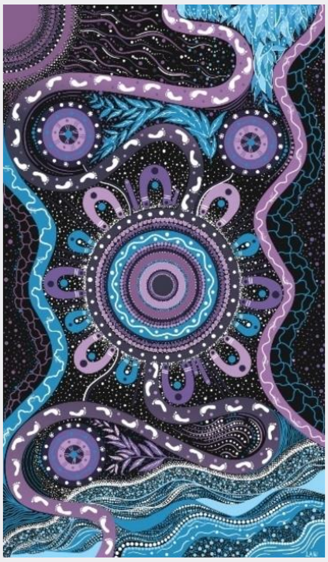
Victorian Planning

Victorian System Strength Requirement

17 April 2025

Regulatory Investment Test for Transmission

Project Assessment Draft Report



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO has prepared this Project Assessment Draft Report in accordance with clause 5.16 of the National Electricity Rules to, among other things, provide information about certain network limitations and potential options to address these limitations.

Disclaimer

This document or the information in it may be subsequently updated or amended.

This document contains data provided by or collected from third parties, and conclusions, opinions, assumptions or forecasts that are based on that data. AEMO has made every reasonable effort to ensure the quality of the information in this document but cannot guarantee that the information, forecasts and assumptions in it are accurate, complete or appropriate for your circumstances.

This document does not include all of the information that an investor, participant or potential participant in the national electricity market might require and does not amount to a recommendation of any investment. Anyone proposing to use the information in this document should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts. This document does not constitute legal or business advice and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Copyright

© 2025 Australian Energy Market Operator Limited. The material in this publication may be used in accordance with the copyright permissions on AEMO's website.

Executive summary

The power system is undergoing a transformational change, with an unprecedented increase in renewable generation, changes in consumption patterns, and the withdrawal of several existing large conventional generation sources. New sources of system strength will be required to maintain power system security.

As the System Strength Service Provider (SSSP) for Victoria, AEMO Victorian Planning (AVP) is responsible for procuring services to meet the system strength requirements to ensure system security in the future.

AVP will commence[1] tendering for service contracts for three new plant able to operate as synchronous condensers,[2] 900 megawatts (MW) of grid-forming (GFM) battery energy storage systems (BESS) in the Moorabool area, and 350 MW of grid-following (GFL) BESS (upgraded to be GFM) in the Hazelwood area – irrespective of their megawatt hour (MWh) capacity – in addition to contracting with existing generation and upgrading some existing units to be capable of operating in synchronous condenser mode. These components are common across all option portfolios, and tendering needs to commence now to enable AVP to meet its system strength requirements from 2 December 2025 to 2029.

Beyond this point, AVP intends to pursue the longer-term specific solutions under option portfolio 3, which is the proposed preferred option recommended in this Project Assessment Draft Report (PADR) since it has the greatest estimated net market benefit and imposes the least cost on customers. However, to do so, two key conditions need to be met in relation to BESS solutions.

If both conditions are met before AVP would otherwise need to commit to procuring system strength services from additional plant able to operate as synchronous condensers, option portfolio 3 will remain the preferred option. However, if either or both are not met, this would be a 'material change in circumstances' (MCC) and AVP would notify the Australian Energy Regulator (AER) of the change and its proposed alternative path to pursue either option portfolio 2 or option portfolio 1. The AER has 40 days from receipt of an MCC notification to make and publish a determination approving or rejecting the alternative actions proposed by AVP.

While AVP may ultimately be required to pivot to either option portfolio 2 or option portfolio 1 (if the procurement of sufficient grid-forming BESS service agreements is not possible ahead of the cut-off points), it is noted that, compared to option portfolio 1, four synchronous condensers can be avoided if option portfolio 3 continues to be the preferred option, or three synchronous condensers can be avoided if AVP pivots to option portfolio 2. This translates to a significant cost saving to end consumers between 2029 and 2036. For example, if option portfolio 3 remains preferred, consumers avoid paying the costs associated with approximately $770 million in capital (equivalent to around $460 million in present value terms)[3].

---

1 While AVP intends to start the procurement process for these components in parallel to preparing the Project Assessment Conclusions Report (PACR), AVP does not expect to finalise contracts before the PACR, and its associated dispute period, are complete. Commencing the procurement process (which is expected to be limited to negotiating contract terms) alongside the preparation of the PACR is considered prudent and will allow AVP to secure system strength services in as timely a manner as possible.

2 While AVP refers to these components as 'new plant able to operate as synchronous condensers', AVP has assumed for the purposes of this PADR that synchronous condensers are used, so use the 'new plant able to operate as synchronous condensers' and 'synchronous condensers' interchangeably in this document.

3 All dollars, including 'present values', in this PADR are in 2023-24 dollars (unless stated otherwise) and align with the *2024 Integrated System Plan* (ISP) and 2024 ISP Inputs, Assumptions and Scenarios Workbook. Please note that this present value does not take account of terminal values (because it refers to the cost to consumers), whereas other present values in this PADR do take account of terminal values (because they refer to costs/benefits over the assessment period), unless otherwise stated.

Overall, the proposed pathway set out in this PADR provides the greatest amount of time for low-cost BESS solutions to be developed, but also retains the flexibility to pivot to additional plant able to operate as synchronous condensers in the future, if required to ensure there is sufficient system strength.

System strength is the ability of the power system to maintain a stable voltage waveform at any given location in the power system, both during steady state operation and following a disturbance. System strength has traditionally been provided by synchronous generation such as coal, gas-fired and hydro-electric power generation that is electromagnetically coupled to the power system. Inverter-based resources (IBR) – which include wind, large scale solar, and batteries – do not inherently provide system strength, and most existing IBR which use GFL technology require adequate system strength for the inverters to work reliably.

The transition from a power system with predominantly synchronous generation to a power system with high levels of IBR has introduced a need to replace the system strength provided by synchronous generators to ensure system security can be maintained and allow protection systems and IBR to work reliably.

AVP has prepared this PADR in accordance with the requirements of clause 5.16 of the National Electricity Rules (NER), for a Regulatory Investment Test for Transmission (RIT-T). It represents the second step in the formal RIT-T process and follows the Project Specification Consultation Report (PSCR) published in July 2023, and the accompanying request for information (RFI) for proponents of non-network solutions.

The 'identified need' is to maintain power system security by meeting the system strength requirements as IBR replace synchronous generation

In October 2021, the Australian Energy Market Commission (AEMC) made its final rule determination on Efficient Management of System Strength on the Power System, which introduced new obligations for SSSPs.

Under NER S5.1.14(b), AVP as the SSSP for Victoria is required to use reasonable endeavours to plan system strength services to:

- maintain the **minimum three-phase fault level** specified by AEMO at each system strength node in Victoria (that is, meet the minimum level of system strength), and
- achieve stable voltage waveforms for the forecast future IBR connections projected by AEMO in steady state conditions and following credible contingencies or protected events (that is, meet the **efficient level** of system strength).

The identified need for this RIT-T is to procure sufficient system strength services to ensure the system strength standard as per NER S5.1.14 is met for both forecast minimum and efficient levels at each of the Victorian system strength nodes from 2 December 2025 onwards.

While the overall characterisation of the identified need for this RIT-T has not changed since the PSCR, the detail regarding the amount of system strength required (both the minimum and efficient levels) at different locations, and the supporting assumptions, have been updated to align with the AEMO 2024 *System Strength Report* released in December 2024.

Developments in the National Electricity Market (NEM) since the PSCR have increased the efficient level of system strength AEMO now projects to be needed in Victoria, while the minimum three phase fault level requirement has remained the same other than treatment of post-contingency requirements.

AVP is undertaking this RIT-T as a 'reliability corrective action', as the considered options are to enable AVP to meet its regulatory obligations under NER S5.1.14.

The assessment has benefited from stakeholder consultation

The PSCR was published with an accompanying RFI that provided additional detail on the technical requirements that non-network solutions would need to meet to provide system strength services, and to seek submissions from potential proponents of these options. On 9 August 2023, AVP held a webinar attended by more than 50 participants to inform stakeholders of the key elements of the PSCR and RFI.

The RFI process resulted in non-network solution submissions from 16 parties, covering 36 individual potential technology solutions and 101 specific solutions.

Figure 1 Summary of solutions proposed in response to the RFI

65	Offers from existing generator owners in Victoria proposing existing synchronous generating units	19	Grid-forming BESS proposals
9	Synchronous condenser submissions from five separate proponents	14	Separate proponents for grid-forming BESS proposals
1	Compressed air storage system	1	'Magnetically controlled shunt reactor' solution
1	Pumped hydro energy storage system	1	Combined synchronous condenser and STATCOM solution

In late August and early September 2024, AVP sent RFI submitters an online survey seeking updated information to understand if proposals remained valid and/or if there were material changes, given the time that had passed since RFI responses were received. The survey resulted in one proposal being withdrawn (one of the GFM BESS), and seven proposals updating their in-service dates (all seven represented delays relative to what was initially proposed).

In addition to the RFI responses, AVP received two non-confidential submissions to the PSCR (from AusNet Services and EnergyAustralia), as well as an additional confidential submission. The queries raised in these submissions have been considered in preparing this PADR.

The analysis presented in this PADR has been strongly informed by the solutions proposed in response to the PSCR RFI (and subsequent survey), as well as the general submissions on the PSCR, which have helped ensure the robustness of the analysis overall. AVP thanks all parties for their valuable input to the consultation process.

Four credible option portfolios have been developed and assessed

AVP has applied a portfolio approach to forming credible options for this RIT-T. This represents a practical way of assessing and grouping the large number of individual solutions proposed in response to the RFI, plus additional network solutions. It also recognises that no one solution can address the requirements in isolation.

The four different option portfolios can be summarised as shown in **Table 1**.

Table 1 Summary of the four credible option portfolios

	Overview	Focus	Capital costs (present value)[A]
Option portfolio 1	10 synchronous condensers[B] (nine new and one existing) + Existing generation[C], including conversion of some units to be capable of operating in synchronous condenser mode, and committed/anticipated GFM BESS, including one that upgrades from GFL to GFM[D]	Includes existing generation, as well as committed/anticipated GFM BESS (for the efficient level) and nine new synchronous condensers (for the minimum and efficient levels)	$1,134.5m for nine new synchronous condensers $1.5m for upgrading a 'committed' GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)
Option portfolio 2	Seven synchronous condensers (six new and one existing) + The same other technology types as option portfolio 1 plus upgrading additional committed/anticipated GFL BESS to be GFM, and an additional (small) GFM BESS	Developed to determine, through comparison with option portfolio 1, whether upgrading additional GFL BESS to be GFM is considered optimal compared to investing in synchronous condensers	$779.1m for six new synchronous condensers $7.8m for upgrading committed/anticipated GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)
Option portfolio 3	Six synchronous condensers (five new and one existing) + The same technology types as option portfolio 2 plus a generic 400 MW GFM BESS from the IBR forecasts	Investigating the cost savings that could be achieved where future modelled GFM BESS become committed/anticipated under the RIT-T	$673.1m for five new synchronous condensers $7.8m for upgrading committed/anticipated GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)
Option portfolio 4	The same as option portfolio 3 – including the same number of new synchronous condensers in total – but with accelerated procurement of two synchronous condensers	This option has been developed to investigate whether expediting synchronous condensers is expected to be net beneficial	$698.4m for five new synchronous condensers $7.8m for upgrading committed/anticipated GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)

A. While the costs listed here reflect the present value of the *total* capital cost for each key option portfolio component, the analysis in the PADR uses a terminal value to ensure that the costs of long-lived assets are included on a like-for-like basis with the market benefits (that is, that both the costs and benefits are included over the same assessment period) – this is outlined in Section 7.4. Section 5 of the PADR also presents the total costs shown in this table in undiscounted terms.
B. As outlined in Section 6.1.2, all new plant able to operate as synchronous condensers have been assumed to be, and costed in the RIT-T assessment as, synchronous condensers for this PADR.
C. While each of the options assumes the use of 'existing generation', AVP considers that this includes any additional generation that connects ahead of AVP needing to commit to its procurement following this RIT-T.
D. The BESS that upgrades from GFL to GFM in option portfolio 1 is considered 'committed' under the RIT-T and has submitted a proposal in response to the RFI. While the other BESS assumed to upgrade from GFL to GFM in option portfolios 2-4 are also considered 'committed' (or 'anticipated') under the RIT-T, they have not submitted a proposal at this stage and are for proposals that are further into the future.

The different option portfolios have been created by considering the annualised costs and expected benefits, as well as the expected timing of when solutions are available, across an 11-year assessment period.

All option portfolios have been costed in accordance with the RIT-T framework and include the costs incurred in constructing or providing the option, the operating and maintenance costs, and the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the credible option (where applicable). The procurement process related to this RIT-T aims to identify the specific lowest cost solutions and the ultimate cost to consumers will be determined from these costs.

Option portfolio 3 is the top-ranked option

Option portfolio 3 is found to generate substantial estimated net benefits over the assessment period – in the order of at least[4] $3.85 billion of net market benefits in present value terms – and is the top-ranked option overall. It also involves the lowest cost to consumers of all four options assessed.

The analysis in this PADR also finds that:

- all options are found to deliver substantial net market benefits (driven both by significant avoided unserved energy and wholesale market benefits relative to the base case)
- accelerating new plant able to operate as synchronous condensers is not found to deliver net benefits (that is, option portfolio 4 is found to have lower estimated net benefits than option portfolio 3)
- upgrading significant additional committed/anticipated GFL BESS to be GFM (option portfolio 2) is found to be the effectively second-ranked[5] option and sits ahead of only using existing generation, committed/anticipated GFM BESS (including one that upgrades from grid-following to grid-forming) and new synchronous condensers (option portfolio 1), and
- option portfolio 3, being the proposed preferred option, is found to be robust to a range of sensitivity tests.

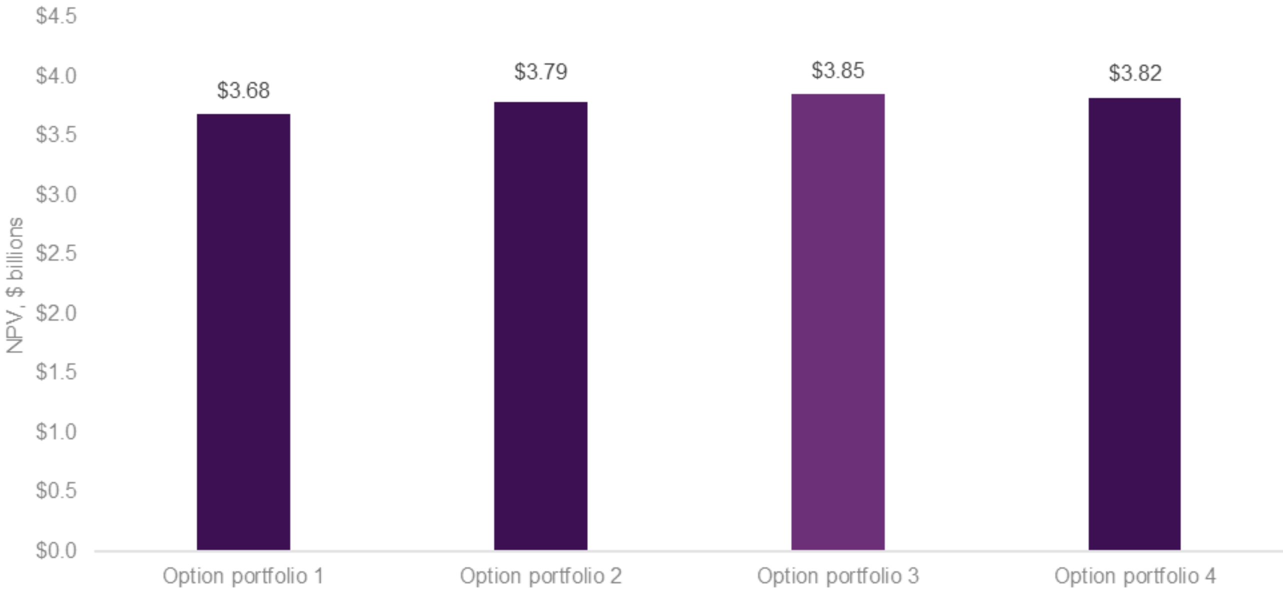
Figure 2 summarises the headline net present value (NPV) results for each of the option portfolios.

The specific components included in option portfolio 3, for meeting both the minimum and efficient system strength requirements, are summarised in Table 2.

[4] 'At least' is used here on account of the avoided unserved energy estimates only being based on the minimum level requirements (as outlined in Section 7.1.4). If the unserved energy was estimated to take account of the efficient level requirements as well, the expected net benefit of all option portfolios would be significantly greater.

[5] Throughout the PADR, option portfolio 2 is referred to as the 'effectively second-ranked' option, since option portfolio 4 (the technically second-ranked option) is just option portfolio 3 with two accelerated synchronous condensers, that is, as opposed to a distinct standalone option.

Figure 2 Headline net benefits under the *Step Change* scenario



Note: While this figure includes approximately $930 million, in present value terms, of avoided unserved energy for each option relative to the 'do nothing' base case, AVP has removed this common benefit to all options from the core analysis presented in the body of this PADR to allow for a more meaningful comparison of the true differences in costs and benefits across the options. This is explained in Section 9.1.

Table 2 Option portfolio 3 – Summary of components

Financial year	Minimum fault levels	Efficient level
2026	Existing generators, including conversion of some units to be capable of operating in synchronous condenser mode 1 x Existing synchronous condenser at the Red Cliffs system strength node (SSN)	Covered by minimum fault level requirements
2027		
2028		900 MW GFM BESS Moorabool SSN
2029	Same as 2028 + 2 x synchronous condensers Hazelwood SSN	Same as 2028 + 350 MW GFL to GFM BESS Hazelwood SSN
2030		
2031	Same as 2030 + 1 x synchronous condenser Hazelwood SSN	
2032		Same as 2031 + 500 MW GFL to GFM BESS Hazelwood SSN 350 MW GFL to GFM BESS Moorabool SSN 400 MW ISP forecast GFM BESS Hazelwood SSN
2033		Same as 2032 + 300 MW GFL to GFM BESS Moorabool SSN
2034	Same as 2033 + 1 x synchronous condenser Hazelwood SSN	
2035		Same as 2034 + 65 MW GFM BESS Red Cliffs SSN + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub
2036		

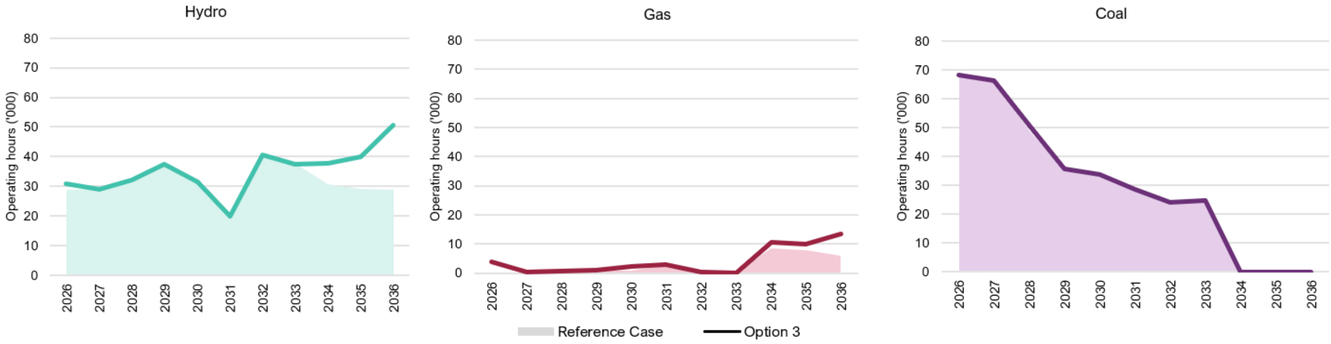
Notes:

- Option portfolio 3 (as well as all other option portfolios) also assumes two synchronous condensers at Buronga in each of 2026 and 2027 as part of Project EnergyConnect (PEC) Stage 1 and Stage 2, respectively. These four synchronous condensers have not been shown in the table above since, while the portfolio options rely on them as an interstate contribution, AVP is not proposing to contract them and they form part of the assumed interstate contribution (which has been factored into the options portfolio development process).
- 'Same as 2028' (and this language used with reference to other years in this table) refers to the same components as that year but, where the use of existing synchronous generation is included in this, it does not imply the same *operation* of these units between years.

Figure 3 below shows the redispatch of existing generators in the Victorian system under option portfolio 3. This demonstrates the possible level of additional synchronous generator dispatch, and therefore potential unit contracting over time, required to meet the system strength requirements with the other option portfolio 3 solutions in place.

Since option portfolio 3 includes some hydro generators being converted to be capable of operating in synchronous condenser mode, the portfolio option dispatch (solid line) of the hydro chart includes operating hours for these units in either hydro generator or synchronous condenser mode.

Figure 3 Victorian synchronous generator operating hours, option portfolio 3 relative to the reference case



Note: This figure shows the redispatch of existing generators in the Victorian system relative to the energy-only dispatch under the 'reference case' (outlined in Section 4.5).

The proposed pathway forward provides low-cost BESS solutions the best chance to develop and be contracted with to meet the requirements

AVP will commence tendering for service contracts:

- to meet the **minimum fault level requirements**:
  - existing generators,[6] including upgrading some to be capable of operating in synchronous condenser mode, from 2026, and
  - three new plant able to operate as synchronous condensers – one existing one in the Red Cliffs area from 2026 and two new ones in the Hazelwood area by 2029, and
- to meet the **efficient requirements:**
  - 900 MW of currently 'committed' grid-forming BESS in the Moorabool area, and
  - 350 MW of currently 'committed' GFL BESS (upgraded to be GFM) in the Hazelwood area.

These components are common across all option portfolios and tendering needs to start now to enable AVP to meet its system strength requirements from 2 December 2025 to 2029 (taking account of expected contracting and procurement lead times). AVP considers that there is no risk associated to committing to these elements now.

[6] While AVP refers here to the use of 'existing generators', AVP considers that this includes any additional generation that connects ahead of AVP needing to commit to its procurement following this RIT-T.

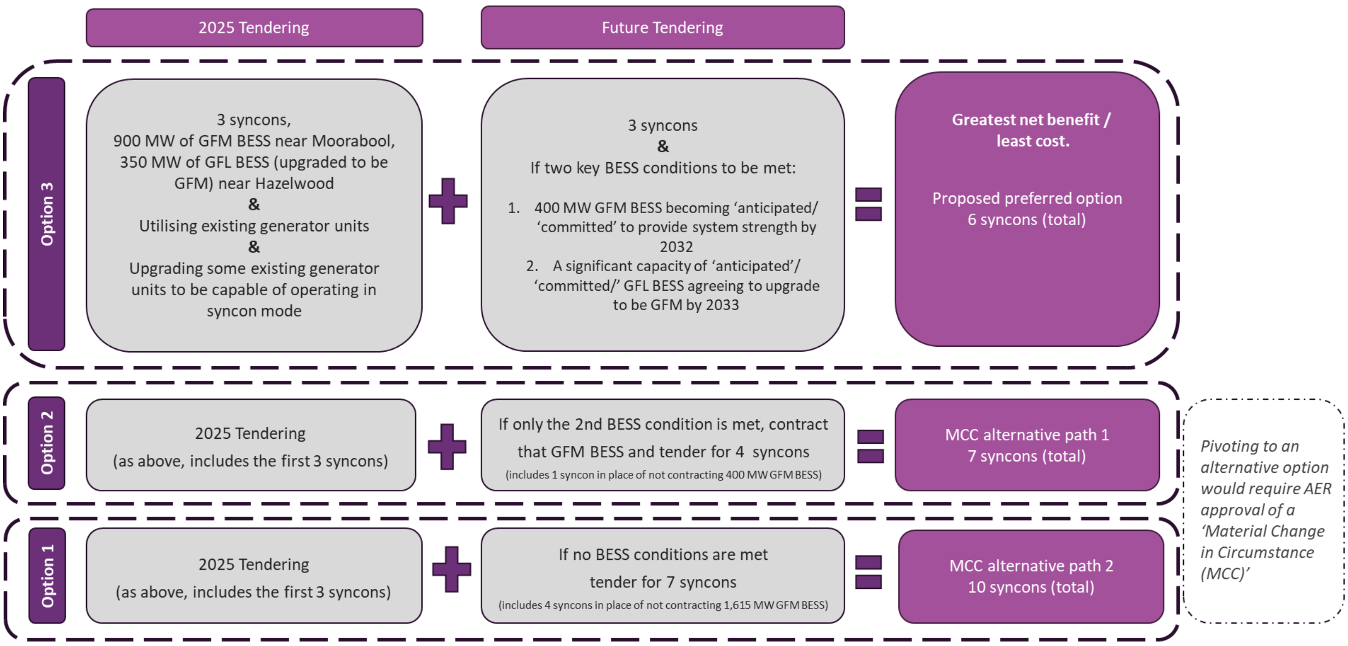
Beyond this point, AVP intends to pursue the longer-term specific solutions of option portfolio 3 – which is the proposed preferred option recommended in this PADR since it has the greatest estimated net market benefit and imposes the least cost on customers.

However, overall, it is of the utmost importance that there is sufficient system strength capacity available in the system. Failing to make this available could result in material outages for consumers. AVP therefore considers that there are natural 'cut-off points' for BESS being able to avoid future synchronous condenser investment (that is, when AVP would otherwise need to commit to procuring system strength services from additional plant able to operate as synchronous condensers to ensure sufficient system strength).

Should AVP be able to contract system strength services from third-party BESS proponents ahead of these cut-off points, AVP expects that additional synchronous condenser investment can be avoided and, instead, these BESS solutions procured. However, if this does not occur, AVP considers that additional plant able to operate as synchronous condensers will need to be committed to, in line with option portfolio 2 or 1 in this PADR, and this would be a 'material change in circumstances' (MCC). If an MCC eventuates, AVP will notify the AER of the change and its proposed alternative path. The AER has 40 days from receipt of an MCC notification to publish the notice and make and publish a determination approving or rejecting the alternative actions proposed by AVP.

The proposed pathway forward is summarised in Figure 4, including the alternative options if an MCC eventuates.

Figure 4 The proposed pathway forward



Syncon: synchronous condenser.

While AVP may ultimately be required to pivot to either option portfolio 2 or option portfolio 1 (if the procurement of sufficient GFM BESS service agreements is not possible ahead of the cut-off points), it is noted that, compared to option portfolio 1, four synchronous condensers can be avoided if option portfolio 3 continues to be the preferred option, or three synchronous condensers can be avoided if AVP pivots to option portfolio 2. This translates to a significant cost saving to end consumers between 2029 and 2036 – for example, if option portfolio 3 remains preferred, consumers avoid paying the costs associated with approximately $770 million in capital (equivalent to around $460 million in present value terms).

At this stage, AVP considers that the indicative cut-off points are three years before the services are expected to be needed. AVP intends to make clear as part of the PACR what it expects the cut-off points to be for each of the tranches of BESS expected to be needed, drawing on any updated information from potential service providers regarding the expected lead times for synchronous condensers.

Overall, the proposed pathway set out in this PADR:

- recognises that action needs to be taken now to meet the system strength requirements in the near term
- provides the greatest amount of time for low-cost BESS solutions to develop and be contracted with over the longer term, and
- retains the flexibility to pivot to additional plant able to operate as synchronous condensers in the future, if required.

This will result in the best outcome for electricity consumers. Setting out this pathway now is also likely to avoid AVP needing to undertake a second RIT-T in the near future, which would potentially jeopardise the ability to address system strength requirements in Victoria in a timely fashion. It also supports the development of non-network solutions in being able to provide system strength services.

Importantly, the PADR analysis assumes that existing synchronous generators are willing to sign contracts that reasonably reflect the costs of their proposed solution. If this appears to not be the case during the procurement process, AVP considers that this would likely represent an MCC, consistent with the AER's recent guidance on system strength RIT-Ts[7], and would result in additional synchronous condensers needing to be procured.

Submissions and next steps

All stakeholders are welcome to provide written submissions on the PADR, including comments on the analysis and ranking of the proposed preferred option portfolio. All forms of feedback will be carefully considered in the preparation of the Project Assessment Conclusions Report (PACR), and all written submissions will be published online, along with a summary of how feedback has been taken into account.

AVP is particularly interested to hear from proponents of currently committed/anticipated BESS (including those that plan to connect as GFL but could upgrade to GFM).

Submissions are due on or before 30 May 2025 and should be emailed to AVP_RIT-T@aemo.com.au.

AVP will provide an industry briefing for stakeholders on the matters set out in this PADR at 1.00 pm (AEST) on 12 May 2025[8].

The final step of the RIT-T process, the PACR, will include the matters outlined in this PADR and consideration of any submissions made in response to this PADR. At this stage, AVP is targeting publication of the PACR in August 2025.

[7] AER, *The Efficient Management of System Strength Framework*, AER Guidance Note, December 2024, p. 25.

[8] Information about this session, including how to register, will be available at https://aemo.com.au/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.

Contents

Tables

Figures

1 Introduction

The power system is undergoing a transformational change, with an unprecedented increase in renewable generation, changes in consumption patterns, and the withdrawal of several existing large conventional generation sources across the NEM, including Victoria.

As the NEM makes this transition, new sources of system strength will be required to maintain power system security. As the SSSP for Victoria, AVP is responsible for procuring services to meet the system strength requirements for Victoria. This is the focus of this RIT-T.

AVP has prepared this PADR in accordance with the requirements of clause 5.16 of the NER, for a RIT-T. It represents the second step in the formal RIT-T process and follows the PSCR published in July 2023, and the accompanying RFI from system strength service providers.

In line with the NER requirements, this PADR describes:

- the identified need for this RIT-T and how the system strength requirements have evolved since the publication of the PSCR, including the publication of AEMO's final 2024 *Integrated System Plan* (ISP) in June 2024 and AEMO's 2024 *System Strength Report* in December 2024
- points raised in submissions to the PSCR and how these have been addressed in the RIT-T analysis
- the options being assessed under this RIT-T, including the non-network solutions put forward in response to AVP's earlier RFI and how these have been combined (together with potential network investment components) into credible 'option portfolios'
- the basis on which the costs for the option portfolios have been estimated at this stage of the RIT-T process
- the market benefits expected from meeting the system strength requirements (including discussion of how benefits from changes in Australia's greenhouse gas emissions have been quantified)
- the results of the NPV analysis for each of the option portfolios assessed
- the key drivers of the NPV results, as well as the assessment that has been undertaken to ensure the robustness of the conclusion (including detailed sensitivity and boundary value testing), and
- details of the overall proposed preferred option at this stage of the RIT-T process to meet the identified need.

While the PADR for this RIT-T was originally due to be published by 6 October 2024, AVP was given approval from the AER to extend the PADR publication date to 30 April 2025. Deferring the publication date allowed AVP to further refine PADR inputs and ensure the RIT-T modelling inputs and assumptions considered publications that were released after the PSCR:

- 2024 ISP
- 2024 NEM *Electricity Statement of Opportunities* (ESOO)
- 2024 *System Strength Report*.

This extension means the PADR, AVP's assessment of electricity demand forecasts and development opportunities, is based on the 2024 ISP and 2024 ESOO and updated system strength requirements for Victoria system strength nodes identified in the 2024 *System Strength Report*.

1.1 Submissions and next steps

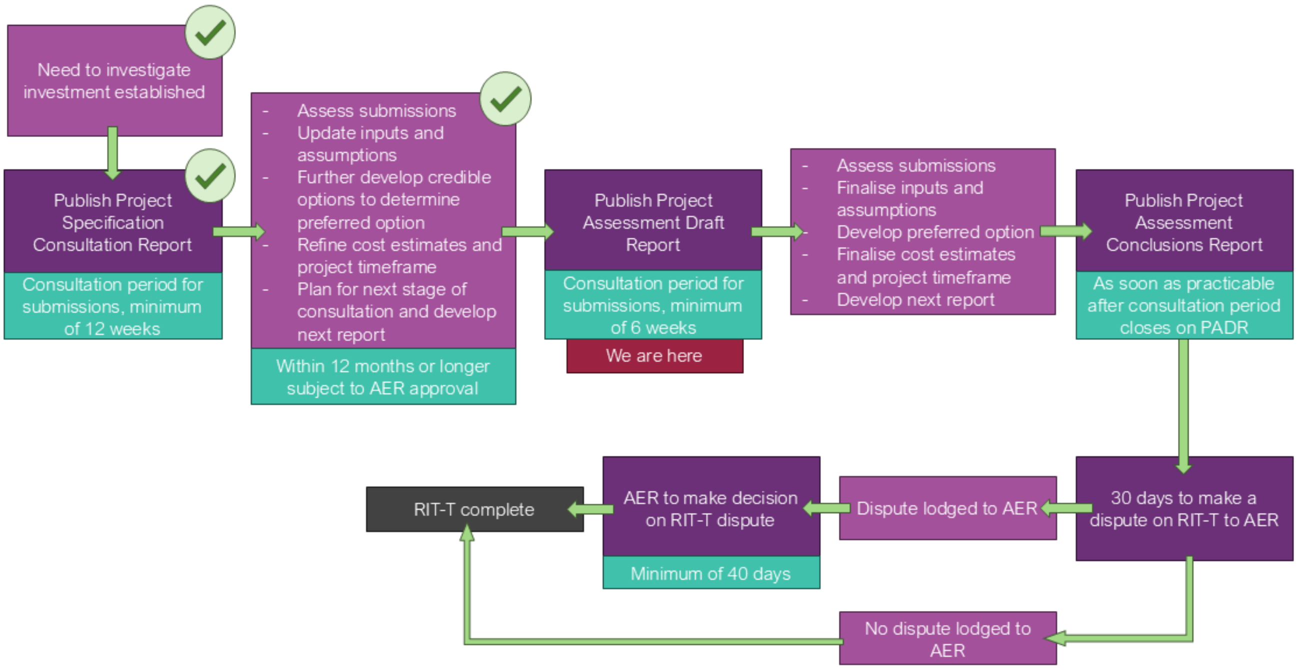
All stakeholders are welcome to provide written submissions on the PADR including comments on the analysis and ranking of the preferred option. All forms of feedback will be carefully considered in preparation of the PACR, and all written submissions will be published online, with a summary of how feedback has been taken into account.

Submissions are due on or before 30 May 2025 and should be emailed to AVP_RIT-T@aemo.com.au.

AVP will provide an industry briefing for stakeholders on the matters set out in this PADR at 1.00 pm (AEST) on 12 May 2025[9].

The final step of the RIT-T process, the PACR, will refine (as required) the matters outlined in this PADR, taking into account any submissions received. At this stage, AVP is targeting publication of the PACR in August 2025.

Figure 5 Overview of the RIT-T process



While AVP intends to commence the procurement process in parallel to preparing the PACR, it does not expect to finalise contracts before the PACR and its associated dispute period are complete. Commencing the procurement process (which is expected to be limited to negotiating contract terms) alongside the preparation of the PACR is considered prudent and will allow AVP to secure system strength services in as timely a manner as possible.

[9] Information about this session, including how to register, will be available at https://aemo.com.au/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.

2 Identified need

As the SSSP for Victoria, AVP is required to undertake this RIT-T to make sufficient system strength available, as specified by AEMO, under NER S5.1.14. AVP is undertaking this RIT-T as a 'reliability corrective action'.

While the overall characterisation of the identified need for this RIT-T has not changed since the PSCR, the detail regarding the amount of system strength required (both the minimum and efficient levels) at different locations, and the supporting assumptions, have been updated to align with the AEMO 2024 *System Strength Report* released in December 2024.

Developments in the NEM since the PSCR have increased the efficient level of system strength AEMO is now projecting is needed in Victoria, while the minimum three phase fault level requirement has remained the same other than treatment of post-contingency requirements.

2.1 Summary of the identified need

System strength is the ability of the power system to maintain a stable voltage waveform at any given location in the power system, both during steady state operation and following a disturbance. System strength has traditionally been provided by synchronous generation such as coal, gas-fired and hydro-electric power generation that is electromagnetically coupled to the power system. IBR – which include wind, large-scale solar, and batteries – do not inherently provide system strength, and most existing IBR which use GFL technology require adequate system strength for the inverters to work reliably.

The transition from a power system with predominantly synchronous generation to a power system with high levels of IBR has introduced a need to replace the system strength provided by synchronous generators to ensure system security can be maintained and to allow protection systems and IBR to work reliably.

In October 2021, the AEMC made its final rule determination on Efficient Management of System Strength on the Power System. This new system strength framework introduces new obligations for SSSPs. Under NER S5.1.14(b), AVP as the SSSP for Victoria is required to use reasonable endeavours to plan system strength services to:

- maintain the **minimum three-phase fault level** specified by AEMO at each system strength node in Victoria (that is, meet the minimum level of system strength), and
- achieve stable voltage waveforms for the forecast future IBR connections projected by AEMO in steady state conditions and following credible contingencies or protected events (that is, meet the **efficient level** of system strength).

The identified need for this RIT-T is to procure sufficient system strength services to ensure the system strength standard as per NER S5.1.14 is met for both forecast minimum and efficient levels at each of the Victorian system strength nodes from 2 December 2025 onwards. The identified need has not changed from the PSCR.

AVP is undertaking this RIT-T as a ‘reliability corrective action’ as the considered options are to enable AVP to meet the regulatory obligations under NER S5.1.14.

2.2 The assessment of system strength requirements in this RIT-T is consistent with AEMO’s 2024 *System Strength Report*

While the characterisation of the identified need for this RIT-T has not changed since the PSCR, the amount of system strength required, and the supporting assumptions, have been refined.

The discussion of the system strength need in the PSCR was based on the minimum three phase fault current requirements and the IBR forecasts in AEMO’s 2022 *System Strength Report*.

Since publication of the PSCR, AEMO has updated its analysis of system strength requirements in Victoria. The system strength nodes identified in Victoria remain the same, but the IBR forecasts at those nodes have been updated, reflecting NEM developments.

The analysis in this PADR uses the latest minimum three phase fault current requirements (which have not changed since the PSCR, other than the consideration of post-contingent requirements) and the latest IBR forecasts (which drive AVP’s obligation to procure the efficient level of system strength) set out in AEMO’s 2024 *System Strength Report*. If AEMO’s latest IBR forecasts are not taken into account, AVP would not be planning for the right amount of system strength for areas where the IBR forecasts have changed materially (which would, in a more extreme case, raise the risk of unserved energy for end consumers and/or result in an inability to allow for the dispatch of low-cost renewable energy in the future)[10].

Given AVP believes there is sufficient time to contract with non-network solutions to meet the revised 2025-26 and 2026-27 IBR forecasts, AVP is planning the system strength remediation based on AEMO’s IBR forecasts from the 2024 *System Strength Report* for all years. This will ensure that AVP’s provision of system strength is prudent and efficient, and in the best interests of consumers.

In line with AEMO’s most recent (2024) *System Strength Report*, this section outlines:

- the key refinements to AVP’s approach to planning for the minimum three phase fault level requirement since the PSCR, and
- key developments since the PSCR that have changed the assumptions underpinning the amount of system strength AVP is seeking to procure to meet the efficient level requirement.

2.2.1 Minimum three phase fault level

The pre-contingency and post-contingency minimum three-phase fault level requirements have not changed between AEMO’s 2022 and 2024 *System Strength Reports*, although the post-contingent values are no longer

[10] AVP also considers this approach consistent with the recently provided system strength guidance provided by the AER (see Section 3.2.3 of AER, *The Efficient Management of System Strength Framework*, Guidance Note, December 2024, pp. 15-16), as well as the intent of the AEMC’s final determination on the efficient management of system strength rule change (see AEMC, *National Electricity Amendment (Efficient Management of System Strength on the Power System) Rule 2021*, 21 October 2021, footnote 155, p. 102). While the AEMC final determination footnote refers directly to the inclusion of new system strength nodes, AVP considers that it supports investing based on the most up-to-date information available where it can be reasonably incorporated.

considered a strict requirement, since the pre-contingent values are designed to ensure the system is in a secure operating state[11].

The 2024 *System Strength Report* specified the pre-contingent and post-contingent minimum three phase fault level at each system strength node that has to be met at all times of the year, starting 2 December 2025. This minimum level is shown in Table 3. These requirements are unchanged across AEMO's 10-year forecast[12].

Table 3 Victorian minimum three phase fault level requirements (megavolt amperes [MVA])

System strength node and voltage	Pre-contingency fault level requirement	Post-contingency fault level requirement
Dederang 220 kilovolts (kV)	3,500	3,300
Hazelwood 500 kV	7,700	7,150
Moorabool 220 kV	4,600	4,050
Red Cliffs 220 kV	1,786	1,036
Thomastown 220 kV	4,700	4,500

Since AEMO's 2022 *System Strength Report*, the timing of full commissioning of Project EnergyConnect (PEC) Stage 2 has been delayed from June 2026 to June 2027 (which is reflected in AEMO's 2024 *System Strength Report*). In the PSCR, AVP identified that a temporary system strength solution was required at Red Cliffs from 2 December 2025 until the full commissioning of PEC Stage 2. Consistent with the PSCR, the delay to PEC Stage 2 has changed the timing of the temporary system strength solution AVP must plan for to meet the minimum three phase fault level, but has not affected the minimum requirements themselves. To meet this requirement in the short term, AVP has exercised its option to extend existing services agreements that were already in place to meet the existing Red Cliffs system strength shortfall, as envisioned in the 2024 *Network Support and Control Ancillary Services Report*[13]. These existing services agreements have now been extended until 31 July 2026, as further described in Section 5.5.

While the timing of PEC Stage 2 has been delayed from June 2026 to June 2027, the synchronous condenser included as part of Stage 1 of PEC was commissioned in late 2024, along with the Red Cliffs – Buronga duplication.

In the PSCR, AVP assessed the system strength requirement for both the minimum and efficient level of system strength on a post-contingent and pre-contingent basis and, at the time the PSCR was published, had proposed to do the same in the PADR. In developing this PADR, and in consultation with AEMO, the decision has been made to consider the system strength service capability on a pre-contingency basis only, acknowledging that the pre-contingent requirements were designed to ensure that the system is in a secure operating state. This approach has been applied to the minimum level, and is understood to be consistent with the Improving Security Frameworks (ISF) dispatch implementation, while the efficient level has been tested against all contingencies.

---

[11] AEMO, 2024 *System Strength Report*, December 2024, p. 62.

[12] It is expected that minimum fault level requirements at Red Cliffs may be impacted by network impedance changes following commissioning of PEC and Victoria – New South Wales Interconnector West (VNI West), and following retirement of synchronous generation in the Latrobe Valley.

[13] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.pdf?la=en.

2.2.2 Efficient level

The 2024 *System Strength Report* forecast IBR by technology and year, which forms the basis of the efficient level requirement. This forecast was subject to the assumed delivery and timing of committed, anticipated and actionable ISP transmission network augmentations set out in Appendix A2.3 of the 2024 *System Strength Report*.

AEMO's 2024 *System Strength Report* reflected several key developments since its 2022 *System Strength Report* that resulted in a material increase to the amount of system strength AVP must plan for to meet the efficient level requirements, including:

- an additional legislated offshore wind energy generation target of 2 gigawatts (GW) by 2032[14]
- the formal declaration of the Gippsland and Southern Ocean offshore wind areas[15,16]
- an update to Victoria's legislated renewable energy targets from 50% to 65% by 2030[17]
- the inclusion of the latest Federal Government policies, in particular targeting 82% renewable energy in Australia's electricity grids by 2030
- changes to coal generator retirement dates in the 2024 ISP, and
- significant uptake in BESS.

Table 4 summarises, at each system strength node, the IBR forecast used in this PADR. The amount of generation commitments that are self-remediating under the old system strength rules at each system strength node have been subtracted from the total requirements. Although included in the Table 4 values, as described in Section 4 AVP has assumed that all modelled batteries in AEMO's IBR forecast connect as GFM and therefore have no system strength demand.

Table 4 AEMO 2024 *System Strength Report* – modified forecast IBR (MW)

System strength node	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Moorabool	-	-	332	1,685	1,960	1,960	1,960	1,960	2,468	2,650	3,383
Hazelwood	-	-	500	900	1,750	2,400	3,400	4,400	5,067	5,733	5,820
Dederang	-	-	-	-	-	-	-	-	-	-	-
Red Cliffs	-	-	-	-	-	-	357	357	357	357	1,338
Thomastown	-	-	-	500	500	500	500	500	500	500	500

Table 5 shows how the modified forecast IBR at each system strength node has changed since the PSCR. Appendix A2 includes a further breakdown of the IBR forecasts by technology type.

---

[14] *Renewable Energy (Jobs and Investment) Act 2017*, s 7B.

[15] *Offshore Electricity Infrastructure (Declared Area OEI-01-2022) Declaration 2022*, 17 December 2022.

[16] See https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas/southern-ocean-region.

[17] *Renewable Energy (Jobs and Investment) Act 2017*, s 7.

Table 5 AEMO 2024 *System Strength Report* – changes to the modified forecast IBR since the PSCR (MW)

System strength node	2025	2026	2027	2028	2029	2030	2031	2032	2033
Moorabool	-	-	+240	+1,593	+1,868	+1,807	+1,016	+504	+912
Hazelwood	-374	-394	+106	+506	+917	+918	+1,399	+2,399	+3,066
Dederang	-	-	-	-	-	-	-	-264	-264
Red Cliffs	-	-	-	-	-	-	+357	+3	-1,080
Thomastown	-	-	-	+500	+500	+500	+500	+500	+500

In summary, there has been:

- a broad increase in IBR forecasts across most system strength nodes, driven by large increases in offshore and onshore wind as well as BESS, as shown in Appendix A2, and
- an acceleration of system strength requirements in earlier years (2027 to 2029) for Moorabool, Hazelwood and Thomastown.

In addition, since the 2022 *System Strength Report*:

- Full capacity release of PEC is now expected to be completed in July 2027, however for the purpose of this report the timing of the synchronous condensers and the Buronga – Red Cliffs duplication remains unchanged. The synchronous condensers and the Buronga – Red Cliffs duplication will have the largest impact on system strength in Victoria.
- The advised timing of Western Renewables Link (WRL) has been delayed from July 2026 to July 2027. When completed, WRL will improve access to renewables in North-West Victoria and form a 500 kV backbone when connected with Victoria – New South Wales Interconnector West (VNI West). This has contributed to the changed timing of forecast IBR planting around the Moorabool system strength node, as reflected in the 2024 *System Strength Report*.
- The targeted full capacity timing of VNI West has accelerated from 2032 to December 2029[18]. When completed, VNI West will improve network capacity for renewables in North-West Victoria.

While the 2024 *System Strength Report* IBR forecasts project out to 2035, AVP has used the latest ISP forecasts to extend these forecasts by a year to match the 11-year assessment period used for this PADR (as discussed in Section 7.4).

Treatment of proponents under the 'do no harm' rules

As part of the new system strength requirements, the current 'do no harm' rules evolve into the System Strength Mitigation Requirement (SSMR), where new connecting parties may opt to pay a system strength charge rather than self-remediate. While these new rules apply to projects that have submitted a Connection Application after 15 March 2023, projects that fall under the old rules may opt into the new SSMR and pay the system strength charge rather than having to self-remediate[19].

[18] AEMO, 2024 ISP, June 2024, p 62.

[19] AEMC, *National Electricity Amendment (Efficient Management of System Strength on the Power System) Rule 2021*, Final Determination, 21 October 2021, p ix.

While AVP is only obliged to plan for enough system strength to support the AEMO IBR forecast, the AEMO IBR forecasts include some projects that fall under the old 'do no harm' rules but are still going through the final stages of their registration.

AVP has therefore assessed each specific project in AEMO's IBR forecast to see their progress in the connection pipeline and, if a project is committed, existing or submitted its Connection Application before 15 March 2023, the project was assumed to sit under the old 'do no harm' rules.

AVP has not identified any such projects that have advised they plan on opting into the new rules and paying the system strength charge. For the purposes of this RIT-T, AVP has therefore assumed that all projects under the 'do no harm' rules are self-remediating.

3 Responses to the RFI and the PSCR

AVP published the PSCR for this RIT-T in July 2023, with an accompanying RFI that provided additional detail on the technical requirements that non-network solutions would need to meet to provide system strength services, and sought submissions from proponents able to provide the system strength services of these options. Submissions to both the PSCR and RFI were requested by 6 October 2023.

On 9 August 2023, AVP held a webinar attended by more than 50 participants to inform stakeholders of the key elements of the PSCR and RFI.

AVP received a substantial number of responses to the RFI, covering 36 individual solutions from 16 separate proponents, as well as three formal submissions to the PSCR (one of which has requested confidentiality) covering issues to be considered in the RIT-T assessment.

In late August and early September 2024, AVP sent all RFI submitters an online survey seeking updated information to understand if proposals remained valid and/or had materially changed given the time that had passed. The responses to this survey have been reflected in this PADR assessment.

3.1 Responses to the RFI

The RFI process resulted in non-network solution submissions from 16 parties, covering 36 individual potential technology solutions and 101 specific solutions:

- 65 solutions from all but one of the existing transmission connected synchronous generator owners in Victoria, proposing their existing synchronous generating units
- nine synchronous condenser submissions from five separate proponents (including one solution involving the conversion of an existing spare generating unit, and another two solutions adding minor station works or a clutch to enable synchronous condenser operation on their synchronous generators)
- 19 GFM BESS submissions from 14 separate proponents
- one compressed air storage system
- one pumped hydro energy storage system
- one ‘magnetically controlled shunt reactor’ solution, and
- one combined synchronous condenser and STATCOM solution.

In late August and early September 2024, AVP sent all RFI submitters an online survey seeking updated information to understand if proposals remained valid and/or had materially changed given the time that had passed since RFI responses were received. The survey sent to proponents subsequently resulted in:

- one proposal being withdrawn (one of the GFM BESS)

- seven proposals updating their in-service dates (all seven represented delays relative to what was initially proposed), and
- no proposals progressing from 'proposed' at the time of the initial RFI to 'anticipated' or 'committed' (which would have affected the manner in which these proposals were assessed, consistent with the AER RIT-T guidance).

The responses to the survey have been reflected in this PADR assessment.

Based on the capacity (megavolt amperes [MVA]) of proposed solutions, and excluding synchronous generator modifications, proposed solutions following the RFI follow-up survey can be broken down into:

- 26% GFM BESS, 11% synchronous condensers, 14% coal, 33% hydro and 17% gas, and
- 32% proposed, 49% existing and 19% committed/anticipated.

The analysis presented in this PADR has been strongly informed by the solutions proposed in response to the PSCR RFI (and subsequent survey), which has helped ensure the robustness of the analysis. AVP thanks all parties for their valuable input to the consultation process to date.

Section 4 outlines how AVP has considered the solutions proposed in submissions to the RFI and included them as part of the PADR assessment.

3.2 Submissions to the PSCR

In addition to the responses to the RFI, AVP received one confidential submission to the PSCR, along with non-confidential submissions from two parties (AusNet Services and EnergyAustralia). Both non-confidential submissions have been published on AEMO's website[20].

Eight key issues were raised across these submissions:

- further specification of the identified need
- option value and the timing of options
- modelling and sensitivities
- how inter-regional assets are assessed
- the location of new system strength resources
- consideration of high benefit network reinforcement solutions
- real-time data and broader issues in procuring system strength, and
- engaging with other SSSPs to ensure a consistent approach.

The key matters raised in non-confidential submissions are summarised and responded to in Appendix A5.

[20] At https://aemo.com.au/en/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.

4 Option portfolio formation process

A portfolio approach to forming credible options for this RIT-T is consistent with other system strength RIT-Ts and represents a practical way of assessing and grouping the large number of individual solutions proposed in response to the RFI, plus additional network solutions. It also recognises that no one solution can address the requirements in isolation.

As noted in the PSCR, AVP has developed 'option portfolios' that are designed to meet its system strength obligations and maximise the present value of net economic benefit to the NEM. This approach, as opposed to having options comprised of a single solution (or a smaller set of solutions), is considered necessary for system strength RIT-Ts in light of the scale and complexity associated with meeting the expected system strength requirements going forward[21].

The different option portfolios have been created by considering the annualised costs and expected benefits of different portfolio elements for addressing both the minimum and efficient level of system strength, as well as the expected timing of when they are available, across the assessment period.

The four different option portfolios can be summarised as follows:

- Option portfolio 1 – Existing generation plus committed/anticipated GFM BESS, including one that upgrades from GFL to GFM, and new synchronous condensers.
  - Option portfolio 1 assumed contracting with existing synchronous generation generators for the purposes of the cost benefits analysis, including conversion of some units to be capable of operating in synchronous mode, as well as the use of committed/anticipated GFM BESS (for the efficient level) and new plant able to operate as synchronous condensers (for the minimum and efficient levels)[22].
- Option portfolio 2 – The same technology types as option portfolio 1, plus upgrading additional committed/anticipated GFL BESS to be GFM.
  - This option portfolio has been developed to determine, through comparison with option portfolio 1, whether upgrading additional GFL BESS to be GFM is considered optimal compared to investing in plant able to operate as synchronous condensers. This option therefore involves fewer plants able to operate as synchronous condensers than option portfolio 1 (as outlined below).
  - This portfolio (as well as option portfolios 3 and 4) also assumed contracting a small amount (65 MW) of GFM BESS to efficiently provide sufficient system strength.
- Option portfolio 3 – The same technology types as option portfolio 2, plus inclusion of a generic 400 MW GFM BESS from the IBR forecasts.
  - This option portfolio has been included to investigate the cost savings that could be achieved where future modelled GFM BESS become committed/anticipated under the RIT-T.

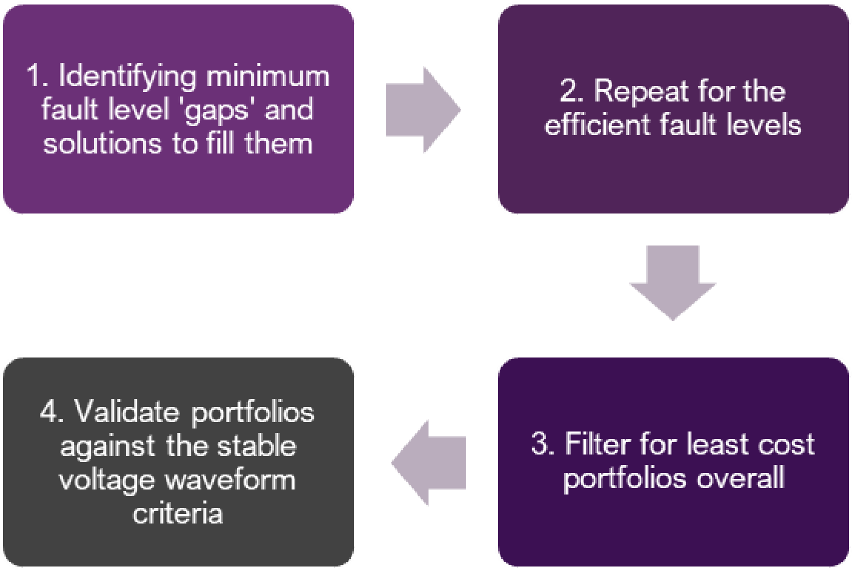
[21] This portfolio option approach is consistent with the PADRs released by Transgrid (in June 2024) and Powerlink (November 2024).

[22] As outlined in Section 6.1.2, all new plant able to operate as synchronous condensers have been assumed to be, and costed in the RIT-T assessment as, synchronous condensers for this PADR. However, the procurement process related to this RIT-T aims to identify the specific lowest cost solutions and the ultimate cost to consumers will be determined from these costs.

- Option portfolio 4 – The same as option portfolio 3, except it includes accelerated procurement of some plant able to operate as synchronous condensers.
  - This option has been developed to investigate whether expediting plant operating as synchronous condensers is expected to be net beneficial.

In forming each option portfolio, AVP applied the following four-stage modelling process. All solutions proposed in response to the RFI, as updated following the 2024 survey, have been considered as part of this process for each option portfolio.

Figure 6 Four-step process applied for forming each option portfolio



AVP applied a number of key technological constraints throughout this process:

- The earliest new plant able to operate as synchronous condensers can be commissioned is 2028-29 – this reflects the current lead times associated with procuring and commissioning these assets.
  - This assumption has been relaxed for option portfolio 4 where an earlier timing proposed in RFI submissions has been assumed (as outlined in Section 5.4).
- GFM BESS:
  - are not considered to have reached a level of maturity that they can be relied on to support minimum fault level requirements over the assessment period (consistent with the 2024 ESOO[23]), and
  - are sufficiently mature to support the stable voltage waveform of the efficient level over the entire assessment period[24].

[23] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[24] While not a forced in requirement, AVP notes that, throughout the assessment period, less than 50% of the total efficient level is supplied from GFM BESS, consistent with the Aurecon report into the maturity of grid-forming inverters. See Aurecon, *Advice on the maturity of grid forming inverter solutions for system strength*, April 2024, pp 11-12, at https://www.transgrid.com.au/media/diyb5fng/2403-aurecon_maturity-of-grid-forming-inverter-solutions-for-system-strength.pdf.

- For 'generic' BESS included in the AEMO IBR forecasts, AVP has assumed that all of the 'modelled' batteries in AEMO's IBR forecast connect as GFM.
  – This assumption was informed by discussions with the AEMO Victorian Connections team, which advised that at present over 90% of the BESS projects at enquiry and application stage are proposing to utilise GFM inverter technology.

The four key steps applied for forming each of the option portfolios are summarised in more detail in the sections below. The outcome of this process was then used to inform the different option portfolios.

No RFI submissions proposed maintaining existing generators beyond the end of their expected retirement dates, and AVP has assumed the ISP *Step Change* unit withdrawal dates in this PADR assessment.

The end of this section describes the 'reference case', which is a key input to the portfolio formation process and is distinct to the 'base case' used to subsequently model the market benefits of the portfolios, as well as providing a summary of how interstate contributions and critical planned outages have been considered.

4.1 Step 1 – Screening for the minimum fault level 'gaps' and the solutions to fill them

The first step in forming each option portfolio is to model how much of the minimum fault level is expected to be provided naturally – through the energy only market – from existing synchronous generation. This step effectively checks whether the minimum fault levels will be met each period of each year of the assessment period, to identify the 'gaps' in system strength that need to be filled. The identified gaps start off low in periods where there are multiple synchronous generators online but grow significantly as new IBR comes online, causing existing synchronous generators to operate less, and as existing synchronous generators in Victoria exit the market.

AVP undertook the modelling for this step on a half-hourly basis, using the energy only dispatch output (with no system strength constraints present) from the PADR reference case. These half-hour intervals were then grouped into unique dispatch combinations where the same synchronous machines are online, noting that for system strength the contribution is driven predominately by machine status as opposed to its megawatt (MW) output.

For each unique dispatch combination, AVP identified the lowest cost additional services available to meet the system strength requirements using the $/MVA of fault level contribution cost assigned to that service. For the purposes of the RIT-T and its cost benefit analysis, additional services can come from either existing generators, additional services proposed in RFI responses, or network solutions where they can be developed within the required timeframe.

The additional services required from existing generators were identified using the power system model in PSS®E, with services brought in based on their $/MVA cost of providing the system strength (that is, they are dispatched in ascending order of their $/MVA cost, where the MVA value is their fault level contribution to the system strength node). Given AVP is required to make available system strength for all periods (not just the 'gap' periods), this modelling also identified the generators required to ensure there are sufficient services available at all times should the actual dispatch not match the modelled dispatch. Both the generators dispatched to fill the gap, and the generators required to provide sufficient system strength services, form part of the option portfolio.

The $/MVA cost for each existing generating unit to provide system strength reflects the following costs (where they are relevant[25]):

- Additional fuel costs – valued at the service's short run marginal cost which is built from the 2024 ISP Inputs and Assumptions Workbook and the RFI responses (for some minimum stable levels)[26]. While additional fuel costs are captured, any fuel cost reductions, from other units reducing their megawatt output to make way for system strength services to operate at their minimum stable level, are not captured at this screening stage because the screening study assessment does not attempt to maintain an energy supply-demand balance.
- Emissions – calculated using emissions intensity values from the 2024 ISP Inputs and Assumptions Workbook and valued at the Value of Emissions Reduction (VER) published by the AER in July 2024[27,28].
- Activation costs – from RFI responses (or estimates from independent sources where not covered in an RFI submission).
- Annualised capital and operating costs for new services – from AEMO's Transmission Cost Database (TCD).
- Additional capital costs and additional fixed costs – from RFI responses (and AVP estimates where not covered in the RFI responses)[29].

Similarly, the same range of costs was considered, as relevant, for each of the solutions proposed in RFI responses and expected to be available from generic BESS included in the AEMO IBR forecasts (which are assumed to connect as GFM). As noted above, before 2028-29, only existing generators and some RFI proposals are able to assist due to expected lead times with plant able to operate as synchronous condensers and expected commissioning dates for some RFI proposed solutions.

The outcome of step 1 was a preliminary view regarding the portfolio of solutions required to meet the minimum fault level requirements over the assessment period. This was then used as the starting point for a similar assessment of the solutions that can meet the efficient level requirements (as outlined in step 2 below).

The assessment undertaken for this step assumed an 11-year modelling horizon (as discussed in Section 7.4).

4.2 Step 2 – Repeat for the efficient fault levels

Using the output of step 1 as a starting point (that is, the portfolio of solutions for ensuring the minimum fault level requirements are met), AVP effectively repeated the same process to ensure the efficient level requirements are met, but applied the available fault level approach outlined in Appendix A of AEMO's System Strength Impact Assessment Guidelines (SSIAG)[30] to determine efficient level requirements. This enabled AVP to identify full

[25] For example, the generators required to provide sufficient system strength services, but that are already operating in the reference case, do not have a dispatch cost as they are not dispatched differently in the model (instead, they are contracted to be made available to dispatch if the 'gap' in real time is larger than the 'gap' seen in this modelling).

[26] RFI responses were used for the minimum stable levels as the default, but, if they were not provided, estimates from the 2024 ISP Inputs and Assumptions Workbook were used.

[27] AER, *Valuing emissions reduction*, AER Amended Final Guidance, July 2024.

[28] While the VER was applied once the overall option portfolio was identified, it has not fed into determining the dispatch order of units, since emissions costs do not affect market dispatch decisions.

[29] Additional costs not covered by the TCD include any costs to convert BESS from GFL to GFM, and site-specific or bespoke solutions such as conversion of existing synchronous generators to be capable of operating in synchronous condenser mode.

[30] AEMO, System Strength Impact Assessment Guidelines V2.2, p 48, July 2024, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/ssiag/system-strength-impact-assessment-guidelines-v22.pdf?la=en.

portfolios of solutions that are expected to meet both the minimum fault levels and the efficient levels over the assessment period.

AVP undertook this modelling assuming a short circuit ratio (SCR) – being the level at which a GFL renewable generator is assumed to remain stable – of 3.0, and alpha factor – being the stability coefficient reflecting assumed limitations in the network the IBR connection – of 1.2, which results in an effective SCR of 1.8 at the GFL IBR's point of connection. Any additional system strength requirements arising from the reticulation design of large solar and (onshore or offshore) wind farms are outside the scope of AVP's obligations and this assessment.

A key difference in the assumptions for this assessment, compared to those under step 1 for the minimum level, is that GFM BESS that form part of the option portfolio were assumed to be able to assist with meeting the efficient level.

For this RIT-T, AVP determined the efficient level solutions assuming a static available fault level requirement at each system strength node, and also considering key future IBR connection locations. While these requirements are static throughout the year, they change annually in line with the IBR forecast, rather than on an interval level IBR dispatch basis.

Although AEMO is required to only enable contracts reasonably necessary to maintain stable voltage waveforms and host the projected level of IBR, but not enable contracts that would result in a significant adverse effect on power system emissions or efficiency[31], AVP considers its simplified static requirement approach taken in the PADR market modelling is appropriate because:

- the additional modelling effort required to optimise the efficient level requirement and dispatch at the interval level is considered disproportionate to any market benefit likely to be realised
- this approach is consistent with how other SSSPs have treated the efficient level requirements[32]
- as stated in AEMO's SSIAG[33], the stable operation of a generating system is determined by whether it can meet its performance standards at any level of megawatt output, and
- the level of IBR that can be hosted based on system strength levels in the operational timeframe is typically based on the nameplate capacity of IBR and whether their inverters are online or offline, rather on their real-time dispatch levels.

4.3 Step 3 – Filter for least cost portfolios overall

The output of steps 1 and 2 allow AVP to construct least cost portfolios overall for each key option portfolio.

This step was undertaken over the assessment period, taking account of the time value of money via the commercial discount rate, and ensures that each option portfolio is the least cost combination of solutions, given the technologies that are assumed able to assist with providing system strength.

[31] AEMC, Improving Securities Framework – Final Rule Determination, p 90, March 2024, at https://www.aemc.gov.au/sites/default/files/2024-03/ERC0290%20-%20ISF%20final%20determination.pdf.

[32] Baringa, Meeting system strength requirements in NSW, p 59, June 2024, at https://www.transgrid.com.au/media/wphjea0f/2406-baringa_meeting-system-strength-requirements-in-nsw-padr-modelling-report.pdf.

[33] AEMO, System Strength Impact Assessment Guidelines V2.2, p 15, July 2024, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/ssiag/system-strength-impact-assessment-guidelines-v22.pdf?la=en.

While step 3 necessarily involves a basic assessment of the unit commitment and start-up costs associated with each potential solution (and, specifically, while this step assesses if a unit was running or not in the previous time-sequence, it does not attempt to account for ramp rate limitations or minimum run times), AVP does not consider this material to the overall construction of the portfolios, since these factors are expected to have a marginal impact relative to the entire modelling period considered, and the four option portfolios were tested through PLEXOS® market modelling, which does include these detailed assumptions, to determine the overall proposed preferred option portfolio.

4.4 Step 4 – Validate portfolios against the stable voltage waveform criteria

Once the option portfolios have been developed, these must be validated against the stable voltage waveform criteria. The approach for validation differs depending on the timeframe. Detailed electromagnetic transient (EMT) modelling is the preferred method for this validation. EMT simulations require detailed models of connected plant – including the tuning of that plant to reflect its location in the network – and is computationally intensive. This is reflected in AEMO's System Strength Requirements Methodology (SSRM), which states that EMT simulations are not fit-for-purpose beyond the time horizons where network and generator models are well understood.

AVP captured this through two different sets of studies to assess the selected option portfolios against the stable voltage waveform requirements.

In the near term, AVP used EMT assessments in PSCAD™ to assess the ability of the option portfolio to meet the requirements. Given the study horizon for the PSCAD™ work, these option portfolios are made up of existing, committed and anticipated generation, synchronous condensers, and GFM BESS.

Beyond the PSCAD™ study horizon, AVP used steady state root-mean-square (RMS) models and undertook switching studies in PSS®E. While the PSCAD™ studies are able to show distortion or oscillations of the voltage waveform (Criterion 3 and 4 of the SSRM), the PSS®E studies provide insight into the ability of the option portfolios to meet the change in voltage magnitude and voltage angle (Criterion 1 and 2 of the SSRM).

The portfolios were assessed in PSS®E and in PSCAD™ to understand their level of voltage waveform stability. Where deemed necessary, additional services were added in the order that they would be added in the portfolio development, on a least cost $/MVA basis accounting for where the solution is required.

Once developed, each option portfolio was modelled in PLEXOS® using short-term dispatch modelling (as discussed in Section 7). Constraints were developed using the contribution of each of the solutions to each system strength node (which were informed by the outcome of the portfolio development studies). Unlike the portfolio development, the PLEXOS® modelling included redispatch of energy where it is economic to do so to meet the system strength constraints, and therefore is considered to provide a more detailed assessment of each short-listed option portfolio's benefits.

Section 4.6.3 outlines how AVP derived equivalent available fault level contributions for GFM BESS in meeting the efficient level.

4.5 The ‘reference case’

AVP undertook the above four-step process assuming a ‘reference case’ set of market modelling outputs.

The reference case has been constructed in the same manner as the ‘base case’ for the assessment of market benefits (as outlined in Section 5.5), except that it does not involve system strength constraints in any regions of the NEM. For the avoidance of doubt, the reference case still includes the same unit commitment requirements as the base case, which were included as a proxy for more realistic bidding while still maintaining a short-run marginal cost bidding approach. The reference case was constructed in this ‘unconstrained’ manner to determine what is likely to be on-line ‘naturally’ – through the energy only market – and to thus form a view of the amount of additional system strength that is needed from the portfolios to meet the requirements.

For example, and as outlined in Section 4.1, the first step in forming each option portfolio was to model how much of the minimum fault levels are expected to be provided naturally from existing synchronous machines. This step effectively checked whether the minimum fault levels will be met each interval of each year of the assessment period to identify the ‘gaps’ in system strength that need to be filled. The reference case assessment enables these gaps to be determined.

While the approach to forming option portfolios for this PADR implicitly assumed that contracting with on-line synchronous generators is the lowest cost solution on a resource cost basis, AVP considers this an appropriate assumption given the build and operational costs of these generators is sunk so there are no, or very little, additional economic costs associated with providing system strength for these units. It also implicitly assumed that generators are willing to sign contracts that reasonably reflect the costs of the credible option (failing to do so is expected to represent an MCC, consistent with the AER’s recent guidance on system strength RIT-Ts)[34].

4.6 Solution contributions to system strength

In developing option portfolios, and their ability to meet the system strength requirements, assumptions must be made about the level of system strength contribution solutions are capable of providing. This section outlines the assumed system strength contribution of the three key option portfolio solution technologies, being existing synchronous generators, new plant able to operate as synchronous condensers, and GFM BESS.

4.6.1 Existing synchronous generators

Existing synchronous generators were assumed available to provide system strength services and to contribute to system strength when operating for the energy market. The level of system strength contribution of existing synchronous generators was based on the specific machine parameters which dictate their fault level contribution at their point of connection. Existing generators were modelled in line with their releasable user guide data, provided through the network connections process, or RFI responses where relevant.

[34] AER, *The Efficient Management of System Strength Framework*, AER Guidance Note, December 2024, p. 25.

4.6.2 New plant able to operate as synchronous condensers

New plant able to operate as synchronous condensers were assumed to provide a fault level 4.4 times their nameplate capacity at their point of connection – that is, a 250 MVA synchronous condenser or other new plant (such as gas turbines) was assumed to contribute 1,100 MVA of fault level at its point of connection. This is based on a review of existing synchronous condensers in the NEM, and their typical machine parameters, along with RFI responses.

4.6.3 Grid-forming (GFM) BESS

Contracted GFM BESS solutions were assumed to provide sufficient stable voltage waveform system strength benefit to support twice their rated installed capacity in GFL IBR, at their point of connection – that is, a GFM BESS with an installed capacity of 250 MVA was assumed capable of supporting 500 MW of GFL IBR. As a contribution to stable voltage waveform, this equates to a change in available fault level (AFL) equivalent to 900 MVA. This is based on a conservative review of existing research comparing synchronous condenser and GFM BESS contribution to a stable voltage waveform, with change in AFL being treated as a proxy for that benefit.

As further detailed in Section 4, GFM technology has not yet been demonstrated to satisfy protection-quality fault current requirements at scale in Australia, and AVP has therefore assumed no contribution from GFM BESS to the minimum fault level requirements. The 900 MVA contribution to stable voltage waveform from a 250 MVA installed capacity GFM BESS is not its ‘real fault level’ contribution; it is instead a measure of a GFM BESS’s system strength contribution to a stable voltage waveform. That is, a GFM BESS can provide stability benefits beyond its real fault level contribution, and this has been represented by an available (equivalent) fault level proxy to allow this benefit to be modelled via constraint equations in market modelling. If GFM BESS was considered capable of contributing to the minimum fault level requirement, the contribution of GFM BESS would be significantly reduced to approximately 1.2 times its installed capacity, meaning a GFM BESS with an installed capacity of 250 MVA would only contribute 300 MVA of real fault level to the minimum fault level requirements.

For the RIT-T assessment, AVP assumed that a GFM BESS can provide its system strength capability irrespective of its MWh energy capacity or its instantaneous state of charge and MW dispatch level. This assumption is considered appropriate based on recent discussions with BESS proponents, and noting that BESS typically have a minimum state of charge considered suitable to respond to the short-term disturbances commonly associated with system strength related instabilities.

4.7 Interstate contributions of system strength

AVP considered contributions to system strength in Victoria from interstate generators based on the minimum fault levels being maintained at each of the nodes in the respective states.

The two synchronous condensers at Buronga in each of 2026 and 2027 as part of PEC Stage 1 and Stage 2, respectively, and the two synchronous condensers at Dinawan in 2027 as part of PEC Stage 2, increase the amount of system strength assumed to be provided from New South Wales in the development of each option portfolio. These four synchronous condensers were implicitly assumed in the base case and all option portfolios, and are not considered to affect the relative rankings of the options at all.

While the contribution of interstate synchronous generation was considered in the minimum and efficient level, no adjustment has been made to efficient level to account for any additional requirements for system strength to support IBR generation in other states.

4.8 Consideration of critical planned outages

AVP assessed each option portfolio's ability to meet the pre-contingent minimum fault level system strength requirements during the critical planned outages included in the 2024 *System Strength Report*[35]. This assessment confirmed that the solutions already forming part of each option portfolio are sufficient to also cover the critical planned outage periods expected across the 11-year system strength planning horizon, and additional procurement of services is therefore not required for critical planned outage management.

In undertaking this assessment, AVP reviewed historical high impact outages in the Victorian transmission system and developed a forward-looking outage schedule of each critical planned outage considering the typical frequency, duration and time of year for these planned outages. For each critical planned outage included in the 2024 *System Strength Report*, this forward-looking outage schedule included a three-year rolling outage plan consisting of one continuous 80-hour outage block and two continuous eight-hour outage blocks (that is, one outage per year total 96 hours every three-year period). Each outage was scheduled between either April and June or September and November, to align with lower demand periods when network outages are more typically scheduled, and outages were scheduled to not occur concurrently.

This approach is considered consistent with the AEMC's final determination[36] that proposed system strength solutions to cover outages should be evaluated on a case-by-case basis, rather than necessarily being an addition to the baseline redundancy already considered under the minimum fault level requirement set by AEMO.

[35] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.pdf?la=en.

[36] AEMC, 2021, Page 98, Efficient Management of System Strength on the Power System, at https://www.aemc.gov.au/rule-changes/efficientmanagement-system-strength-power-system.

5 Options to address the need

This PADR has assessed four different credible option portfolios that have been developed to meet the system strength requirements under a range of different assumptions.

This section provides more detail on each of the four credible option portfolios that have been developed and assessed as part of this PADR, and their associated costs. It also provides more detail in Section 5.5 on the base case for the assessment of these options (the 'do nothing' case that all option portfolios are assessed against under the RIT-T).

Table 6 provides a summary of the four different option portfolios developed and assessed in this PADR.

Table 6 Summary of the four credible option portfolios

	Overview	Focus	Capital costs (present value)
Option portfolio 1	10 synchronous condensers[A] (nine new and 1 existing) + Existing generation[B], including conversion of some units to be capable of operating in synchronous condenser mode, and committed/anticipated GFM BESS, including one that upgrades from GFL to GFM	Includes existing generation, as well as committed/anticipated GFM BESS (for the efficient level) and nine new synchronous condensers (for the minimum and efficient levels)	$1,134.5m for nine new synchronous condensers $1.5m for upgrading a 'committed' GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)
Option portfolio 2	Seven synchronous condensers (six new and one existing) + The same other technology types as option portfolio 1 plus upgrading additional committed/anticipated GFL BESS to be GFM, and an additional (small) GFM BESS	Developed to determine, through comparison with option portfolio 1, whether upgrading additional GFL BESS to be GFM is considered optimal compared to investing in synchronous condensers	$779.1m for six new synchronous condensers $7.8m for upgrading committed/anticipated GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)
Option portfolio 3	Six synchronous condensers (five new and one existing) + The same technology types as option portfolio 2 plus a generic 400 MW grid-forming BESS from the IBR forecasts	Investigating the cost savings that could be achieved where future modelled GFM BESS become committed/ anticipated under the RIT-T	$673.1m for five new synchronous condensers $7.8m for upgrading committed/anticipated GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)
Option portfolio 4	The same as option portfolio 3 – including the same number of new synchronous condensers in total – but with accelerated procurement of two synchronous condensers	This option has been developed to investigate whether expediting synchronous condensers is expected to be net beneficial	$698.4m for five new synchronous condensers $7.8m for upgrading committed/anticipated GFL BESS to be GFM $8.7m for upgrading an existing generator (to also be capable of operating in synchronous condenser mode)

A. As outlined in Section 6.1.2, all new plant able to operate as synchronous condensers have been assumed to be, and costed in the RIT-T assessment as, synchronous condensers for this PADR.
B. While each of the options assumes the use of 'existing generation', AVP considers that this includes any additional generation that connects ahead of AVP needing to commit to its procurement following this RIT-T.

Wherever a system strength node (SSN) location is mentioned in this PADR, this should be interpreted as being 'in the vicinity of' this location (with the exact location of services to be determined via the procurement process), and not necessarily at that specific location.

All option portfolios also assumed two synchronous condensers at Buronga in each of 2026 and 2027 as part of PEC Stage 1 and Stage 2, respectively. These four synchronous condensers have not been shown in the option component tables below since, while the option portfolios rely on them as an interstate contribution, AVP is not proposing to contract them and they form part of the assumed interstate contribution (which has been factored into the option portfolio development process, as discussed in Section 4.7).

5.1 Option portfolio 1 – Existing generation plus committed/anticipated GFM BESS and new synchronous condensers

Option portfolio 1 assumes that existing synchronous generation can assist with providing system strength, as well as committed and anticipated GFM BESS (for the efficient level), including one that upgrades from GFL to GFM, and new plant able to operate as synchronous condensers (for the minimum and efficient levels).

In total, option portfolio 1 involves nine new plant able to operate as synchronous condensers over the assessment period. It also assumes the use of one existing synchronous condenser (however, this is assumed in all four option portfolios).

The specific components included in this portfolio, for meeting both the minimum and efficient system strength requirements, are summarised in Table 7.

Table 7 Option portfolio 1 – Summary of components

Financial year	Minimum fault levels	Efficient level
2026	Existing generators, including conversion of some units to be capable of operating in synchronous condenser mode 1 x Existing synchronous condenser Red Cliffs SSN	Covered by minimum fault level requirements
2027		
2028		900 MW GFM BESS Moorabool SSN
2029	Same as 2028[A] + 2 x synchronous condensers Hazelwood SSN	Same as 2028 + 350 MW GFL to GFM BESS Hazelwood SSN
2030		
2031	Same as 2030 + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub[B]	
2032		Same as 2031 + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub
2033		Same as 2032 + 1 x 500 kV synchronous condenser Bulgana Terminal Station
2034	Same as 2033 + 1 x synchronous condenser Hazelwood SSN	Same as 2033 + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub
2035		Same as 2034 + 1 x 500 kV synchronous condenser Kerang
2036		Same as 2035 + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub

A. 'Same as 2028' (and this language where used with reference to other years in this table and all other tables of this type in the PADR) refers to the same components as that year but, where the use of existing synchronous generation is included in this, it does not imply the same *operation* of these units between years.

B. While this synchronous condenser is installed mainly for minimum fault level for this particular year, in future years it also helps for efficient level and hence has been located closer to the IBR, that is, in the Giffard area.

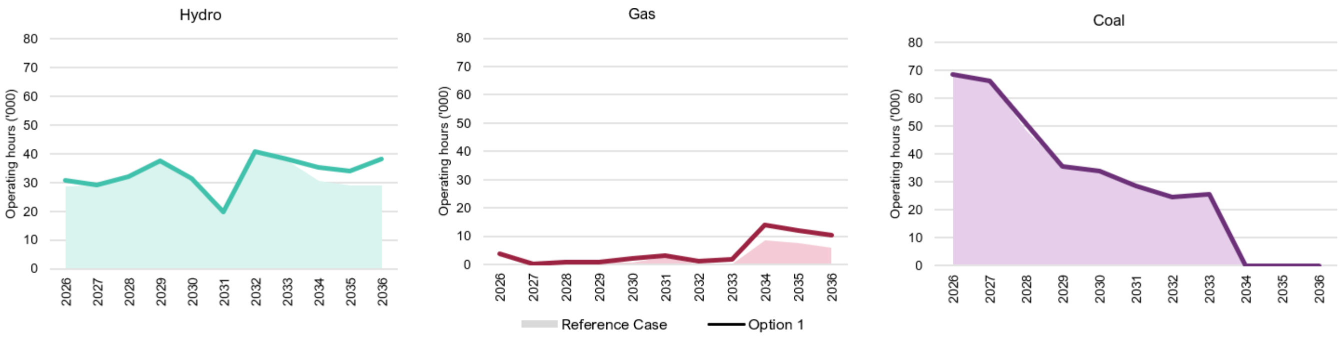
In present value terms[37], the total estimated capital cost of this option, over the life of the assets, is approximately $1,144.7 million, which can be broken down as follows:

- $1,134.5 million for synchronous condensers
- $1.5 million for upgrading a 'committed' GFL BESS to be GFM[38], and
- $8.7 million for upgrading an existing generator (to also be capable of operating in synchronous condenser mode).

Over the 11-year assessment period, and considering the terminal value (as outlined in Section 7.4), this equates to approximately $453.2 million and $41.3 million in total capital and operating costs, respectively.

Figure 7 shows the redispatch of existing generators in the Victorian system under option portfolio 1, relative to the energy-only dispatch of the reference case. This demonstrates the possible level of additional synchronous generator dispatch, and therefore potential unit contracting over time, required to meet the system strength requirements with the other option portfolio 1 solutions in place.

Figure 7 Victorian synchronous generator operating hours, option portfolio 1 relative to the reference case



In the above chart, and all charts of this type in the PADR:

- the option portfolio dispatch is shown using a solid line, while the reference case dispatch is shown by the shaded area, and
- since the option portfolio includes some hydro generators being converted to be capable of operating in synchronous condenser mode, the option dispatch line of the hydro chart includes operating hours for these units in either hydro generator or synchronous condenser mode.

5.2 Option portfolio 2 – The same technology types as option portfolio 1 plus upgrading additional GFL BESS to be GFM

Option portfolio 2 includes the same technology types as option portfolio 1[38] plus upgrading additional 'committed'/'anticipated' GFL BESS to be GFM.

[37] All present values presented in this PADR use the central discount rate of 7% (as discussed in section 7.4).

[38] The BESS that upgrades from GFL to GFM in option portfolio 1 is considered 'committed' under the RIT-T and has submitted a proposal in response to the RFI. While the other BESS assumed to upgrade from GFL to GFM in option portfolios 2-4 are also considered 'committed' (or 'anticipated') under the RIT-T, they have not submitted a proposal at this stage and are for proposals that are further into the future.

This portfolio has been developed to determine, through comparison with option portfolio 1, whether upgrading additional GFL BESS to be GFM is considered optimal compared to investing in synchronous condensers. This option therefore involves fewer plant bale to operate as synchronous condensers than option portfolio 1 (as outlined below).

The upgrading of additional GFL BESS to be GFM for meeting the efficient level ramps up over time and allows the following BESS capacities to be used *in addition to those included for option portfolio 1*:

- 500 MW at the Hazelwood SSN and 350 MW at the Moorabool SSN from 2032
- a further 300 MW at the Moorabool SSN from 2033, and
- 65 MW at the Red Cliffs SSN from 2035.

This allows the following to be avoided to meet the efficient levels, compared to option portfolio 1:

- two synchronous condensers at the Giffard (Gippsland) Offshore Wind Hub 500 kV in 2031 and 2032 (although option portfolio 2 has one more synchronous condenser at the Hazelwood SSN in 2031)
- one Bulgana Terminal Station 500 kV synchronous condenser in 2033, and
- one Kerang Terminal Station 500 kV synchronous condenser in 2035.

In total, option portfolio 2 involves six new plant able to operate as synchronous condensers over the assessment period (three fewer than under option portfolio 1).

The specific components included in this portfolio, for meeting both the minimum and efficient system strength requirements, are summarised in Table 8.

Table 8 Option portfolio 2 – Summary of components

Financial year	Minimum fault levels	Efficient level
2026	Existing generators, including conversion of some units to be capable of operating in synchronous condenser mode 1 x Existing synchronous condenser Red Cliffs SSN	Covered by minimum fault level requirements
2027		
2028		900 MW GFM BESS Moorabool SSN
2029	Same as 2028 + 2 x synchronous condensers Hazelwood SSN	Same as 2028 + 350 MW GFL to GFM BESS Hazelwood SSN
2030		
2031	Same as 2030 + 1 x synchronous condenser Hazelwood SSN	
2032		Same as 2031 + 500 MW GFL to GFM BESS Hazelwood SSN 350 MW GFL to GFM BESS Moorabool SSN
2033		Same as 2032 + 300 MW GFL to GFM BESS Moorabool SSN
2034	Same as 2033 + 1 x synchronous condenser Hazelwood SSN	Same as 2033 + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub
2035		Same as 2034 + 65 MW GFM BESS Red Cliffs SSN
2036		Same as 2035 + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub

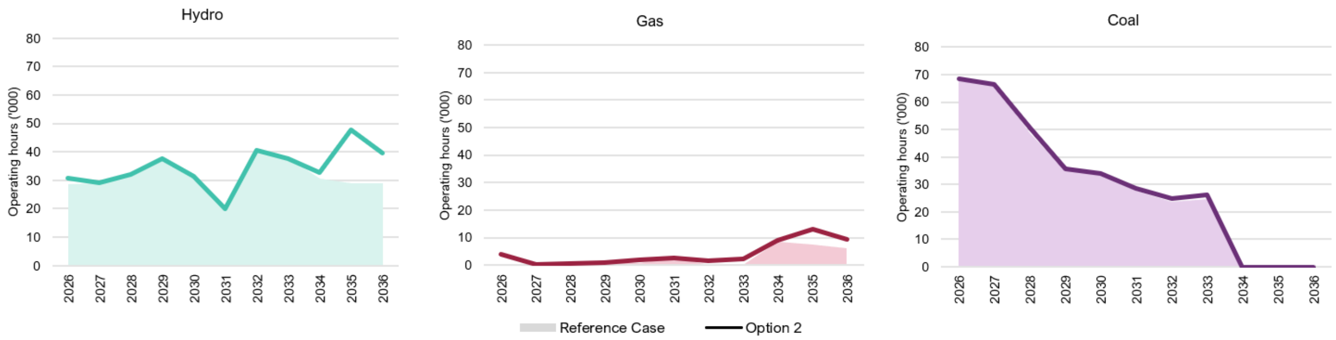
In present value terms, the total estimated capital cost of this option, over the life of the assets, is approximately $795.6 million, which can be broken down as follows:

- $779.1 million for synchronous condensers
- $7.8 million for GFL BESS to be GFM, and
- $8.7 million for upgrading an existing generator (to also be capable of operating in synchronous condenser mode).

Over the 11-year assessment period, and considering the terminal value (as outlined in Section 7.4), this equates to approximately $335.5 million and $30.8 million in total capital and operating costs, respectively.

Figure 8 shows the redispatch of existing generators in the Victorian system under option portfolio 2, relative to the energy-only dispatch of the reference case. This demonstrates the possible level of additional synchronous generator dispatch, and therefore potential unit contracting over time, required to meet the system strength requirements with the other option portfolio 2 solutions in place.

Figure 8 Victorian synchronous generator operating hours, option portfolio 2 relative to the reference case



5.3 Option portfolio 3 – The same technology types as option portfolio 2 plus a GFM BESS from the IBR forecasts

Option portfolio 3 involves the same technology types as option portfolio 2, plus a generic GFM BESS from the IBR forecasts to help meet the efficient level requirements.

The inclusion of option portfolio 3 shows the potential cost savings from being able to use future 'committed'/'anticipated' BESS, and therefore the value (cost savings to consumers) of waiting to see whether these emerge rather than committing to more plant able to operate as synchronous condensers now.

In addition to the BESS assumed in option portfolio 2 from 2032, option portfolio 3 also assumed the use of a generic 400 MW GFM BESS at the Hazelwood SSN, which is included in AEMO's IBR forecasts but is not yet considered 'anticipated' or 'committed' under the RIT-T to meet the efficient level requirements from that point. This BESS allows one synchronous condenser at Gippsland South to be avoided in 2036, and the other synchronous condenser to be deferred by one year (from 2034 to 2035), compared to option portfolio 2.

In total, option portfolio 3 involves five new plant able to operate as synchronous condensers over the assessment period (four fewer than under option portfolio 1).

The specific components included are in Table 9.

Table 9 Option portfolio 3 – Summary of components

Financial year	Minimum fault levels	Efficient level
2026	Existing generators, including conversion of some units to be capable of operating in synchronous condenser mode 1 x Existing synchronous condenser Red Cliffs SSN	Covered by minimum fault level requirements
2027		
2028		900 MW GFM BESS Moorabool SSN
2029	Same as 2028 + 2 x synchronous condensers Hazelwood SSN	Same as 2028 + 350 MW GFL to GFM BESS Hazelwood SSN
2030		
2031	Same as 2030 + 1 x synchronous condenser Hazelwood SSN	
2032		Same as 2031 + 500 MW GFL to GFM BESS Hazelwood SSN 350 MW GFL to GFM BESS Moorabool SSN 400 MW ISP forecast GFM BESS Hazelwood SSN
2033		Same as 2032 + 300 MW GFL to GFM BESS Moorabool SSN
2034	Same as 2033 + 1 x synchronous condenser Hazelwood SSN	
2035		Same as 2034 + 65 MW GFM BESS Red Cliffs SSN + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub
2036		

In present value terms, the total estimated capital cost of this option, over the life of the assets, is approximately $689.6 million, which can be broken down as follows:

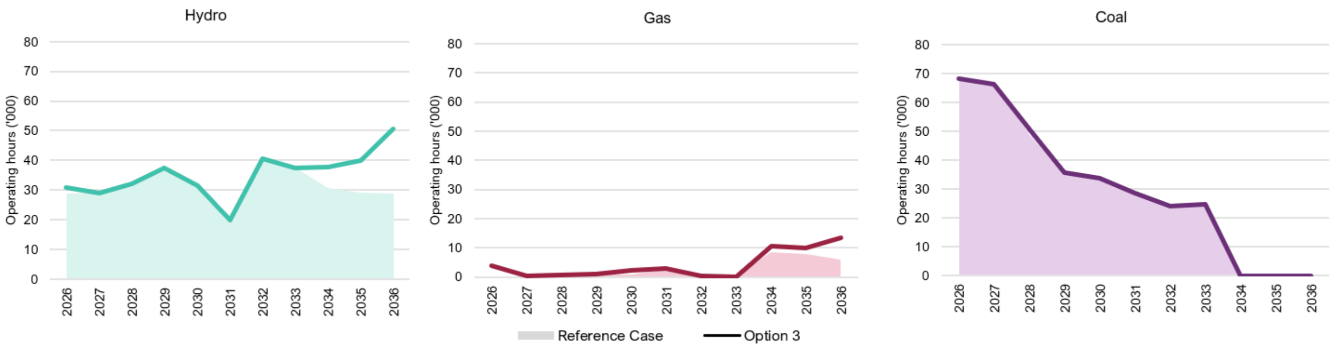
- $673.1 million for synchronous condensers
- $7.8 million for GFL BESS to be GFM, and
- $8.7 million for upgrading an existing generator (to also be capable of operating in synchronous condenser mode).

Over the 11-year assessment period, and considering the terminal value (as outlined in Section 7.4), this equates to approximately $311.2 million and $28.9 million in total capital and operating costs, respectively.

As outlined in Section 6.1.4, and as with existing and committed/anticipated GFM BESS, AVP has not included a capital cost for the 'generic' GFM BESS from the IBR forecast, because the costs were assumed to be in the base case. In addition, AVP has not assumed upgrade cost, but has treated all new BESS as being GFM based on recent connection enquiries and application information from AEMO's Victorian Connections team (see Section 4).

Figure 9 shows the redispatch of existing generators in the Victorian system under option portfolio 3, relative to the energy-only dispatch of the reference case. This demonstrates the possible level of additional synchronous generator dispatch, and therefore potential unit contracting over time, required to meet the system strength requirements with the other option portfolio 3 solutions in place.

Figure 9 Victorian synchronous generator operating hours, option portfolio 3 relative to the reference case



5.4 Option portfolio 4 – The same technology types as option portfolio 3, except with accelerated procurement of synchronous condensers

Option portfolio 4 includes exactly the same components as option portfolio 3, but expedites the timing of plant able to operate as synchronous condensers. Specifically:

- option portfolio 3 adds two Hazelwood SSN synchronous condensers in 2029, one Hazelwood SSN synchronous condenser in 2031, and one Hazelwood SSN synchronous condenser in 2034, and
- option portfolio 4 adds one Hazelwood SSN synchronous condenser in 2028, two Hazelwood SSN synchronous condensers in 2029, and one Hazelwood SSN synchronous condenser in 2034.

Option portfolio 4 is the same as option portfolio 3 from 2031 onwards.

This option has been developed to investigate whether expediting synchronous condensers is expected to be net beneficial. While AVP currently considers that the earliest realistic commissioning is 2029, option portfolio 4 applied an assumption proposed in response to the RFI that a synchronous condenser could be in place by 2028.

Option portfolio 4 is based on option portfolio 3 as option portfolio 3 it is the top-ranked portfolio (see section 9).

In total, option portfolio 4 involves five new plant able to operate as synchronous condensers over the assessment period (the same as option portfolio 3, and four fewer than under option portfolio 1).

The specific components included in this portfolio, for meeting both the minimum and efficient system strength requirements, are summarised in Table 10.

Table 10 Option portfolio 4 – Summary of components

Financial year	Minimum fault levels	Efficient level
2026	Existing generators, including conversion of some units to be capable of operating in synchronous condenser mode 1 x Existing SC Red Cliffs SSN	Covered by minimum fault level requirements
2027		
2028	Same as 2027 + 1 x synchronous condenser Hazelwood SSN	900 MW GFM BESS Moorabool SSN
2029	Same as 2028 + 2 x synchronous condensers Hazelwood SSN	Same as 2028 + 350 MW GFL to GFM BESS Hazelwood SSN
2030		
2031		

Financial year	Minimum fault levels	Efficient level
2032		Same as 2031 + 500 MW GFL to GFM BESS Hazelwood SSN 350 MW GFL to GFM BESS Moorabool SSN 400 MW ISP forecast GFM BESS Hazelwood SSN
2033		Same as 2032 + 300 MW GFL to GFM BESS Moorabool SSN
2034	Same as 2033 + 1 x synchronous condenser Hazelwood SSN	
2035		Same as 2034 + 65 MW GFM BESS Red Cliffs SSN + 1 x 500 kV synchronous condenser Giffard (Gippsland) Offshore Wind Hub
2036		

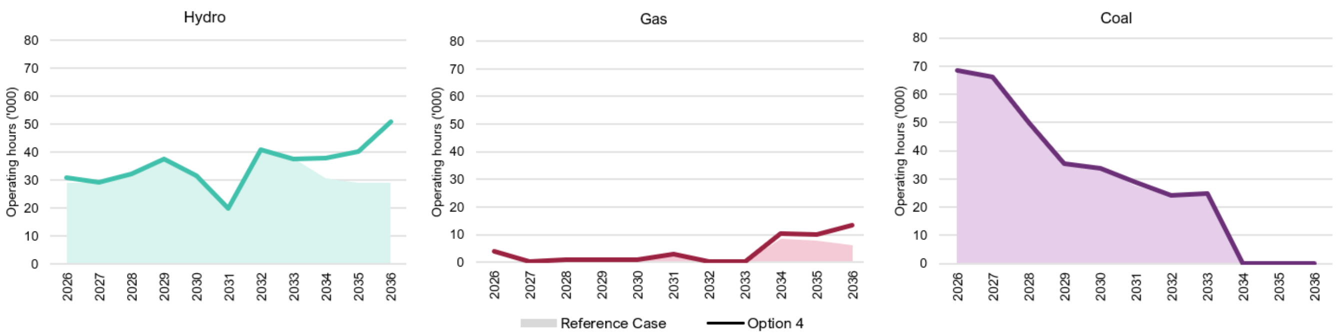
In present value terms, the total estimated capital cost of this option, over the life of the assets, is approximately $714.9 million, which can be broken down as follows:

- $698.4 million for synchronous condensers
- $7.8 million for GFL BESS to be GFM, and
- $8.7 million for upgrading an existing generator (to also be capable of operating in synchronous condenser mode).

Over the 11-year assessment period, and considering the terminal value (as outlined in Section 7.4), this equates to approximately $342.9 million and $33.1 million in total capital and operating costs, respectively.

Figure 10 shows the redispatch of existing generators in the Victorian system under option portfolio 4, relative to the energy-only dispatch of the reference case. This demonstrates the possible level of additional synchronous generator dispatch, and therefore potential unit contracting over time, required to meet the system strength requirements with the other option portfolio 4 solutions in place.

Figure 10 Victorian synchronous generator operating hours, option portfolio 4 relative to the reference case



5.5 The base case

Consistent with the RIT-T requirements, the assessment undertaken in the PADR compares the costs and benefits of each portfolio option to a 'do nothing' base case for each scenario. The base case is the (hypothetical) projected case if no action is taken, that is:

> *"The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented"* [39].

The base case for this PADR assumed no proactive investment in meeting the system strength requirements in Victoria, beyond investments that were committed to separately from, and ahead of, this RIT-T. These committed investments, which were also considered as committed investments in assessing each option portfolio, include:

- Koorangie Battery Energy Storage System (KESS) System Strength Support Agreement, contracting 120 MVA of GFM BESS capacity at Koorangie Terminal Station until approximately 2045
- Ararat Synchronous Condenser System Strength Support Agreement, contracting 250 MVA of synchronous condenser capacity at Ararat Terminal Station until approximately 2045, and
- Red Cliffs SSN shortfall services agreements, contracting up to 145 MVA of existing synchronous condenser capacity in the Red Cliffs SSN area until 31 July 2026.

The Victorian Government has made the KESS and Ararat Synchronous Condenser agreements available to meet Victoria's system strength requirements, which has reduced the need for additional system strength services in Victoria to support new IBR. Other than the committed investments noted, the RIT-T assessment only assumed the use of existing synchronous generators to meet the system strength requirements under the base case, resulting in very high forecast levels of unserved energy in the future as existing synchronous generators exit the market.

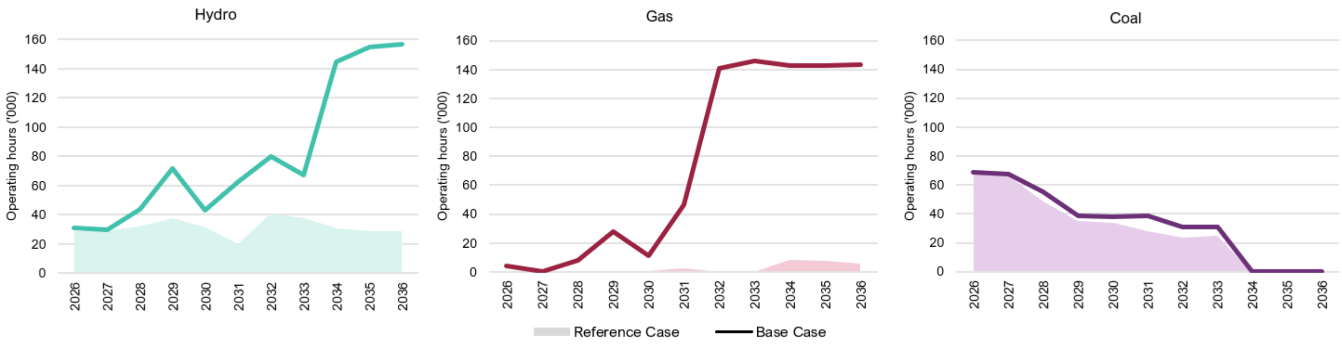
While this is not a situation AVP plans to encounter, and the NER obligations and this RIT-T have been initiated specifically to avoid them, the assessment is required under the RIT-T to consider this base case as a common point of reference when estimating the net benefits of each credible option. To be clear, AVP does not intend to let power system security decline in this way.

While the forecast unserved energy due to insufficient system strength is extremely high, it is ultimately not considered material for the comparison of the options in the RIT-T assessment, due to each option portfolio avoiding it equally, given they are each designed to meet the system strength requirements in the same way. While the avoided unserved energy has been quantified and presented at the start of Section 9 (the NPV results), AVP removed it for the remainder of the PADR to allow for a more meaningful comparison of the real differences in the costs and benefits of each option portfolio (as explained in Section 9.1).

Figure 11 shows the redispatch of existing generators in the Victorian system under the base case, relative to the energy-only dispatch of the reference case. This demonstrates the possible level of additional synchronous generator dispatch required to meet the system strength requirements prior to 2030 (at which point there are insufficient existing synchronous machines available to meet the requirements) if no other proactive system strength solutions were put in place.

[39] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 22.

Figure 11 Victorian synchronous generator operating hours, counterfactual base case relative to the reference case



The base case (and the options cases) assumed minimum synchronous unit commitment, as a proxy for more realistic bidding while maintaining a short-run marginal cost bidding approach. The synchronous unit commitment also provides a form of a system strength constraint for the other states.

Once the minimum unit commitments cease, it was assumed that other states would be maintaining system strength in their regions, predominantly through the use of synchronous condensers or already committed GFM BESS (which would not impact energy dispatch outcomes, so did not need to be modelled explicitly). For all cases, specific system strength constraints were developed for the Victorian region, as outlined in Section 7.2.

5.6 Land, environmental and social considerations

In the PSCR, AVP made an initial assessment of land availability to identify preferred credible options of installing three 250 megavolt amperes reactive (MVAr) synchronous condensers connected at Moorabool 500 kV, Bulgana Terminal Station 500 kV and a new proposed terminal station at Kerang 500 kV to be delivered by VNI West.

Updated analysis for the PADR presents the number of new network and non-network assets connecting to nominated host terminal stations to meet system strength needs at each system strength node.

While a shortlist of sites for new network components has been presented as part of the credible options described in Section 6.1, other sites with similar technical effectiveness and similar ability to host new components could form part of the option portfolios instead. Therefore, any sites ultimately selected to host assets providing contracted services will be assessed through the procurement process, which is expected to include consideration of environmental and social impacts and value for money, balancing technical effectiveness with service provision cost.

AVP acknowledges there may be temporary impacts during construction of new assets, and the siting of assets to support system strength services should be carefully considered to minimise potential environmental and social impacts. The option portfolios are not anticipated to cause significant social license risks during operation for communities surrounding sites ultimately selected to host assets. There may be other requirements that need to be considered as part of planning and environment approval processes. AVP has presented an indicative build period that factors in time and estimated costs of planning and environmental approval processes in Section 6.1.2.

The analysis in this PADR is based on desktop available information only, is subject to change, and has not been informed by any field investigations, community or landholder engagement, or the specific requirements of any planning and environmental approval processes relevant at the time. Further detailed studies assessing the potential environmental and planning impacts will form part of the relevant planning and approval processes for the option portfolios.

6 Estimating option costs

This section outlines how the various option components have been costed for the purposes of the PADR assessment.

The cost estimation approach adopted includes a mixture of specific costs proposed by proponents and the use of cost information contained in AEMO's 2024 ISP Inputs and Assumptions Workbook, including the AEMO Transmission Cost Database.

All option portfolios have been costed in accordance with the RIT-T framework. The procurement process accompanying this RIT-T aims to identify the specific lowest cost solutions and the ultimate cost to consumers will be determined from these costs.

6.1 Components included in the four option portfolios

The sections below outline how the various components included in the four option portfolios have been costed.

All option portfolios have been costed in accordance with the RIT-T framework and include the costs incurred in constructing or providing the option, the operating and maintenance costs, and the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the credible option (where applicable)[40]. As required under the RIT-T Application Guidelines[41] and reconfirmed in the AER guidance note[42], funds that move between participants, such as non-network proponent offer costs above the economic cost estimated for the purposes of the RIT-T, have been treated as a wealth transfer and do not affect the calculation of the final net economic benefit under the RIT-T. The procurement process accompanying this RIT-T aims to identify the specific lowest cost solutions and the ultimate cost to consumers will be determined from these costs.

6.1.1 Existing and committed/anticipated grid-forming BESS

AVP has not included a capital cost for these components in the analysis, because the costs were assumed to be sunk and/or included in the base case. No upgrade cost was assumed because AVP treated all new BESS as being GFM, based on recent connection enquiries and application information from AEMO's Victorian Connections team.

6.1.2 New plant able to operate as synchronous condensers

All new plant able to operate as synchronous condensers have been costed in the RIT-T assessment as synchronous condensers and assumed to have a capital cost of $193.6 million (in 2023-24 dollars). This has been sourced from the AEMO TCD, version number 4-0, and escalated to be in 2023-24 dollars.

[40] AEMC, *National Electricity Rules version 227*, March 2025, NER 5.15A.2(8).

[41] AER, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024, p. 59.

[42] AER, *The Efficient Management of System Strength Framework AER Guideance Note*, December 2024, p. 23.

Common synchronous condenser costs have been applied, regardless of location. Although shortlisted sites have been identified based on their ability to host new assets, considering technical, environmental and social factors, the ultimate location of assets contracted to provide system strength services will be determined through the procurement process, and overall, each area is expected to have similar known and unknown risks that are accounted for within the accuracy class of the cost estimate applied. AVP included standard connection assets assumed necessary to connect to the Declared Shared Network in the synchronous condenser costs.

The capital costs of new synchronous condensers applied in this PADR were developed to a class 5A (+/- 30% accuracy) estimate using AEMO's TCD and have been escalated to 2023-24 dollar terms based on the Consumer Price Index (CPI).

The TCD is substantially based on the Association for Advancement of Cost Engineering (AACE) international classification system commonly used in many industries[43]. The TCD enables the selection of known and unknown risks for each build component to reflect the level of project complexity and risks that will or could arise during further development of credible options:

- Known risks:
  - Compulsory acquisition.
  - Cultural heritage.
  - Environmental offset risks.
  - Macroeconomic influences.
  - Market activity.
  - Geotechnical conditions.
  - Outage restrictions.
  - Weather delays.
- Unknown risks:
  - Productivity and labour cost.
  - Plant procurement costs.
  - Project overheads.
  - Scope and technology.

Known and unknown risks, in line with the TCD, were produced as a proportion of the total cost and considered a contingency in line with AEMO's Mott MacDonald: Transmission Cost Database Update final report released in July 2023[44]. A contingency allowance of $23.2 million, in undiscounted terms and without factoring in a terminal

---

[43] The approach taken in the TCD differs from the AACE system in two superficial ways – see AEMO, 2023 *Transmission Expansion Options Report*, September 2023, p 21, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-planisp/current-inputs-assumptions-and-scenarios.

[44] As referenced in *AEMO Transmission Cost Database, Building Blocks Costs and Risk Factors Update Final Report*, 24 July 2023, prepared by Mott MacDonald, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database.

value, was included in all new synchronous condenser cost estimates, reflecting the known and unknown risks selected in line with the TCD.

AVP also assumed an annual operating and maintenance cost for synchronous condensers of 1% of the upfront capital expenditure[45].

AVP estimates build periods to be three years for synchronous condensers[46] and two years for BESS, starting after a future procurement process contract award is complete. These indicative build periods provide time to commence long-lead procurement and secure land, planning and environmental approval processes prior to construction, as well as a period in which testing is conducted prior to in-service dates for operation identified in Section 6.1.

6.1.3 Upgrading grid-following BESS to be grid-forming

The cost of upgrading committed/anticipated GFL BESS to be GFM has been assumed to be a flat $2 million per BESS (in 2023-24 dollars). This has been informed through responses to the RFI and reflects the costs associated with the NER 5.3.9 processes (to enable GFM mode).

This upgrade cost was assumed to be a once-off cost, not involving any ongoing additional operating or maintenance costs (since the upgrade is effectively just a procedural step that needs to be undertaken, mostly involving power system analysis to demonstrate grid code compliance and legal fees to amend connection agreements).

While this upgrade cost has not been estimated using the AACE cost estimate classification system, the approach taken is considered more suitable for these costs given they are not covered in the TCD. AVP notes that this assumed cost was ultimately found to not be material in the PADR assessment (as outlined in Section 9.6.1).

6.1.4 'Generic' grid-forming BESS from the IBR forecasts

As with existing and committed/anticipated grid-forming BESS, AVP has not included a capital cost for this component in the analysis, because the costs were assumed to be in the base case. AVP did not assume any upgrade cost, treating all new BESS as being GFM based on recent connection enquiries and application information from AEMO's Victorian Connections team.

6.1.5 Upgrading an existing generator (to also be capable of operating in synchronous condenser mode)

The cost of upgrading an existing synchronous generator to also be capable of operating in synchronous condenser mode has been assumed at a total capital cost of $10 million (in 2023-24 dollars). This cost covers conversion of multiple units of an existing generator, has been informed through responses to the RFI, and reflects the minor station works required to enable synchronous condenser mode.

AVP also assumed an annual operating and maintenance cost of 1% of the upfront capital expenditure.

---

[45] As referenced in AEMO, *Transmission Expansion Options Report*, September 2023, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[46] The one exception is for the first accelerated synchronous condenser under option portfolio 4, which was assumed in 2028 (a two-year assumed build period).

While this upgrade cost has not been estimated using the AACE cost estimate classification system, the approach taken is considered more suitable for these costs given they are not covered in the TCD.

6.2 Other components considered but not ultimately included in the four option portfolios

All other components that were proposed (such as STATCOMs and Magnetically Controlled Shunt Reactors) were ultimately not included in the four option portfolios on account of them not yet being 'anticipated' or 'committed' under the RIT-T, and therefore having significantly greater costs than the components outlined above (without being expected to deliver any additional market benefits). Moreover, each of these potential solutions is only able to contribute to the efficient level, and not the minimum level, requirements.

Conversion of existing plant to operate as synchronous condensers was included in the development of the options portfolio and included where it formed part of the least cost option portfolio.

6.3 Treatment of 'anticipated' and 'committed' projects

In preparing this PADR, AVP engaged with solution proponents on the commitment status of their projects. Specifically, AVP liaised directly with proponents to determine whether their solutions are considered 'anticipated' or 'committed' under the RIT-T (that is, whether they meet the criteria for these classifications under the RIT-T).

The RIT-T defines a 'committed' project as one that meets the following criteria[47]:

- the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement
- the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction
- contracts for supply and construction of the major components of the necessary plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments
- the necessary financing arrangements, including any debt plans, have been finalised and contracts executed, and
- construction has either commenced or a firm commencement date has been set.

An 'anticipated' project is defined as one that does not meet all of the criteria of a committed project but is in the process of meeting at least three of the criteria[48].

All projects AVP considered as 'anticipated' or 'committed' in the PADR assessment have the same status in AEMO's NEM Generation Information January 2025 workbook[49]. Where proponents suggested projects should be

[47] AER, *Regulatory Investment Test for Transmission*, August 2020, p. 13.

[48] AER, *Regulatory Investment Test for Transmission*, August 2020, p. 13.

[49] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

considered ‘anticipated’ but were not classified as such in this version of AEMO’s NEM Generation Information workbook, AVP assessed the projects against the RIT-T criteria based on information provided by proponents, and all these projects were ultimately determined to be ‘publicly announced’ for the PADR assessment.

Where projects have been determined as ’anticipated’ or ‘committed’ under the RIT-T, they have been included in the base case and option cases for AVP’s assessment. Since costs and/or market benefits associated with the provision of system strength from anticipated or committed projects are netted off between the base case and portfolio options, AVP only estimated project costs to the extent they differed to what was assumed in the base case.

7 Estimating market benefits

AVP estimated four categories of market benefit under the RIT-T as part of this PADR assessment, including the recently added 'changes in Australia's greenhouse gas emissions'. Wholesale market modelling was used to estimate these categories of market benefits.

The four options considered were found to have similar levels of market benefit over the first five years of the assessment period. This is predominantly driven by the need for the minimum fault level requirement to be met by synchronous machines, and the feasibility of options available within that period being relatively limited, considering the expected procurement lead times for development of new assets such as plant able to operate as synchronous condensers.

Competition benefits, option value, changes in network losses, voluntary load curtailment, and ancillary service costs are not expected to be material for this RIT-T, so were not estimated.

7.1 Expected market benefits from the option portfolios

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken with the 'state of the world' with each of the credible portfolio options in place, separately. 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 and storage investment as well as unrelated future transmission investment.

The specific categories of market benefit under the RIT-T that have been modelled as part of this PADR are:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch
- changes in Australia's greenhouse gas emissions
- changes in costs for parties, other than the RIT-T proponent (that is, changes in investment in generation and storage capital and fixed and variable operating and maintenance costs), and
- changes in involuntary load curtailment.

AVP engaged Jacobs to conduct wholesale market modelling to quantify these benefits. A wholesale market modelling approach similar to the short-term (ST) time-sequential modelling approach used in the ISP has been applied to estimate the market benefits associated with each credible option included in this RIT-T assessment[50].

While the remainder of this Section 7.1 provides further detail on the approach taken to estimating each of these market benefits, it is also discussed in greater detail in the accompanying Jacobs market modelling report.

[50] The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the transmission network service provider(s) (TNSP(s)) can provide reasons why this methodology is not relevant. See AER, *Regulatory Investment Test for Transmission*, August 2020, p. 8.

7.1.1 Changes in fuel consumption in the NEM

This category of market benefit is expected where credible option portfolios result in different patterns of generation and storage dispatch across the NEM, compared to the base case. This is found to be the largest category of market benefit estimated across the option portfolios (noting that the avoided unserved energy estimates have been removed from the assessment, as explained in Section 7.1.4 below)

In the base case, renewable energy sources are curtailed in favour of dispatching existing synchronous machines to meet the growing system strength requirements. All option portfolios see a considerable buildout of plant capable of operating as synchronous condensers and GFM batteries, which reduce the need for significant additional coal, gas and hydro redispatch relative to the base case and therefore result in net market benefits associated with avoided fossil fuel consumption.

7.1.2 Changes in Australia's greenhouse gas emissions

Following the change to the National Electricity Objective (NEO) in September 2023 to include changes in Australia's greenhouse gas emissions, and the subsequent change to the NER on 1 February 2024, RIT-T proponents now need to include a new benefit category to cater for changes in emissions in RIT-T assessments (where material). This category was found to be the second largest category of market benefit estimated for each of the portfolio options.

Reductions in emissions under the option portfolio have been valued using the VER published by the AER. AVP also investigated sensitivities assuming +/- 25% on the VER value, consistent with guidance from Australia's Energy Ministers[51]. The VER is not considered in the dispatch of energy within the market model, instead being added to the resultant dispatch, considering emissions intensity values from the 2024 ISP Inputs and Assumptions Workbook, for each portfolio to estimate the economic benefits. This is consistent with the approach taken in the 2024 ISP, as required under the AER guidance and explanatory statement on valuing emissions reduction[52].

7.1.3 Changes in costs for other parties in the NEM

This category of market benefits is expected where the operational patterns of assets within portfolio options change in response to meeting system strength constraints, relative to the base case.

This market benefit class captures the differences in capital costs, fixed operations and maintenance (FOM) costs, variable operations and maintenance (VOM) costs, and generator start and stop costs. While these avoided costs have been estimated for each option, they were found to be relatively small compared to the avoided fuel and emissions costs.

7.1.4 Changes in involuntary load curtailment

Where no action is taken to meet Victoria's minimum and efficient level system strength requirements, there would be a significant deficit in system strength because of the withdrawal of coal generation and increasing renewable connections.

---

[51] See https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf.

[52] See https://www.aer.gov.au/system/files/2024-08/Amended%20VER%20MCE%20Statement.pdf.

In this hypothetical future, it is expected that AEMO would direct existing synchronous generators to operate, or constrain renewable generation (where possible) to maintain system security. If the efficient level of system strength is not met, the remaining renewable generation that is able to operate securely may be insufficient to meet system demand, which may lead to load shedding. If the minimum level of system strength is not met, voltage instability might occur and protection systems might not operate correctly, potentially leading to cascading failures and/or power system instability and, in the worst case, widespread and extensive power outage and power system plant damage.

While the forecast unserved energy due to insufficient system strength is extremely high, it is ultimately not considered material in the comparison of options for the RIT-T assessment, due to each option portfolio avoiding it equally, given they are each designed to meet the system strength requirements in the same way. While the avoided unserved energy has been quantified and presented at the start of Section 9 (the NPV results), AVP removed it for the remainder of the PADR to allow for a more meaningful comparison of the real differences in the costs and benefits of each option portfolio (as explained in Section 9.1).

Moreover, while AVP estimated unserved energy as part of this PADR assessment, it was only estimated based on the minimum fault level requirements, and not the efficient level requirements. While this approach significantly underestimates the expected level of unserved energy, it is considered proportionate under the RIT-T given the additional computational time to expand the calculations to cover the efficient level, which can also be met by first constraining down IBR generation to maintain a stable voltage waveform, and the fact that all option portfolios are designed to avoid the expected unserved energy equally.

Where AVP has quantified the changes in involuntary load curtailment at the start of Section 9, the modelling estimated the megawatt hours of unserved energy in each trading interval over the modelling period as a result of violations in minimum-level requirements, and then applied a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided unserved energy for each option. The exact amount of load to be shed at a node is not easily quantifiable, and a factor of 0.25 was applied to the system demand as a proportion of the (total) shortfall, reflecting that it is likely to be unnecessary to disconnect all the load on that node.

This estimate of the load to be shed is considered conservative, as the reduction in load at time of minimum demand would likely include a significant contribution of rooftop solar which is not included in the system demand. AVP adopted the AER's most recent assumptions for the Victorian VCR for the purposes of this assessment.

7.2 Market modelling has been used for the wholesale market benefits

AVP engaged Jacobs to undertake the wholesale market modelling to assess the market benefits expected to arise under each of the option portfolios.

Jacobs performed market modelling in PLEXOS®[53], which employed mixed integer programming to solve the unit commitment problem associated with Victorian synchronous generators to accurately reflect system strength contribution from each of these assets. This was carried out on the AEMO 2024 ISP database, which uses a 12-node framework.

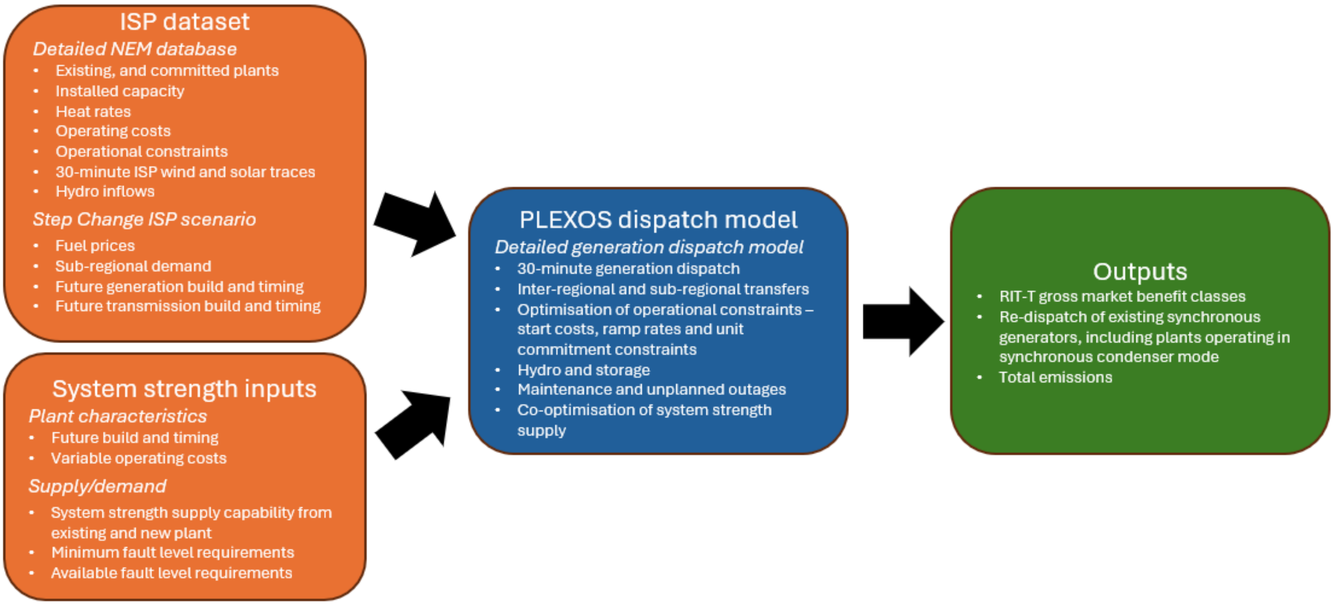
[53] PLEXOS® is an energy simulation software, developed by Energy Exemplar.

System strength constraints were integrated into the database to dispatch sufficient services to meet the system strength requirement. The dispatch was co-optimised for least cost system strength provision and energy demand, then evaluated in PSS®E to ensure the accuracy of the constraint equations and that the system strength requirement was met.

Input modelling assumptions were primarily based on the Final 2024 ISP *Step Change* scenario, including the 2024 ISP Inputs and Assumptions Workbook, with adjustments made for more recently announced changes to the retirement of coal-fired power stations, as well as unit commitment requirements in the first half of the assessment period as a proxy for more realistic bidding while maintaining a short-run marginal cost bidding approach. Transmission development was based on the 2024 ISP's optimal development pathway (ODP) and used the least cost generation expansion plan (candidate development path [CDP] 14).

The modelling undertaken by Jacobs assumed short-run marginal cost bidding, consistent with the ISP, as well as fit-for-purpose assumed synchronous unit commitment (in all regions of the NEM), to provide more realistic modelling outcomes. This aims to balance the risk of over-procurement of system strength solutions, while erring on the side of having sufficient system strength in the system.

Figure 12 Summary of the wholesale market modelling undertaken by Jacobs



Further details on the inputs and methodologies applied by Jacobs for estimating the market benefits of each option portfolio can be found in the Jacobs market modelling report accompanying this PADR.

7.3 Market benefits that are not expected to be material

Table 11 summarises the other categories of market benefit catered for under the RIT-T and why each is not considered material in this RIT-T assessment.

Table 11 Market benefit categories that are not expected to be material

Market benefit	Reason(s) why it is not considered material
Competition benefits	As the option portfolios considered in this PADR do not address network constraints between competing generators, and all credible options are expected to meet the system strength requirements, competition benefits are not expected to be material for this RIT-T assessment.
Option value	While each portfolio option is found to involve a number of flexible/modular elements, 'option value' is also not considered material for this RIT-T, on account of only one scenario being considered relevant for the assessment (as outlined in Section 8.1). Moreover, as outlined in Section 8.1, AVP considers that each portfolio option exhibits the same approximate level of flexibility and so does not consider materially different levels of option value across the portfolios.
Changes in voluntary load curtailment	As each option portfolio is designed to meet the system strength requirements in the same way, changes in voluntary load curtailment are expected to be common across all option portfolios, and have been excluded on this basis.
Changes in network losses	Network losses were not modelled because the market model was based on the ISP framework, which does not include any intra-regional flows for the Victorian region. Changes in network losses are more influenced by dispatch of power and are not anticipated to materially influence the rankings of net market benefits.
Differences in the timing of transmission investment	This benefit category relates to the costs, or timing, of unrelated transmission investment and typically captures intra-regional investment associated with the development of renewable energy zones (REZs) that could be avoided if an option portfolio is pursued. This category of market benefit is not considered material for this RIT-T assessment, as the option portfolios considered are not likely to significantly change the requirement for any planned augmentations. While the portfolio options may alter power flows, and therefore thermal loadings and voltages levels, in the system, and this has potential to impact the quantity of risk associated with the monitored limitations identified in the 2024 *Victorian Annual Planning Report* (VAPR), there is currently insufficient certainty around the need and timing of these investments to be able to ascribe benefits under this category. AVP notes, as set out in Section 9.6.1, that system strength can often contribute to the provision of inertia (and vice versa), and expects flywheels to be included as part of the synchronous condensers procured and commissioned as part of this RIT-T. However, the avoided alternate investment under the base case (retrofitting synchronous condensers to add flywheels at a later date to provide inertia) is not material to the outcome of this RIT-T. That is, at this stage, AVP expects that all option portfolios assessed will avoid this alternate investment equally. AVP also notes that the difference in the amount of synchronous condenser investment, and thus flywheel investment, across the option portfolios is not large enough to change the ranking of the option portfolios (driven largely by the relatively low cost of adding a flywheel to synchronous condenser as part of the initial build). AVP has therefore not explicitly modelled the benefit of avoiding this alternate investment as part of the PADR.
Changes in ancillary services costs	While the cost of frequency control ancillary services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following any increase to transfer capacity from the options, AVP considers that changes in FCAS costs are not likely to be materially different between options and are not expected to be material in the selection of the preferred option (because the quantity of GFM BESS is relatively similar across all option portfolios, independent of whether they are part of the option portfolio). FCAS costs are relatively small compared to total market costs and the market is relatively shallow. There are unlikely to be material changes between portfolio options to the costs of network support and control ancillary services (NSCAS), or system restart ancillary services (SRAS) because of the options being considered.

7.4 General cost benefit analysis parameters adopted

The PADR analysis considers an 11-year assessment period from 2025-26 to 2035-36. This period was determined by taking into account the interaction with the engineering exercise necessary for this PADR assessment, which suggests that only the immediate 10 years can be sufficiently and confidently assessed (the eleventh year has been included to reflect the terminal value of capital components). Overall, AVP considers it reflects an appropriate period given the horizon that forecasts are available and the size, complexity and expected asset lives of the options, as well as providing a reasonable indication of the costs and benefits over a long outlook period.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values has been calculated based on the undepreciated value of capital costs at the end of the analysis period and expected operating and maintenance cost for the remaining asset life.

A real, pre-tax discount rate of 7% has been adopted as the central assumption for the NPV analysis presented in this PADR, consistent with AEMO's 2024 ISP Inputs and Assumptions Workbook and the latest final *Inputs, Assumptions and Scenarios Report* (IASR)[54]. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. AVP therefore tested the sensitivity of the results to a lower bound discount rate of 3.63%[55]. AVP also adopted an upper bound discount rate of 10.5% (the upper bound in the 2024 ISP Inputs and Assumptions Workbook and the latest IASR)[54].

[54] AEMO, 2023 IASR, July 2023, p 123, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[55] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis. See AER, *TasNetworks – 2024-29 – Final decision – PTRM*, April 2024, WACC sheet.

8 Ensuring the robustness of the analysis

Each option portfolio has been assessed against the ISP *Step Change* scenario, consistent with how the system strength obligations are set by AEMO.

AVP used the assumptions in the 2024 ISP Inputs and Assumptions Workbook, or final 2023 IASR where not otherwise available, for assessments undertaken as part of this PADR (that is, both the portfolio option formation process and the wholesale market modelling).

AVP has undertaken a number of sensitivity tests to confirm the robustness of the RIT-T assessment, and the conclusions reached in this PADR.

8.1 The assessment considered the ISP *Step Change* scenario

AVP assessed each option portfolio against the ISP *Step Change* scenario, consistent with how its system strength obligations are set by AEMO[56]. The *Step Change* scenario is summarised by AEMO as achieving 'a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels'[57].

AVP did not use the other two ISP scenarios (*Progressive Change* and *Green Energy Exports*) in the analysis. This is because AVP does not consider them to be relevant in light of its current obligations, in which stable voltage waveform requirements are driven by AEMO's IBR forecasts, which have been determined by AEMO using the *Step Change* scenario.

Appendix A3 summarises the specific key variables that influence the net benefits of the options under the *Step Change* scenario. Additional detail can be found in the accompanying Jacobs market modelling report.

8.2 Sensitivity analysis

In addition to the core modelling, AVP also considered the robustness of the ranking of portfolios under the NPV assessment through undertaking a range of sensitivity tests.

Specifically, AVP investigated:

- 25% higher and lower VER values, consistent with guidance from Australia's Energy Ministers[58]
- 30% higher and lower assumed synchronous condenser costs (both capital and operating costs), consistent with the class of costs included in the transmission cost database
- 25% higher and lower GFM BESS upgrade costs

[56] This is also consistent with how both Transgrid and Powerlink have undertaken their system strength RIT-T analysis.

[57] AEMO, 2023 IASR, July 2023, p. 15 at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[58] See https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf.

- lower and higher commercial discount rates (as discussed in Section 7.4), and
- where the Gippsland and Portland offshore wind IBR are assumed to self-remediate (to reflect current uncertainty around whether self-remediation will occur).

AVP also estimated the ‘boundary value’ for key variables (such as assumed capital costs) beyond which the outcome of the analysis would change. As there are inter-dependencies between many of these variables, the boundary values are indicative only and assume that other variables do not change.

9 Net present value analysis

Option portfolio 3 – which includes a 'generic' 400 MW GFM BESS from the IBR forecasts – is found to be the top-ranked option at this point in time, delivering at least $3.85 billion in net benefits over the assessment period, in present value terms.

The top ranking attributed to option portfolio 3 is driven primarily by significant avoided generator fuel costs and lower emissions with option portfolio 3 in place. These two sources of benefit are derived from a reduced need for existing synchronous machines in Victoria to provide system strength due to the introduction of dedicated system strength assets such as GFM BESS and plant able to operate as synchronous condensers. Option portfolio 3 also avoids substantial unserved energy relative to the base case.

9.1 Summary of the results

Option portfolio 3 (where a generic GFM BESS from the IBR forecasts is included) is found to generate substantial estimated net benefits over the assessment period – at least[59] $3.85 billion in present value terms – and is the top-ranked option overall.

The analysis also finds that:

- all options are found to deliver substantial net market benefits (driven both by significant avoided unserved energy and wholesale market benefits relative to the base case)
- accelerating synchronous condensers is not found to deliver net benefits; that is, option portfolio 4 is found to have lower estimated net benefits than option portfolio 3), and
- upgrading significant additional committed/anticipated GFL BESS to be GFM (option portfolio 2) is found to be the effectively second-ranked[60] option, and sits ahead of only using existing generation, committed/anticipated GFM BESS (including one that upgrades from GFL to GFM) and new synchronous condensers (option portfolio 1).

Figure 13 summarises the headline NPV results for each of the option portfolios.

[59] 'At least' is used here on account of the avoided unserved energy estimates only being based on the minimum level requirements (as outlined in Section 7.1.4). If the unserved energy was estimated to take account of the efficient level requirements as well, the expected net benefit of all option portfolios would be significantly greater.

[60] Throughout the PADR, option portfolio 2 is referred to as the 'effectively second-ranked' option since option portfolio 4 (the technically second-ranked option) is just option portfolio 3 with two accelerated synchronous condensers, as opposed to a distinct standalone option.

Figure 13 Headline net benefits of each option portfolio under the *Step Change* scenario (including avoided unserved energy)

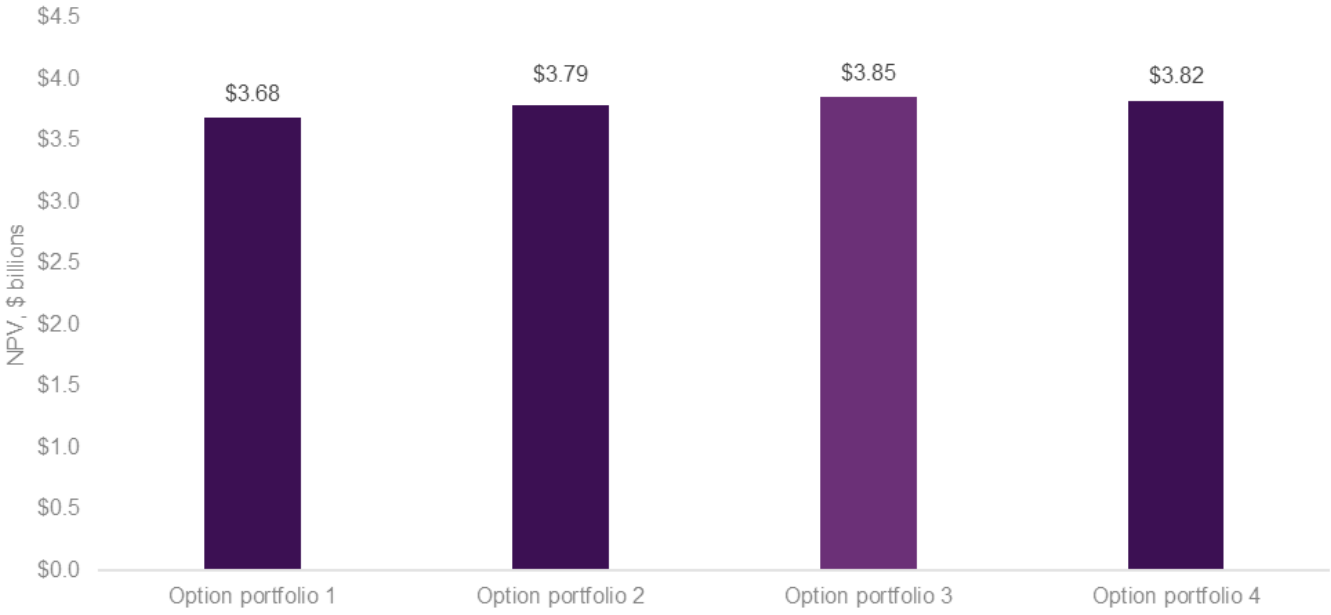
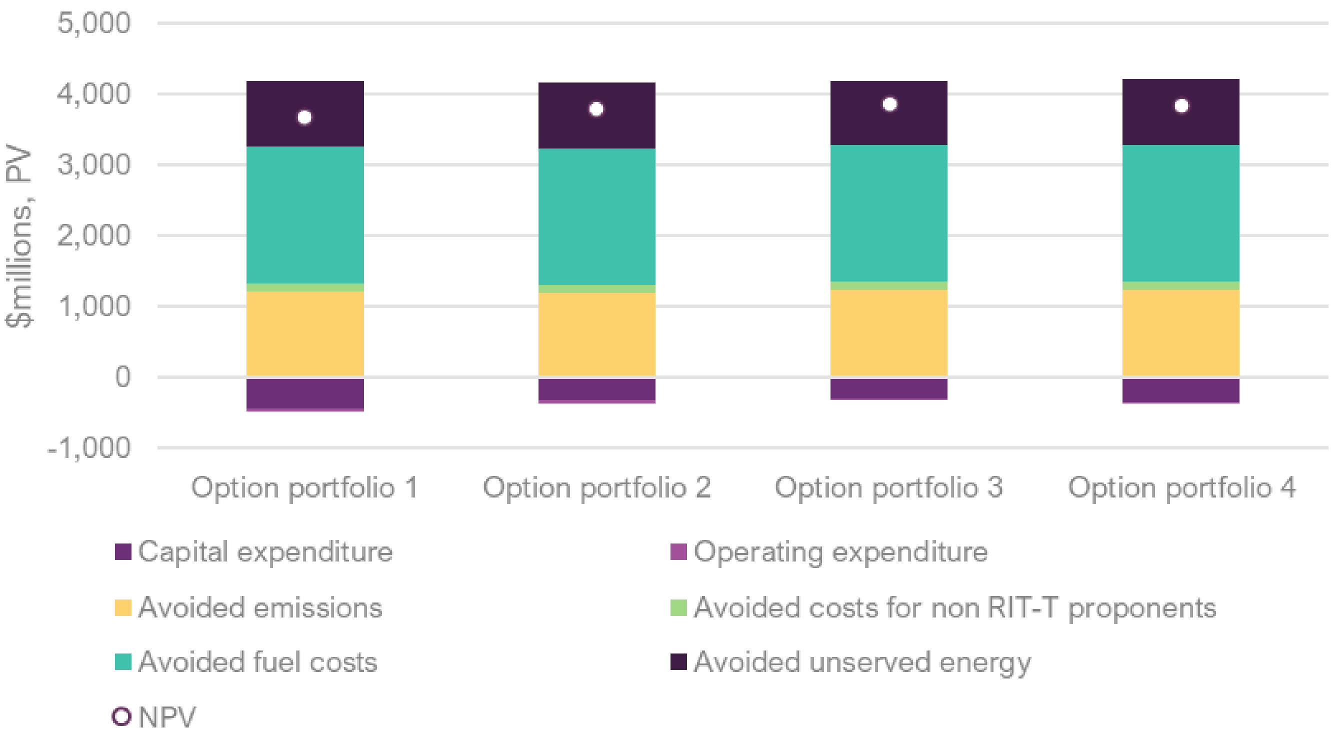


Figure 14 shows the composition of the estimated net market benefits for each option portfolio.

Figure 14 Breakdown of estimated net benefits of each option portfolio under the *Step Change* scenario (including unserved energy)



Since all option portfolios have been designed to avoid the catastrophic outcomes of having insufficient system strength under the base case, they all avoid the same (substantial) level of unserved energy under the base case.

This unserved energy is expected to occur under the base case from 2031, and all option portfolios avoid approximately $930 million of unserved energy (in present value terms) in aggregate across the assessment period (as shown in Figure 14 above).

For the remainder of this PADR, AVP has removed this common avoided unserved energy from the NPV assessment, given it does not help identify the top-ranked option, and removing it makes the real differences in other costs and benefits across the option portfolios more clearly seen, as shown in Figure 15.

Figure 15 Headline net benefits of each option portfolio under the *Step Change* scenario (excluding common avoided unserved energy)

The following sections discuss the results for each option portfolio in turn, and use the results excluding the common avoided unserved energy.

9.2 Option portfolio 1 – Existing generation plus committed/anticipated GFM BESS and new synchronous condensers

Option portfolio 1 assumed that existing synchronous generation can assist with providing system strength, as well as committed and anticipated GFM BESS (for the efficient level), including one that upgrades from GFL to GFM, and new synchronous condensers (for the minimum and efficient levels).

Option portfolio 1 is made up of:

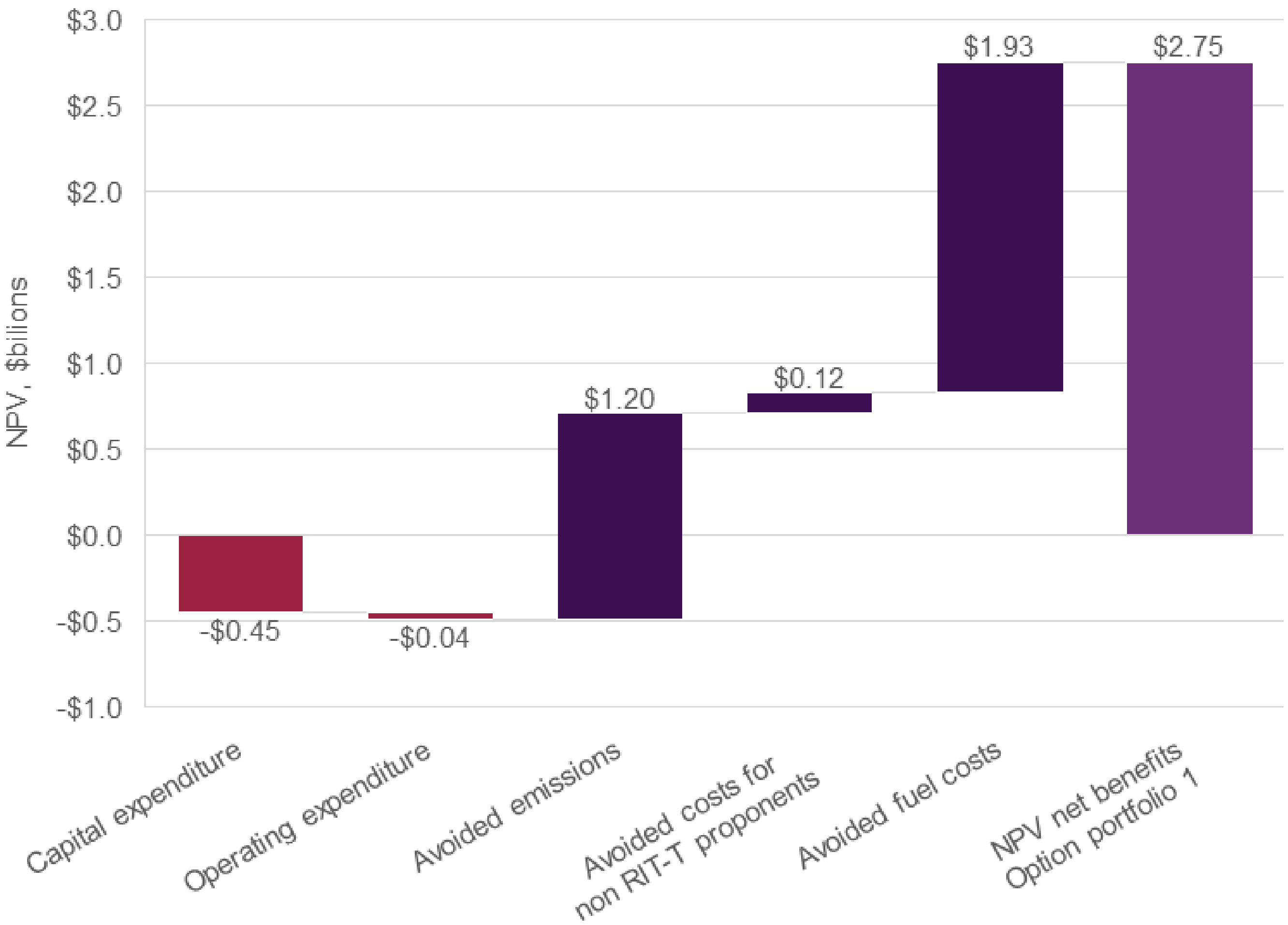
- existing generation for both the minimum and efficient levels
- an increasing number of synchronous condensers over the assessment period (up to five by 2036) to meet the minimum fault levels, and

- a further five synchronous condensers between 2032 and 2036 (at Giffard, Bulgana and Kerang), as well as 900 MW of GFM BESS at the Moorabool SSN and 350 MW of BESS capacity that converts from GFL to GFM at the Hazelwood SSN, to meet the efficient level.

In total, option portfolio 1 involves nine new synchronous condensers over the assessment period. It also assumed the use of one existing synchronous condenser (however, this was assumed in all four option portfolios).

Overall, option portfolio 1 is found to deliver at least[61] $2.75 billion in net benefits (in present value terms) over the assessment period. This result is driven primarily by significant avoided generator fuel costs and lower emissions with the portfolio option in place, compared to the base case (as shown in Figure 16).

Figure 16 Composition of the estimated net market benefits for option portfolio 1 (NPV, $billions)



Both the avoided fuel costs and lower emissions of portfolio option 1 relative to the base case stem from a reduced need for the re-dispatch of synchronous machines. This is primarily due to the introduction of dedicated system strength assets such as GFM BESS and synchronous condensers reducing the need to dispatch existing synchronous generators for system strength reasons.

[61] 'At least' is used here and elsewhere in the PADR on account of the approach taken to removing the common avoided unserved energy in the assessment to allow for a meaningful comparison across options (as outlined in Section 9.1). If the full unserved energy is added to the analysis, the expected net benefit of all option portfolios would be significantly greater.

9.3 Option portfolio 2 – The same technology types as option portfolio 1 plus upgrading additional GFL BESS to be GFM

Option portfolio 2 includes the same technology types as option portfolio 1, plus upgrading additional committed/anticipated GFL BESS to be GFM. This portfolio has been developed to determine, through comparison with option portfolio 1, whether upgrading additional GFL BESS to be GFM is considered optimal compared to investing in new synchronous condensers.

The upgrading of GFL BESS to be GFM for meeting the efficient level ramps up over time and allows the following BESS capacities to be used *in addition to those included for option portfolio 1*:

- 500 MW BESS at the Hazelwood SSN and 350 MW BESS at the Moorabool SSN from 2032
- a further 300 MW BESS at the Moorabool SSN from 2033, and
- a 65 MW BESS at the Red Cliffs SSN from 2035.

This allows the following to be avoided to meet the efficient fault levels, compared to option portfolio 1:

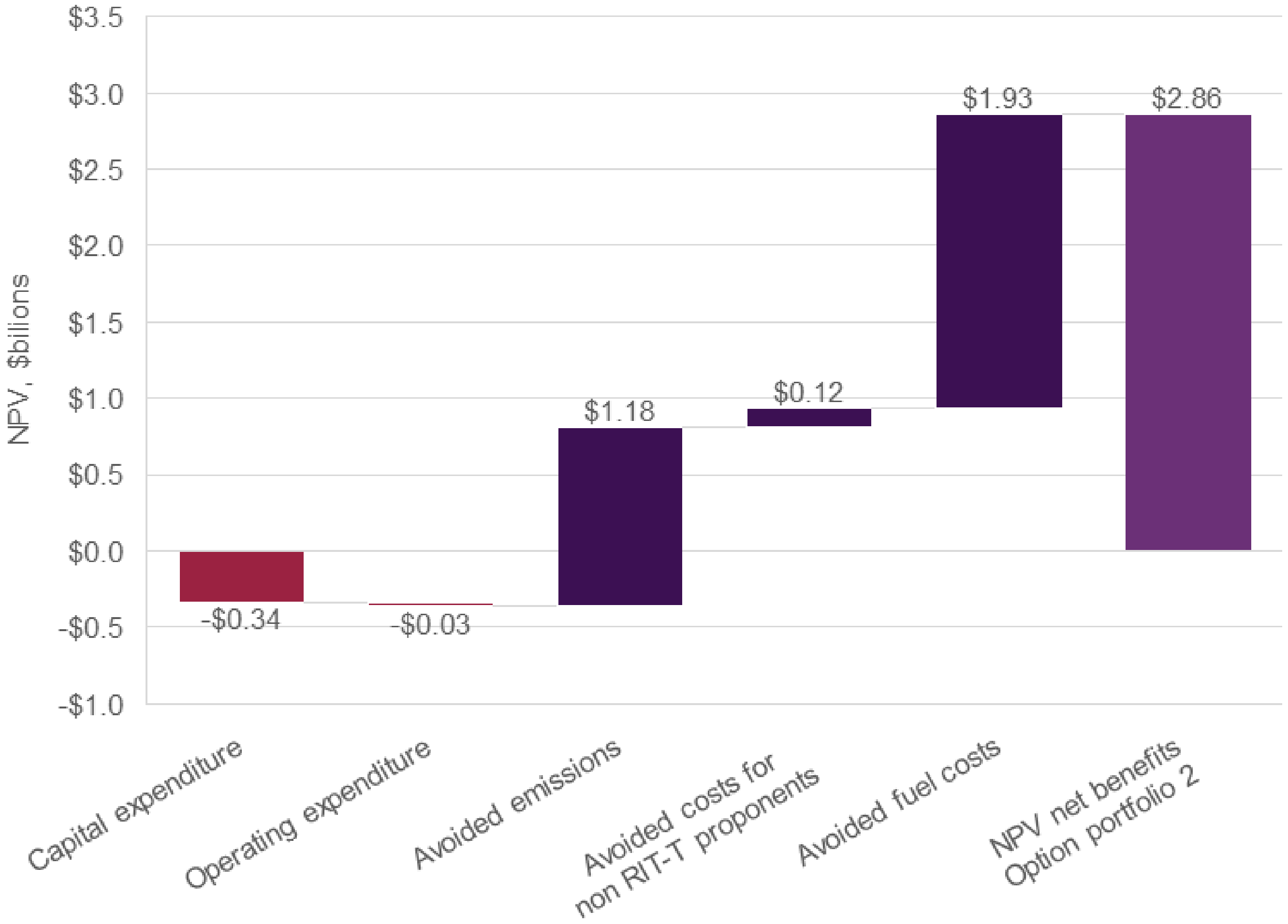
- two synchronous condensers at the Giffard (Gippsland) Offshore Wind Hub 500 kV in 2031 and 2032, although option portfolio 2 has one more synchronous condenser at the Hazelwood SSN in 2031
- one Bulgana Terminal Station 500 kV synchronous condenser in 2033, and
- one Kerang Terminal Station 500 kV synchronous condenser in 2035.

In total, option portfolio 2 involves six new synchronous condensers over the assessment period (three fewer than under option portfolio 1).

Overall, option portfolio 2 is found to deliver at least $2.86 billion in net benefits (in present value terms) over the assessment period. As with option portfolio 1, this result is driven primarily by significant avoided generator fuel costs and lower emissions with the portfolio option in place, compared to the base case (as shown in Figure 17).

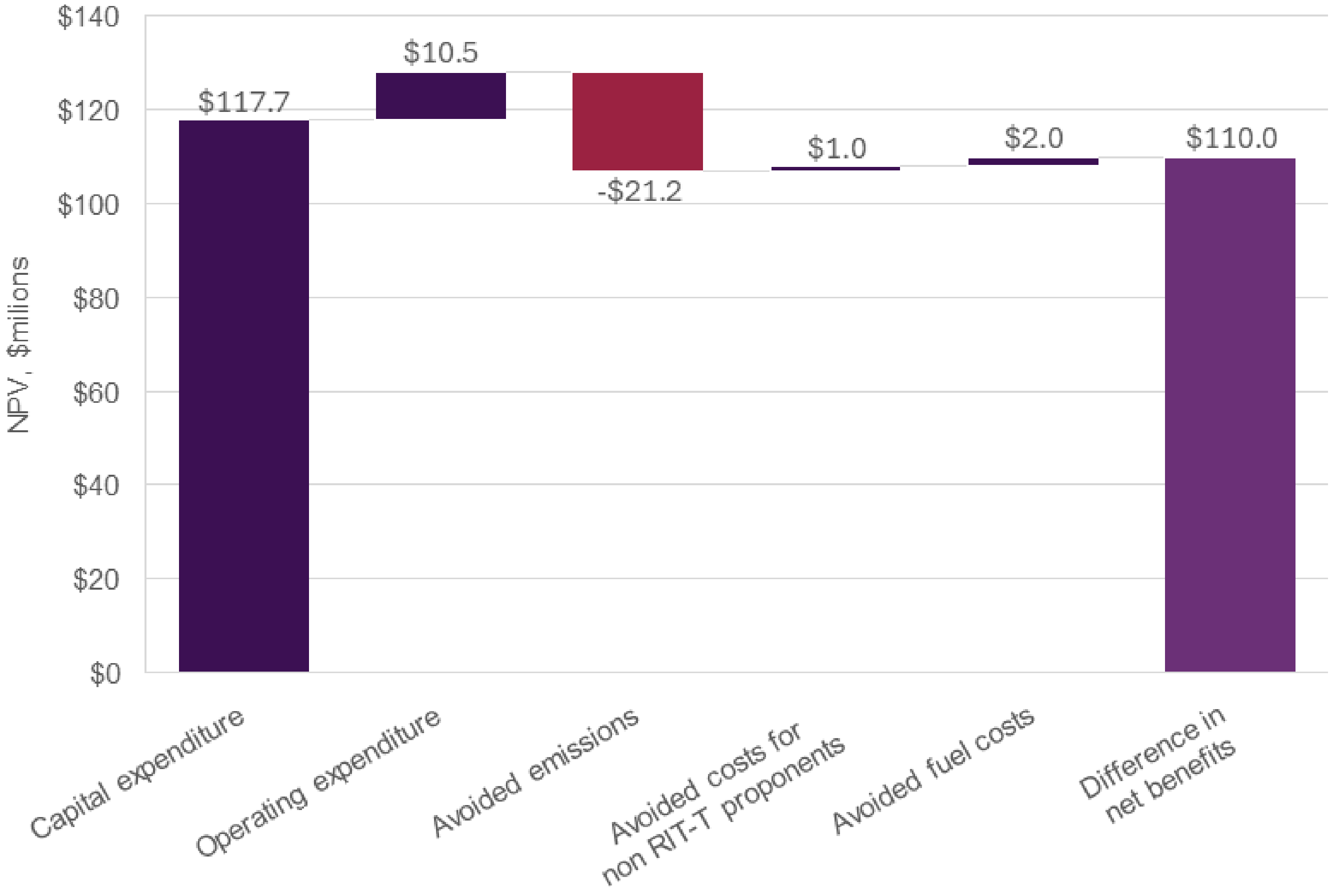
In present value terms, option portfolio 2 involves approximately $340 million of capital costs relative to the base case, which is approximately $112 million lower than option portfolio 1 due to the capital expenditure it avoids.

Figure 17 Composition of the estimated net market benefits for option portfolio 2 (NPV, $billions)



Under this option portfolio, the expected net market benefits increase by approximately $110.0 million (in present value terms), compared to under option portfolio 1. This increase is driven primarily by the avoided capital expenditure it allows for by avoiding significant investment in new synchronous condensers (as shown below in Figure 18).

Figure 18 Key changes in the composition of the estimated net market benefits for option portfolio 2, compared to option portfolio 1 (NPV, $millions)



The slightly greater level of emissions with option portfolio 2 in place, compared to option portfolio 1, is primarily driven by differences in 2031, 2032 and 2033. This is attributed to the slower build-out of synchronous condensers, with more coal-fired generation needing to be dispatched (in these three years, there is between 0.5% and 1.9% more coal-fired dispatch than under option portfolio 1).

9.4 Option portfolio 3 – The same technology types as option portfolio 2 plus a GFM BESS from the IBR forecasts

Option portfolio 3 involves the same technology types as option portfolio 2, plus the use of a generic GFM BESS from the IBR forecasts to help meet the efficient level requirements.

Specifically, in addition to the BESS assumed in option portfolio 2 from 2032, option portfolio 3 also assumed the use of a generic 400 MW GFM BESS at the Hazelwood SSN that is not yet considered ‘anticipated’ or ‘committed’ under the RIT-T to meet the efficient level requirements from that point on. This BESS allows the following differences to option portfolio 2:

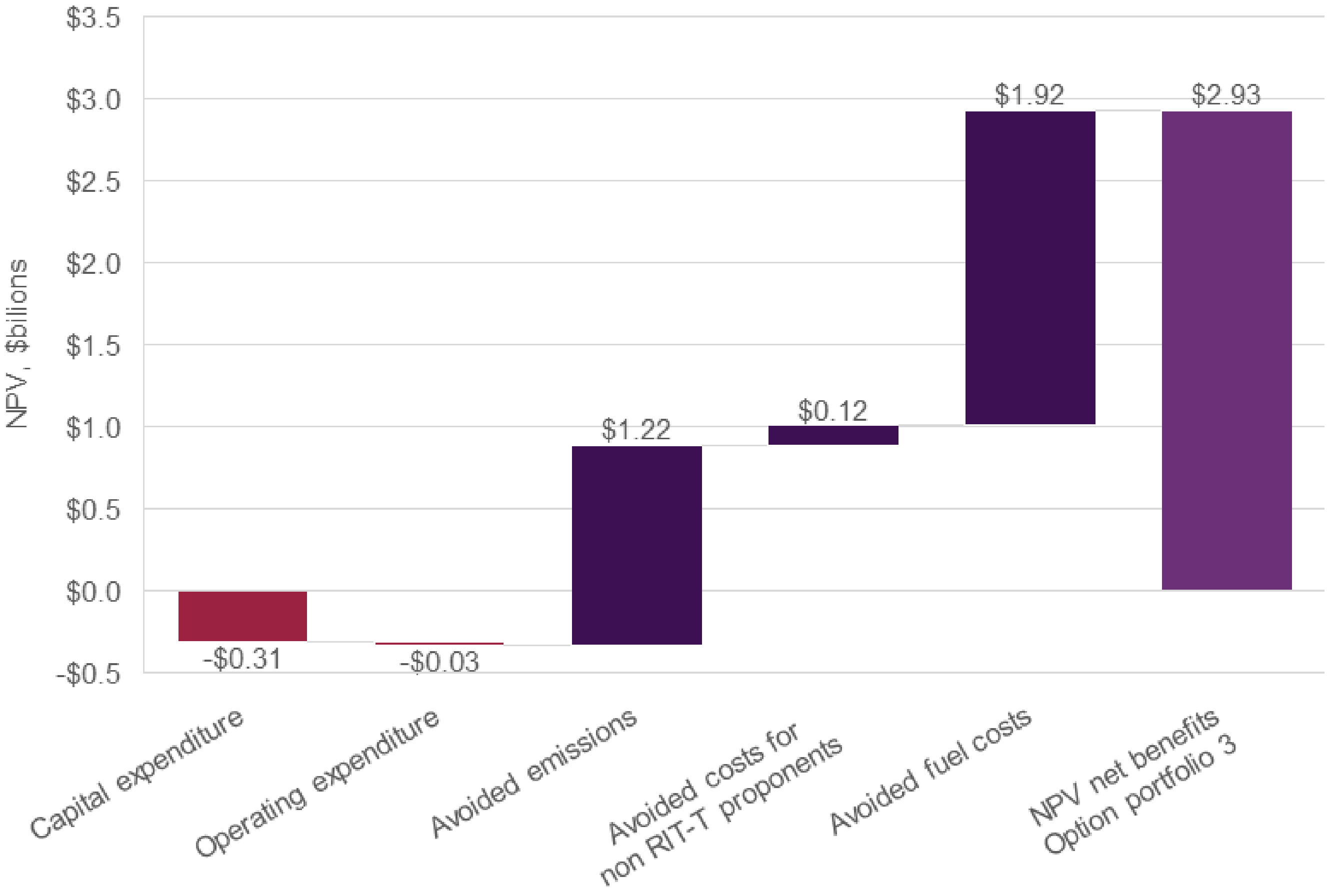
- one 500 kV synchronous condenser at Giffard (Gippsland) Offshore Wind Hub to be deferred by one year (from 2034 to 2035), and

- one 500 kV synchronous condenser at Giffard (Gippsland) Offshore Wind Hub to be avoided in 2036.

In total, option portfolio 3 involves five new synchronous condensers over the assessment period (four fewer than under option portfolio 1).

Overall, option portfolio 3 is found to deliver at least $2.93 billion in net benefits (in present value terms) over the assessment period. As with the preceding two options, this result is driven primarily by significant avoided generator fuel costs and lower emissions with the portfolio option in place, compared to the base case (as shown below in Figure 19).

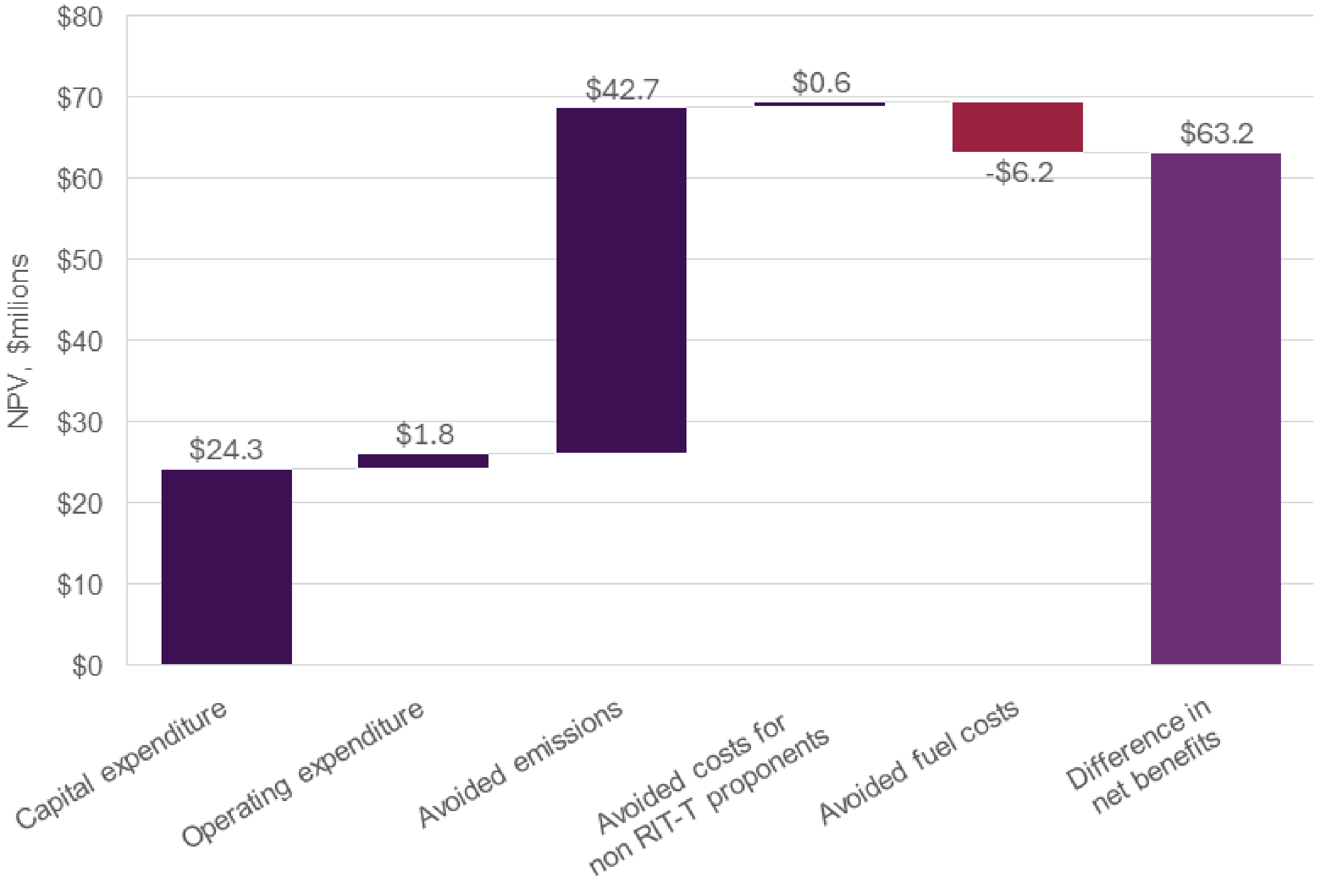
Figure 19 Composition of the estimated net market benefits for option portfolio 3 (NPV, $billions)



In present value terms, option portfolio 3 involves approximately $310 million of capital costs relative to the base case, which is approximately $24 million lower than option portfolio 2 due to the capital expenditure it avoids/defers (as shown below in Figure 20).

Under this option portfolio, the expected net market benefits increase by approximately $63.2 million (in present value terms), compared to under option portfolio 2. This increase is driven primarily by the avoided/deferred synchronous condenser capital costs and additional avoided emissions.

Figure 20 Key changes in the composition of the estimated net market benefits for option portfolio 3, compared to option portfolio 2 (NPV, $millions)



The slightly greater avoided emissions with option portfolio 3 in place, compared to option portfolio 2, are driven by coal dispatch differences in 2032 and 2033. Specifically, in these years, option portfolio 2 results in 2.3% and 3.8% more coal dispatch, respectively, when compared on an average interval basis to option portfolio 3, on account of option portfolio 3 involving more GFM BESS system strength solutions (which offset the need to dispatch coal).

9.5 Option portfolio 4 – The same technology types as option portfolio 3, except with accelerated procurement of synchronous condensers

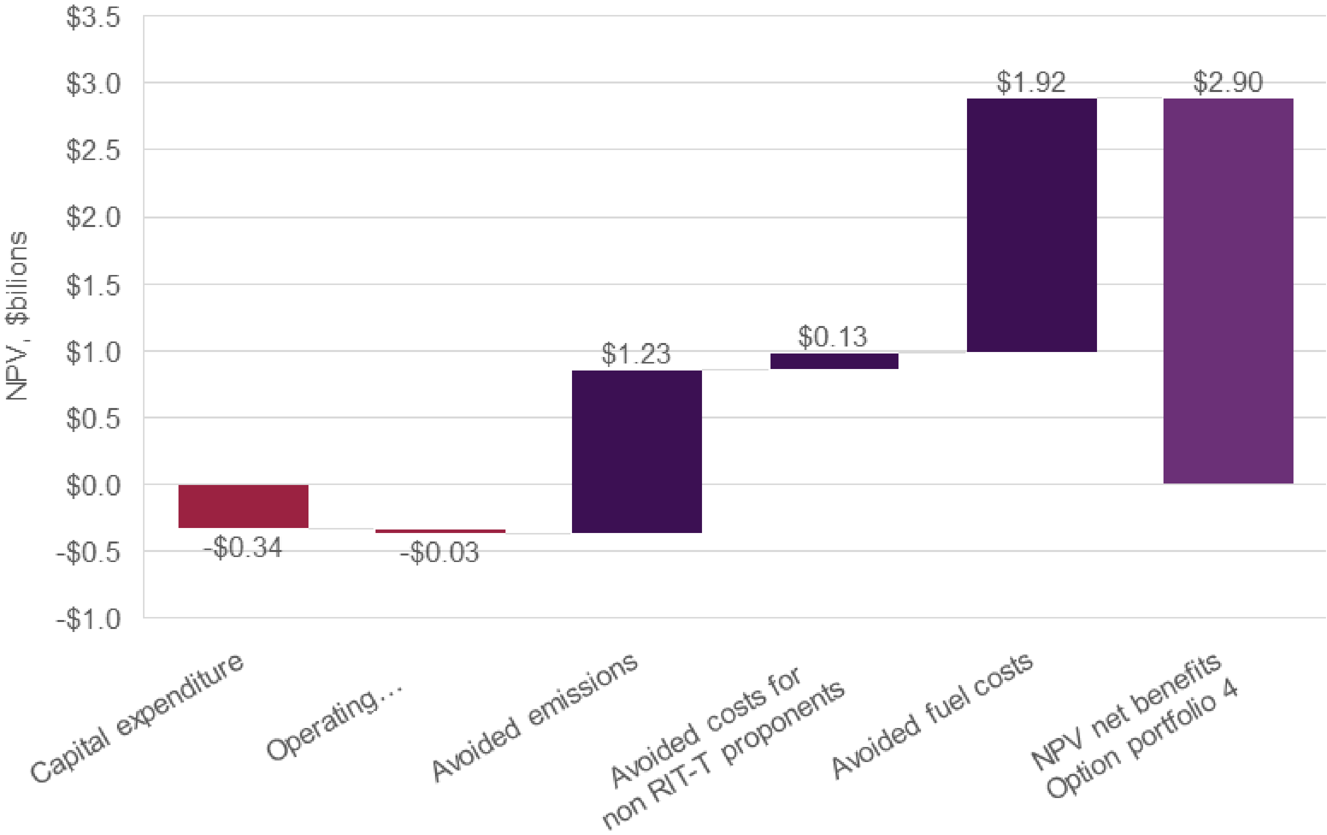
Option portfolio 4 includes exactly the same components as option portfolio 3, but expedites the timing of synchronous condensers. Specifically:

- option portfolio 3 has two Hazelwood synchronous condensers in 2029, one Hazelwood synchronous condenser in 2031, and one Hazelwood synchronous condenser in 2034, and
- option portfolio 4 has one Hazelwood synchronous condenser in 2028, two Hazelwood synchronous condensers in 2029, and one Hazelwood synchronous condenser in 2034.

Option portfolio 4 is the same as option portfolio 3 from 2031 onwards and, in total, option portfolio 4 involves five new synchronous condensers over the assessment period (the same as option portfolio 3 and four fewer than under option portfolio 1).

Overall, option portfolio 4 is found to deliver at least $2.90 billion in net benefits (in present value terms) over the assessment period. As with option portfolio 3 (which this option is based on), this result is driven primarily by significant avoided generator fuel costs and lower emissions with the portfolio option in place, compared to the base case (as shown below in Figure 21).

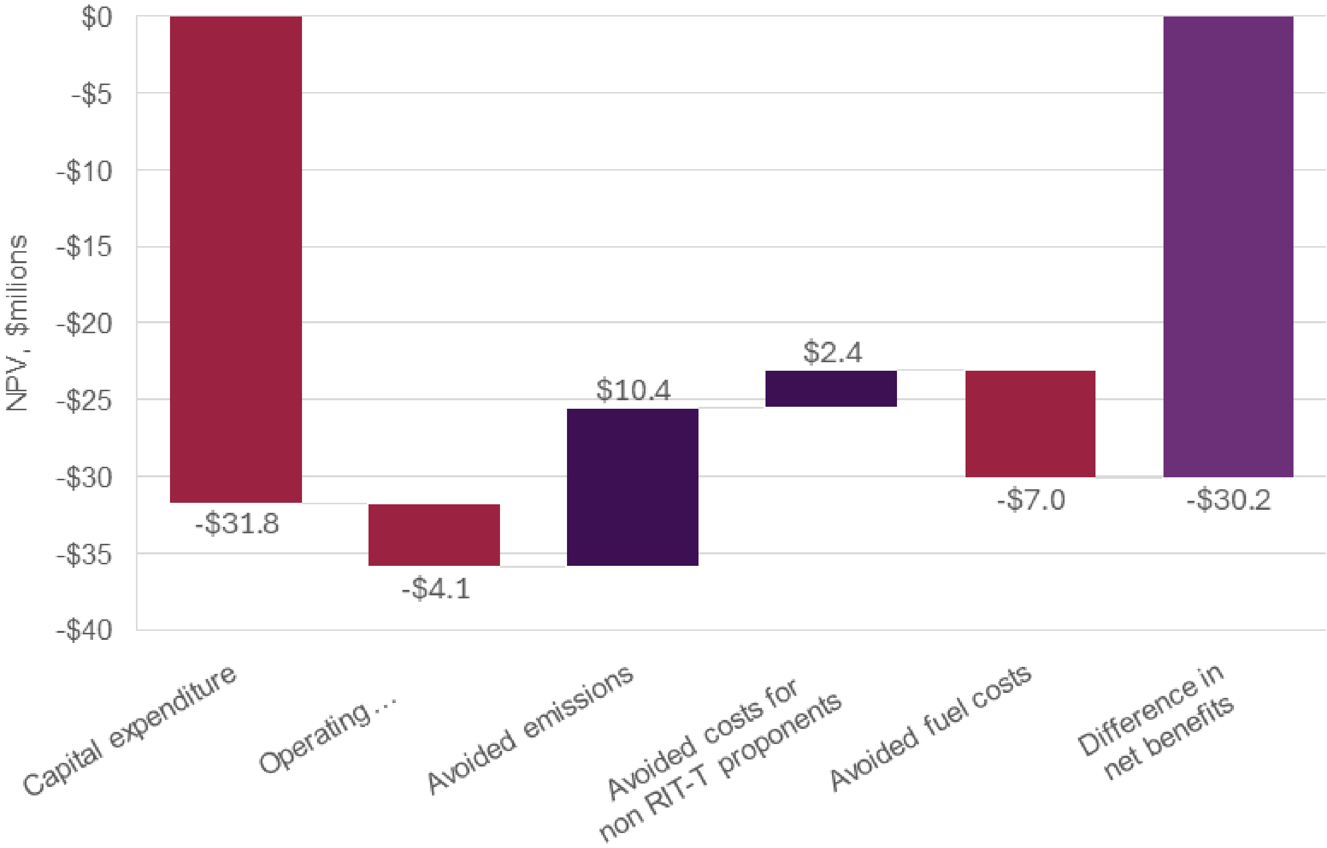
Figure 21 Composition of the estimated net market benefits for option portfolio 4 (NPV, $billions)



In present value terms, option portfolio 4 involves approximately $342.9 million of capital costs relative to the base case, which is approximately $32 million more than option portfolio 3 due to the increased present value of the synchronous condenser costs (as shown below in Figure 22).

Under this option portfolio, the expected net market benefits decrease by approximately $30.2 million (in present value terms), compared to under option portfolio 3. This decrease is driven primarily by the increased present value of the synchronous condenser costs, which are not offset by the additional benefits (primarily additional avoided emissions), suggesting that accelerating the use of synchronous condensers is not net beneficial.

Figure 22 Key changes in the composition of the estimated net market benefits for option portfolio 4, compared to option portfolio 3 (NPV, $millions)



9.6 Sensitivity analysis

AVP tested the robustness of the above core NPV assessment by changing a number of key variables. These tests investigated whether the ranking of the options changes (and whether the preferred option portfolio changes) under these alternate key assumptions.

Specifically, AVP tested the impact on the portfolio rankings of:

- 25% higher and lower VER values – consistent with the guidance of Australia's Energy Ministers[62]
- 30% higher and lower assumed synchronous condenser costs (both capital and operating costs) – consistent with the class of costs included in the transmission cost database
- 25% higher and lower GFM BESS upgrade costs
- lower and higher commercial discount rates (as discussed in Section 7.4), and
- where the Gippsland and Portland offshore wind IBR are assumed to self-remediate (to reflect the current uncertainty around whether this will occur).

[62] See https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf.

AVP has not investigated a sensitivity on the assumed VCR, because the avoided involuntary load shedding is the same across all four options (and thus not considered a material market benefit for this RIT-T). Similarly, AVP has not investigated a sensitivity on the assumed cost of upgrading an existing generator to also be capable of operating in synchronous condenser mode, since this component is included in all option portfolios equally (and thus its costs do not affect the ranking of the options).

The results of the sensitivity testing are discussed in the two sections below. Section 9.6.1 discusses the first four sensitivities listed above (undertaken on the NPV assessment alone), while Section 9.6.2 discusses the offshore wind self-remediating sensitivity (which required a re-optimisation of the preferred option portfolio).

9.6.1 General sensitivity analysis on the RIT-T NPV assessment

None of these sensitivities have been found to change the key findings of the core assessment, and AVP does not find any realistic boundary values that would change the key findings of the core assessment. Appendix A4 presents the results of all general sensitivity tests investigated.

The boundary values, where they exist, are summarised in Table 12 below. For clarity, each boundary test has been set as when/whether option portfolio 3 is no longer the preferred option, and all percentages show the percentage of the core assumption (for example, the assumed VER would need to nearly triple to change the conclusion).

Table 12 Summary of the boundary assessments undertaken in this PADR

	VER	Synchronous condenser capex	GFL to GFM BESS upgrade capex	Discount rate
Boundary value	291%	-84%	5,020%	N/A

System strength can often contribute to the provision of inertia, and vice versa, and with the addition of a relatively low-cost flywheel, a synchronous condenser can provide substantially more inertia while still providing system strength. The AER noted in its December 2024 guidance that it expects that including flywheels, where synchronous condensers have been found to be part of the preferred option for meeting the system strength requirements, would ultimately be considered to be prudent and efficient expenditure[63].

As part of this PADR assessment, AVP has estimated that the addition of a flywheel would add approximately 1.9% to the estimated capital cost of the synchronous condensers included in the option portfolios. Given this is well within the synchronous condenser capital cost boundary assessment, shown above, AVP considers that this additional cost would not change the ranking of the option portfolios.

9.6.2 Gippsland and Portland offshore wind self-remediating

The 2024 *System Strength Report* includes significant Victorian offshore wind in the:

- Gippsland region (in the order of 3.42 GW by 2035), which is assumed to connect at the Hazelwood node, and
- Portland region (in the order of 0.58 GW by 2035), which is assumed to connect at the Moorabool node.

[63] AER, *The Efficient Management of System Strength Framework*, AER Guidance Note, December 2024, p. 31.

This reflects the legislated offshore wind energy generation target of 2 GW by 2032[64], coupled with the formal declaration of the Gippsland (Victoria) declared offshore wind area in December 2022[65].

This offshore wind was not included in the 2022 *System Strength Report*, and represents a substantial change in forecast IBR from what was contemplated at the time of preparing the PSCR.

AVP therefore investigated a sensitivity where the Gippsland and Portland offshore wind IBR are self-remediated (to reflect current uncertainty around whether this self-remediation will occur). This sensitivity differs to the other general ones above (which hold the option portfolio components and wholesale market modelling constant), as it required both a re-optimising of the option portfolio and thus subsequent re-running of the wholesale market modelling for these new components.

In this sensitivity, AVP modelled:

- option portfolio 3 only, given the extent of the modelling required, and
- the self-remediation of the offshore wind so it has no net negative effect on system strength in the wider power system.

If the offshore wind assumed to connect at the Hazelwood and Moorabool nodes self-remediates, AVP finds that the following changes to option portfolio 3 are required for the efficient level requirements (and no changes for the minimum level requirements):

- one Giffard (Gippsland) Offshore Wind Hub 500 kV synchronous condenser from 2035 can be avoided
- 500 MW of GFL to GFM BESS upgrades at Hazelwood and 350 MW of GFL to GFM BESS upgrades at Moorabool are deferred from 2032 to 2034
- 400 MW of generic IBR BESS at Hazelwood is deferred from 2032 to 2033, and
- 500 MW of generic IBR BESS at Thomastown is added in 2033.

The specific components included in this portfolio, for meeting both the minimum and efficient system strength requirements, are summarised in Table 13 below.

While this sensitivity has only been run on the preferred option, AVP does not consider that expanding it to include all four options would affect their relative rankings. Specifically, AVP considers that the options would be affected in the same/very similar ways (that is, a reduction in the services required at Giffard). AVP also notes that the services found to be affected (above) are beyond what AVP is seeking to procure in the immediate term, so AVP will naturally review the need for them going forward and ahead of committing to any procurement.

Under this sensitivity, the expected net market benefits of option portfolio 3 increase by approximately $183.0 million (in present value terms), compared to under the core option portfolio 3. This increase in benefits is driven primarily by additional emissions and fuel costs being able to be avoided (due to conventional generation needing to run less if offshore wind self-remediates) and the avoided/deferred capital expenditure (as shown below in Figure 23).

[64] *Renewable Energy (Jobs and Investment) Act 2017*, s 7B.

[65] *Offshore Electricity Infrastructure (Declared Area OEI-01-2022) Declaration 2022*, 17 December 2022.

Table 13 Option portfolio 3 when offshore wind is assumed to self-remediate – summary of components

Financial year	Minimum fault levels	Efficient level
2026	Existing generators, including conversion of some units to be capable of operating in synchronous mode Existing synchronous condenser Red Cliffs SSN 1	Covered by minimum fault level requirements
2027		
2028		GFM BESS 900 MW SSN Moorabool
2029	Same as 2028 + 2 x Hazelwood SSN synchronous condensers	Same as 2028 + GFL to GFM BESS 350 MW SSN Hazelwood
2030		
2031	Same as 2030 + 1 x Hazelwood SSN synchronous condenser	
2032		
2033		Same as 2032 + ISP forecast GFM BESS 400 MW SSN Hazelwood GFL to GFM BESS 300 MW SSN Moorabool ISP forecast GFM BESS 500 MW SSN Thomastown
2034	Same as 2033 + 1 x Hazelwood SSN synchronous condenser	Same as 2033 + GFL to GFM BESS 500 MW SSN Hazelwood GFL to GFM BESS 350 MW SSN Moorabool
2035		Same as 2034 + GFM BESS 65 MW Red Cliffs SSN
2036		

Figure 23 Key changes in the composition of the estimated net market benefits for option portfolio 3 when offshore wind is assumed to self-remediate (NPV, $millions)

10 PADR conclusion

Option portfolio 3 is the proposed preferred option identified in this PADR. It involves a number of near-term solutions to meet Victoria's system strength requirements from 2 December 2025 to 2029, which are common across all option portfolios, as well as a number of longer-term solutions that are specific to the preferred option.

Given the lead time for the near-term solutions, AVP will commence[66] tendering for service contracts. Specifically, AVP will tender for synchronous machine services from plant that is the equivalent of three synchronous condensers, as well as 900 MW of committed GFM BESS in the Moorabool area and 350 MW of committed GFL BESS (upgraded to be GFM) in the Hazelwood area – in addition to contracting for synchronous machine services from existing generation and upgrading some existing generation units to be capable of operating in synchronous condenser mode[67]. The minimum level of services from synchronous plant – existing, upgraded or new – included in option portfolio 3 are required to meet the minimum fault level requirements and provide sufficient protection-quality fault current, since GFM technology has not yet been demonstrated to satisfy protection-quality fault current at scale in Australia.

Beyond this point, AVP intends to pursue the longer-term specific solutions of option portfolio 3. This option has the greatest estimated net market benefit and imposes the least cost on customers. However, it relies on the further progression of potential BESS solutions. If these conditions are not met before AVP would need to otherwise commit to contracting additional plant able to operate as synchronous condensers to provide sufficient system strength, this would be a 'material change in circumstances' (MCC) and AVP would notify the AER of the change, giving the AER 40 days to make a determination approving or rejecting AVP's proposed alternative path to pivot to either option portfolio 2 or option portfolio 1.

While AVP may ultimately be required to pivot to either option portfolio 2 or option portfolio 1, it is noted that, compared to option portfolio 1, the equivalent of four synchronous condensers can be avoided if option portfolio 3 continues to be the preferred option, or the equivalent of three synchronous condensers can be avoided if AVP pivots to option portfolio 2. This would avoid a significant cost to consumers.

Overall, the proposed pathway involves contracting for services from new plant able to provide the equivalent of four synchronous condensers, to provide sufficient fault level for protection system operation, while providing the greatest amount of time for low-cost BESS solutions to develop and be contracted with, but also retains the flexibility to pivot to additional plant able to operate as synchronous condensers in the future, if required, to ensure sufficient strength requirements are met.

[66] While AVP intends to commence the procurement process for these components in parallel to preparing the PACR, it does not expect to finalise contracts before the PACR, and its associated dispute period, are complete. Commencing the procurement process (which is expected to be limited to negotiating contract terms) alongside the preparation of the PACR is considered prudent and will allow AVP to secure system strength services in as timely a manner as possible.

[67] Those services may also be procured from new plant if it is more cost-effective (noting the RIT-T comparison of the options assessment has costed this based on assumed existing plant costs).

The PADR analysis has found that the near-term solutions to meet Victoria's system strength requirements from 2 December 2025 to 2029 are common across all option portfolios. AVP will commence tendering for service contracts:

- to meet the minimum fault level requirements:
  - existing generators,[68] including upgrading some to be capable of operating in synchronous condenser mode, from 2026, and
  - three new plant able to operate as synchronous condensers – one existing one in the Red Cliffs area from 2026 and two new ones in the Hazelwood area by 2029, and
- to meet the efficient requirements:
  - 900 MW of currently 'committed' GFM BESS in the Moorabool area, and
  - 350 MW of currently 'committed' GFL BESS (upgraded to be GFM) in the Hazelwood area.

These components are common across all option portfolios and tendering needs to commence now to ensure sufficient system strength from 2 December 2025 to 2029 (taking account of expected contracting and procurement lead times). AVP considers that there is no risk associated to commencing tendering of these elements now, ahead of the PACR.

Beyond this point, AVP intends to pursue option portfolio 3 – which is the preferred option identified in this PADR, since it has the greatest estimated net market benefit and imposes the least cost on customers.

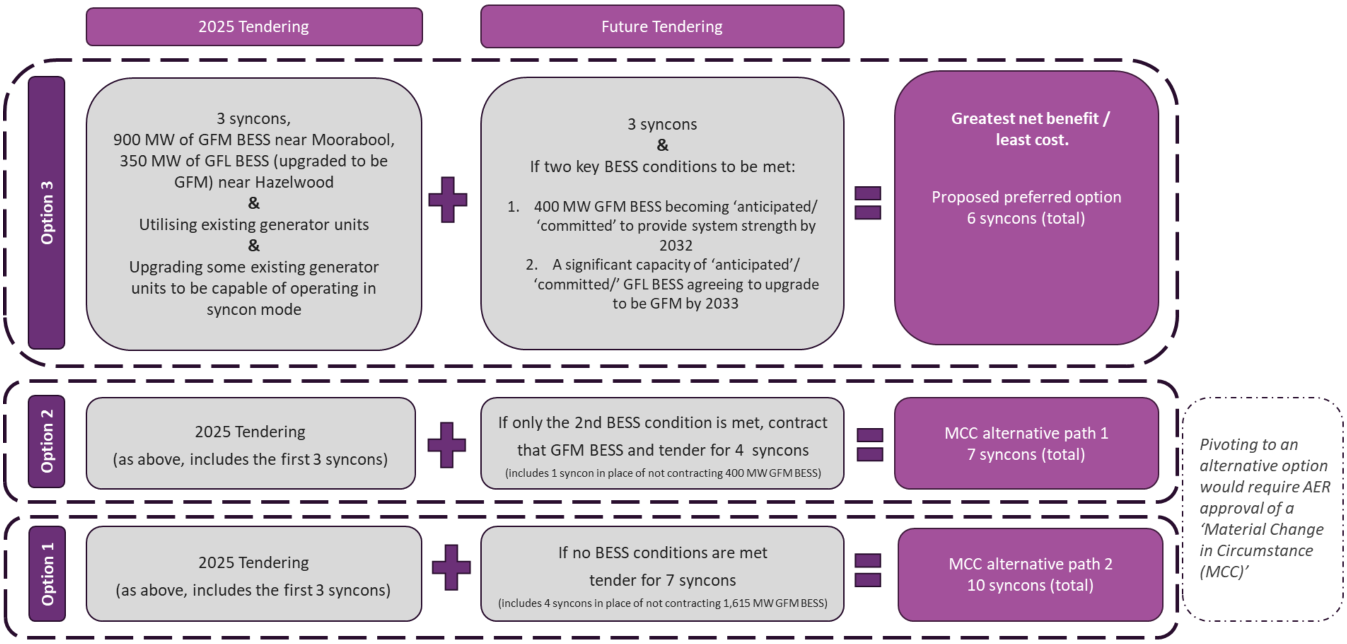
However, overall, it is of the utmost importance that there is sufficient system strength capacity available in the system. Failing to make this available could result in material outages for consumers. AVP therefore considers that there are natural 'cut-off points' for BESS being able to avoid future investment in plant able to operate as a synchronous condenser (that is, when AVP would otherwise need to commit to procuring system strength services from additional plant able to operate as synchronous condensers to ensure sufficient system strength).

Should AVP be able to contract system strength services from third-party BESS proponents ahead of these cut-off points, AVP expects that investing in additional plant able to operate as a synchronous condenser can be avoided and, instead, these BESS solutions procured. However, if this does not occur, AVP considers that additional synchronous condenser capable plant investment will need to be committed to, in line with option portfolio 2 or 1 in this PADR, and this would be an MCC. If an MCC eventuates, AVP will notify the AER of the change and its proposed alternative path to pursue either option portfolio 2 or 1. The AER has 40 days from receipt of an MCC notification to make and publish a determination approving or rejecting the alternative actions proposed by AVP.

The proposed pathway forward is summarised in Figure 24, including the alternative options if an MCC eventuates.

[68] While AVP refers here to the use of 'existing generators', it considers that this includes any additional generation that connects ahead of AVP needing to commit to its procurement following this RIT-T.

Figure 24 The proposed pathway forward



While AVP may ultimately be required to pivot to either option portfolio 2 or option portfolio 1 (if the procurement of sufficient GFM BESS service agreements is not possible ahead of the cut-off points), it is noted that, compared to option portfolio 1, investing in four plant able to operate as synchronous condensers can be avoided if option portfolio 3 continues to be the preferred option, or plant able to operate as three synchronous condensers can be avoided if AVP pivots to option portfolio 2. Specifically, compared to option portfolio 1, contracting with GFM BESS in option portfolio 3 avoids plant capable of operating as synchronous condensers being needed at the[69]:

- Giffard (Gippsland) Offshore Wind Hub 500 kV in 2032
- Bulgana Terminal Station 500 kV in 2033
- Giffard (Gippsland) Offshore Wind Hub 500 kV in 2034, and
- Kerang 500 kV in 2035.

This translates to a significant cost saving to end consumers between 2029 and 2036 – for example, if option portfolio 3 remains preferred, consumers avoid paying the costs associated with approximately $770 million in capital (equivalent to around $460 million in present value terms)[70].

At this stage, AVP considers that the indicative cut-off points are three years before the services are expected to be needed. AVP intends to make clear as part of the PACR what it expects the cut-off points to be for each of the tranches of BESS expected to be needed, drawing on any updated information from proponents regarding the expected lead times for new plant capable of operating as synchronous condensers.

[69] While option portfolio 3 also avoids one synchronous condenser at the Giffard (Gippsland) Offshore Wind Hub 500 kV in 2031, this synchronous condenser is replaced with one at the Hazelwood SSN in the same year (so effectively a zero-sum game). It also brings forward one synchronous condenser from 2036 to 2035, compared to option portfolio 1, at the Giffard (Gippsland) Offshore Wind Hub 500 kV.

[70] This present value does not take account of terminal values (as it is referring to the cost to consumers), whereas all other present values in this PADR do take account of terminal values (as they are referring to the costs/benefits over the assessment period).

Overall, the proposed pathway set out in this PADR:

- recognises that action needs to be taken now to meet the system strength requirements in the near term
- provides the greatest amount of time for low-cost GFM BESS solutions to develop and be contracted with over the longer term, and
- retains the flexibility to pivot to investing in additional plant able to operate synchronous condensers in the future, if required.

This will result in the best outcome for electricity consumers. Setting out this longer-term pathway now is also likely to avoid AVP needing to undertake a second RIT-T in the near future, which would potentially jeopardise the ability to address system strength requirements in Victoria in a timely fashion. It also supports the development of non-network solutions in being able to provide system strength services.

Importantly, AVP notes that the PADR analysis was based on contracting with existing Victorian synchronous generators that reasonably reflect the costs of their proposed solution. If this appears to not be the case during the procurement process, AVP considers that this will likely represent an MCC, consistent with the AER's recent guidance on system strength RIT-Ts,[71] and would result in additional plant able to operate as synchronous condensers needing to be contracted with.

AVP considers that the detailed analysis set out, and the preferred option identified, in this PADR, satisfies the RIT-T.

[71] AER, *The Efficient Management of System Strength Framework*, AER Guidance Note, December 2024, p. 25.

A1. Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PADR with the requirements of the NER version 227.

Table 14 Checklist for compliance with NER requirements

Rules clause	Summary of requirements	Relevant section(s) in the PADR
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	3 & A5
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	4, 7 & 9
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	7 & 8
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	7.3
	(6) 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);	9
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	9
	(8) the identification of the proposed preferred option;	10
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: – 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 Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and – a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	5.3 – (9)(i) 6.1.2 – (9)(ii) NA – (9)(iii) 10 – (9)(iv)
	(10) if each of the following apply to the RIT-T project: – the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and – AEMO is not the sole RIT-T proponent, the RIT reopening triggers applying to the RIT-T project.	N/A
5.16.4(l)	If a Network Service Provider affected by a RIT-T project elects to proceed with a project which is for reliability corrective action, it can only do so where the proposed preferred option has a proponent. The RIT-T proponent must identity that proponent in the project assessment draft report.	While all solutions included in the option portfolios have proponents, AVP is not able to state who they are at this stage due to requested confidentiality.

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Table 15 Checklist for compliance with the Australian Energy Regulator's RIT-T guidelines

Section	Summary of the requirements	Section in the PADR
3.2.5	A RIT-T proponent must consider social licence issues in the identification of credible options. A RIT proponent should include information in its RIT reports about when and how social licence considerations have affected the identification and selection of credible options.	N/A[A] – however, AVP has considered social licence issues in forming the credible options (see Section 5.6)
3.4.3	The value of emissions reduction (VER), reported in dollars per tonne of emissions (CO2 equivalent), is used to value emissions within a state of the world. A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	N/A[A] – however, AVP considers it complies with this requirement (see Sections 4.1 and 7.1.2)
3.5A.1	Where the estimated capital costs of the preferred option exceeds $103 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application: • outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T • for all credible options (including the preferred option), either: – apply the cost estimate classification system published by the AACE, or – if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.	Section 6.1.2
3.5A.2	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	Sections 5, 6 and A3
3.5	In the RIT-T, costs must include the following classes: • Costs incurred in constructing or providing the credible option • Operating and maintenance costs over the credible option's operating life • Costs of complying with relevant laws, regulations and administrative requirements • For, asset replacement projects or programs, there are costs resulting from removing and disposing of existing assets, which a RIT-T assessment should recognise. RIT-T proponents should include these costs in the costs of all credible options that require removing and disposing of retired assets. For completeness, the RIT-T proponent would exclude these costs from the 'BAU' base case.	
3.5.3	The RIT-T proponent is required to provide the basis for any social licence costs in its RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.	N/A[A] – however, AVP has considered social licence issues in forming the credible options (see section 5.6), and has applied the classes of market benefits consistently across all credible options (see Section 7) AVP has also estimated the annual benefit from changes in Australia's greenhouse gas emission consistently with the AER RIT-T Guidelines Section
3.6	RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	
3.7.3	When calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to: • include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome: – direct emissions from generation – direct emissions other than from generation • estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by	

Section	Summary of the requirements	Section in the PADR
	the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions	3.7.3 (AVP considers including direct emissions other than from generation would not material to the RIT-T outcome)
3.8.2	Where the estimated capital cost of the preferred option exceeds $103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.	Sections 8.2, 9.6 and A4
3.9.4	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and how the level or quantum of the contingency allowance was determined.	Sections 5.1 to 5.4 and 6.1.2
3.11.2	Where a concessional finance agreement is included, the RIT-T proponent is required to provide sufficient detail about the concessional finance agreement to justify an agreement's inclusion and such that it can articulate how the value of the concession is to or would be shared with consumers. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate.	N/A[A]
4.1	RIT-T proponents are required to describe in each RIT-T report: • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or • why this project does not require community engagement.	

A. These are new requirements stipulated in the latest RIT-T guidelines released by the AER, which came into effect on 21 November 2024. For compliance purposes, the AER only has regard to the guidance that was in effect when AVP initiated the RIT-T in question. In this context, initiated means from the publication of a PSCR so, since the PSCR was published prior to 21 November 2024 for this RIT-T, these new requirements are not applicable.

A2. Additional detail on the forecast IBR

Table 16 presents a breakdown of forecast IBR by technology used in the PADR assessment.

Table 16 AEMO 2024 *System Strength report* – forecast IBR by type (MW)

System strength node	Technology	Forecast IBR (MW)										
		Financial year ending										
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Moorabool	Solar	0	0	300	300	300	300	300	300	300	300	300
	Wind	0	0	32	1,385	1,660	1,660	1,660	1,660	2,168	2,350	3,083
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**332**	**1,685**	**1,960**	**1,960**	**1,960**	**1,960**	**2,468**	**2,650**	**3,383**
Hazelwood	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	500	500	1,350	2,000	3,000	4,000	4,667	5,333	5,420
	Battery	0	0	0	400	400	400	400	400	400	400	400
	Total IBR	**0**	**0**	**500**	**900**	**1,750**	**2,400**	**3,400**	**4,400**	**5,067**	**5,733**	**5,820**
Dederang	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Red Cliffs	Solar	0	0	0	0	0	0	357	357	357	357	1,338
	Wind	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**357**	**357**	**357**	**357**	**1,338**
Thomastown	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	500	500	500	500	500	500	500	500
	Total IBR	**0**	**0**	**0**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**

Table 17 presents a breakdown of forecast IBR by technology used in the PSCR assessment.

Table 17 AEMO 2022 *System Strength Report* – forecast IBR by type (IBR proposed in the PSCR) (MW)

System strength node	Technology	Forecast IBR (MW)										
		Financial year ending										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Moorabool	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	92	92	92	153	358	870	970
	Battery	0	0	0	0	0	0	0	0	586	586	586
	Total IBR	**0**	**0**	**0**	**0**	**92**	**92**	**92**	**153**	**944**	**1,456**	**1,556**
Hazelwood	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	374	394	394	394	833	1482	2001	2001	2001
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**374**	**394**	**394**	**394**	**833**	**1,482**	**2,001**	**2,001**	**2,001**
Dederang	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0	264	264
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**264**	**264**
Red Cliffs	Solar	0	0	0	0	0	0	0	0	0	354	1437
	Wind	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**354**	**1,437**
Thomastown	Solar	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 18 compares the forecast IBR by technology used in the PADR assessment against that used in the PSCR assessment for overlapping years.

Table 18 Comparison of IBR forecast by technology in the PADR compared to that proposed in the PSCR (MW)

System strength node	Technology	Forecast IBR (MW) Financial year ending								
		2025	2026	2027	2028	2029	2030	2031	2032	2033
Moorabool	Solar	0	0	300	300	300	300	300	300	300
	Wind	0	0	-60	1,293	1,568	1,507	1,302	790	1,198
	Battery	0	0	0	0	0	0	-586	-586	-586
	Total IBR	**0**	**0**	**240**	**1,593**	**1,868**	**1,807**	**1,016**	**504**	**912**
Hazelwood	Solar	0	0	0	0	0	0	0	0	0
	Wind	-374	-394	106	106	517	518	999	1,999	2,666
	Battery	0	0	0	400	400	400	400	400	400
	Total IBR	**-374**	**-394**	**106**	**506**	**917**	**918**	**1,399**	**2,399**	**3,066**
Dederang	Solar	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	-264	-264
	Battery	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-264**	**-264**
Red Cliffs	Solar	0	0	0	0	0	0	357	3	-1,080
	Wind	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	0	0	0	0	0	0
	Total IBR	**0**	**0**	**0**	**0**	**0**	**0**	**357**	**3**	**-1,080**
Thomastown	Solar	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	500	500	500	500	500	500
	Total IBR	**0**	**0**	**0**	**500**	**500**	**500**	**500**	**500**	**500**

A3. Key assumptions used in the market modelling

Table 19 summarises the specific key variables that influence the net benefits of the options under *the Step Change* scenario.

Table 19 PADR modelled scenario key drivers input parameters

Key input parameters	*Step Change* scenario
Underlying consumption	AEMO Final 2024 ISP – 50% probability of exceedance (POE).
Demand side participation (DSP)	AEMO Final 2024 ISP.
Rooftop solar	
Victorian Renewable Energy Target (VRET)	AEMO Final 2024 ISP – 95% minimum variable renewable energy (VRE) of statewide generation by FY35. ISP interim targets and ISP interpolation of target also modelled to this point.
Queensland Renewable Energy Target (QRET)	AEMO Final 2024 ISP – 80% minimum VRE share of underlying consumption by FY35. ISP interim targets also modelled to this point.
Tasmanian Renewable Energy Target (TRET)	AEMO Final 2024 ISP – 21,000 gigawatt hours (GWh) of renewable generation by FY40. Interim target and ISP interpolation of target followed to this point.
Resource limits	AEMO Final 2024 ISP.
Group REZ limits	
VIC offshore wind	AEMO Final 2024 ISP – 9 GW of Victorian offshore wind capacity by FY40. ISP interim targets also modelled to this point.
Victorian Energy Storage Target	AEMO Final 2024 ISP – 2.6 GW by 2030 and 6.3 GW of energy storage systems by FY35.
New South Wales Energy Infrastructure Roadmap (EIR) Generation	AEMO Final 2024 ISP – 33,600 GWh per year by FY30.
New South Wales EIR Storage	AEMO Final 2024 ISP – 2,000 MW of eligible large-scale storage by FY30.
New South Wales firming constraint	Final 2024 ISP – 930 MW of eligible installed capacity by FY26.
Flow path augmentations	New South Wales flow path augmentations aligned to ODP Final 2024 ISP. Queensland flow path augmentations aligned to ODP Final 2024 ISP.
Interconnector developments	ODP Final 2024 ISP.
Network representation	AEMO Final 2024 ISP.
Emissions intensity	2024 Inputs and Assumptions Workbook.
VER	AER Guidance Valuing Emissions Reduction.
Fixed date asset retirement - coal	AEMO Final 2024 ISP, Eraring retirement deferred to August 2027[A].
Fixed date asset retirement - gas	AEMO Final 2024 ISP.
Fixed date non-thermal asset retirement	
Snowy 2.0	December 2028. October 2024 NEM Generation Information.
New entrant build limits	AEMO Final 2024 ISP.
Generator energy limits	
Capital costs	

Key input parameters	*Step Change* scenario
WACC	
New entrant generators	
REZ representation	
Capacity factors	
Coal fuel cost	
Gas fuel cost	
Technical parameters of existing generation and storage	

A. As per the announcement of the agreement between Origin Energy and the New South Wales Government released on 23 May 2024.

A4. NPV sensitivity results

This appendix sets out the range of sensitivities for which AVP tested the impact on option portfolio rankings:

- 25% higher and lower VER values
- 30% higher and lower assumed synchronous condenser costs (both capital and operating costs)
- 25% higher and lower GFM BESS upgrade costs, and
- lower and higher commercial discount rates.

All sensitivity tests were run on the results excluding the common avoided unserved energy (as discussed in Section 9.1).

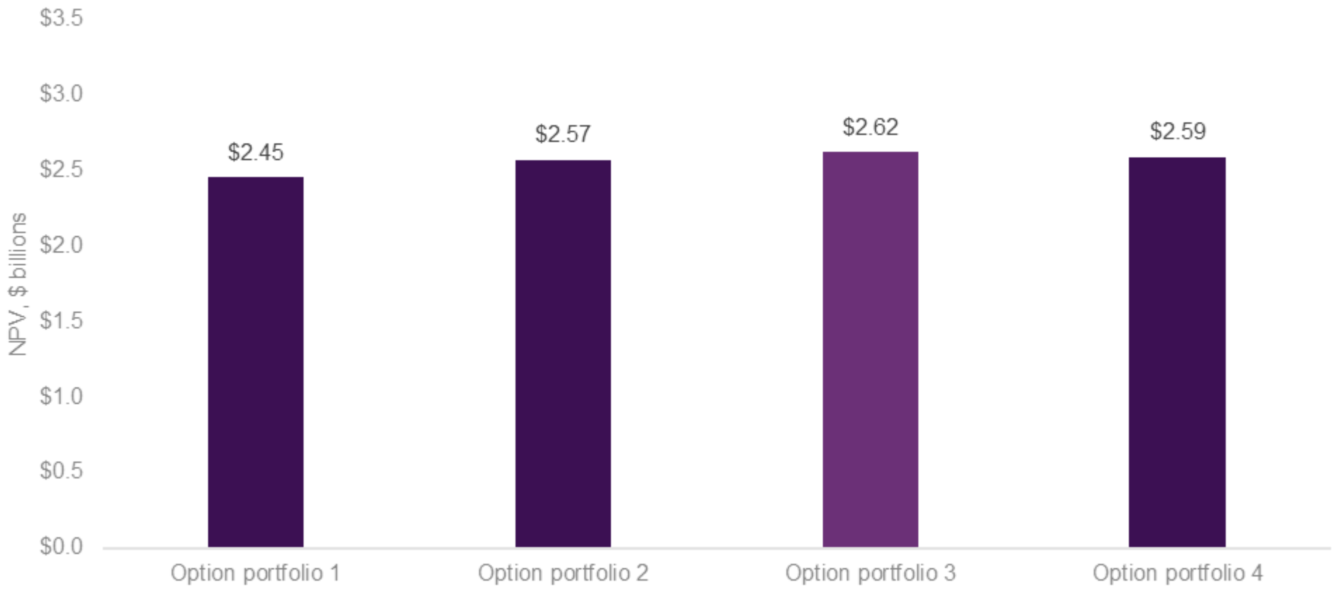
Option portfolio 3 is the top-ranked option under all sensitivity tests investigated (this conclusion does not change if the common avoided unserved energy is included in the analysis).

A4.1 Higher and lower VER values

Figure 25 and Figure 26 show the net market benefit results of assuming 25% higher and lower VER.

Figure 25 NPV results for each of the portfolio options with 125% VER

Figure 26 NPV results for each of the portfolio options with 75% VER



A4.2 Higher and lower synchronous condenser costs

Figure 27 and Figure 28 show the net market benefit results of assuming 30% higher and lower synchronous condenser costs.

Figure 27 NPV results for each of the portfolio options with 130% synchronous condenser costs

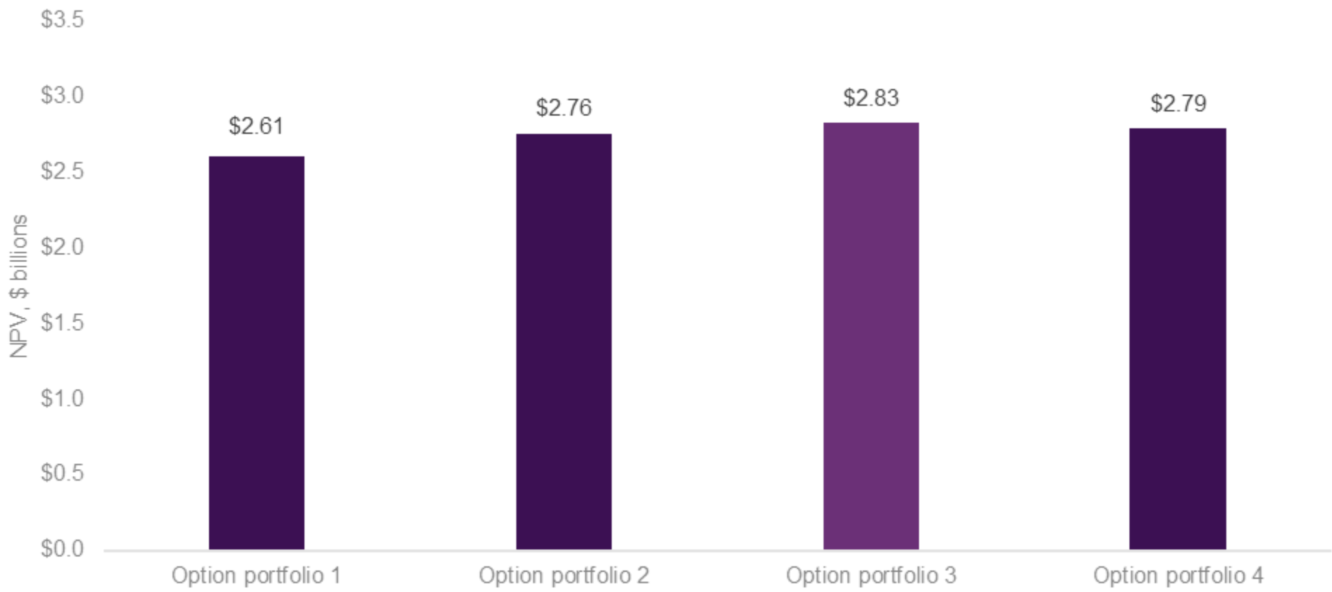


Figure 28 NPV results for each of the portfolio options with 70% synchronous condenser costs

A4.3 Higher and lower grid-forming BESS upgrade costs

Figure 29 and Figure 30 show the net market benefit results of assuming 25% higher and lower GFM BESS upgrade costs.

Figure 29 NPV results for each of the portfolio options with 125% grid-forming BESS upgrade costs

Figure 30 NPV results for each of the portfolio options with 75% grid-forming BESS upgrade costs

A4.4 Higher and lower discount rate

Figure 31 and Figure 32 show the net market benefit results of assuming higher and lower discount rates.

Figure 31 NPV results for each of the portfolio options with 10.5% discount rate

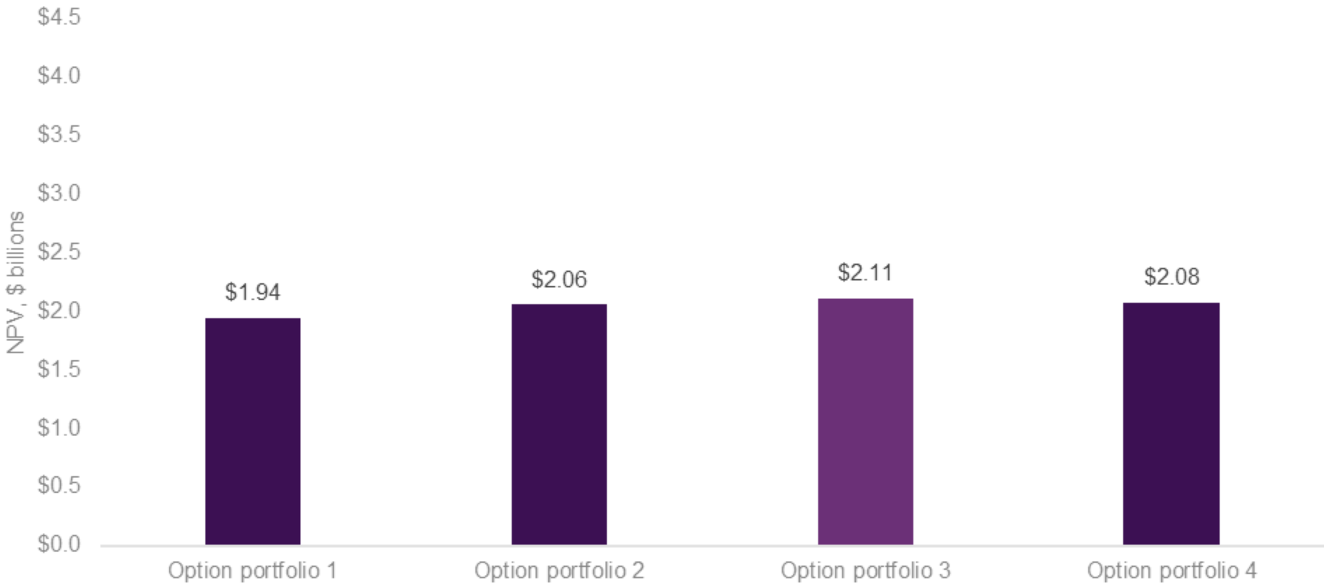


Figure 32 NPV results for each of the portfolio options with 3.63% discount rate

A5. Additional detail on non-confidential points raised in PSCR submissions

In addition to the responses to the RFI, AVP received submissions from two parties (EnergyAustralia and AusNet) directly in response to the PSCR, both of which have been published[72].

Eight broad areas were raised across these submissions:

- further specification of the identified need
- option value and the timing of options
- modelling and sensitivities
- how inter-regional assets are assessed
- the location of new system strength resources
- consideration of high benefit network reinforcement solutions
- real-time data and broader issues in procuring system strength, and
- engaging with other SSSPs for a consistent approach.

The key matters raised in non-confidential submissions are summarised and responded to in the following subsections.

A5.1 Further specification of the identified need

EnergyAustralia made a number of specific requests regarding information to be covered in the PADR, as summarised, and responded to, in the table below[73].

EnergyAustralia comments	AVP response
How will AVP deal with progressive changes to the specification of the system strength standard, which will change each year as new *System Strength Reports* are released (including after the PACR is published)?	AVP will continue to monitor changes to the system strength requirements going forward and ramp up/down provision (as catered for through this RIT-T) and/or initiate a new RIT-T.
How will AVP incorporate the potential declaration of a new node at Mortlake and other nodes that may occur over the coming years?	AVP would assess the materiality of the change and assess appropriate next steps, which may be providing an update and/or potentially triggering a new RIT-T. The PADR assessment has included efficient level constraint equations in the modelling to assist with more optimally located solutions to supply system strength closer to where IBR is forecast to connect. However, if minimum fault level requirements at future nodes were unable to be met by the preferred option portfolio identified in this RIT-T, that may constitute a material change in circumstance and/or trigger a new RIT-T.

[72] See https://aemo.com.au/en/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.

[73] EnergyAustralia, pp. 2-3.

EnergyAustralia comments	AVP response
How will potentially large changes to the efficient level of system strength requirement be reflected in the PADR? AVP should clarify the extent of its discretion in relying on these IBR forecasts as AEMO appears to have provided SSSPs the flexibility to adjust near term forecasts as new information becomes available.	See Section 2.2.2 for a discussion of how the efficient level of system strength requirements have been updated since the PSCR to reflect the most up to date information. In addition, the proposed preferred option set out in this PADR is a contingent one that allows AVP to adapt in response to key changes where possible.
The NER appear to prescribe the 10-year IBR forecasts in the most recent *System Strength Report*, yet AVP's assessment will extend to the earlier of 2050 or the end of the asset life (expected to be 2050 as synchronous condensers have at least a 30-year technical life). We would support cost benefit assessments based on a full set of IBR forecasts and associated system strength needs over the full modelling horizon however AVP's obligations are unclear.	The assessment in this RIT-T is based on the 10-year IBR forecast in the 2024 *System Strength Report*, plus one additional year of modelling. As the life of new assets, as well as existing assets, is not equal, a terminal value representing the remaining value of the assets is applied at the conclusion of the assessment period.
AVP's presentation of IBR forecasts implies a largely mechanistic translation of these into efficient fault level requirements. The PADR should contain technical analysis on how it has translated AEMO's four criteria relating to voltage waveforms into a single minimum MVA fault level metric. Our expectation is that it has adopted the same approach as AEMO when determining shortfalls. AVP should demonstrate that this approach is robust and that it has explored opportunities for innovation in the provision of solutions	The IBR forecasts are first translated into a fault level equivalent using the AFL calculation outlined in AEMO's System Strength Impact Assessment Guidelines[A]. Option portfolios are developed to meet the AFL and then tested against the stable voltage waveform criterion by testing voltage step change impacts in PSS®E and assessing for the presence of any voltage oscillation in PSCAD™ to verify the viability of option portfolios. See Section 4.4 of the PADR for additional detail, including how AVP derived equivalent fault level contribution for GFM BESS to the efficient level.
AVP states that services must be provided at a high level of availability (97%), however further data on the profile of system strength needs should be provided to justify the resource capabilities it will plan towards and eventually procure. We encourage AVP to publish supply and demand of system strength needs as a time series, at each system strength node from the base case and alternative scenario market modelling exercise undertaken for the RIT-T analysis.	The availability of system strength services was modelled using 2024 ISP Inputs and Assumptions Workbook data, in line with the AER guidelines. Depending on the machine type, this availability differs to the high level of availability indicated in the PSCR and better reflects what is expected to be achievable for a specific machine type. The synchronous generator dispatch in each interval was used to calculate the total fault level provision on a 30-minute basis. The requirement was met in all periods for each system strength node in each option portfolio. In the base case the requirement was met in all periods for each system strength node prior 2030, after which time coal generator retirements result in a lack of available services to meet the system strength requirements, resulting in forecast unserved energy due to a lack of system strength. AVP's approach addresses the non-linearity characteristic of system strength given that AVP constructed constraints on an interval basis and determined a different offset dependent on the synchronous units online. This detail is outlined in Section 4 (Constraints Methodology) of the Jacobs market modelling report.
AVP appears to apply the system strength standard as needing to be met "at all times of the year" implying 100% compliance. We encourage AVP to confer with other SSSPs on the interpretation of the planning standard and justify its approach, noting that the system strength specification in S5.1.14(a) applies "at any time in a relevant year" while subclause (b) provides for "reasonable endeavours" in meeting associated requirements. Delivering 100% compliance under very unusual circumstances may result in a very expensive system strength solution portfolio based on a 'fix it at any cost' approach.	AVP understands that the need is to meet the requirements 100% of the time (using reasonable endeavours). AVP's interpretation is that reasonable endeavours means planning to be able to cover requirements 100% of time, but acknowledging that planning timeframes and real-time operational events can result in different outcomes. As such, AVP has developed option portfolios that, for the minimum level, are capable of landing secure following a planned outage and any credible contingency or protected event, and, for the efficient level, that are capable of landing secure following any credible contingency or protected event (that is, for the efficient level AVP assumes it is acceptable to constrain off IBR for planned outages to ensure the system remains stable after any credible contingency or protected event).

A. AEMO, SSIAG, p.15, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/ssrmiag/final-report/system-strength-impact-assessment-guideline_v2.pdf.

AusNet has undertaken independent power system analysis and consulted with its transmission operations team to provide AVP with some early feedback for consideration as part of the PADR. This is summarised and responded to in the table below[74].

AusNet comments	AVP response
AusNet requests AVP take into account the need to facilitate critical planned outages when identifying solutions to meet minimum standard in the PADR as a matter of priority. Planned outages are an essential BAU activity to conduct essential maintenance, connections, augmentation works and capital replacement. Deteriorating network operating conditions have required AEMO National Planning to introduce or modify constraints in Victoria that have made it very difficult for TNSPs such as AusNet to schedule and undertake planned outages	AVP acknowledges the importance that system strength services play in managing outages, and the operational challenges that low system strength creates. Section 4.8 details how AVP has considered critical planned outages in development of its option portfolios.
Request AVP consult with AusNet's transmission operations team to ensure the list of critical planned outages is accurate and up to date (and suggested that the list of Victorian critical planned outages in the 2022 *System Strength Report* was incomplete).	Since publication of the PSCR, AVP has continued to consult with AusNet on both the treatment and list of critical planned outages considered in this PADR. While the list of critical planned outages remains effectively unchanged in the 2024 *System Strength Report*, AVP supports ongoing joint planning between AVP, AusNet and AEMO, including through consultation on AEMO's annual *System Strength Report* where the list of critical planned outages are maintained, to ensure the critical planned outages that AVP can consider in future RIT-Ts remains relevant and complete as the network develops.
Suggests the system strength standard needs to be updated to meet Victoria's future needs. In order to meet the standard, the solution proposed in the PSCR focusses investment in synchronous condensers at Hazelwood (HWTS) and Moorabool Terminal Station (MLTS) that then serve to 'prop up' system strength across the Victorian network. AusNet is concerned that placement of systems strength at these locations is inefficient and reflects historical needs. AusNet sees an opportunity for AEMO National Planning to update the system strength standard in the 2023 system strength report to reflect material changes in Victoria's future needs since the 2022 ISP, before proceeding to the PADR in early 2024. This includes declaring new system strength nodes where new network investment is planned, and updating minimum and efficient fault level requirements. Proceeding with the existing standard would be a missed opportunity to maximise the benefits of this investment to Victorians	Section 2 outlines how the assumptions underpinning the identified need for this RIT-T have been updated since the PSCR, including AVPs decision to use the revised 2025-26 and 2026-27 IBR forecasts. AVP will continue to monitor changes in the network and to system strength requirements, including any future knowledge advancements that might result updated minimum fault level requirements, and will invest in services that meet our requirements in the long-term interests of Victorian consumers.

A5.2 Option value

EnergyAustralia considered that there could be material option value in the procurement of flexible non-network solutions, which are also likely to be less capital-intensive and ready for immediate deployment[75].

AVP agrees that the procurement of flexible solutions (those that provide the ability to ramp up or down requirements as circumstances change) is expected to be important for this RIT-T given future uncertainty.

While each portfolio option is found to involve a number of flexible elements, 'option value' is not considered material for this RIT-T on account of only one scenario being considered relevant for the assessment (as outlined in Section 8.1). Moreover, as outlined in Section 8.1, AVP considers that each portfolio option exhibits the same

[74] AusNet, pp. 1-2.

[75] EnergyAustralia, p. 4.

approximate level of flexibility and so does not consider materially different levels of option value exist across the portfolios.

A5.3 Modelling and sensitivities

EnergyAustralia made several comments on the modelling parameters and sensitivities, which are summarised and responded to in the table below[76].

EnergyAustralia comments	AVP response
EnergyAustralia offered to assist AVP prior to and after any market modelling is undertaken, to review key inputs and results – notably regarding how Yallourn, Jeeralang, Newport and Wooreen assets may be dispatched[A].	While AVP appreciates the offer of support, in the interest of tender probity management, AVP has decided to not engage directly with proponents on modelling dispatch outcomes outside of any information that can be shared publicly through the PADR and market modelling report.
EnergyAustralia considered that there may be a bias in using AEMO's modelling parameters around thermal generation, as AEMO's methods and input parameters presume existing plant would be run inflexibly and without fuel limits, thus overstating the level of system strength present and understating the need for additional services. They stated that AEMO's standard set of fuel cost and unit commitment assumptions may also affect the modelling of non-network services and, overall, this could materially affect the ranking of network candidate options which will tend to have lower variable costs and AVP should explore these effects through input sensitivities[A].	The maximum annual capacity factor for an individual Victorian coal-fired generating unit is 75% over the entire modelling horizon, which is well within the current operating regime of these coal plants, which can be over 80% annually. Gas-fired generators have much lower capacity factors. Both of these points indicate that dispatch of the thermal plants is reasonable thus mitigating the risk of overstating system strength supply by incumbent generators. On the second point, the optimal mix was found to be a combination of network and non-network options. In addition, the ranking of options based on gross market benefits favoured more non-network options and less network options. These outcomes suggest the modelling was not biased against non-network solutions and so there is no need for additional sensitivity analysis.
It may be prudent for AVP to conduct further sensitivity analyses on the location of IBR investment. Generally, there is a presumption that generation will diversify away from the Latrobe Valley. To the extent the analysis follows the 2024 ISP (which will move from draft to final over the course of this RIT-T assessment) AEMO's new approaches to accommodating social licence issues might favour developments that align to existing generation and transmission sites, with different implications on system strength needs.	Section outlines how the assumptions underpinning the identified need for this RIT-T have been updated since the PSCR, including a large increase in forecast IBR connecting to the Latrobe Valley. While sensitivities to 2024 *System Strength Report* IBR forecast would provide insights to how the optimal location of services might change under an alternative capacity outlook, doing so would require additional detailed long-term market modelling, complete option portfolio redevelopment and additional short-term market modelling that AVP considers disproportionate to associated investment risk, particularly given that this RIT-T is a reliability corrective action where AVPs requirements are based on the *System Strength Report* IBR forecast.
Expect the timing of VNI West will also be a key variable considered in the context of social licence issues.	AVP is required to meet the standards set by AEMO and have based assumptions on these. While AVP could undertake a sensitivity considering the delay of VNI West or other major investments, this would require full long-term modelling similar to the ISP to reassess the capacity build over time and then reapply similar modelling to that done by AEMO as part of its annual *System Strength Report*. While this is theoretically possible, the resourcing effort to do so in the timeframe available prior to AVP's obligations coming into effect is not feasible.

A. EnergyAustralia, p. 4.

[76] EnergyAustralia, pp. 4-5.

A5.4 Treatment of inter-regional assets

EnergyAustralia asked AVP to explain how services from neighbouring jurisdictions are accounted for[77].

System strength does not stop at state boundaries, and some system strength naturally flows from interstate into Victoria. If AVP does not account for some of this system strength, it will effectively over-procure system strength in Victoria, leading to higher costs for consumers.

Since the PSCR was released, AVP consulted with other SSSPs and it was agreed that:

- for the minimum level of system strength, SSSPs should rely on joint planning arrangements to account for all interstate system strength contributions (and consequently 'expect' a certain level flowing from interstate), and
- for the efficient level of system strength, SSSPs should not consider any benefit from interstate since it is not known when it will be scheduled (that is, it may not be online all the time), and because it is not known which technologies will provide a stable voltage waveform (voltage support is more 'local' than fault current – that is, stable voltage waveform support may not travel very far).

While interstate contributions have not generally been included to support the efficient level, AVP has accounted for the contribution of the four synchronous condensers being developed in south-west New South Wales as part of PEC.

For the minimum level of system strength, AVP has also moderately reduced the amount assumed to come from each state (beyond N-1) so each state is not relying on the other states meeting their minimum requirements in full (otherwise all states will be relying on each other, which would likely result in a gap in what is provided). See Section 4.7 for a discussion of how inter-state contributions have been considered.

A5.5 Location of new system strength resources

AusNet suggested the PADR explore a more dispersed portfolio of system strength solutions that supports generation connections in renewable energy zones (REZs) as generation in the Latrobe Valley is reduced. It suggested a more dispersed portfolio of solutions has a greater ability to uplift hosting capacity in Victorian REZs, which have strong developer interest particularly after the completion of committed transmission projects, as well as better resolution of issues from undertaking planned outages by more evenly distributing system strength across the Victorian network[78].

Section 2 outlines how the assumptions underpinning the identified need for this RIT-T have been updated since the PSCR, including AVP's decision to use the revised 2025-26 and 2026-27 IBR forecasts.

While sensitivities to the 2024 *System Strength Report* IBR forecast would provide insights to how the optimal location of services might change under an alternative capacity outlook, doing so would require detailed long-term market modelling, complete option portfolio redevelopment, and additional short-term market modelling. AVP considers this disproportionate to the associated investment risks, particularly given that this RIT-T is a reliability corrective action where AVP's requirements are set based on the *System Strength Report* IBR forecast.

[77] EnergyAustralia, pp. 4-5.

[78] AusNet, p. 2.

AVP will continue to monitor changes in the network and to system strength requirements going forward, including any future knowledge advancements that might result in updated minimum fault level requirements, and will ramp up/down its investment in services to meet requirements in the long-term interests of Victorian consumers.

A5.6 Consider high benefit network reinforcement solutions

AusNet suggested the PADR should consider 'high benefit network reinforcement solutions', such as new transformers and turn-in projects that can be delivered within similar timeframes to non-network solutions. It said its preliminary analysis suggests that these solutions offer a wider range of market and essential system service benefits during both system normal and post-contingency conditions compared to non-network alternatives[79].

In developing the option portfolios, AVP considered the merits of network reinforcement solutions as alternatives to, or in addition to, the solutions forming the identified option portfolios. However, it was found that the proposed network reinforcements proposed would predominantly provide system strength support during prior outage conditions, the benefits of which are expected to be minor compared to the requirement for services under system normal conditions. As such, the solutions that form the option portfolios, which include contracting with existing generators, synchronous condensers and GFM BESS, were found to be more cost-effective options than the network reinforcement solutions identified.

Also, while additional line cut-ins, such as at Haunted Gully and Tarrone that AusNet proposed in its submission, will increase fault levels at these locations, AVP does not have a minimum fault level requirement at these locations, and the PADR assessment demonstrated that the efficient level requirements are more economically met by contracting committed or anticipated GFM BESS proximal to the connecting IBR, than by investing in higher capital cost solutions. The committed cut-in of the Haunted Gully to Tarrone line to the 500 kV terminal station at Mortlake will also improve the coupling to nearby system strength sources.

A5.7 Real-time data and broader issues in procuring system strength

EnergyAustralia saw a need for AEMO and jurisdictional planners to publish real-time data on system strength, and purpose-designed and quality-controlled models that allow participants to evaluate their portfolio assets' impact on system strength nodes across a range of operating conditions and scenarios[80]. EnergyAustralia said that the ability of technologies and service providers to satisfy different system needs requires sufficiently granular datasets to understand how the existing mix of resources contributes to inertia, system strength and reactive support in operational timeframes and over different regional and subregional boundaries[81].

EnergyAustralia requested the publication of actual data on system strength relative to forecast requirements to identify the extent of any under- or over-procurement[82].

[79] AusNet, p. 2.

[80] EnergyAustralia, p. 2.

[81] EnergyAustralia, p. 2.

[82] EnergyAustralia, p. 2.

AVP considers that publication of data to assist service providers in providing system strength on a real-time basis is outside the scope of this RIT-T (which is looking at the planning horizon procurement of system strength services, as opposed to the real-time delivery of system strength).

A5.8 Engage with other SSSPs for consistent approach

EnergyAustralia urged AVP to engage with other SSSPs to develop a consistent and transparent approach to dealing with system needs under changing market and regulatory frameworks[83].

AVP has worked closely with the SSSP Working Group, which is comprised of the parties undertaking (or to undertake) the system strength RIT-Ts and AEMO and the AER, over the course of 2023 and 2024. This has greatly benefited the approaches taken by each party to their respective RIT-Ts.

[83] EnergyAustralia, p. 1.

Abbreviations

Abbreviation	Term	Abbreviation	Term
AACE	Association for Advancement of Cost Engineering	**NPV**	net present value
AEMC	Australian Energy Market Commission	**NSCAS**	network support and control ancillary services
AEMO	Australian Energy Market Operator	**ODP**	optimal development path
AER	Australian Energy Regulator	**PACR**	Project Assessment Conclusions Report
AFL	available fault level	**PADR**	Project Assessment Draft Report
AVP	AEMO Victorian Planning	**PEC**	Project EnergyConnect
BESS	battery energy storage system/s	**POE**	probability of exceedance
CDP	candidate development path	**PSCR**	Project Specification Consultation Report
CPI	Consumer Price Index	**QRET**	Queensland Renewable Energy Target
DSP	demand side participation	**REZ**	renewable energy zone
EIR	Energy Infrastructure Roadmap	**RFI**	request for information
EMT	electromagnetic transient	**RIT-T**	Regulatory Investment Test for Transmission
ESOO	*Electricity Statement of Opportunities*	**RMS**	root mean square
FCAS	frequency control ancillary services	**SCR**	short circuit ratio
FOM	fixed operations and maintenance	**SRAS**	system restart ancillary services
GFL	grid-following	**SSIAG**	System Strength Impact Assessment Guidelines
GFM	grid-forming	**SSMR**	System Strength Mitigation Requirement
GW	gigawatt/s	**SSN**	system strength node
GWh	gigawatt hour/s	**SSRM**	System Strength Requirements Methodology
IASR	*Inputs, Assumptions and Scenarios Report*	**SSSP**	System Strength Service Provider
IBR	inverter-based resource/s	**ST**	short-term
ISF	Improving Security Frameworks	**syncon**	synchronous condenser
ISP	*Integrated System Plan*	**TCD**	Transmission Cost Database
KESS	Koorangie Battery Energy Storage System	**TNSP**	transmission network service provider
kV	kilovolt/s	**TRET**	Tasmanian Renewable Energy Target
MCC	material change in circumstances	**VAPR**	*Victorian Annual Planning Report*
MVA	megavolt ampere/s	**VCR**	Value of Customer Reliability
MVAr	megavolt ampere/s reactive	**VER**	Value of Emissions Reduction
MW	megawatt/s	**VNI West**	Victoria – New South Wales Interconnector West
MWh	megawatt hour/s	**VOM**	variable operations and maintenance
NEM	National Electricity Market	**VRET**	Victorian Renewable Energy Target
NEO	National Electricity Objective	**WACC**	weighted average cost of capital
NER	National Electricity Rules	**WRL**	Western Renewables Link