to be slower than what was forecast in the 2018 ESOO due to a combination of declining incentives and easing of retail prices.
- Market saturation in the uptake of rooftop PV.
- Battery charging at times of minimum demand is expected to be lower than previously forecast.

Figure 3 Comparison of minimum demand forecasts – 2019 ESOO versus 2018 ESOO



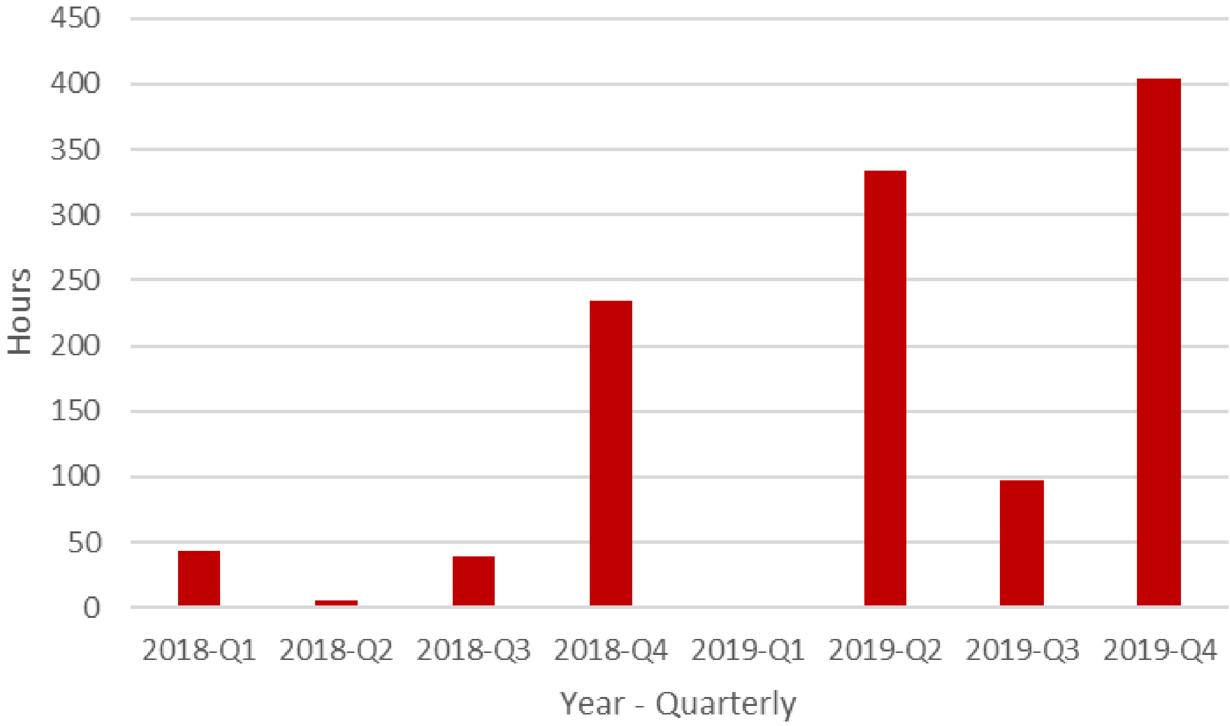
2.3.2 Keilor 100 MVAr reactor approved

In August 2019, the Australian Energy Regulator (AER) approved the installation of a 100 MVAr 220 kV reactor at Keilor Terminal Station proposed by AusNet Services as a Network Capability Incentive Parameter Action Plan (NCIPAP) project. Therefore, one of the 100 MVAr reactors proposed to be installed at Keilor Terminal Station in the PADR is now considered committed, and therefore has been assumed in the PACR analysis. This reduces the need for reactive power support through this RIT-T by 100 MVAr.

2.3.3 Trends in requirements for operator action

The frequency and severity of voltage control interventions has increased more rapidly than previously anticipated (see Figure 4). As at 1 December, AEMO switched out 500 kV transmission lines on 57 separate occasions in 2019, for a total duration of 835 hours. By comparison, for the same duration in 2018, lines were switched out on 42 occasions for 314 hours.

Figure 4 Trend of increased line switching[A]



A. 2019-Q4 data till 30 November only.

2.3.4 System strength requirements

In July 2018, AEMO published a System Strength Requirements and Fault Level Shortfalls report[27] which outlined the minimum three phase fault levels at each fault level node in each region, in accordance with the system strength requirements methodology.

Under certain dispatch conditions, fault levels can fall below the minimum requirements set out in this document, and AEMO is required to direct generation to come online or remain online to manage system strength requirements[28]. As inverter-based generation displaces traditional synchronous units in Victoria, it is anticipated that the need for intervention to maintain a minimum combination of synchronous units online will increase.

Since PADR publication, AEMO has completed detailed studies to review and refine the minimum requirement definitions, and to consider how system strength requirements might be impacted when 500 kV lines are switched out of service for voltage control purposes. In October 2019, AEMO published a Transfer Limit Advice – System Strength report[29] which specifies the requirement for system strength in South Australia and Victoria. Table 2 of this document presents the 33 combinations of synchronous generating units that would provide sufficient system strength in Victoria to withstand a credible fault and loss of a synchronous unit (the most critical contingency for these combinations is loss of a Loy Yang A unit).

The increased set of synchronous generator combinations are less onerous than those assumed in PADR analysis. PACR analysis considers the increased set of combinations, which has reduced the magnitude and frequency of interventions required to maintain a secure combination of synchronous generating units online at any time.

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[27] At www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[28] AEMO was required to direct a generating unit to remain online on 17 November 2018 to manage system strength. See www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2018/Intervention-pricing-for-system-security-directions.pdf.

[29] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

System strength gap

In December 2019, AEMO published a Notice of Victorian Fault Level Shortfalls in Red Cliffs[30], in north-west Victoria. This identified an immediate fault level shortfall of 312 MVA at Red Cliffs fault level node.

Option 2 considered in this RIT-T includes a synchronous condenser at South Morang Terminal Station, north of Melbourne. This synchronous condenser would not resolve the shortfall declared at Red Cliffs, due to the remote location of this node. Likewise, a synchronous condenser located in north-west Victoria would not address the reactive power need being addressed by this RIT-T.

AEMO is addressing this shortfall as the System Strength Service Provider in Victoria. However, given the distinct nature of the need, timing, and location, AEMO is progressing system strength remediation activities outside of this current reactive power RIT-T.

2.4 Refinements to the identified need

AEMO has used the updated information described in Section 2.3 and assessed the voltage performance of the Victorian transmission system based on a range of reasonable scenarios, and identified the locations where voltages may exceed operational limits.

This analysis indicates that:

- Under most scenarios, additional absorbing reactive power support of approximately 200-350 MVAr is required (in addition to AusNet Services' 100 MVAr 220 kV Keilor reactor NCIPAP project) to maintain post-contingent voltages within limits during the study period.
- The most effective locations for installing the additional reactive power support include the existing Geelong, Moorabool, South Morang, Keilor, and Sydenham terminal stations.

[30] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice_of_Victorian_Fault_Level_Shortfall_at_Red_Cliffs.pdf

3. Credible options

Analysis has considered all credible network and non-network options to address the identified need. The options described cover a range of potential solution sizes, technologies, locations, and timings. These combinations have been refined to identify those likely to maximise the net market benefits through a full cost-benefit assessment.

3.1 Credible options assessed in the PADR

The PADR assessed a range of credible options, as listed in Table 6 below. The assessment found Option 2 to have the highest weighted net market benefits under the assessed scenarios and sensitivities.

Further analysis of these options was performed for the PACR considering new information available since the publication of the PADR (detailed in Section 2.3) to determine whether any new information would impact the overall net market benefit and the ranking of the options.

Table 6 Credible options assessed in the PADR

Option	Description	Capital cost, $M (2019-20)	Capital cost, $M (net present value [NPV])	Neutral – net market benefit, $M (NPV)	Fast change – net market benefit, $M (NPV)	Slow change – net market benefit, $M (NPV)	Weighted – net market benefit, $M (NPV)
1A	2 x 220 kV 100 MVAr shunt reactor at Keilor 1 x 220 kV 100 MVAr shunt reactor at Moorabool	19.1	16.7	48.2	14.9	144.1	63.9
1B	2 x 220 kV 100 MVAr shunt reactor at Keilor 2 x 220 kV 100 MVAr shunt reactor at Moorabool	25.4	21.5	53.0	15.1	165.4	71.7
1C	2 x 220 kV 100 MVAr shunt reactor at Keilor 3 x 220 kV 100 MVAr shunt reactor at Moorabool	31.7	26.9	53.5	13.8	178.9	74.9
1D	2 x 220 kV 100 MVAr shunt reactor at Keilor 4 x 220 kV 100 MVAr shunt reactor at Moorabool	38.8	32.3	51.4	10.8	185.2	74.7
2	2 x 220 kV 100 MVAr shunt reactor at Keilor 2 x 220 kV 100 MVAr shunt reactor at Moorabool 1 x 330 kV +200/-100 MVAr synchronous condenser at South Morang	84.7	72.3	64.9	18.5	208.7	89.2

3.2 Credible options assessed in the PACR

All credible options considered in the PADR (and listed in Table 6) were further assessed for the PACR considering the following new information:

- The new minimum demand forecast and the new ISP load traces – the 2019 ESOO demand forecast includes three updated scenarios; Central, Slow Change, and Step Change. The ISP scenarios include two additional scenarios – Fast Change and High DER (see Section 2.3.1 for scenario information).
- Keilor Terminal Station 100 MVAr reactor committed project – the first 220 kV 100 MVAr reactor to be built by 2021 at Keilor Terminal Station is now included in the base case model as a committed project, and has been removed from all options.
- New combinations of synchronous generators to maintain adequate system strength – based on AEMO's Transfer Limit Advice – System Strength report[31].
- Revised cost estimates, including the cost for NMAS services.

An additional sub-option, Option 1.0, was also included under Option 1 in the PACR to test the benefits of installing a single 100 MVAr reactor. The details are presented below.

Option 1 – Combination of shunt reactors at various 220 kV locations

As noted in the above section, the first 220 kV 100 MVAr reactor to be built by 2021 at Keilor Terminal Station has now been removed from all options and included in the base case as a committed project.

Option 1 now consists of five separate sub-options – including the additional Option 1.0 which was not included in the PADR – that considered a range of shunt reactor installation combinations (in 100 MVAr increments) connecting to the 220 kV network at Keilor and Moorabool Terminal Stations.

A combination of option sizes was tested in this PACR, to determine which option provided the greatest weighted net market benefit.

The timing of the investments was determined by the cost-benefit analysis, which generally showed that the optimal timing is staged between 2022 and 2025 (see Section 6.3.5).

Keilor and Moorabool Terminal Stations were identified as the least-cost connection locations for shunt reactor installations. Modelling determined that shunt reactors at Keilor and Moorabool contributed the largest amount of reactive power support to the 220 kV network. The spread of shunt reactor installations across two sites also provides diversity benefits.

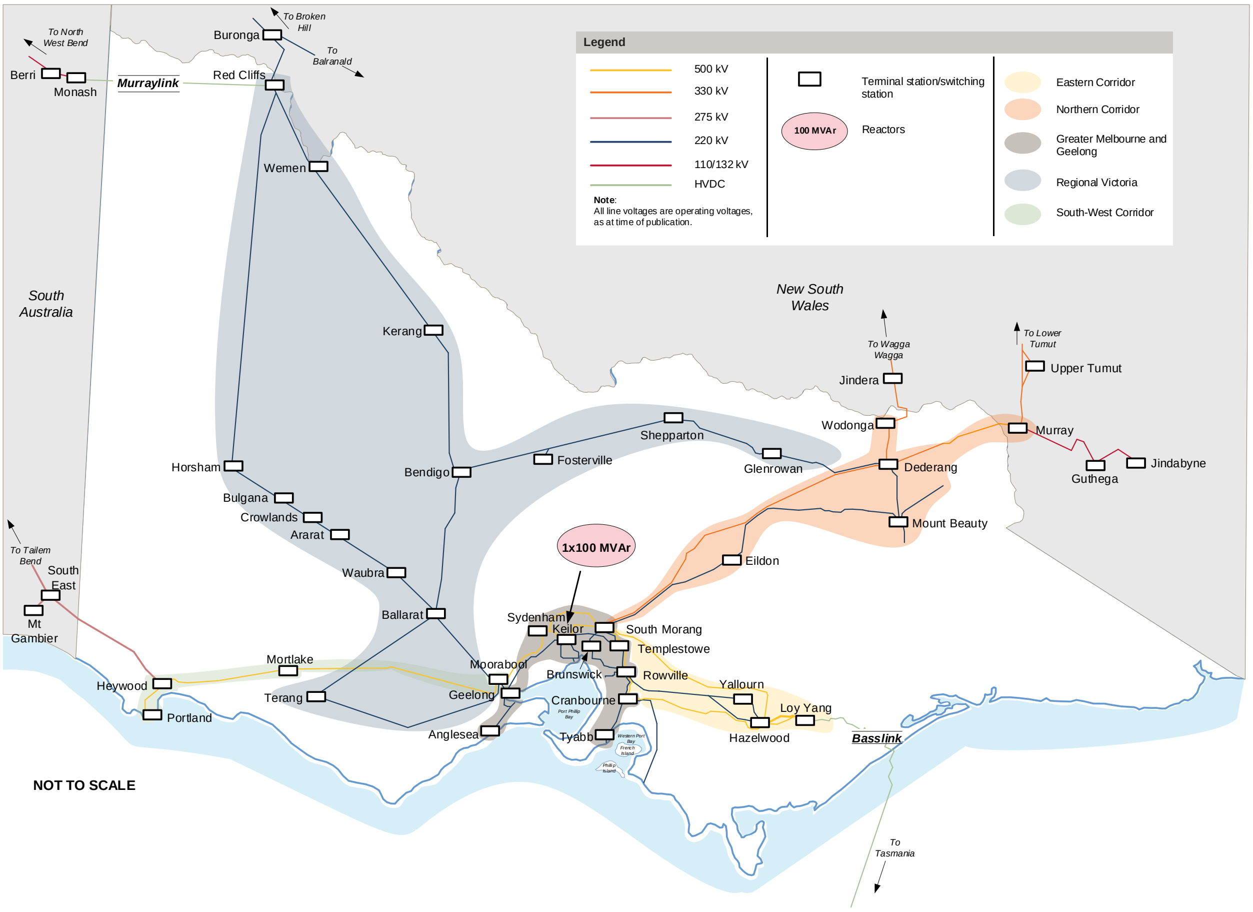
[31] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

Option 1.0 – Single 1 x 100 MVAr shunt reactors

Figure 5 presents Option 1.0, which consists of a single 220 kV 100 MVAR shunt reactor. In this option:

- A single 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2022.

Figure 5 A single 100 MVAr reactor (Option 1.0)



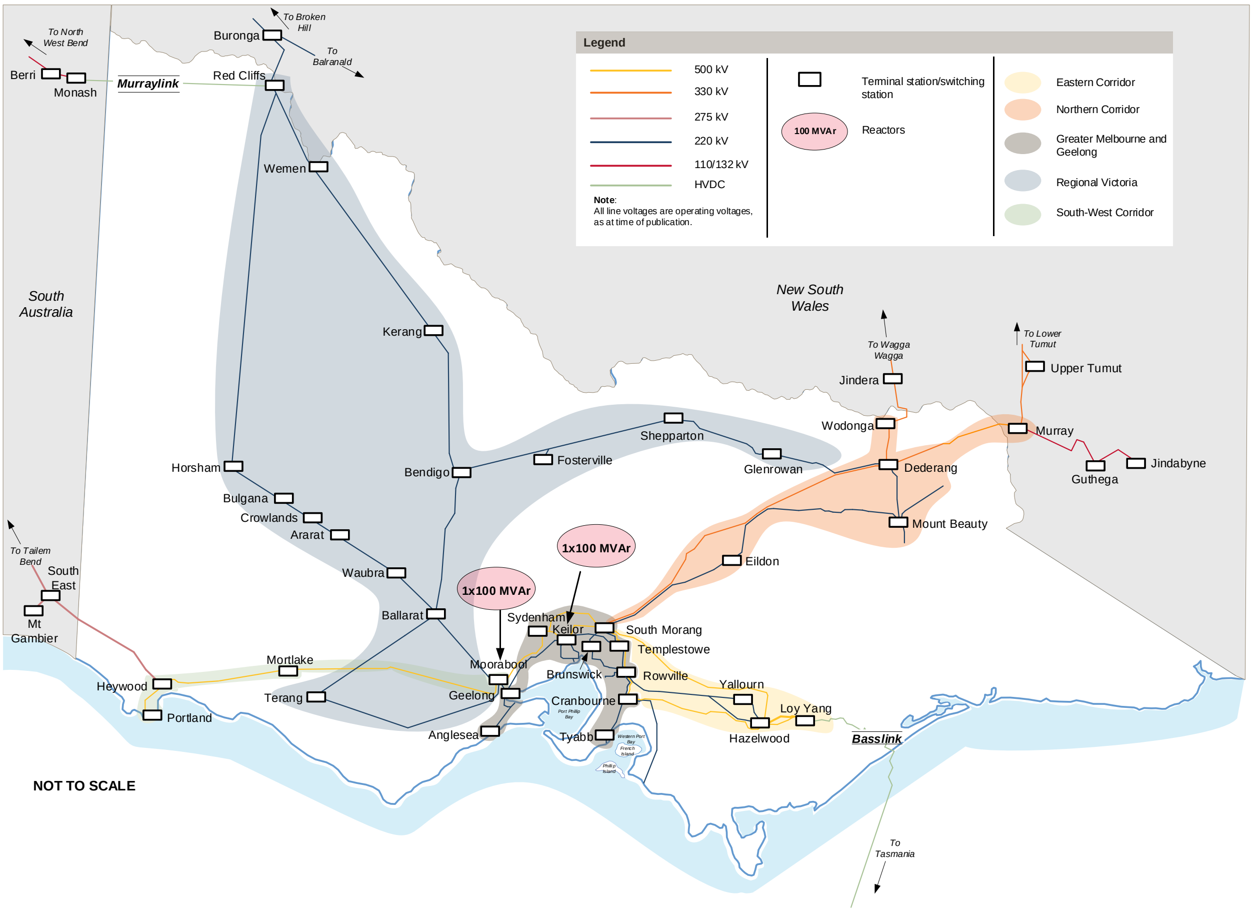
Scope of works	• Installation of a 220 kV 100 MVAr shunt reactor at Keilor Terminal Station. This is in addition to the first 220 kV 100 MVAr shunt reactor at Keilor Terminal Station by 2021, which is deemed a committed project. • Connection to 220 kV bus at each location through a single switched arrangement. • Installation of all associated secondary equipment. • Include all associated interface work.
Change to option since PADR	• This option is a new option and was not considered in the PADR.
Impact on interconnector limits	• No material impact on interconnector limits.
Construction type	Brownfield
Expected commissioning year	By 2022
Estimated capital cost (2019-20)	$6.5 million
Ongoing operating cost	2% of capital cost

Option 1A – Combination of 2 x 100 MVAr shunt reactors

Figure 6 presents Option 1A, which consists of two 220 kV 100 MVAr shunt reactors. In this option:

- A single 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2022.
- A single 100 MVAr shunt reactor is installed at Moorabool Terminal Station in 2023.

Figure 6 Two 100 MVAr reactors (Option 1A)



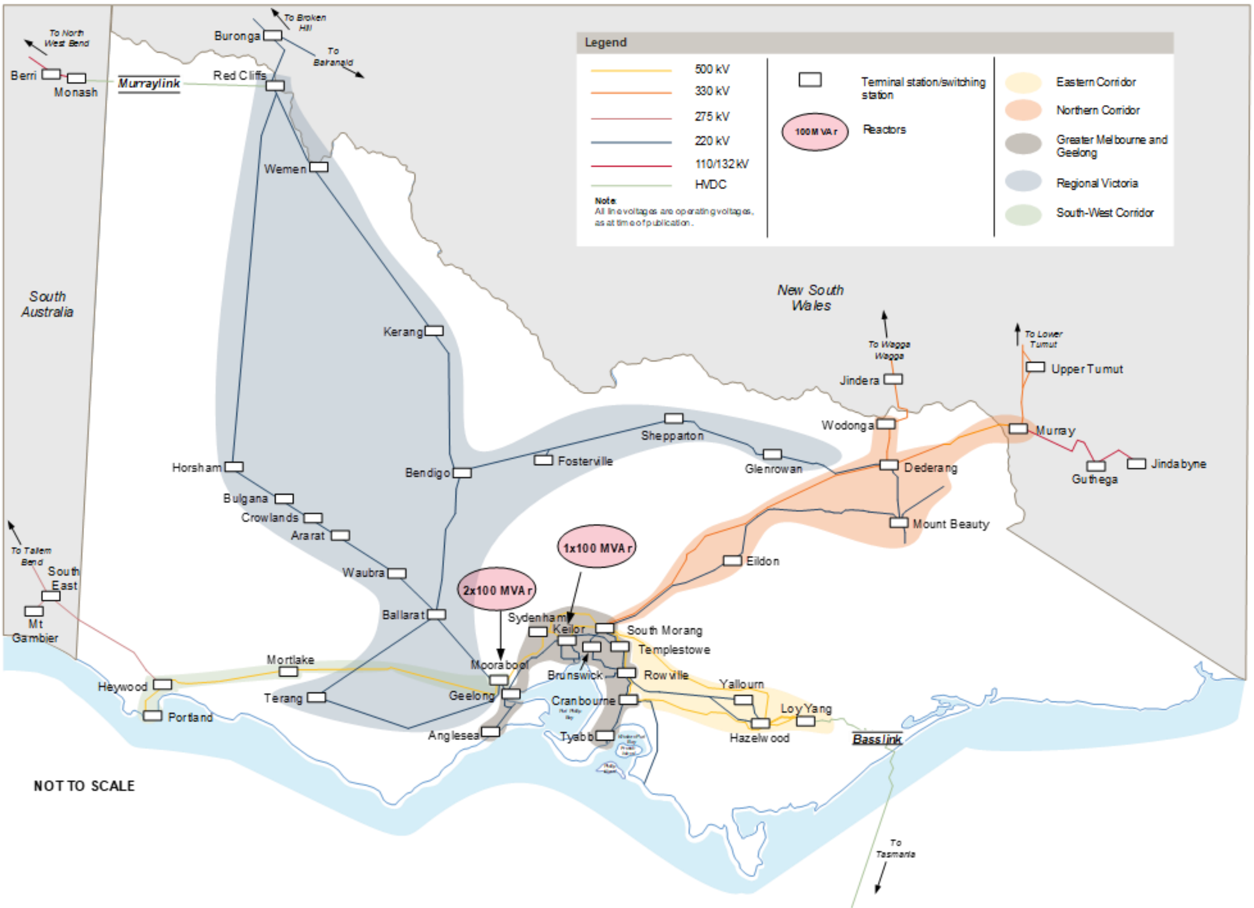
Scope of works	• Installation of two 220 kV 100 MVAr shunt reactors, one at Keilor Terminal Station and one at Moorabool Terminal Station, providing 200 MVAr of total absorbing reactive power service. • Connection to 220 kV bus at each location through a single switched arrangement. • Installation of all associated secondary equipment. • Include all associated interface work.
Change to option since PADR	• The PADR specified a 300 MVAr requirement in Option 1A. In the PACR, the first 220 kV 100 MVAr shunt reactor at Keilor Terminal Station by 2021 is deemed a committed project and has been removed from all options.
Impact on interconnector limits	• No material impact on interconnector limits.
Construction type	Brownfield
Expected commissioning year	By 2022 and 2023
Estimated capital cost (2019-20)	$13.3 million
Ongoing operating cost	2% of capital cost

Option 1B – Combination of 3 x 100 MVAr shunt reactors

Figure 7 presents Option 1B, which consists of three 220 kV 100 MVAR shunt reactors. In this option:

- A single 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2022.
- Two 100 MVAr shunt reactors are installed at Moorabool Terminal Station – one in 2023, and the other in 2025.

Figure 7 Combination of three 100 MVAr reactors (Option 1A)



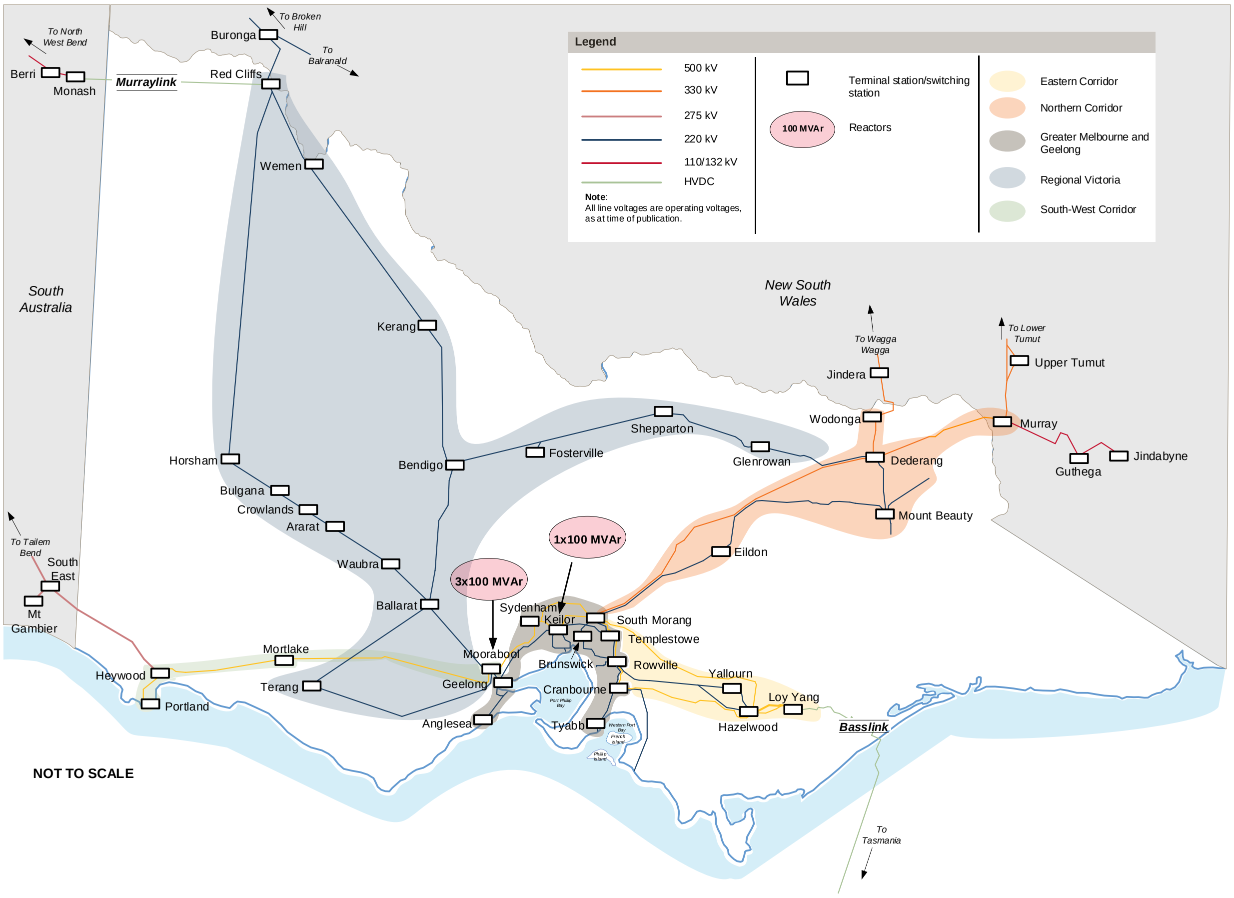
Scope of works	• Installation of three 220 kV 100 MVAr shunt reactors, one Keilor Terminal Station and two at Moorabool Terminal Station, providing 300 MVAr of total absorbing reactive power service. • Connection to 220 kV bus at each location through a single switched arrangement. • Installation of all associated secondary equipment. • Inclusion of all associated interface work.
Change to option since PADR	• The PADR specified a 400 MVAr requirement in Option 1B. In the PACR, the first 220 kV 100 MVAr shunt reactor at Keilor Terminal Station by 2021 is deemed a committed project and has been removed from all options.
Impact on interconnector limits	• No material impact on interconnector limits.
Construction type	Brownfield
Expected commissioning year	By 2022-25
Estimated capital cost (2019-20)	$20.8 million
Ongoing operating cost	2% of capital cost

Option 1C – Combination of 4 x 100 MVAr shunt reactors

Figure 8 presents Option 1C, which consists of four 220 kV 100 MVAR shunt reactors. In this option:

- A single 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2022.
- Three 100 MVAr shunt reactors are installed at Moorabool Terminal Station – one in 2023, two in 2025.

Figure 8 Combination of four 100 MVAr reactors (Option 1C)



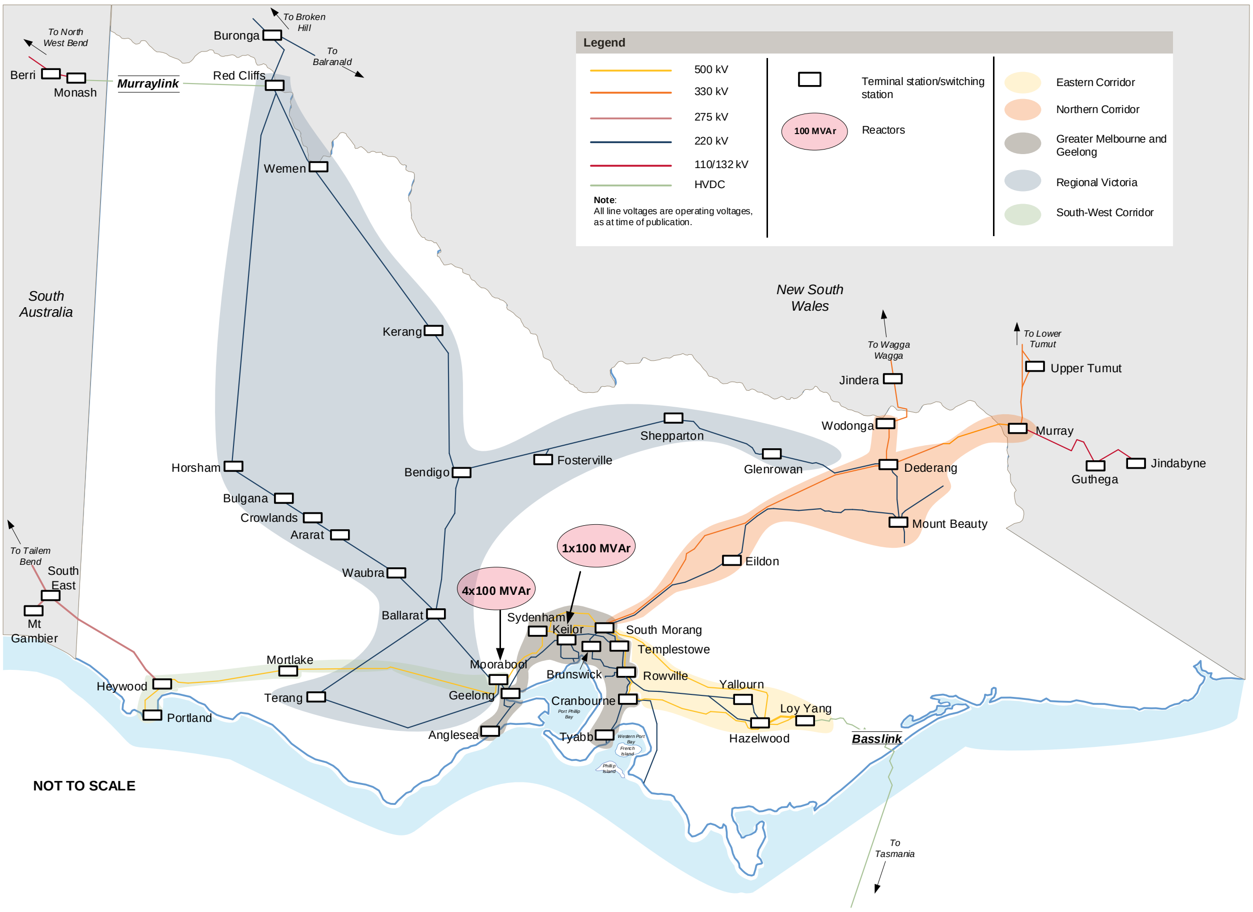
Scope of works	• Installation of four 220 kV 100 MVAr shunt reactors, one Keilor Terminal Station and three at Moorabool Terminal Station, providing 400 MVAr of total absorbing reactive power service. • Connection to 220 kV bus at each location through a single switched arrangement. • Installation of all associated secondary equipment. • Inclusion of all associated interface work.
Change to option since PADR	• The PADR specified a 500 MVAr requirement in Option 1C. In the PACR, the first 220 kV 100 MVAr shunt reactor at Keilor Terminal Station by 2021 is deemed a committed project and has been removed from all options.
Impact on interconnector limits	• No material impact on interconnector limits.
Construction type	Brownfield
Expected commissioning year	By 2022-25
Estimated capital cost (2019-20)	$28.3 million
Ongoing operating cost	2% of capital cost

Option 1D – Combination of 5 x 100 MVAr shunt reactors

Figure 9 presents Option 1D, which consist of five 220 kV 100 MVAR shunt reactors. In this option:

- A single 100 MVAr shunt reactor is installed at Keilor Terminal Station, in 2022.
- Four 100 MVAr shunt reactors are installed at Moorabool Terminal Station – one in 2023, three in 2025.

Figure 9 Combination of five 100 MVAr reactors (Option 1D)



Scope of works	• Installation of five 100 MVAr 220 kV shunt reactors, one Keilor Terminal Station and four at Moorabool Terminal Station, providing 500 MVAr of total absorbing reactive power service. • Connection to 220 kV bus at each location through a single switched arrangement. • Installation of all associated secondary equipment. • Inclusion of all associated interface work.
Change to option since PADR	• The PADR specified a 500 MVAr requirement in Option 1D. In the PACR, the first 220 kV 100 MVAr shunt reactor at Keilor Terminal Station by 2021 is deemed a committed project and has been removed from all options.
Impact on interconnector limits	• No material impact on interconnector limits.
Construction type	Brownfield
Expected commissioning year	By 2022-25
Estimated capital cost (2019-20)	$35.7 million
Ongoing operating cost	2% of capital cost

Option 2 – Combination of reactors with a single dynamic reactive plant

Option 2 is a variation of option 1C, where a single 100 MVAR shunt reactor replaced by a +200/-100 MVAr synchronous condenser (shown in Figure 10). The timing of the investments was determined by the cost-benefit analysis (see Section 6.3.5). In this option:

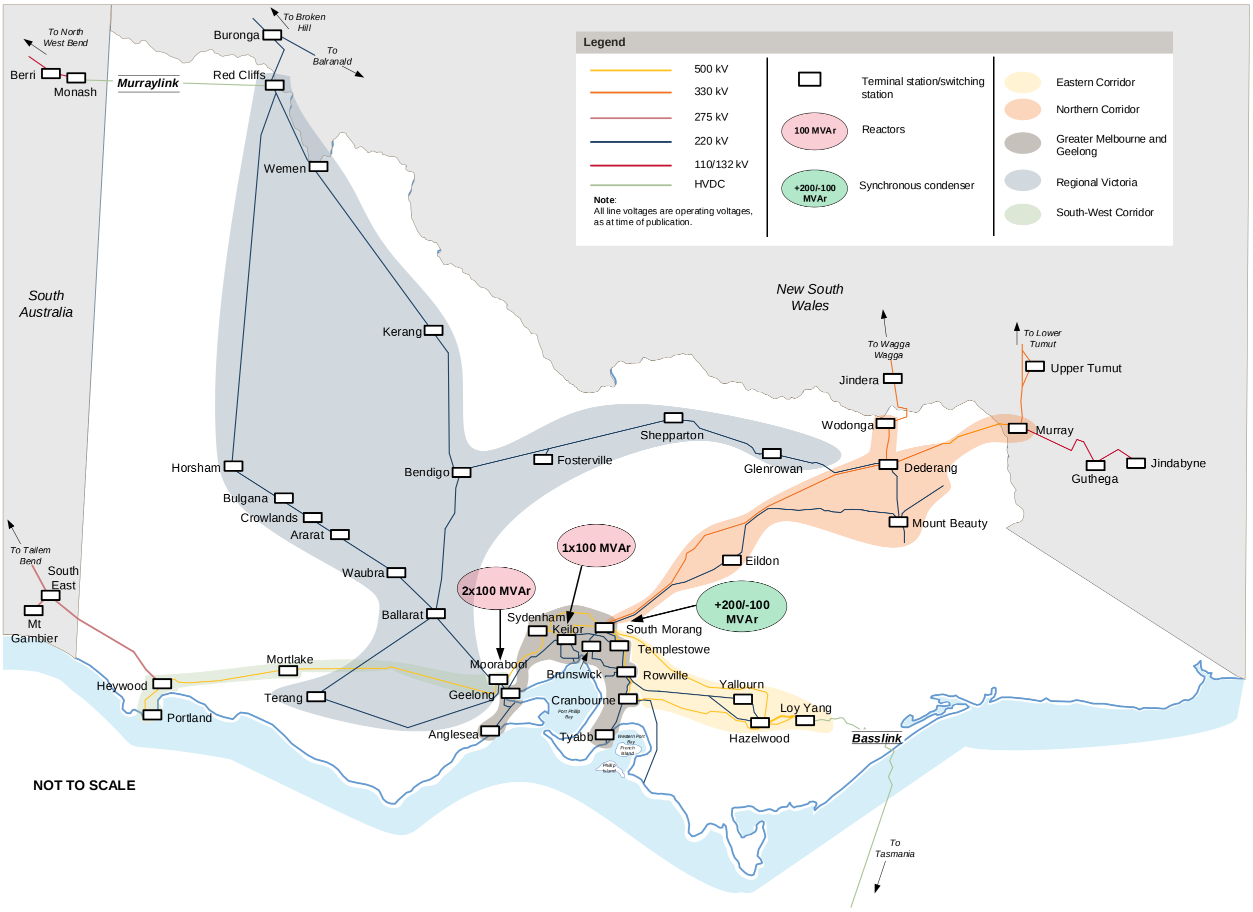
- A single 100 MVAr shunt reactor is installed at Keilor Terminal Station, in 2022.
- Two more 220 kV 100 MVAr shunt reactors are installed at Moorabool Terminal Station – one in 2023, and one in 2025.
- A 330 kV +200/-100 MVAr synchronous condenser is installed at South Morang Terminal Station in 2025.

The cost of a synchronous condenser is significantly higher than a reactor. The synchronous condenser was included as an option to determine possible additional market benefits, which arise due to:

- The synchronous condenser being available during times of system strength issues in Victoria, leading to benefits of not directing generators to come on line or not using the NMAS contract.
- Increasing Victoria to New South Wales export limits (transient and voltage stability).

AEMO also considered testing combinations with even higher numbers of dynamic reactive plant, however initial studies showed that the increased benefit of these options was not sufficient to justify the increased costs.

Figure 10 Combination of three 100 MVAr reactors and one +200/-100 MVAr synchronous condenser (Option 2)



Scope of works	• Installation of three 220 kV 100 MVAr shunt reactors, one at Keilor Terminal Station and two at Moorabool Terminal Station, providing 300 MVAr of total absorbing reactive power service. • Installation of a single 330 kV +200/-100 MVAr synchronous condenser at South Morang Terminal Station. • Connection to 220 kV and 330 kV buses at each location through a single switched arrangement. • Installation of all associated secondary equipment. • Inclusion of all associated interface work.
Change to option since PADR	• The PADR specified a 500 MVAr requirement in Option 2. In the PACR, the first 220 kV 100 MVAr shunt reactor at Keilor Terminal Station by 2021 is deemed a committed project and has been removed from all options.
Impact on interconnector limits	• Increase in Victoria to New South Wales export limits (transient and voltage stability).
Construction type	Brownfield
Expected commissioning year	By 2022-25
Estimated capital cost (2019-20)	$90.7 million
Ongoing operating cost	2% of capital cost

3.3 Cost estimates of credible options

The cost estimates provided in the PADR for each credible option has been revised to include more refined cost estimates and excludes the cost of the first 100 MVAr 220 kV reactor at Keilor Terminal Station. Cost estimates for each of the above credible options are presented in Table 7, based on information provided by AusNet Services. Costs were provided on a P50[32] basis, and do not include finance charges, overheads, or management reserve risk costs. Operational cost was assumed to be 2% of the capital cost.

Table 7 Summary of cost estimates of credible network options

Option	Description	Total MVAr (absorbing)	Estimated capital cost ($M 2019-20)	Estimated operational cost ($M 2019-20)
1.0	1 x 220 kV 100 MVAr shunt reactor at Keilor	100	6.5	0.13
1A	1 x 220 kV 100 MVAr shunt reactor at Keilor 1 x 220 kV 100 MVAr shunt reactor at Moorabool	200	13.3	0.27
1B	1 x 220 kV 100 MVAr shunt reactor at Keilor 2 x 220 kV 100 MVAr shunt reactor at Moorabool	300	20.8	0.42
1C	1 x 220 kV 100 MVAr shunt reactor at Keilor 3 x 220 kV 100 MVAr shunt reactor at Moorabool	400	28.3	0.57
1D	1 x 220 kV 100 MVAr shunt reactor at Keilor 4 x 220 kV 100 MVAr shunt reactor at Moorabool	500	35.7	0.71
2	1 x 220 kV 100 MVAr shunt reactor at Keilor 2 x 220 kV 100 MVAr shunt reactor at Moorabool 1 x 330 kV +200/-100 MVAr synchronous condenser at South Morang	400	90.7	1.81

[32] An estimate prepared at any stage of a project which has a 50% confidence factor of not being exceeded by cost at completion.

3.4 Material inter-network impact

Options 1.0-1D have no material inter-network impact, as they do not materially impact interconnector limits.

Option 2 would increase the Victoria to New South Wales transient and voltage stability export interconnector limits. The potential benefits of this are included in the market benefit assessment.

4. Submissions to the Project Assessment Draft Report

The Victorian Reactive Power Support PADR was published in June 2019, and stakeholder submissions closed on 16 August 2019. AEMO received four submissions, and has considered these submissions when undertaking the PACR assessment.

4.1 Consultation on the Victorian Reactive Support RIT-T

AEMO consulted on the Victorian Reactive Support RIT-T PSCR[33], and issued a Request for Information (RFI)[34] seeking information from generators, loads, and other parties that may have capability to suppress high voltages during low demand periods in Victoria. No submissions were received on the PSCR or for the RFI.

AEMO received four stakeholder submissions on the Victorian Reactive Support RIT-T PADR, which are published on AEMO's website[35]. The matters raised in these submissions, and AEMO's responses, are summarised in Table 8.

4.2 Submissions

AusNet Services, Energy Australia, Major Energy Users Inc (MEU), and Mondo provided submissions.

Table 8 Matters raised in submissions and AEMO response

Matters raised in submission by general topic	AEMO response
Importance of proposed preferred solution to reduce system risks and costs to Victorian consumers	In completing this PACR, AEMO has balanced the need for immediate action to reduce the costs of market intervention to Victorian consumers with the uncertainty in the medium to long term, highlighted by the wide range of minimum demand forecasts across the reasonable scenarios. The updated assumptions discussed in Section 2.3 and used in this PACR assessment have changed the preferred option, from Option 2 as proposed in the PADR to Option 1B in this PACR. This change has reduced the effective reactive support by 100 MVAr and no longer includes dynamic reactive support in the form of a synchronous condenser. The additional market benefits under Option 2, compared with Option 1B, relate to the synchronous condenser and arose from reducing the need for market intervention to maintain system strength levels under low demand conditions with limited synchronous generators online. The analysis under the updated demand forecast and system strength assumptions in this PACR (see Section 2.3.4) shows that the need to intervene in the market for system strength is forecast to continue, however, at this time the costs of market intervention do not outweigh the costs of the synchronous condenser. AEMO will continue to monitor this need and will commence a RIT-T if and when appropriate.

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

[34] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Request-for-Information-for-reactive-power-Non-market-Ancillary-Services-in-VIC.

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

Matters raised in submission by general topic	AEMO response
Consideration of a battery energy storage system (BESS)	As noted in the PADR, a BESS could be a viable technical solution to address the identified need, but due to cost and product life, a BESS was not included as a credible option in the market benefit analysis.
Further information on: **1. Basis and need for interventions, including the sensitivity to demand levels, online synchronous generators and level of inverter-based generation.** **2. Assumptions around technical characteristics and costs of generators.** **3. Capacity expansion outcomes, including generation closures.** **4. Changes to minimum demand level forecasts.** **5. Provision of examples of system conditions and time duration curves.**	The numbers in this section correspond with the numbered stakeholder requests on the left. 1. Basis and need for interventions, including the relationship of the reactive need to key parameters, is discussed in Section 5.3.1. 2. Assumptions around technical characteristics and costs of generators are in Section 5.3.2. 3. Discussion on capacity expansion outcomes is included in Section 5.3.2. 4. Changes to minimum demand level forecasts are discussed in Section 2.3.1. 5. Examples of system conditions are included in 5.3.1 and load duration curves are supplied as Attachment C.
Market benefit assessments: **1. Explanation of PADR preferred option (Option 2) interaction with VNI RIT-T.** **2. Further explore the incremental benefit of Option 2 over Option 1B, and give consideration to the ratio of the benefits to the capital costs.** **3. Consideration of a staged solution given uncertainty in the NEM.** **4. Inclusion of more sensitivities, including varying multiple parameters at a time, and a higher weighting of the Fast Change scenario.** **5. Explanation of terminal values used.**	The numbers in this section correspond with the numbered stakeholder requests on the left. 1. Option 2 was modelled assuming the preferred option from the VNI RIT-T was already implemented, to avoid any double-counting of benefits. 2. The PACR analysis has further assessed the incremental benefits of Option 2 over Option 1B and the preferred option has changed to Option 1B as a result. 3. The preferred option under this RIT-T includes a staged solution. See Section 7.2 for details on AEMO's implementation of the preferred option. 4. Sensitivity analysis, focusing on the key sensitivities is included in Section 6.3.3. 5. The approach to terminal values is discussed in Section 5.2.1.

5. Methodology and assumptions

The modelling carried out in this RIT-T was based on detailed power flow studies to estimate the impact of credible options in meeting the identified need, and economic modelling to rank credible options and identify the preferred option that delivers the highest net economic benefit. Where possible, all input assumptions have been based on AEMO's most recently published planning datasets.

5.1 Overview

The assessments in this PACR are based on the RIT-T application guidelines published in December 2018[36] by the AER. This chapter describes the key assumptions and methodologies applied in this RIT-T.

5.2 Cost-benefit assumptions

5.2.1 Analysis period

The RIT-T analysis has been undertaken over the period from 2020-21 to 2029-30.

Terminal values[37] have been used to capture the remaining asset life of the credible options with asset life extending past 2029-30.

To calculate the terminal value of a credible option with asset life extending past 2029-30, the market dispatch benefits calculated for the final three years of the modelling period have been averaged, and this average value has been assumed to be indicative of the annual market dispatch benefit that would continue to arise under that credible option in the future.

5.2.2 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 5.90% (real, pre-tax) commercial discount rate calculated in Energy Network Australia's RIT-T Economic Assessment Handbook[38].

The cost-benefit assessment has included sensitivity testing with a lower discount rate equal to the regulated weighted average cost of capital (WACC) of 3.2% based on the AER's most recent transmission determination[39], and a symmetrically higher rate of 8.6%.

5.2.3 Reasonable scenarios and weighting

The RIT-T requires 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.

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

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

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

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

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. Section 2.3.1 discusses the five reasonable scenarios AEMO has developed, in consultation with stakeholders, to provide a suitable wide range of possible developments.

This RIT-T analysis included the three reasonable scenarios from the 2019 ESOO – the Central, Step Change, and Slow Change scenarios – in the base cost-benefit analysis, with a 50% weighting for the Central scenario and 25% weighting for the Step Change and Slow Change scenarios.

It should be noted that the Central scenario is not necessarily considered the most likely scenario; it represents the scenario with current policy settings and technology trajectories. However, as this scenario has the highest minimum demand forecasts of the five scenarios, a conservative approach has been adopted in assigning the base weightings.

Sensitivity studies were undertaken by including the two additional ISP scenarios – Fast Change and High DER – and by varying the weightings used. The results from these are discussed in Section 6.3.3.

5.3 Modelling methodology and assumptions

AEMO used a combination of power systems studies and market modelling to estimate the market benefits associated with each credible option.

This estimation was done by comparing the 'state of the world' in the base ('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.

The cost-benefit results in this PACR used the following models:

- Power system studies – determines the impact of the credible options on the power system.
- Market intervention model – calculates the benefits of avoided market intervention for reactive support and system strength support under each credible option.
- Market simulation model – calculates the benefits of increased export from Victoria to New South Wales under Option 2.

The rest of this chapter describes the assumptions and methodology used in these three models.

5.3.1 Power system studies

Assumptions

- Power system analysis base case – power system studies were conducted using minimum operational demand base cases based on historical Operations and Planning Data Management System (OPDMS) snapshots corresponding to a minimum operational demand at midday. The minimum operational demand midday cases were used (instead of overnight cases), because the 2019 ESOO forecasts minimum operational demand in Victoria moving to a midday trough due to the projected rooftop PV intake. The results were also validated with historic overnight operational minimum demand cases.
- The 2018 ESOO minimum demand forecast was used in the PADR studies, and later updated with 2019 ESOO minimum demand forecast values for PACR analysis.
- Target operational voltages for Victoria were as per the National Electricity Rules (NER) and limits provided by asset owners.
- According to the capability curves of new renewable generators, an average value of 25% reactive power contribution of Pmax (maximum nameplate rating) was assumed to be available, if the units were online.
- Reactive output of renewable generators was based on the renewable generator output traces, capability curves and the location factors.

- Under minimum demand conditions in Victoria, six Latrobe Valley units were assumed to be in service for the technical studies.
- The output of Latrobe Valley units was varied to keep supply and demand balanced.
- Sensitivity of reactive power contribution was tested with five Latrobe Valley units under different demand scenarios, with and without renewable generation.
- Switching out a single 500 kV line in Victoria during high voltage periods for suppressing high voltage was assumed prior to directing generators for voltage support services.
- The quantity of reactive power support needed in each study case was based on the post-contingent voltage of the most critical contingency which would not exceed operational voltage limits.
- The most critical contingency was identified as a trip of Heywood–Tarrone–APD line which trips the load at APD and the 500 kV line reactor or a Heywood–Mortlake–APD line which also trips the load at APD and the 500 kV line reactor.
- The PACR assumes the 220 kV 100 MVAr reactor NCIPAP project to be built by AusNet Services by 2021 at Keilor Terminal Station is a committed project.

Static reactive

Power system studies were undertaken with a PSS®E[40] model to determine the Victorian reactive power requirements under a range of scenarios, and to quantify the sensitivity of reactive requirements to the following factors:

- Operational demand level.
- Number of coal units online.
- Location and output of renewable generators.
- Critical contingencies.
- Location of credible options.
- 500 kV line switching.

The aim of the power system analysis was to determine the reactive power requirements to maintain voltage limits under a range of low demand conditions, taking account of potential de-energisation of a single 500 kV line. These reactive requirements were then used as the inputs into the reactive modelling.

Results of power system analysis

Table 9 presents the reactive power support requirements based on four cases studied in the PACR. These are a subset of 16 cases used in the PADR power system analysis.

The quantity of reactive power needed depends on a number of factors. The key factors are demand (MW and MVAr consumed at each connection point), number of coal units online, reactive power output from online generators, and the number of lines that are switched out which otherwise would be producing reactive power.

The sensitivity of reactive power requirement to demand is not always linear. As the demand decreases the amount of power flow through the transmission lines decreases, but the decrease is not linear. In general, during operational demand of 2,000-3,000 MW in Victoria, a 100 MW decrease can require 25-50 MVAr of reactive power to maintain voltages within limits.

Latrobe Valley coal power units can contribute about 50-100 MVAr, depending on the voltage requirements in the area and in the 220 kV network.

[40] 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.

Each 500 kV transmission line switching used currently as a short term operational measure is effective in reducing the reactive power requirements in the range of 100-150 MVAr considering different scenarios. A single 500 kV line switching has been included in the PACR analysis.

Table 9 Results of power system analysis

Snapshot	Operational demand (sent-out) (MW)	Coal units online (number)	Reactive output from generators (MVAr)	Lines switched out (number)	Reactive requirement (MVAr)[A]
1	2,864	7	400	1	0-150
2	2,308	6	475	1	240-275
3	2,120	6	480	1	320-360
4	1,920	6	490	1	360-410

A. Assumes the committed 220 kV 100 MVAr Keilor reactor is in service.

The contribution factors from renewable generators will depend on the connection locations and the respective generator performance standards. Table 10 presents the location factors assumed for the renewable generators.

Table 10 Location factors assumed for renewable generators during minimum demand periods

Location	Location factor
Red Cliffs 220 kV	10%
Horsham 220 kV	15%
Ararat 220 kV	40%
Kerang 220 kV	15%
Shepparton 220 kV	45%
Terang 220 kV	80%
Stockyard Hill	99%

Dynamic reactive

As Option 2 includes a dynamic reactive component, AEMO also studied the impact of this option on the Victoria to New South Wales transient and voltage stability limits, under periods of high Victoria to New South Wales export. Multiple snapshots representing different network operating conditions were studied using PSS®E dynamic simulations.

This study identified that a +200/-100 MVAr synchronous condenser at South Morang 330 kV will increase the Victoria to New South Wales export interconnector transient stability limit by approximately 150 MW, and the voltage stability limit by approximately 30 MW. These increases are in addition to the proposed preferred option identified in the Victoria to New South Wales Interconnector (VNI) Upgrade RIT-T PADR[41].

[41] 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.

System strength

System strength reflects the sensitivity of power system variables to disturbances. It indicates inherent local system robustness, with respect to properties other than inertia.

AEMO has undertaken studies to identify possible combinations of synchronous generating units that can provide adequate system strength to ensure secure operation of the Victorian power system[42].

These combinations have been published in the Transfer Limit Advice for System Strength[43] and used in the RIT-T PACR analysis.

Capacity (MVAr) of reactive power plant

Based on discussions with suppliers about construction efficiencies, incremental costs implications, experience with existing plant in the system, and network studies on the impact of reactor switching, this PACR considers the optimal individual unit sizes to be:

- 100 MVAr for static reactors.
- +200/-100 MVAr for dynamic plant.

For example, the switching impact of a single 200 MVAr reactor, especially at light load conditions, could result in voltage step changes of greater than 3%. This is outside the permitted limits for rapid voltage changes[44]. Selecting multiple smaller unit sizes (less than 100 MVAr) begins to unduly increase the cost per MVAr of each solution.

5.3.2 Market intervention model

During low demand periods, AEMO as system operator may need to intervene in the market to maintain voltages within operational and design limits or to maintain adequate system strength. This intervention, via a direction or the activation of a NMAS contract, involves AEMO dispatching a generator online 'out-of-merit' order, or, in other words, running a more expensive generator than would be dispatched without the intervention.

A simplified market model – the market intervention model – was used to calculate the market benefits associated with avoiding these interventions for reactive and system strength support.

The critical inputs to the model include:

- Victorian demand and rooftop PV levels, renewable generation output, and the number of Latrobe Valley coal units online – used to calculate the number of interventions required.
- Technical characteristics and costs of Victorian generators – used to calculate the costs of interventions.

Demand and rooftop PV assumptions

The RIT-T PACR analysis applied the demand forecasts from the 2019 ESOO[45].

Rooftop PV forecasts and half-hourly traces for each scenario were also based on the 2019 ESOO.

Half-hourly demand traces used included the 50% POE, 90% POE, and 10% POE minimum demand conditions with weightings of 39.2%, 30.4%, and 30.4% respectively[46].

[42] The methodology used is at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[43] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice.

[44] AS/NZS 61000.3.7:2001.

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

[46] The methodology used to determine these weightings is at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/ESOO-Methodology-Document.pdf.

Reference years

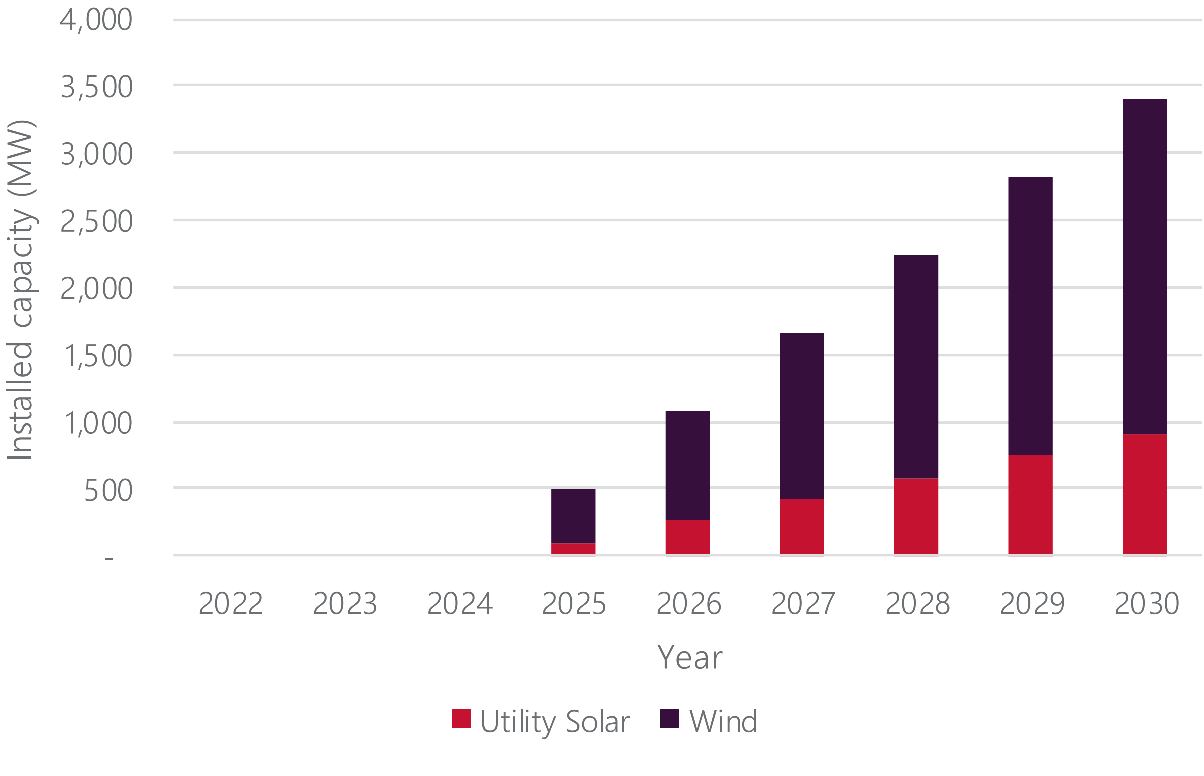
The half-hourly analysis was undertaken using demand, rooftop PV, and renewable energy traces using historical reference years from 2010-11 to 2018-19[47]. The outputs from each reference year were weighted equally.

Renewable generation assumptions

The RIT-T PACR analysis assumptions included committed generator projects from the 08 August 2019 Generation Information update[48]. This represents 1,904 MW of committed wind generation, and 325 MW of committed solar generation in Victoria. The successful projects for the Victorian Renewable Energy Auction Scheme (VREAS), as announced in September 2018, were also included as committed. This represents an additional 338 MW of wind generation and 185 MW of solar generation.

In addition to existing and committed generation, modelled wind and solar projects were included based on the outcomes of the generation expansion modelling discussed in Section 5.3.3. Figure 11 shows the additional modelled installed capacity in Victoria in the Central scenario. Attachment A includes the modelled capacity in all scenarios.

Figure 11 Additional modelled installed capacity in Victoria – Central scenario



Latrobe Valley coal unit availability assumptions

The analysis was undertaken with six different Latrobe Valley coal unit availability scenarios, with the results weighted as shown in Table 11. These weightings were calculated using historical outcomes over the 2018-19 year, for example, over that period all 10 Latrobe Valley coal units were online 17.2% of the year, and nine units were online for 28.8% of the year.

As a conservative assumption, no closures of thermal generation were included in any scenario over the modelling horizon.

[47] Traces available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

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

Table 11 Latrobe Valley coal unit availability weighting

Coal unit scenario	Latrobe Valley coal units online	Weighting
1	All 10 units	17.2%
2	9 units	28.8%
3	8 units	32.8%
4	7 units	17.1%
5	6 units	4.1%
6	5 units	0.1%

Generator technical characteristics and cost assumptions

The following generator technical characteristics were based on confidential agreed performance standards:

- Reactive power capability[49].
- Minimum generation levels.
- Start-up times.

Generator heat rates, corresponding to the minimum generation levels, and generator start-up costs were taken from GHD's 2018 AEMO cost and technical parameter review databook[50].

Generator fuel costs, and variable and fixed operating and maintenance costs (OPEX) were taken from the 2019 Input and Assumptions workbook[51] developed in consultation with stakeholders for AEMO's Planning and Forecasting activities for 2019-20.

Intervention model methodology

To capture the market cost of intervention for reactive support in the market modelling, the following steps were undertaken for each half-hour in the modelling period, with and without the credible options in place:

- Step 1 – calculate the reactive power requirement using the:
  - Victoria operational demand based on the demand trace and the demand sensitivity shown in Section 5.3.1.
  - Reactive output from the renewable generation online based on the renewable output traces.
  - Reactive output from the Latrobe Valley coal units online (dependent on the coal unit scenario).
  - Reactive output from the credible option under assessment.

  If the minimum generation level from the Latrobe Valley coal units plus the renewable output exceeds the Victorian operational demand plus exports from Victoria, then the renewable generation output is scaled down equally across all renewable generators until supply no longer exceeds demand.

  If the minimum generation level from the Latrobe Valley coal units exceeds the Victorian operational demand plus exports from Victoria, then additional coal units are assumed to be turned off until supply no longer exceed demands.

[49] Future renewable generation reactive contribution was assumed at 25% of their maximum active power contribution as an average.

[50] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/GHD-AEMO-revised---2018-19-Costs_and_Technical_Parameter.xlsb.

[51] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook-Sept-19.xlsx.

- Step 2 – calculate the system strength shortfall:
  - If the number of coal units turned off in Step 1 was greater than five, intervention for system strength is assumed to be required for all options except Option 2, which includes a dynamic reactive component.
- Step 3 – for a non-zero reactive power shortfall, determine the number of representative generators (see below) required to be online:
  - To remove the reactive power shortfall.
  - To remove the system strength shortfall if more than five coal units were offline and Option 2 is not in place.
- Step 4 – calculate the additional market cost of starting-up and dispatching the additional generators brought online in Step 3.

Representative generators

Combinations of Victorian grid connected generators that could deliver at least 100 MVAr absorbing reactive capability and meet system strength need were developed to form a representative generator with average:

- Absorbing reactive capability.
- Minimum dispatch levels.
- Dispatch costs (fuel plus variable OPEX).
- Start-up hours.
- Start-up cost.

These representative generators were then dispatched as required to remove the reactive power and system strength need.

Table 12 below shows the average of the characteristics of a representative generator. See Attachment A for average fuel costs for all years and scenarios.

Table 12 Characteristics of average representative generator

Parameter	Value
Minimum load (MW)	90
Start-up (hrs)	2
Absorbing reactive support (MVAr)	125
Variable O&M ($/megawatt hours [MWh]) cost	9
Start-up cost ($/MW)	100
Heat rate at minimum load (GJ/MWh)	27
Fuel cost ($/MWh) – 2019-20 central scenario	267

Market cost of dispatching representative generators

The market cost of dispatching the representative generators was calculated using the following:

(Generator start-up costs + minimum generation x generator dispatch cost) – (minimum generation x displaced generator cost)

The displaced generator cost was calculated as:

- The average annual market generator dispatch cost (fuel plus variable OPEX) from the full market modelling simulation using PLEXOS® short-term dispatch model (on average $19/megawatt hours [MWh]), if generation was not required to be constrained due to supply-demand constraints, or
- The average of the wind and solar variable OPEX ($1.36/MWh) if the supply-demand balance constraint required renewable generators or coal units to be displaced, on the basis that renewable generation would be the marginal unit in these dispatch periods.

Gross market benefits

The gross market benefits of avoiding market benefits for each credible option were calculated by comparing the market cost of dispatching the representative generators with the credible option in place with the market cost of dispatching the representative generators in the 'do-nothing' case (no credible options in place).

Note that only Option 2 was assumed to be able to displace the system strength shortfall interventions.

The gross market benefits were calculated for each reasonable scenario and for each of the following:

- Nine reference year traces weighted equally at 11%.
- 50% POE, 90% POE and 10% POE demand traces weighted 39.2%, 30.4%, and 30.4% respectively.
- Six coal unit scenarios weighted as in Table 11.

5.3.3 Market simulation model

A market simulation model was used to forecast the market benefits associated with the increase in the Victorian to New South Wales transient and voltage stability export limits due to the dynamic reactive plant in Option 2.

Modelling assumptions

This market simulation modelling was undertaken for the Victorian Reactive Power Support PADR and has not been updated for the PACR. All model inputs for the market simulation model were published with the PADR for this RIT-T and are consistent with those in the VNI Upgrade RIT-T PADR[52].

The increases in the Victorian to New South Wales transient and voltage stability export limits were modelled over and above the limits in the proposed preferred option (Option 2) proposed in the VNI Upgrade RIT-T PADR to ensure no double counting of market benefits.

Capacity outlook model

The capacity outlook model determines the most cost-efficient long-term trajectory of generator, storage, and transmission investments and retirements to maintain power system reliability.

The capacity expansion model outputs from the VNI Upgrade RIT-T PADR upgrade option were used for the 'do nothing' case and for Option 2. The capacity outlook model uses notional interconnector limits, and while Option 2 increases the Victorian to New South Wales transient and voltage stability export limits, these limits are not the only network limits impacting the overall export limit.

Time sequential model

The time sequential modelling 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.

Detailed market modelling was undertaken with the PLEXOS® short-term dispatch model for Option 2 as part of the Victorian Reactive Support PACR. The 'do nothing' case short-term modelling results were taken directly from the VNI Upgrade RIT-T PADR proposed preferred option.

[52] 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.

Model outputs

This model produced an hourly pricing and dispatch solution for generation, which was used to forecast operational benefits (reduction in fuel and operation and maintenance costs). These benefits primarily stem from a reduction in dispatch costs from New South Wales and Queensland black coal generation due to an increase in export from Victoria.

Table 13 shows the mapping of the PADR reasonable scenarios to the PACR reasonable scenarios.

Table 13 Scenario mapping

PACR scenarios	PADR scenarios
Central	Neutral
Slow change	Slow change
Step change	Fast change
Fast change	Fast change
High DER	Fast change

Note that this is a conservative approach because the market benefits from additional export from Victoria to New South Wales, over and above that enabled by the proposed preferred option in the VNI Upgrade RIT-T, are lowest in the Fast Change scenario.

5.4 Option cost estimate methodology

Cost estimates for each network location and technology type were based on information provided by AusNet Services. Costs were provided on a P50[53] basis, and do not include finance charges, overheads, or management reserve risk costs. Operational cost was assumed to be 2% of the capital cost.

The cost of each option includes the following components:

- Project management.
- Engineering support.
- Equipment and services procurement.
- Installation.
- Commissioning and testing.
- Project management risk allowance.

Cost estimates were based on assumed standard capacities of reactive power plant (100 MVAr) and standard connection arrangements (single-switching). For credible options with more than one component at the same terminal station, cost estimates were developed for the reactors being installed at the same time as well as for the reactors being installed one at a time.

The typical lead time assumed is 12-18 months for installing reactors, and 18-36 months for installing synchronous condensers. The actual time required will depend on factors such as the location of the manufacturer, whether they are off-the-shelf products, and the location of the installations.

[53] An estimate prepared at any stage of a project which has a 50% confidence factor of not being exceeded by cost at completion.

6. Market benefits

The primary source of market benefits is fuel and operating cost savings associated with avoided market intervention and avoided use of non-market ancillary services. Option 2 also provides potential increases to the Victoria to New South Wales export stability limits.

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:

- Network losses – the identified need of this RIT-T is related to suppression of high voltages during light load periods. While augmentation options to suppress high voltages could marginally increase network losses, it is not expected the increase will be material in relation to the RIT-T assessment for a specific option, as all options which can suppress high voltage will have similar (small) impact on network losses.
- Changes in ancillary services costs – there is no expected change to the costs of Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS), or System Restart Ancillary Services[54] (SRAS) because of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.
- Differences in timing of transmission investment – investments to address the identified need of this RIT-T could postpone other transmission investments. Although it is likely that additional synchronous condensers will be required in Victoria after the retirement of brown coal generators in the 2030s, this benefit has not been included in this RIT-T, because it will not change the sign or the ranking of the credible options.
- Competition benefits – competition benefits are not expected to be material to the outcome of this RIT-T assessment. The high voltages are localised in nature and have a limited impact on spot market outcomes, except when line de-energisation is used to manage the issue. It is expected that all options which can suppress high voltage will have a similar (small) impact on spot market outcomes. The estimation of any competition benefit in this RIT-T assessment would require significant modelling, which would be disproportionate to any competition benefits arising from any of the credible options in this RIT-T.
- Option value – for this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis in the RIT-T would require significant modelling, which would be disproportionate to any additional option value benefit that may be identified for this specific RIT-T assessment. In this case, appropriate identification of credible options and reasonable scenarios should capture any option value. AEMO does not therefore propose to estimate any additional option value market benefit for this RIT-T assessment.
- Changes in voluntary/involuntary load curtailment – without additional reactive power support, there still may be high-impact low-probability reliability risk associated with de-energisation of multiple 500 kV lines under extreme conditions, and thus market benefits can be captured by additional reactive support for mitigating this risk. However, these market benefits are not considered material for the purposes of this

[54] Although not quantified, a synchronous condenser will provide greater flexibility during a system restart process and enable a broader range of SRAS providers.

RIT-T, because any such benefits would be common to all credible options and would therefore not influence the selection of a preferred option.

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 costs to parties other than the TNSP, due to differences in the operational and maintenance costs of different plant.

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

6.2.1 Changes in fuel consumption

Changes in fuel consumption through different patterns of generation dispatch are the primary source of market benefits identified in this RIT-T.

For all credible options, the reduction in the need for AEMO as system operator to intervene in the market via either directing generators online or by calling on an NMAS contract has been captured by reduction in:

- Fuel costs of generators dispatched through market intervention.
- Start-up fuel costs of generators dispatched through market intervention.

Additionally, as noted in the previous section, dynamic plant such as synchronous condensers can meet the identified need under this RIT-T and have other benefits such as improving system strength and voltage stability in an area. Studies indicate installation of a synchronous condenser to address the identified need would also increase the Victoria to New South Wales transient and voltage stability limits, under periods of high Victoria to New South Wales export.

AEMO calculated the difference in total fuel costs between the 'do nothing' base case and the case with the credible option involving dynamic reactive plant (Option 2) to capture any reduction in total fuel costs due to the increased stability limit. Fuel costs are calculated for the entire NEM and will therefore capture benefits to states other than Victoria.

6.2.2 Changes in costs for other parties

Changes in costs for other parties is the other class of market benefits quantified in this RIT-T. 'Other parties' in this context refers to costs incurred by market participants due to:

- Differences in variable operating and maintenance costs of generators dispatched through market intervention.
- Start-up operating and maintenance costs of generators dispatched through market intervention.
- Differences in variable operating and maintenance cost of generators due to different market dispatch patterns due to the increased Victoria to New South Wales export stability limits.

6.2.3 Other benefits not quantified in this RIT-T

The PSCR also included the reduction in market costs during periods of de-energisation of 500 kV lines as a potential market benefit. This is because the de-energisation of 500 kV lines can reduce Victoria's ability to export, and create a market impact through the use of higher marginal cost generation in other regions. This potential market benefit has not been calculated in this PACR, because the cost from reducing export limits in these periods is significantly smaller than the cost of the market intervention required in these periods. This minor benefit will not affect the ranking of credible options.

Option 2 would also provide additional benefits compared to the other credible options that were not quantified in the market benefits assessment, including the ability of the synchronous condenser to:

- Improve voltage control and voltage stability during high demand periods where necessary, which could delay the need for future voltage control devices such as capacitors.
- Facilitate system restart by providing stability. It will enable a broader range of SRAS providers and provide greater operational flexibility during the restart process.
- Provide dynamic voltage support after the retirement of brown coal generation in Victoria.

These benefits were not quantified because the assessment showed that Option 2 was significantly lower in net market benefits across the base weighted scenario with the updated minimum demand forecasts. As such, they would not affect the outcome of the PADR assessment.

6.3 Net market benefit assessment

6.3.1 The 'do nothing' base case and non-network NMAS option

The 'do nothing' base case is defined in the RIT-T guidelines as the case where the RIT-T proponent does not implement a credible option to meet the identified need. For this RIT-T, if AEMO as TNSP does not implement a credible option, then AEMO as system operator would be required to intervene in the market either by directing generators or by entering into, and activating, a NMAS contract, to maintain the power system in a satisfactory and secure operating state.

The underlying cost of directing generators, or a NMAS contract, has been calculated using generator fuel costs and operating and maintenance costs, as discussed in Section 5.3.2.

A non-network option in the form of AEMO's current NMAS contract[55] is assumed to have the same underlying costs (based on fuel and operating and maintenance cost) as either directing generators or a system operator NMAS contract.

6.3.2 Net market benefits of network augmentations

Table 14 presents the net market benefits for each augmentation option. Refer to Attachment B for more details on the NPV calculations.

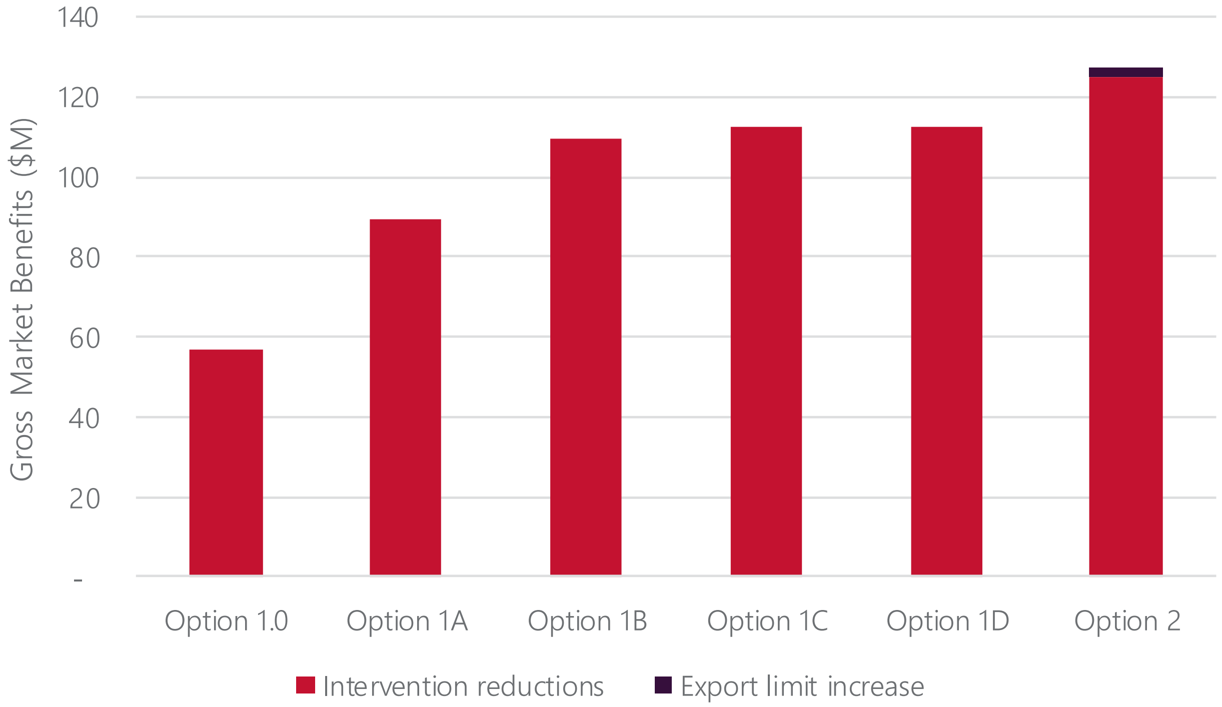
[55] In December 2018, AEMO's NTNDP identified an NSCAS gap for voltage control in Victoria, and AEMO has subsequently entered an NMAS contract as an interim measure to resolve this gap while the reactive power support RIT-T investigates a permanent solution.

Table 14 Weighted net market benefits for each augmentation option

Option	Description	Capital cost, $M (2019-20)	Capital cost, $M (NPV)	Central – net market benefit, $M (NPV)	Step change – net market benefit, $M (NPV)	Slow change – net market benefit, $M (NPV)	Weighted – net market benefit, $M (NPV)
Scenario weighting				50%	25%	25%	
1.0	1 x 220 kV 100 MVAr Shunt Reactor at Keilor	6.5	5.6	14.1	122.5	54.4	51.2
1A	1 x 220 kV 100 MVAr Shunt Reactor at Keilor 1 x 220 kV 100 MVAr Shunt Reactor at Moorabool	13.3	11.1	14.9	211.6	73.2	78.6
1B (preferred option)	1 x 220 kV 100 MVAr Shunt Reactor at Keilor 2 x 220 kV 100 MVAr Shunt Reactor at Moorabool	**20.8**	**16.5**	**9.8**	**276.2**	**75.7**	**92.8**
1C	1 x 220 kV 100 MVAr Shunt Reactor at Keilor 3 x 220 kV 100 MVAr Shunt Reactor at Moorabool	28.3	21.9	4.3	282.2	71.0	90.5
1D	1 x 220 kV 100 MVAr Shunt Reactor at Keilor 4 x 220 kV 100 MVAr Shunt Reactor at Moorabool	35.8	27.4	-1.1	276.8	65.6	85.1
2	1 x 220 kV 100 MVAr Shunt Reactor at Keilor 2 x 220 kV 100 MVAr Shunt Reactor at Moorabool 1 x 330 kV +200/-100 MVAr Synchronous Condenser at South Morang	90.7	67.1	-35.8	279.5	34.2	60.5

Figure 12 shows the weighted gross market benefits for each augmentation option, highlighting that all market benefits for Options 1.0 to 1D, and most of the market benefits for Option 2, arise from a reduction in market costs associated with the market interventions that would otherwise be required to maintain system security.

Figure 12 Weighted gross market benefits for each augmentation option



Market intervention outcomes – weighted outcomes

Figure 13 shows the projected annual hours of market intervention under each credible option, and Figure 14 shows the number of start-ups required each year, for the 'do nothing' base case and for each credible option. The number of start-ups represents the number of times a generator was brought online to provide reactive support or to fulfil system strength requirements, and the annual hours of market intervention represent the total running hours of generators brought online to provide reactive support or to fulfil system strength requirements (as described in Section 5.3.2).

Figure 13 Annual hours of intervention

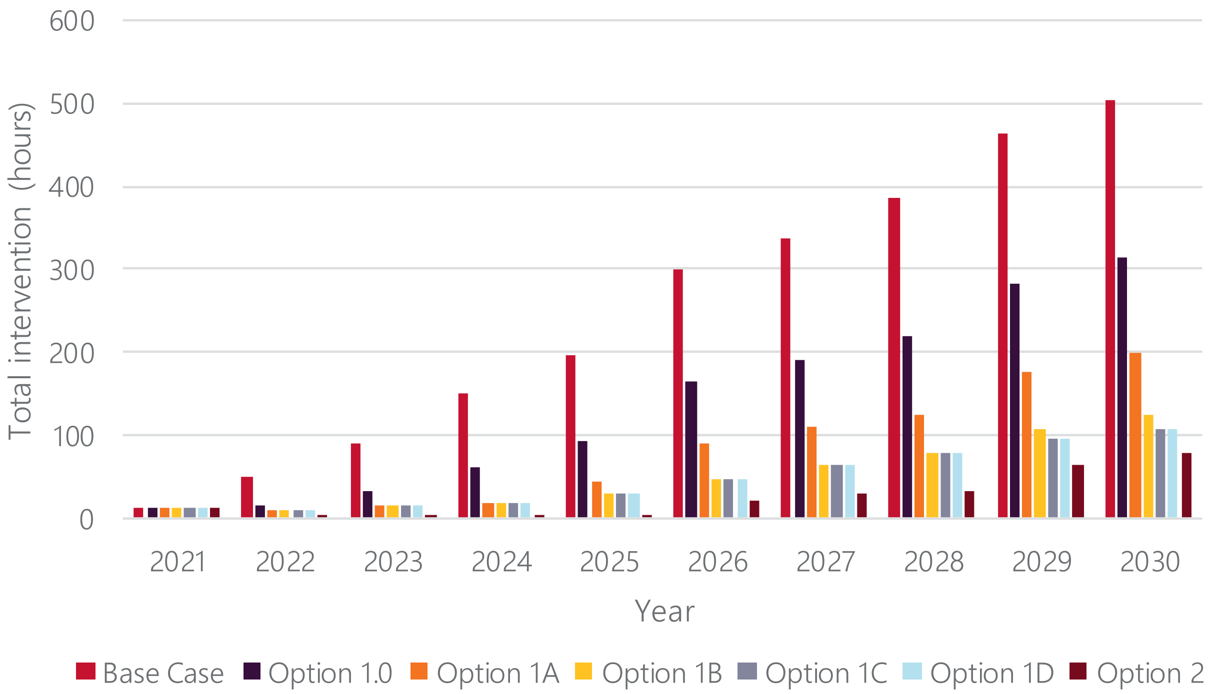
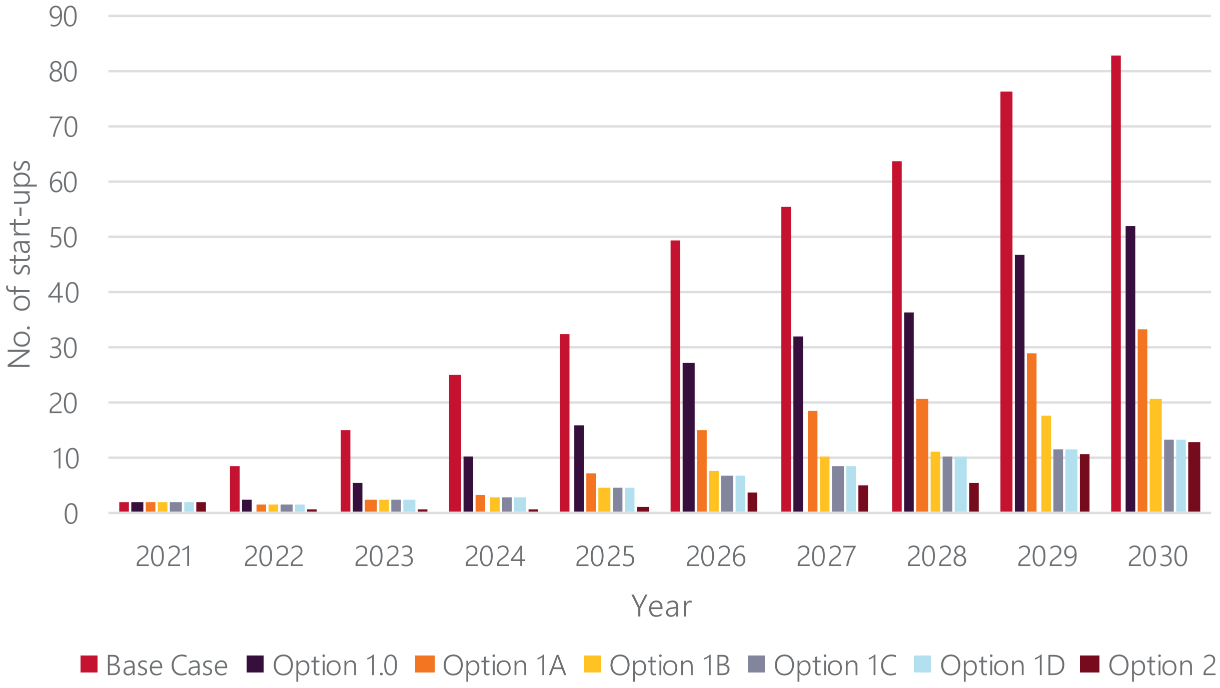


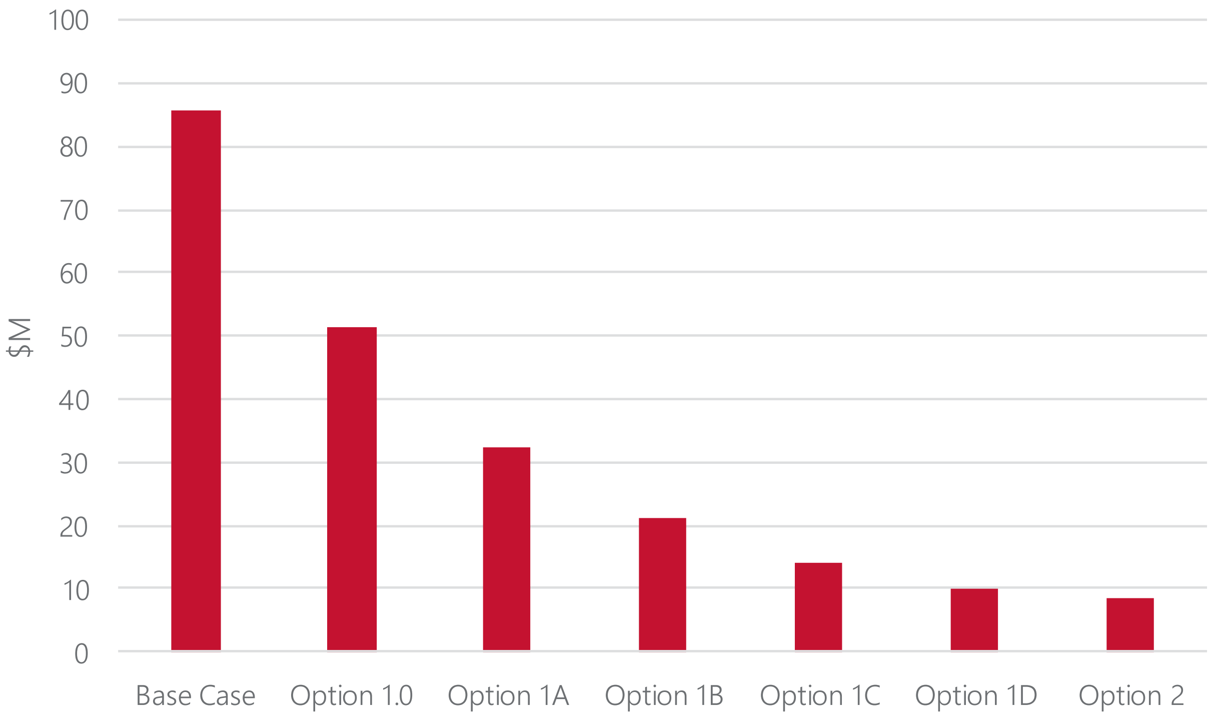
Figure 14 Annual number of start-ups



Credible options 1.0 to 1D deliver increasing levels of reactive support (from 100 MVAr to 500 MVAr). As the reactive support increases, the extent of market intervention required to remove reactive shortfalls decreases. Option 2 also reduces the need for market intervention to maintain system strength, and this option has the greatest decrease in market intervention incidents.

Figure 15 shows the total cost of market intervention between 2021 and 2030 for the 'do nothing' base case and for each credible option.

Figure 15 Cost of market intervention from 2021 to 2030 ($M)



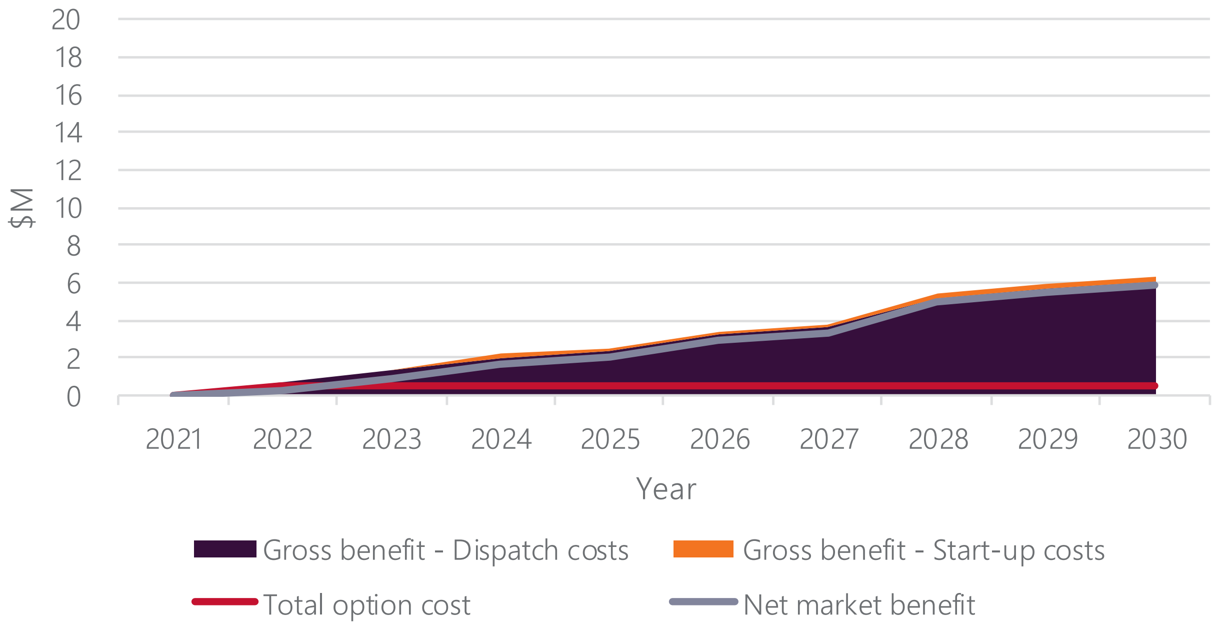
Option 1.0,1A,1B,1C, and 1D – weighted outcomes

Options 1.0-1D have a combination of 100 MVAr additional reactors installed in the network between Keilor and Moorabool terminal stations. For these options, all quantified market benefits arise from the reduction of market intervention for reactive shortfalls.

Figures 16 to 20 below show the annual gross benefits and the annual investment cost for each of Options 1.0 to 1D. The net market benefit is positive from the first year of investment (2022) for all options, and increases steadily from 2023 onwards as minimum demand continues to decline.

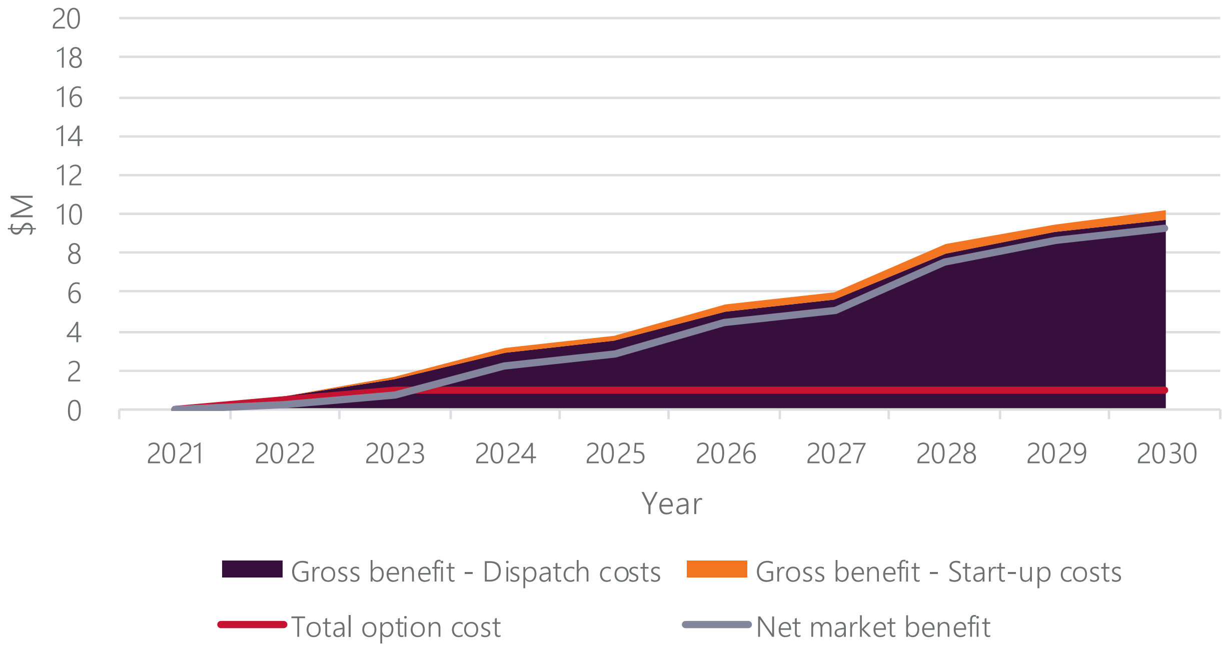
Option 1.0, with 100 MVAr of new reactors, has the lowest investment cost but also the lowest gross benefits and lowest net market benefits out of the Option 1 variants across all scenarios. This shows that at 100 MVAr, the benefits of additional reactive support would outweigh the increase in investment cost.

Figure 16 Option 1.0 gross benefits and investment costs



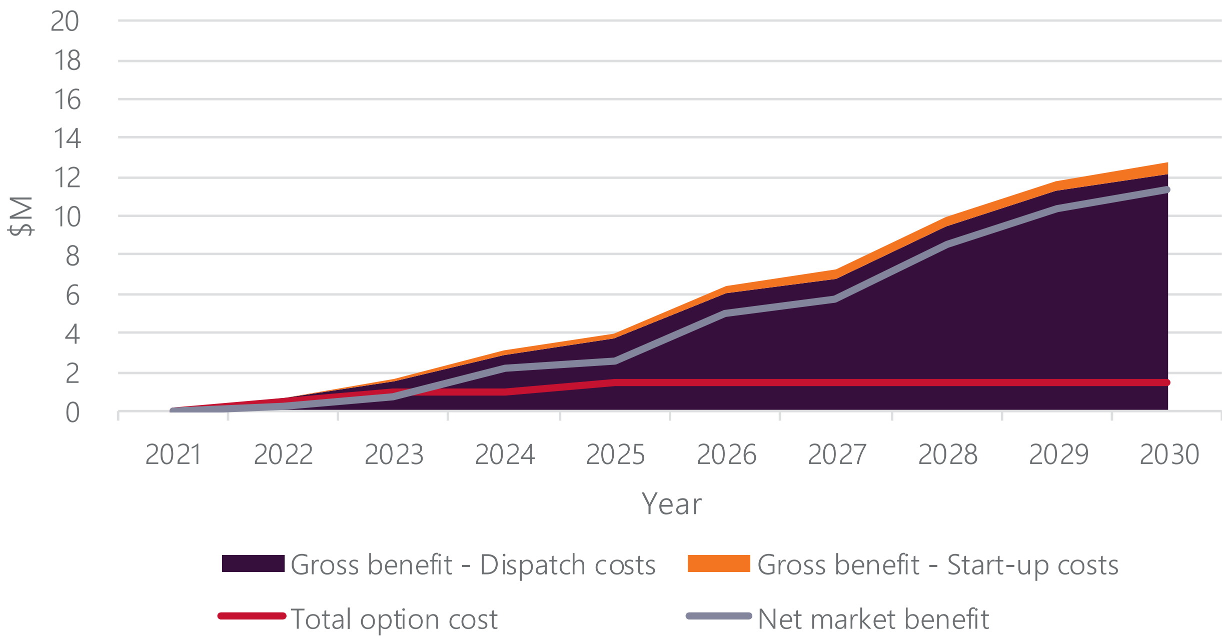
Option 1A, with 200 MVAr of reactive support, has higher investment costs but also delivers higher net market benefits than Option 1.0.

Figure 17 Option 1A gross benefits and investment costs



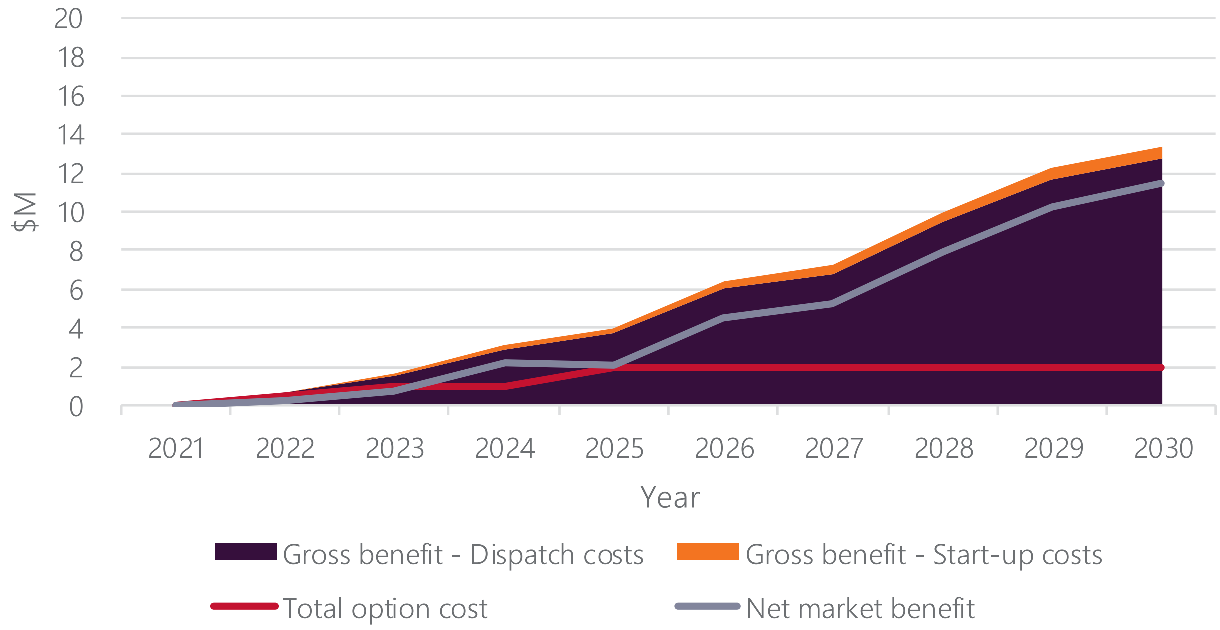
Option 1B, with 300 MVAr of reactive support, has higher investment costs than Option 1.0 and 1A but also higher net market benefits. This option has the highest net market benefits out of the Option 1 variants, showing that after 300 MVAr the incremental value of additional reactive support does not outweigh the additional investment cost in the base scenario.

Figure 18 Option 1B gross benefits and investment costs



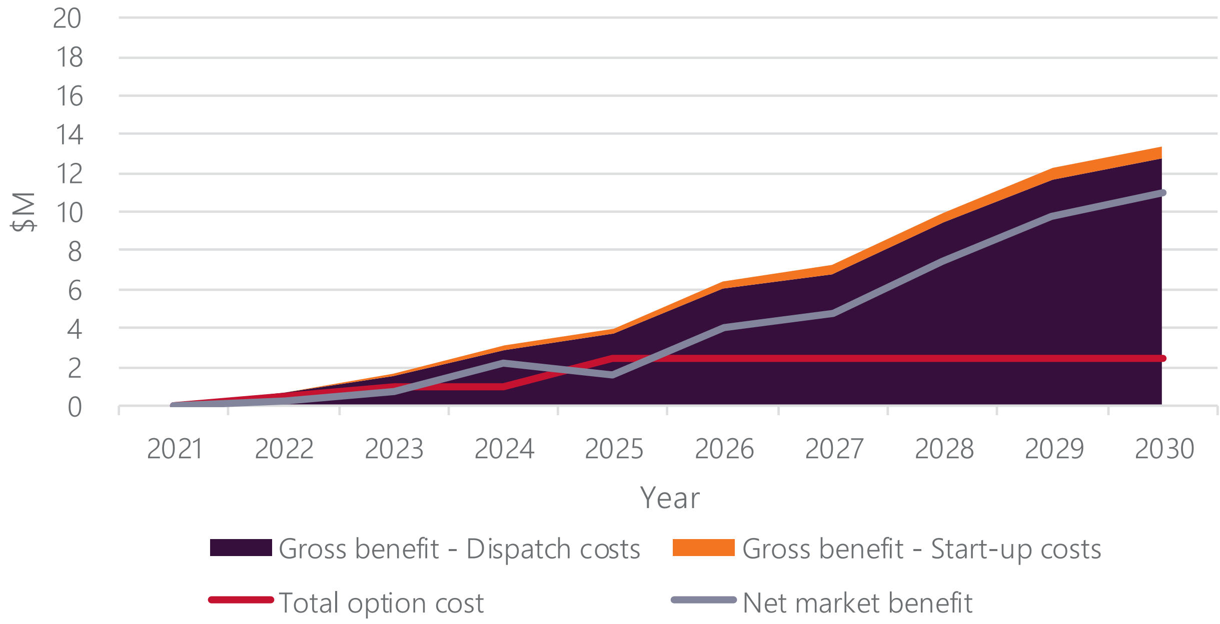
Option 1C, with 400 MVAr of reactive support, has higher investment costs than Option 1B, and higher gross market benefits. The net market benefit of Option 1C is slightly less than Option 1C because its higher investment cost was only partially offset by additional market benefits under this option.

Figure 19 Option 1C gross benefits and investment costs



Option 1D, with 500 MVAr of reactive support, has higher investment costs than Option 1C but very similar gross market benefits, showing that an additional 100 MVAr of reactive support has little additional value under the weighted scenarios.

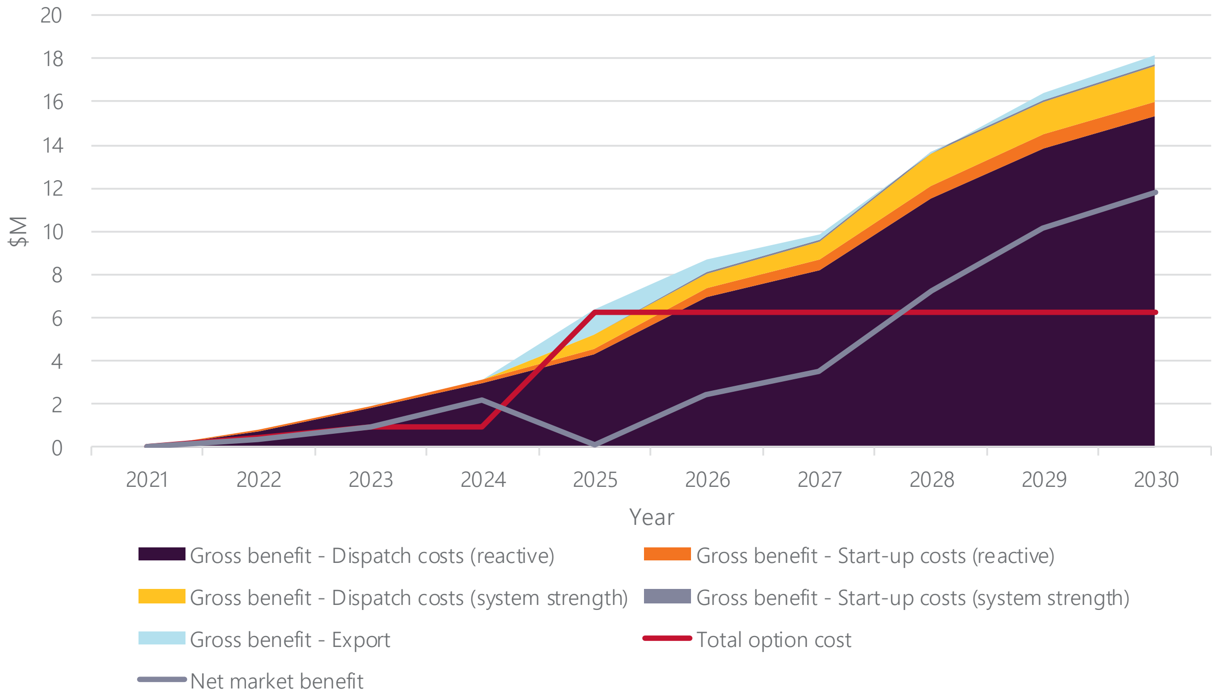
Figure 20 Option 1D gross benefits and investment costs



Option 2 – weighted outcomes

Option 2 has a total of 400 MVAr of reactive support – 300 MVAr of reactors and one +200/-100 MVAr synchronous condenser. Figure 21 shows the annual gross benefits and investment cost for this option.

Figure 21 Option 2 gross benefits and investment costs



The Option 2 gross market benefits include the additional benefits from increasing the Victoria to New South Wales export limit. These benefits commence from 2025 with the installation of the synchronous condenser, and are relatively minor because the proposed investment in the transmission network under the VNI RIT-T PADR increases the export limit in the 'do nothing' base case.

Option 2 also captures additional benefits from reducing the need for market intervention to maintain system strength. These benefits are projected to commence from 2025 and continue to increase as minimum demand decreases.

Option 2 has the highest cost, and highest gross market benefits, but lower net benefits than Option 1B.

6.3.3 Sensitivity studies

Sensitivity analysis was carried out to test the robustness of the analysis resulting in the preferred option and to determine if any factors will change the order of the credible options assessed.

Discount rates and costs

Sensitivities on discount rate and costs were undertaken on both the base weighted and the central scenarios.

- Change in cost – costs were changed by ±30%.
- Change in discount rate – sensitivity testing has been conducted on the base discount rate, with a lower bound discount rate of 3.2% and an upper bound discount rate of 8.6%.

Table 15 compares the weighted net market benefits delivered by each credible option. Option 1B is the preferred option across all sensitivities under the base weighted scenario.

Table 15 Sensitivity studies – weighted net market benefits NPV ($M)

Option	Base	High discount rate	Low discount rate	High cost	Low cost
1.0	51.2	33.6	81.2	49.6	52.9
1A	78.6	50.7	126.5	75.3	82.0
1B	**92.8**	**58.8**	**151.9**	**87.9**	**97.8**
1C	90.5	56.1	150.6	83.9	97.1
1D	85.1	51.4	144.3	76.9	93.3
2	60.5	27.5	121.6	40.4	80.6

Table 16 compares the net market benefits delivered by each credible option under the Central scenario. In this scenario, the option with the highest net market benefits changes between Option 1.0 and Option 1A across sensitivities. Option 1B remains positive across all sensitivities, whereas Option 1C, 1D, and 2 have negative net benefits in some sensitivities.

Table 16 Sensitivity studies – Central scenario net market benefits NPV ($M)

Option	Central scenario	High discount rate	Low discount rate	High cost	Low cost
1.0	14.1	8.3	24.1	12.4	15.7
1A	14.9	7.5	27.8	11.5	18.2
1B	9.8	3.1	21.9	4.8	14.7
1C	4.3	-1.6	15.6	-2.2	10.9
1D	-1.1	-6.2	9.3	-9.3	7.1
2	-35.8	-36.8	-29.7	-55.9	-15.7

Scenario analysis

The preferred option is most sensitive to the minimum demand forecasts in the reasonable scenarios considered. The Central scenario has the highest minimum demand forecast across all five of the 2019 Forecasting and Planning scenarios, hence the net market benefits are lowest under this scenario. The option with the highest net market benefits also changes under each scenario, as shown in Table 17.

Table 17 Option with highest net market benefits in each of the five 2019 Forecasting and Planning scenarios

Scenario	Option with highest net market benefits	Net market benefits ($M)
Central	Option 1A	14.9
Step Change	Option 1C	282.2
Slow Change	Option 1B	75.7
Fast Change	Option 1C	171.1
High DER	Option 1C	227.8

This makes the preferred option sensitive to the scenario weightings, and the weighted net market benefits under the following weighting sensitivities are shown in Table 18:

- Base weighting – 50% Central, 25% Step Change, and 25% Slow Change.
- Equal weighting – 33% Central, 33% Step Change, and 33% Slow Change.
- Equal ISP 5 scenarios – Central, Step Change, Slow Change, Fast Change, and High DER at 20%.
- Excluding Step Change scenario, 50% Central, 25% Fast change, and 25% Slow change (equivalent to the base weighting applied in the PADR).

Option 1B is the option with the highest net market benefits under the base weighting, equal weighting, and when replacing the Step Change with the Fast Change scenario. Option 1C, with an additional 100 MVAr of reactive support, has the highest net market benefits when including the additional ISP scenarios (Fast Change and High DER).

Table 18 Scenario weighting sensitivities – weighted net market benefits ($M)

Option	Base weighted	Equal weighted	Equal ISP five scenarios	Excluding Step Change
1.0	51.2	63.0	75.9	42.2
1A	78.6	98.9	121.4	60.5
1B	**92.8**	**119.3**	**148.3**	**65.8**
1C	90.5	118.0	151.3	62.7
1D	85.1	112.6	145.9	57.3
2	60.5	91.7	117.9	21.5

Regret analysis

To further test the robustness of Option 1B, a least worst regret analysis was undertaken. The least worst regret approach is used to identify which option produces the least regret, or risk, across all of the scenarios analysed. Regret is defined as the difference in benefits between the decision made and the optimal decision given the realisation of a scenario.

To do this analysis, AEMO calculated the net market benefits for each of the reasonable scenarios and the level of regret, or risk, relative to the option with the highest benefits in the scenario. The option with the lowest level of regret is then the preferred option.

The regret for each option under each scenario, as well as the highest regret when considering the three ESOO scenarios and two additional ISP scenarios, is shown in Table 19.The option with the lowest regret is Option 1B when considering the three base ESOO scenarios. Option 1C has less regret when considering all five scenarios, because Option 1B has a higher regret in the High DER scenario. The regret under the options with less reactive support (Option 1.0 and 1A) is significantly higher than in Option 1B because the market costs of intervention increase rapidly in the scenarios with lower minimum demand forecasts.

Table 19 Least worst regrets analysis – regret ($M)

Option	Central	Step Change	Slow Change	Fast Change	High DER	Worst regret – three ESOO scenarios	Worst regret – all five scenarios
1.0	0.8	159.7	21.3	84.6	125.5	159.7	159.7
1A	-	70.6	2.5	32.1	59.4	70.6	70.6
1B	**5.1**	**6.0**	**-**	**3.2**	**15.9**	**6.0**	**15.9**
1C	10.5	-	4.7	-	-	10.5	10.5
1D	15.9	5.4	10.1	5.4	5.2	15.9	15.9
2	50.7	2.7	41.5	47.5	39.7	50.7	50.7

6.3.4 Preferred option

Table 20 compares the weighted net market benefits (NPV) across all credible options considered across the base weighted scenario. This shows that all credible options provide positive net market benefits, with Option 1B providing the highest net market benefits at $92.8 million in the base weighting scenario.

Table 20 Weighted net market benefits NPV ($M)

Option	1.0	1A	1B (preferred option)	1C	1D	2
NPV ($M)	51.2	78.6	92.8	90.5	85.1	60.5

Although Option 1B does not have the highest net benefits under all scenarios and sensitivities, it has positive net benefits under all scenarios and sensitivities assessed. Option 1B also has higher net benefits across most scenarios and sensitivities, and less regrets, than the options with less reactive support (Option 1.0 and 1A).

Option C, with 100 MVAr additional reactive support compared to Option 1B, has higher net benefits when varying the scenario weighting, and also has lower regrets when using a least worst regrets approach across all five scenarios. However, this option has negative net benefits under some sensitivities.

The staging of the preferred option, discussed below, enables AEMO to revert to Option 1A, or even Option 1.0, if minimum demand outcomes are closer to, or higher than, those forecast in the Central scenario, rather than in the other four scenarios assessed. AEMO will continue to monitor prevailing market conditions and demand forecasts during the procurement and delivery phase of the RIT-T.

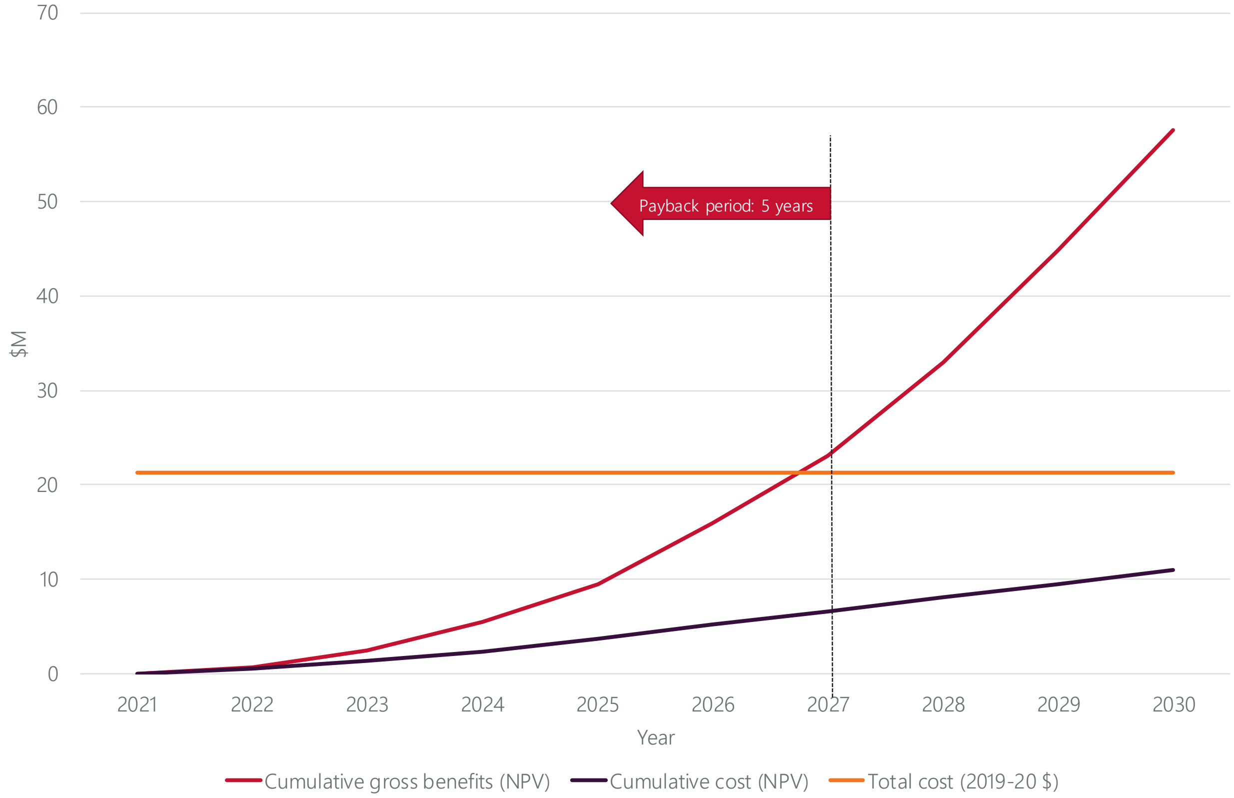
6.3.5 Timing of preferred option

The proposed timing of the preferred network option is staged between 2022 and 2025 as follows:

- 100 MVAr of reactive support in 2022.
- 100 MVAr of reactive support in 2023.
- 100 MVAr of reactive support in 2025.

Figure 22 shows the cumulative gross market benefits and the cumulative cost for Option 1B for the base weighted scenario. The total option cost (capital and O&M cost) in 2019-20 dollars is also shown. The gross market benefits (red) exceed the annualised option cost (blue) in each year following the investment start date in 2022. Additionally, the gross market benefits (red) exceed the total option cost (orange) from 2027, meaning the payback period for Option 1B is five years.

Figure 22 Option 1B gross benefits and investment cost



7. Conclusion

The preferred option is to install 300 MVAr of static reactive plant at 220 kV across Keilor and Moorabool terminal stations.

7.1 Preferred option

The NER requires 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.

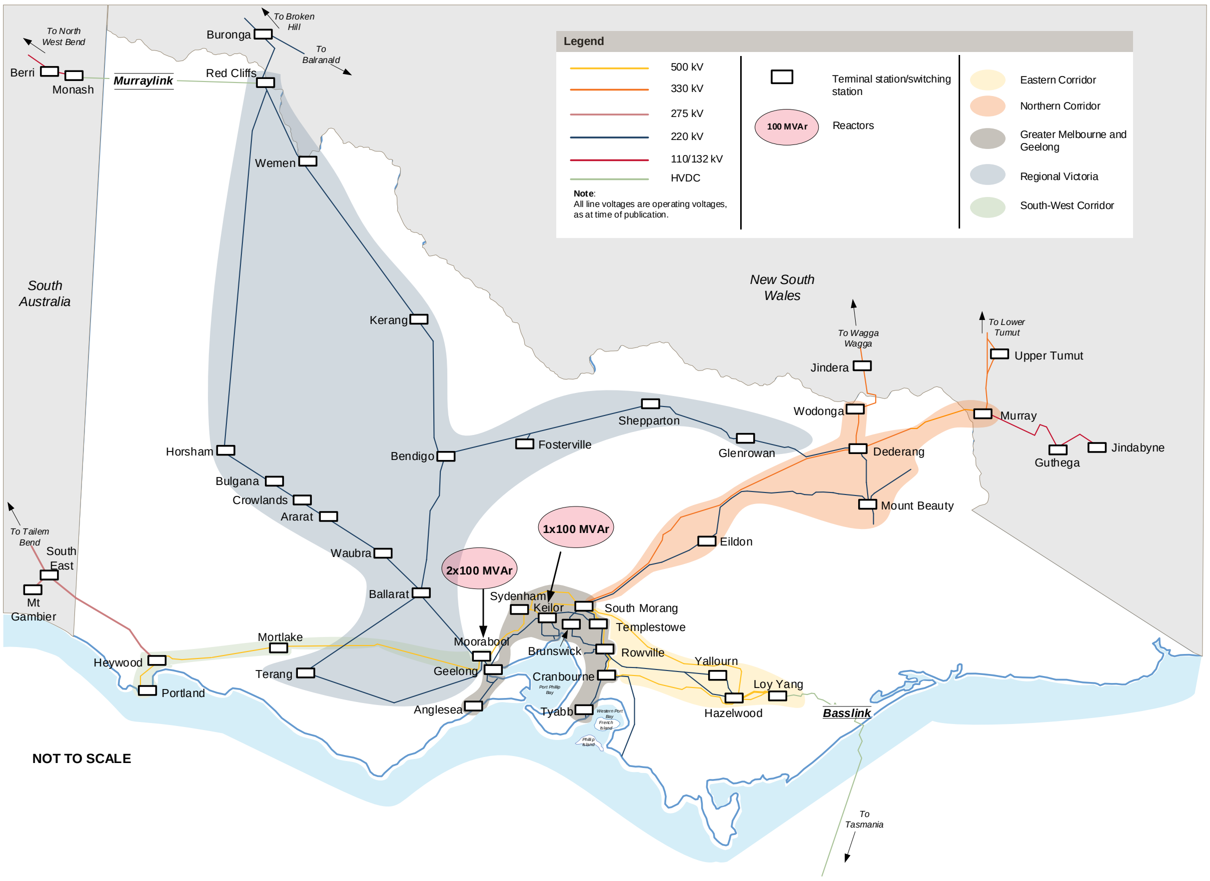
The preferred option (discussed in Chapter 6) is the installation of reactive power devices that is capable of absorbing 300 MVAr of reactive power in the south-west transmission corridor around Geelong, Keilor, and Moorabool.

The preferred network option identified in this PACR (and shown in Figure 23) is to install:

- One 220 kV 100 MVAr shunt reactor at Keilor Terminal Station in 2022.
- One 220 kV 100 MVAr shunt reactor at Moorabool Terminal Station in 2023.
- One 220 kV 100 MVAr shunt reactor at Moorabool Terminal Station in 2025.

The preferred option has a cost of approximately $16.5 million (in present value terms), and yields the highest net market benefits when weighted across all reasonable scenarios considered.

Figure 23 Preferred option of three 100 MVAr reactors



The PACR analysis identifies that investing in this option will deliver a weighted net present economic benefit of approximately $92.8 million, by reducing market costs associated with dispatching generators that are normally offline during light load periods to maintain voltages within operational and design limits.

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

7.2 Procurement of transmission network augmentation

AEMO will undertake the process set out in the National Electricity Law and the NER to procure the required reactive power services under this RIT-T, and AEMO will keep stakeholders informed through project updates during the procurement and implementation activities.

Staging of the preferred option (discussed in Section 6.3.5), enables AEMO to revert to Option 1A, or Option 1.0, if supply or demand assumptions deviate significantly from those considered in the RIT-T scenarios. AEMO will continue to monitor prevailing market conditions and demand forecasts following conclusion of the RIT-T; adjusting course where appropriate.

A1. Compliance with NER

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

Table 21 Information provided in this PACR, as required by NER 5.16.4

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, 3.2, 3.3
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).	3.4, 6.3.2
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 proposed preferred option, with: • Details of the technical characteristics; • The estimated construction timetable and commissioning date; • If the proposed preferred option is likely to have a material inter-network impact and if the TNSP 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